ON THE ROAD TO NET ZERO

POWERING A GREEN FUTURE: A FORECAST TO 2030 FOR SOLAR, WIND, AND ENERGY STORAGE

InfoLink
CONSULTING

WHITE PAPER
JUNE 2023

A WORD FROM THE CHIEF ANALYST

The 21st Session of the Conference of the Parties (COP21) passed the Paris Agreement in 2015, which agreed to "limit the increase in global average temperature to well below 2°C above pre-industrial levels, and pursue efforts to limit the temperature increase to 1.5°C." However, the Intergovernmental Panel on Climate Change (IPCC) announced in its 2021 report that the 1.5°C limit is to be surpassed by 2030, sounding a major alarm on the issue of climate change.

In view of this, countries around the world have intensified climate action efforts, making the period from 2020 to 2022 a crucial time for global progress toward achieving net zero carbon emissions. In September 2020, during the United Nations General Assembly, Chinese President Xi Jinping announced China's plan to achieve carbon neutrality by 2060. Additionally, the U.S. re-entered the Paris Agreement, whilst the COP26 introduced the new Glasgow Climate Pact, recognizing the urgency to significantly reduce carbon emissions within the coming decade and for the first time included the commitment to "phase down unabated coal power" in the final text, marking the end of the fossil fuel era.

Major energy-consuming countries mostly planned to achieve net-zero carbon emissions between 2050 and 2060. Most countries have also established milestones to review their progress between 2030 and 2040. Meanwhile, the costs of solar and wind power were finally reduced to levels that rival traditional energy sources. Additionally, the post-pandemic economy, international disputes, and energy shortages propelled the rapid growth of renewable energy in 2022. This phenomenon not only highlights the imperative of energy storage, with which the integration of grid-parity solar and wind power will lead the world to a net-zero future.

As a leading research institution in the field of renewable energy, InfoLink Consulting strives to establish and deepen information to provide a clearer view of the current pace and landscape of energy transition. By comparing the costs of renewable and traditional energy sources, as well as analyzing government targets and the renewable energy industry, we aim to assist the energy sector in discerning trends and seizing opportunities to hop on the bandwagon of energy transition.

Corrine Lin

Chairperson and Chief Analyst

InfoLink
CONSULTING

InfoLink

CONSULTING

InfoLink Consulting is a world-leading renewable energy research and consulting firm. From market research to data analytics, consulting, and net-zero solutions, InfoLink offers a comprehensive suite of services tailored to meet the unique needs of each client, empowering them to make informed decisions, optimize operations, and achieve their strategic goals. With a dedication to providing real-time, research-based information and a commitment to building long-term relationships, InfoLink continues to earn the trust and confidence of industry leaders as an indispensable partner to navigate the complexity of today's rapidly evolving business landscape.

service@infolink-group.com

MARKET REPORTS

PV

- Supply Chain Cost Structure Report
- Price Forecast Report
- Supply Chain Utilization Rate Report
- Monthly Note Report
- Supply and Demand Database Report
- New Technology Market Report

ESS

- Global Lithium-ion Battery Supply Chain & Trend Report
- Solar-plus-storage Global Market Report
- Taiwan Energy Storage Market Report

DataFactory — SOLAR SUPPLY AND DEMAND DATABASE

Real-time industry information:
Keep you up to date with the latest market trends and give you a head start on key news.

Various analysis functions:
The dashboard reduces the time you need to compile data across files and enables data filtering, sorting, and aggregation for manufacturing capacity comparisons or competitor analysis, etc.

Data and image export:
Export data to Excel and charts to images for business purposes with one click.

Analyst note:
Get instant access to analysts' views before the release of regular reports.

SOLUTIONS

PV competitor analysis
Gain a strategic advantage with InfoLink's PV competitor analysis solution, encompassing supply-demand modeling, short-term, mid-term, and long-term price forecasts, technology and product-wise competitor analysis, and comprehensive competitive benchmarking.

PV cost reduction consultation
Achieve significant cost savings and increased profitability with cost structure analysis, benchmarking with industry leaders, cost-benefit analysis, and tailored cost optimization strategies.

B2B clean electricity matchmaking
Unlock new business opportunities and foster sustainable partnerships in the renewable energy sector with customized clean energy solutions, analysis of renewable energy PPA prices, electricity market competitiveness analysis, and efficient matchmaking services.

CONTENT

PREFACE

How much more renewable energy does the world need to install by 2050?

Based on the goals of the Paris Agreement and factoring in growing energy demand worldwide, InfoLink calculates the required increase in installed renewable energy capacity by 2050 in two scenarios: "limiting the temperature increase to well below 2°C above pre-industrial levels" and "pursuing efforts to limit the increase to 1.5°C." Additionally, InfoLink examines whether the world can keep global warming to the agreed target or even lower temperatures, based on the current forecast of installed renewable energy capacity.

With sustained economic development, global energy demand continues to rise. InfoLink's calculation, based on an assumed annual compound growth rate of 2.5% in global electricity demand from 2019 (26,937 TWh), indicates that electricity demand will reach 35,343 TWh by 2030 and 57,914 TWh by 2050. However, statistics show that in 2019, renewable energy sources only generated 9,928 TWh of electricity worldwide. Meeting the additional electricity demand while achieving emission reduction goals still requires significant improvements and advancements in renewable energy capacity.

To limit global warming below 2°C and 1.5°C by 2030, the deadline for most countries to attain their goals, the world needs to reduce 88.8 billion metric tonnes and 207.6 billion metric tonnes of CO2 equivalent, respectively. Currently, power generation accounts for approximately 30% of total carbon emissions. By installing renewable energy sources, the maximum potential reduction in CO2 emissions would be 26.6 billion and 62.2 billion metric tonnes under the two scenarios. Taking into account the larger proportion of solar energy, wind power, and other renewable energy sources, calculations indicate that in order to meet the carbon reduction targets of 2°C and 1.5°C, the world must cumulate 6,887 GW and 3,409 GW of renewable energy capacity by 2030, respectively.

Based on current progress, InfoLink estimates the world to cumulate 9,145 GW of renewable energy by 2030, achieving the emission reduction targets of the power generation industry. If a higher emission reduction target, such as temperature control within 1°C, is desired, a cumulative installed capacity of 10,959 GW of renewable energy would be required by 2030. The current pace of progress suggests that there is still room for improvement.

Levelized cost of electricity of traditional energy sources

Currently, coal and natural gas are the dominant conventional energy sources used internationally. However, as the world march towards energy transition, the more pollutive coal-fired power plants have been scheduled for elimination by many countries. While natural gas can serve as a transitional alternative before renewable energy takes hold, there have been no major technological breakthroughs in this regard, and cost reductions have not been significant.

However, in addition to financial costs influenced by technological and economic factors, the current traditional energy sources face significant fluctuations in generation costs primarily due to the volatility of fuel costs. Both natural gas and coal are commodities, and their prices are affected by various factors. Firstly, the sufficiency of resources varies among markets. For example, the U.S. has abundant natural resources, resulting in significantly lower prices for coal and natural gas compared to other regions. On the other hand, Europe and China rely on gas imports, leading to higher and more volatile prices. Other factors such as international politics, economics, and oil prices also contribute to fluctuations in the prices of coal and natural gas, consequently affecting the costs of coal and natural gas power generation.

In 2020, global demand for commodities weakened due to the Covid-19 pandemic, leading to significant declines in natural gas and coal prices. However, as governments eased restrictions and lifted lockdown measures, demand rebounded, driving up prices of natural gas and coal along with bulk commodities. In 2022, the conflict between Ukraine and Russia significantly reduced Russia's natural gas supply to Europe. Europe shifted to importing natural gas overseas, increased electricity supply from other sources, and ceases purchasing Russian coal under international sanctions. This led to the cessation of coal purchases from Russia. As a result, factors have caused a sharp increase in the prices of natural gas and coal. According to ICE Futures Europe, coal prices increased by nearly fivefold, while European natural gas prices rose by more than tenfold. As fuel costs soared, the cost of generating electricity from traditional sources spiked.

With the growing environmental awareness, governments have imposed carbon taxes in recent years, building up the operating costs of power plants using traditional energy sources with high greenhouse gas emissions, such as coal and natural gas. While showing a clear stance on imposing carbon taxes on traditional energy sources, countries have also offered free allowances to companies considering the speed of their energy transition and the profitability of their businesses. Currently, the EU is the most aggressive in implementing a carbon tax – Carbon Border Adjustment Mechanism (CBAM), but the actual impact of the CBAM on the operating costs of power plants is expected to increase from 2027 onwards due to the provision of free allowances. On the other hand, other countries that have yet to implement a national carbon tax are expected to impose related taxes in the future to avoid trade barriers created by the CBAM. In addition to fluctuations in commodity prices due to economic factors, such as coal and natural gas, traditional energy sources will face another hike in generation costs from carbon taxes around 2027. To achieve actual carbon reduction, the government will gradually increase the rate of carbon tax, leading to higher costs of electricity generation from traditional sources.

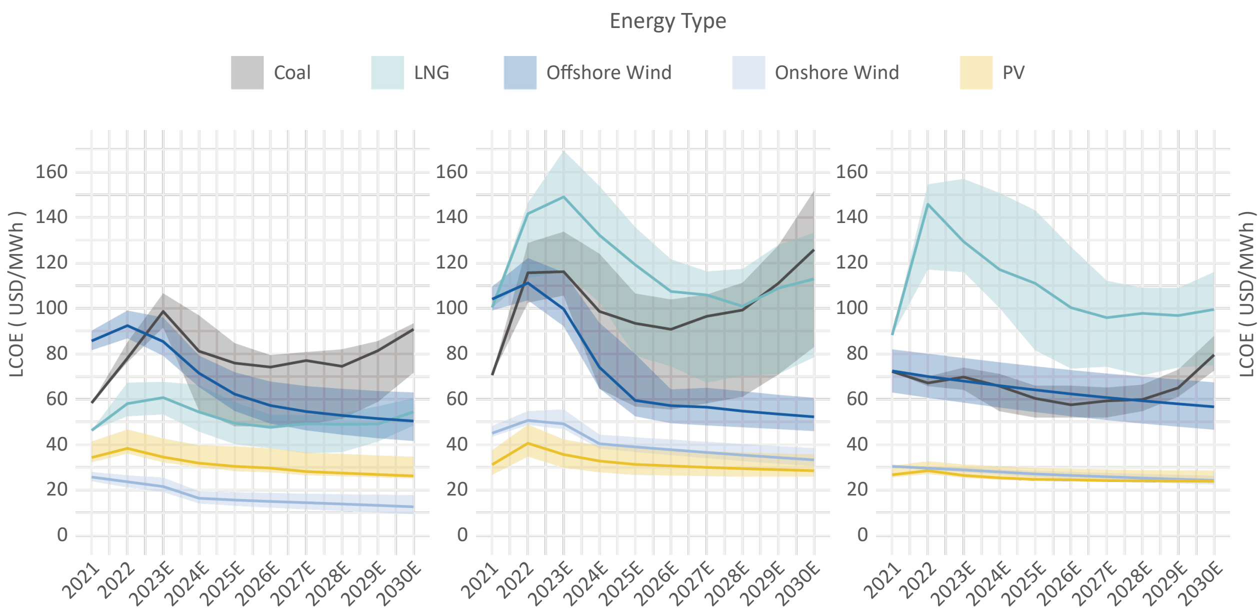


Figure 0-1.
LCOE trends of energy sources in the U.S.

Figure 0-2.
LCOE trends of energy sources in EU + the U.K.

Figure 0-3.
LCOE trends of energy sources in China

Carbon tax calculation method:

InfoLink's carbon tax estimation is based on the assumption that coal generates 0.82 kilograms of CO2 equivalent per kilowatt-hour (kgCO2e/kWh) of electricity produced before 2025, while natural gas generates 0.49 kgCO2e/kWh. From 2026 onwards, coal is estimated to produce 0.74 kgCO2e/kWh, and natural gas is estimated to produce 0.41 kgCO2e/kWh of electricity.

As the Chinese government aims to reach carbon peak by 2030, the carbon price trend forecast takes into account the need to avoid trade barriers caused by carbon taxes, as well as targets set out in the Paris Agreement and inflation. The carbon price baseline is aligned with listed trades on China's carbon trading market.

The U.S. carbon tax forecast is based on the goal of reducing emissions by 50% by 2030 compared to 2005 levels. Due to the absence of a national carbon trading market in the U.S., the rate of the carbon tax is based on existing carbon pricing in California, with inflation factored in.

The EU has been the most aggressive in promoting carbon taxes, aiming to reduce emissions by 40% compared to 1990 levels by 2030. The relationship between carbon emissions and carbon pricing is estimated based on historical data, as well as inflationary considerations.

Due to limitations in technological development, fluctuations in commodity prices, carbon taxes, and various other unfavorable factors, traditional energy sources see little room for future cost reduction. On the other hand, renewable energy sources continue to benefit from technological advancements, scaling up operations, and government incentives, leading to a sustained decrease in generation costs. At present, each region has seen the costs of power generation of solar power and onshore wind power being lower than those of traditional energy sources. The generation cost of offshore wind power is expected to be lower than that of traditional energy sources, with the gap widening further, highlighting the cost advantage of renewable energy.

In the following sections, InfoLink focuses on China, the U.S., Europe (EU and the U.K.), providing an overview of renewable energy installation targets and actual progress, supply-demand dynamics in the supply chain, the decline in LCOE, and the impact of the Inflation Reduction Act of the U.S.

This white paper examines three major aspects: solar, wind, and energy storage, shedding light on the progress of renewable energy development:

- Despite surging commodity prices and supply chain costs in 2022, the LCOE of solar remains notably lower than that of traditional energy sources in the three markets. Solar power has become the most-installed renewable energy, and its annual installation rate continues to rise.
- Wind power still has room for cost reduction due to ongoing technological advancements, particularly in the development of offshore wind power, which has seen accelerated growth in recent years.
- With the rapid expansion of cell production capacity by companies in recent years, global cell supply and demand will reach a balance after 2025. This will further drive down the cost of energy storage. Rapidly increasing installed solar and wind capacity will ramp up the development of energy storage.

DISCLAIMER

The data in this white paper are taken from InfoLink's database, engagements with industry professionals through various communication channels such as face-to-face meetings and phone interviews. It also includes data collected from financial reports, public records, and government publications. Our utmost priority has been to ensure the comprehensiveness and integrity of the information presented.

The information provided in this white paper is intended solely for reference purposes. Neither InfoLink nor its employees, data providers, affiliated enterprises, nor any other third parties make any explicit or implied guarantees regarding the accuracy, reliability, or suitability of the content within. InfoLink assumes no liability or obligation for any consequences arising from the utilization of the information contained in this white paper.

The usage of names and representations of materials in this context is purely illustrative and shall not be construed as expressing any opinions or endorsements by InfoLink concerning the legal status, boundaries, or demarcation of any country, region, territory, or city.

01 PV

CH1 PV CHAPTER HIGHLIGHTS

DEMAND

Capitalizing on this trend, global PV market added 250 GW of new capacity in 2022, bringing the cumulative installed capacity to 1 TW. By 2030, the world will add 1 TW of solar capacity annually, reaching a cumulative installed capacity of 6 TW.

In 2022, China connected 87 GW of PV capacity to the grid, a 58% increase on 2021's 32 GW. In 2023, as module prices decline, the previously postponed utility-scale projects are likely to reinitiate, pushing up demand. China could cumulate 150 GW of installed PV capacity in 2023.

Europe is expected to add 64 GW of installed capacity in 2023, a 38% year-on-year increase. The growth will continue, reaching nearly 100 GW of annual capacity addition by 2030.

The Withhold Release Order (WRO) and the Uyghur Forced Labor Prevention Act (UFLPA) even require manufacturers to provide certifications for non-Xinjiang quartz sand. The U.S.' ban on Xinjiang-made polysilicon strangles local supply. As a result, short-term demand will remain mild despite the market's robust growth.

SUPPLY CHAIN

Had been hitting decade highs during 2021 and the first quarter of 2023 amid short supply, polysilicon prices started to decline amid production expansions in 2023. In the second half of the year, upstream prices will drop faster as production capacity rises.

Wafer format is the key to cost reduction over recent years. 182mm and 210mm will coexist as the mainstream formats for a considerable period and not be replaced by newer, larger formats in the near future.

With rapid production expansion, TOPCon is likely to replace PERC as the mainstream cell technology, enabling n-type cells to outperform p-type cells in market share in 2024. In 2030, as TOPCon and HJT gradually near efficiency limits, perovskite-integrated technology will be ready for mass production. The market is expected to see small volumes of perovskite and perovskite-silicon tandem cells emerge in the market from 2027 onwards.

Global crystalline module production capacity was the smallest among the four sectors in 2022 as professional module makers earned little profit under pressures from upstream sectors. With ongoing capacity expansion, global module capacity is expected to exceed 1,400 GW by the end of 2030.

LCOE

Modules alone hold the largest share of hardware costs, ranging from 30% to 50%, depending on the region. Therefore, reducing module costs will significantly affect the LCOE.

China: In 2022, the PV LCOE is estimated to be USD 28.57/MWh (RMB 205.40/MWh), an increase compared to USD 26.77/MWh in 2021.

The U.S.: Calculated based on an ITC rate of 26.0%, the PV LCOE in the U.S. rose from USD 34.36/MWh in 2021 to USD 38.38/MWh in 2022, given price hikes across the supply chain and rising commodity prices.

Europe (EU and the U.K.): In 2022, having no escape from the cross-supply chain price hikes, Europe saw average module prices increase to USD 0.311/W. Against this backdrop, the LCOE in 2021 was USD 31.22/MWh, and USD 37.11/MWh in 2022.

1.1 PV DEMAND

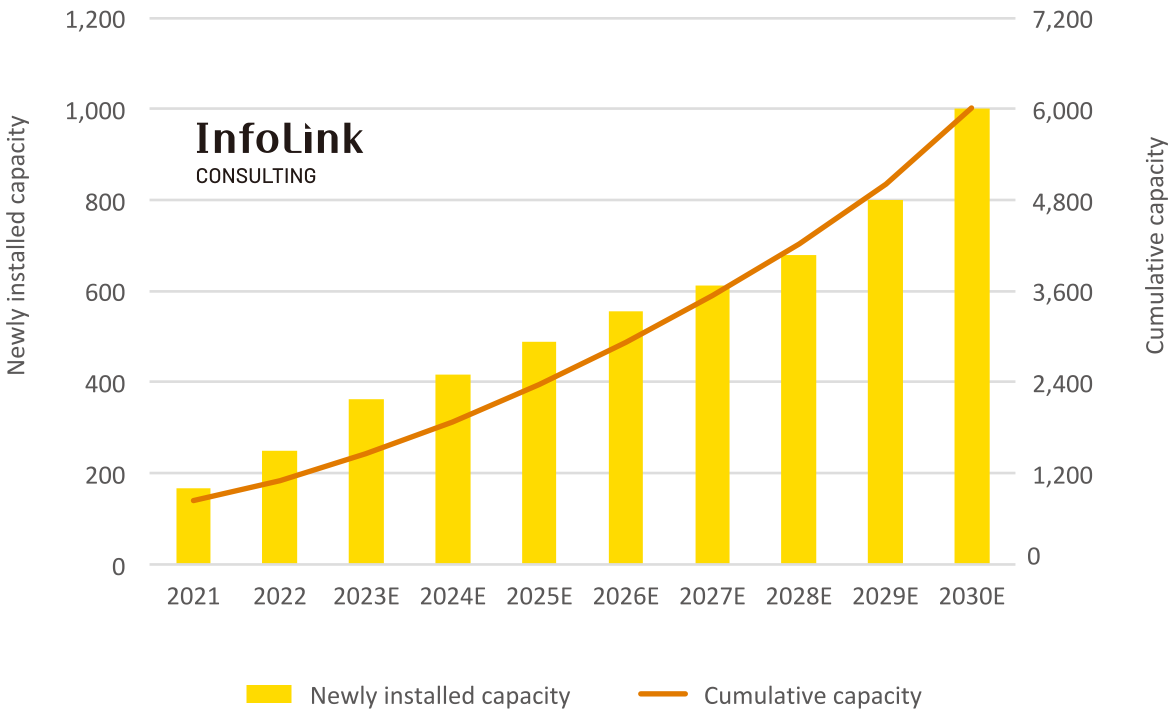


Figure 1.1-1. Global PV Installation, Unit: GW

In 2022, the Russia-Ukraine conflicts spurred global efforts towards energy independence to wean itself off energy supply from one single country. Meantime, a global shortage of natural gas sent electricity prices to surge, notably in Europe, underscoring the pressing demand for energy transition.

Capitalizing on this trend, global PV market added 250 GW of new capacity in 2022, bringing the cumulative installed capacity to 1 TW, with regional markets exhibiting steady growths every year. By 2030, the world will add 1 TW of solar capacity annually, reaching a cumulative installed capacity of 6 TW.

Regional markets: China, the U.S., Europe (EU and the U.K.)

China

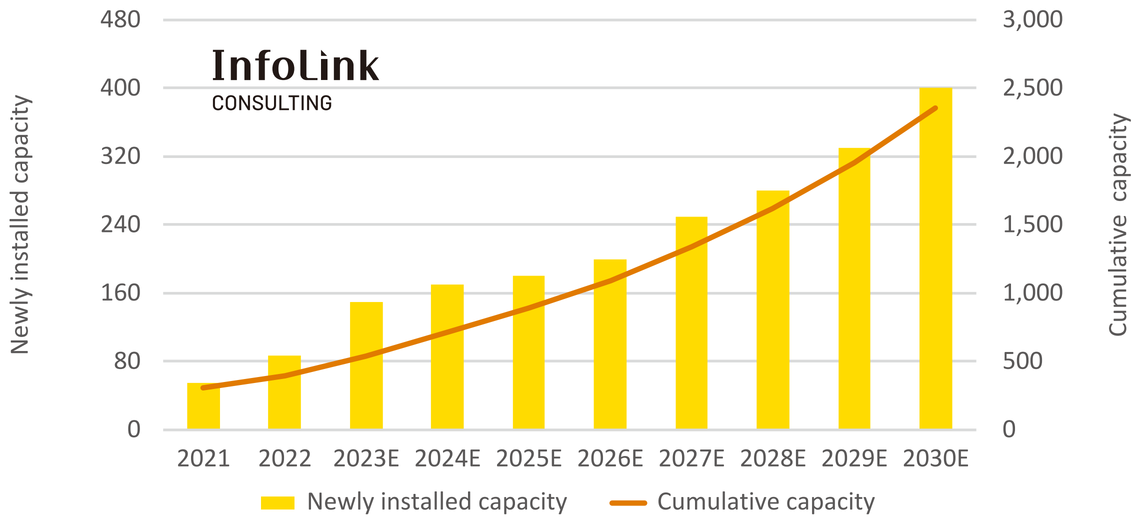


Figure 1.1-2. China PV installation, Unit: GW

China sees solar capacity increasing rapidly. The nation added 53 GW in 2021, a 10% year-on-year increase. Distributed generation projects accounted for 55% of total additions, hitting a milestone of overtaking the share of utility-scale one for the very first time. Distributed generation projects will keep expanding, becoming the major driving force behind the development of Chinese PV industry. As of the end of 2021, China has 306 GW of PV capacity connected to the grid.

In 2022, China connected 87 GW of PV capacity to the grid, a 58% increase on 2021's 32 GW. Subject to lofty prices across the supply chain, distributed generation projects underpinned demand during the first three quarters. The fourth quarter was expected to see an installation rush due to lower supply chain prices, module makers vying for market share and ranking, and the traditional high season. However, prices stay elevated. As a result, installation was not as active as expected, with 34.8 GW added to the grid. Utility-scale projects account for merely 36.3 GW of the addition in 2022, while residential and C&I projects saw an increase to 25.2 GW and 25.9 GW, respectively. Distributed generation projects represent 58% of the total addition. **In 2023, as module prices decline, the previously postponed utility-scale projects are likely to reinitiate, pushing up demand. China could cumulate 150 GW of installed PV capacity in 2023.**

Long been a major driving force behind the rapid growth of the global PV market, China is committed to the ambitious goals of achieving carbon peak by 2030 and carbon neutrality by 2060. In 2021, solar energy reached grid parity in China. The nation aims for 20% of its electricity consumption to be met by renewable energy by 2025, 25% by 2030, and 1,200 GW of cumulative wind and solar capacity. **InfoLink projects China to reach 893 GW of cumulative installed PV capacity and 474 GW of installed wind capacity by 2025, attaining the 1,200 GW target ahead of schedule by 2025.** China sustains the strong development through specific measures, such as the province-wide promotion, the grid-connection guarantee scheme, and the 450-GW of utility-scale wind and solar projects in the desert. The market is expected to grow every year. In 2030, China is expected to reach 400 GW of new capacity additions per year, retaining its dominance as largest PV market of the world.

The U.S.

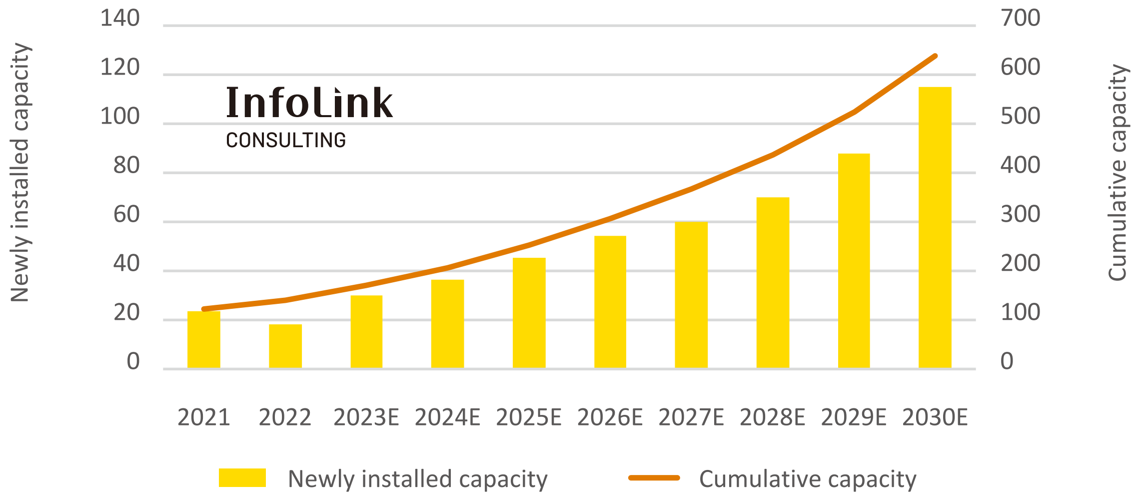


Figure 1.1-3. US PV installation, Unit: GW

At first, the U.S. relied on low-priced, high-cost-effective products from China. However, as trade war between the two escalates, the U.S. launches tariff barriers, such as anti-dumping duty, countervailing duties, Section 201, and the Section 301, to protect local enterprises. Consequently, Chinese imports to the US decrease, giving the US manufacturers a slim chance of survival. Yet, Chinese manufacturers act promptly, setting up factories in Southeast Asia to evade US tariffs. The U.S. retaliates by initiating anti-circumvention investigation on Chinese-funded manufacturers in Southeast Asia.

Currently, despite the two-year exemption of anti-circumvention tariffs on Southeast Asia, the U.S. market still relies on products from this region to fill the untapped demand. However, the local market still faces severe shortages, as many Southeast Asian modules are detained at the customs due to the Withhold Release Order (WRO) and the Uyghur Forced Labor Prevention Act (UFLPA) activated in mid-June last year. The two legislations even require manufacturers to provide certifications for non-Xinjiang quartz sand. The U.S.' ban on Xinjiang-made polysilicon strangles local supply. **As a result, short-term demand will remain mild despite the market's robust growth.**

In the third quarter of 2022, the Inflation Reduction Act (IRA) brought a new lease of life to the US PV market. The IRA allocates $369 billion to renewable energy and relevant industries, aiming to reduce greenhouse gas emissions by 40% below 2005 levels. To boost long-term PV demand, the IRA extends and increases the rate of investment tax credit (ITC) of the Build Back Better Plan, whilst providing production tax credit (PTC). The IRA also offers subsidies for the local supply chain. **Many manufacturers assess actively the feasibility of setting up production plants in the U.S.**

However, subject to the UFLPA, the U.S. will continue facing severe shortage in the short term. In 2022, the nation added merely 20 GW of PV capacity due to Xinjiang issues and price fluctuations across the supply chain. While high energy costs pushed up installed capacity of distributed generation projects significantly, installed capacity of utility-scale projects declined by 31% to 11.8 GW compared with 2021. In 2023, manufacturers will be better prepared as the U.S. Customs and Border Protection (CBP) will release more data and detailed measures of customs enforcement. **In the second half of this year, the US PV market will recover, as supply chain prices lose ground, and the U.S. customs loosens regulations, allowing installations of ground-mounted projects to pick up. Annual PV installation will return to 30 GW to 40 GW in 2023. The increase will continue driven by the IRA. By 2030, the US market is expected to see 115 GW of installed PV capacity per year.**

Europe (EU and the U.K.)

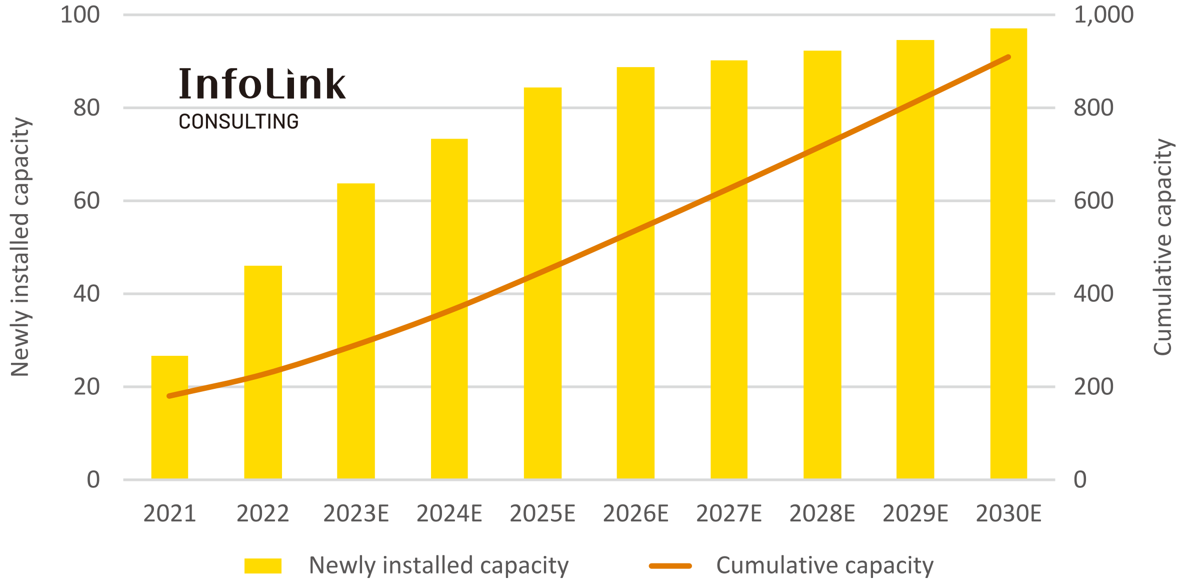


Figure 1.1-4. EU + UK PV installation, Unit: GW

Europe faced a surge in natural gas prices in 2022, which accelerated the installation of PV and energy storage systems. EU member states and the U.K. together saw demand increasing by 45 GW, cumulating 226 GW of installed PV capacity.

Demand for renewables surged as natural gas prices soared in Europe amid the Russia-Ukraine conflicts. In the first half of 2022, the EU rolled out plans for the PV industry, such as REPowerEU, EU Solar Energy Strategy, European Solar Rooftops Initiative, and European Solar Initiative. On Sept. 13, 2022, the European Parliament passed the Renewable Energy Directive (REDII) to extend the REPowerEU plan. The EU aims to achieve a cumulative installed solar capacity of 320 GW by 2025 and 600 GW by 2030, with 45% of the energy coming from renewable sources. With individual countries such as Germany and France raising their renewable energy targets, the future of the European PV market looks promising.

For the short term, numerous challenges lie ahead of European markets. European Parliament resolution of June 9, 2022 bans products made with forced labor from entering EU member countries. Later, the European Commission on Sept. 14, 2022 released a draft proposal banning goods made with forced labor. The law will take two years to be fully implemented, but its impact on the highly import-dependent European PV market could be considerable.

In 2022, labor shortage and unstable IGBT chip supply for inverters disrupted installations. In the long run, the European market still has a promising future with strong demand and high price acceptance. **The market is expected to add 64 GW of installed capacity in 2023, a 38% year-on-year increase. The growth will continue, reaching nearly 100 GW of annual capacity addition by 2030.**

Echoing the IRA of the U.S., the EU proposed the Green Deal Industrial Plan earlier this year, allocating EUR 250 billion to attain the REPowerEU targets. To streamline regulations and enhance predictability, the EU also proposed the Net Zero Industry Act and the Critical Raw Material Act in March, mandating that 40% of EU demand must be met by local manufacturing capacity (PV included) and encouraging diversification of raw material sources. Since these bills are still in the proposal stage and will undergo modifications and deliberations, the actual passage may be one to two years away.

Major European markets:

Germany

In June 2022, the German Federal Cabinet approved the Easter Package plan based on the proposal of Robert Habeck, Vice Chancellor and Federal Minister for Economic Affairs and Climate Protection. The plan has been submitted to the German Federal Parliament and will enter the legislative process after review. The Easter Package is wide-ranging, amending various energy laws to accelerate the expansion of renewable energy.

The Easter Package consists of:
Renewable Energy Sources Act (RES Act, or EEG)
Offshore Wind Energy Act
Energy Industry Act
Federal Requirements Plan Act
Grid Expansion Acceleration Act (NABEG)

The Federal Ministry for Economic Affairs and Climate Action, abbreviated BMWK, aims to cumulate 75 GW of installed PV capacity in 2023, **meaning to add 9 GW within the year, then add 13 GW by 2024, 18 GW by 2025, and 22 GW during 2026 and 2030, bringing the cumulative installed PV capacity to 215 GW.**

The European Commission approved Germany's EUR 28 billion new renewable energy development plan in December 2022. The plan aims to increase tender capacity and address insufficient project subscriptions, underscoring Germany's strong support for solar energy. In the future, there will be more incentives, boosting the German PV market to attain the country's installation goals.

Spain

Spain is characterized by vigorous utility-scale projects and PPAs. Most projects are ground-mounted ones, but distributed generation projects have some potentials. In 2022, high electricity prices pushed up demand for distributed generation projects. Presently, projects are yet to be constructed, but complex and inconsistent application regulations keep most projects pending for approval. In 2023, as price declines across the supply chain, these projects may yield progress. With increasing demand, Spain will remain one of the major markets in Europe.

France

Despite a lack of progress in ground-mounted projects due to high supply chain prices and land access difficulties, the French residential market continues to grow following the authorities' decision to increase the cap capacity for FIT subsidy from 100 kW to 500 kW in 2020. France is targeting 20.1 GW of cumulative installed capacity by 2023, and 35.1 GW to 44 GW by 2028. To achieve this, the country needs to add 3.8 GW in 2023.

The Netherlands

The Netherlands added 3.9 GW of PV capacity in 2022, a mild growth from 2021's 3.8 GW. Due to land limitations, the Netherlands mainly focuses on rooftop projects. As one of the early movers to develop solar energy, the Netherlands is a mature market. Therefore, future growth may be limited, despite the government's effort to encourage residential installations by exempting value-added tax on private PV systems.

Poland

Poland launched the "My Electricity (Mój Prąd)" program in 2019, successfully stimulating the installation of residential projects. In 2022, Poland's PV demand reached 4.5 GW, making it the third largest source of demand in Europe. Last year, Poland not only increased the subsidies under the Mój Prąd 4.0 program but extended the application deadline for projects under the program from the end of December 2022 to March 2023. In 2023, Poland's module demand is expected to increase to 6.5 GW. With its potential for further development, the outlook for Poland's PV industry is optimistic.

The U.K.

Despite supply chain prices pushing up installation costs, the PV industry in the U.K. thrives amid energy crisis. In 2022, the U.K. added 680 MW of PV capacity, with distributed generation projects accounting for 60%. For now, solar energy has reached grid parity in the country. Demand is projected to reach 1.2 GW in 2023 and continue to grow annually. By 2030, the U.K. may add 3.6 GW of solar capacity per year.

1.2 PV SUPPLY CHAIN

In demonstration of their determination to achieve net zero, countries across the globe set targets to be attained between 2050 and 2060. Doubled with electricity price hikes amid the Russia-Ukraine conflicts, the world ramps up its progress of energy independence and diversification, giving rise to a faster-than-expected increase in demand for renewable energy.

Vertically, the PV supply chain comprises polysilicon, wafer, cell, module sectors, and system developers downstream. As PV demand increases annually, manufacturers expand production and investments to meet installation demand and secure dominance in the market. Meantime, high gross profits and relatively low barriers to entry attract many newcomers to the industry.

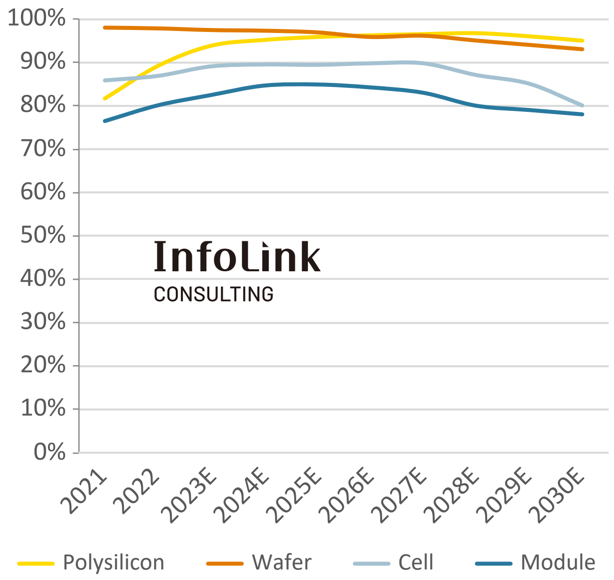


Figure 1.2-1.
Share of Chinese capacity in the world by sector

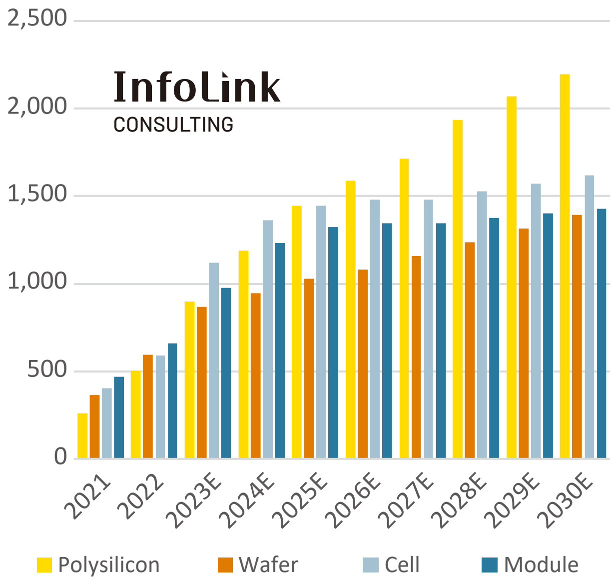


Figure 1.2-2.
Capacity forecast for each sector for 2022-2030, Unit: GW

China is home to over 90% of the production capacity of polysilicon and wafers, as these require stable and cheap electricity supply. Cell and module production, on the other hand, has been relocated to Southeast Asia since 2012, due to trade wars with the U.S. and India. In the long run, China's share of production capacity in each sector across the supply chain will continue to decline gradually, given ongoing trade wars and domestic manufacturing incentives.

The PV industry is bullish, with manufacturers expanding production capacity to meet current and future market demand for long-term installation targets. Below are expected changes in the main sectors of the supply chain.

Polysilicon sector

Polysilicon production belongs to the chemical engineering industry. Due to its high temperature, high energy consumption, and highly risky characteristics, regular maintenance is required to ensure the safe operation of the facilities. With surging PV demand and rapid production expansions downstream, **the polysilicon sector became the bottleneck of the entire industry chain during 2021 and 2022.**

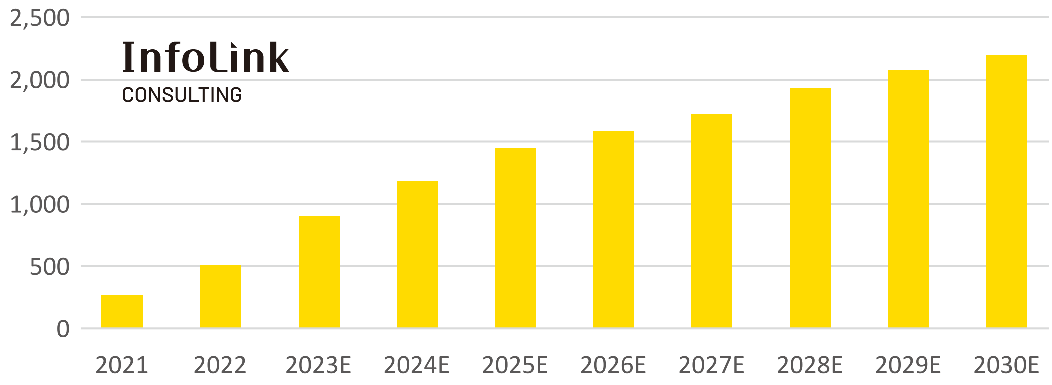


Figure 1.2-3. Polysilicon capacity forecast for 2021-2030, Unit: GW

As of the end of 2022, annual polysilicon production capacity reached 1,241,300 MT (507 GW), a 72% annual growth. The high growth rate will sustain at 75% in 2023, the highest over the past decade. The strong growth of production capacity will result in excess supply. By the end of 2030, the annualized production capacity is expected to reach 4,831,148 MT (over 2,000 GW), quadrupling that of 2022.

Had been hitting decade highs during 2021 and the first quarter of 2023 amid short supply, polysilicon prices started to decline amid production expansions in 2023. In the second half of the year, upstream prices will drop faster as production capacity rises.

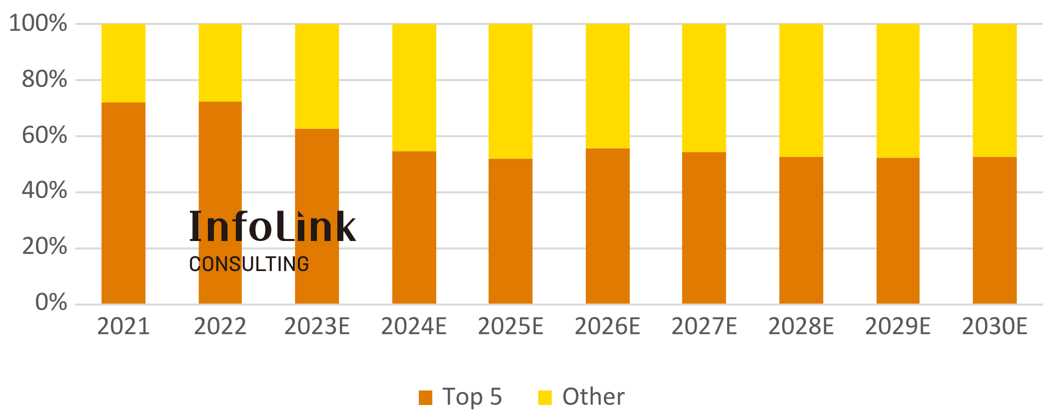


Figure 1.2-4. Market share of top 5 polysilicon manufacturers

In the polysilicon sector, the top 5 manufacturers[1] dominate the expansion and commissioning of production capacity. By the end of 2022, the top 5 together cumulated 898,000 MT (367 GW) of production capacity, accounting for a market share of nearly 72%. As the manufacturing process of polysilicon has matured, leading enterprises, with excellent cost control ability, will be more advantaged in future price competition. Newcomers have slim chance to overtake leading manufacturers through technological innovation. Yet, high profits during 2021 and 2023 attract many new entrants, which drive down market share of the top 5 to 65% to 70% after new capacities came online. In the long run, market share of the top 5 will rebound slightly when polysilicon becomes the most surplus sector in the supply chain.

As cell manufacturing technology iterates, manufacturers shift towards expanding n-type technology due to the cost reduction bottleneck approaching p-type technology. However, n-type technology requires higher purity of polysilicon, making it crucial for polysilicon manufacturers to maintain quality production.

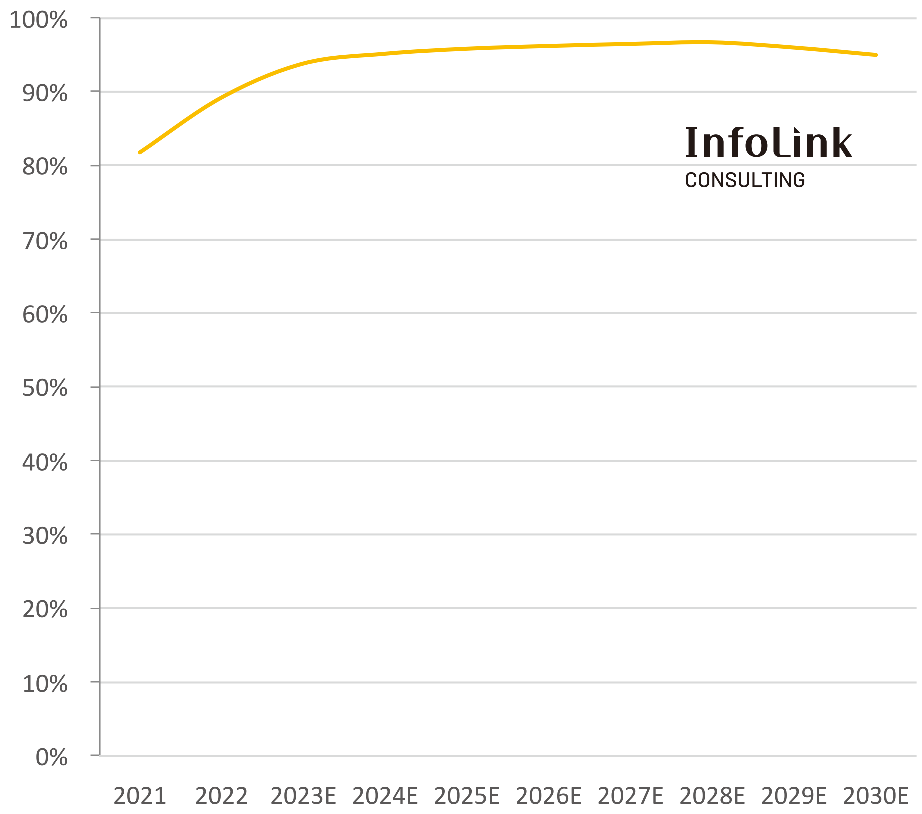


Figure 1.2-5. Share of China polysilicon capacity in the world

For now, polysilicon manufacturers locate plants in China for the massive amount of electricity required for production. China has extremely cheap electricity from fossil fuel power generation in Xinjiang and Inner Mongolia and hydroelectric power in Yunnan and Sichuan. These regions are the most favored for polysilicon manufacturers to set up factories.

As part of the U.S.-China trade war, the U.S. placed sanctions on products produced in Xinjiang on the ground of human rights issues, requiring manufacturers to provide documents certifying the origin of their products, ranging from cell and modules to polysilicon, even quartz sand. Other markets, including Europe, Canada, Mexico, Germany, Norway, etc., followed suit.

[1] Top 5 manufacturers include Tongwei's unit of Yongxiang, GCL, Daqo, TBEA, and East Hope.

Against this backdrop, polysilicon has been classified into "Xinjiang" and "non-Xinjiang" polysilicon. As of the end of 2022, there are 355,000 MT (145 GW) of polysilicon production capacity in Xinjiang, accounting for 32% of the total production capacity in China and 29% of the global market share. Due to the Xinjiang issue, future expansions will take place outside of the disputed region. The market share of non-Xinjiang polysilicon will rise, and that of Xinjiang-made polysilicon will drop to 21% by the end of 2030.

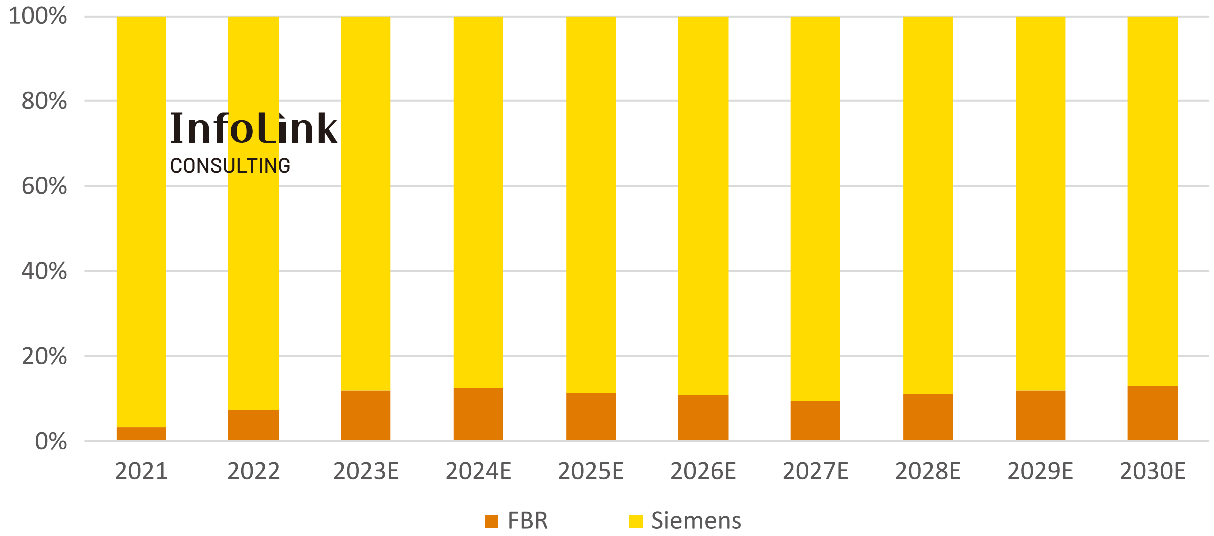


Figure 1.2-6. Market share of the Siemens process and the FBR process

The few non-China polysilicon manufacturers include Wacker in Germany and the U.S., OCI in Malaysia, Hemlock, and REC in the U.S., whose production costs are much higher compared to Chinese manufacturers. Non-China manufacturers can export polysilicon freely into Xinjiang. The use of clean electricity, such as hydroelectricity, allows them to obtain higher low-carbon footprint scores. **In the future, with growing demand in the U.S. and the ongoing Xinjiang issue, the price gap between Xinjiang and non-Xinjiang polysilicon will widen.**

There are two polysilicon manufacturing processes, the modified Siemens process and the fluidized bed reactor (FBR) process, with fundamental differences. The modified Siemens process produces silicon rods, which must be crushed into silicon chunks and recycled polysilicon scrap. The FBR process produces granular polysilicon, which can be used directly to pull mono-Si ingot.

The Siemens process is a mature technology with lower production risks, despite its high temperature requirement and energy consumption. The Siemens process, which produces polysilicon of better quality than electronic-grade polysilicon, is currently the most widely adopted manufacturing process.

The FBR process produces granular polysilicon, which remains merely an alternative to polysilicon since the process is relatively dangerous due to its use of silane. With lower temperature requirement, granular polysilicon is an optimal raw material for making low-carbon footprint products. As of the end of 2022, global granular polysilicon capacity reached 160,000 MT, accounting for 13% of total polysilicon capacity and 7% of total shipments in the world. Actual growth hinges on the development of leading granular polysilicon manufacturers.

Wafer sector

During 2016 and 2020, mono-Si wafers replaced multi-Si ones as the mainstream product. The market share of multi-Si wafers decreased to merely 3% in 2021 and 1% in 2022. Therefore, the discussion here will focus on mono-Si wafers.

Due to the delicate and complex nature of ingot growing process in mono-Si wafer manufacturing, the process is highly vulnerable to earthquakes and power outages. Earthquakes disrupt power supply and damage crucibles, making wafer factories among the first victims of the natural disaster over the years.

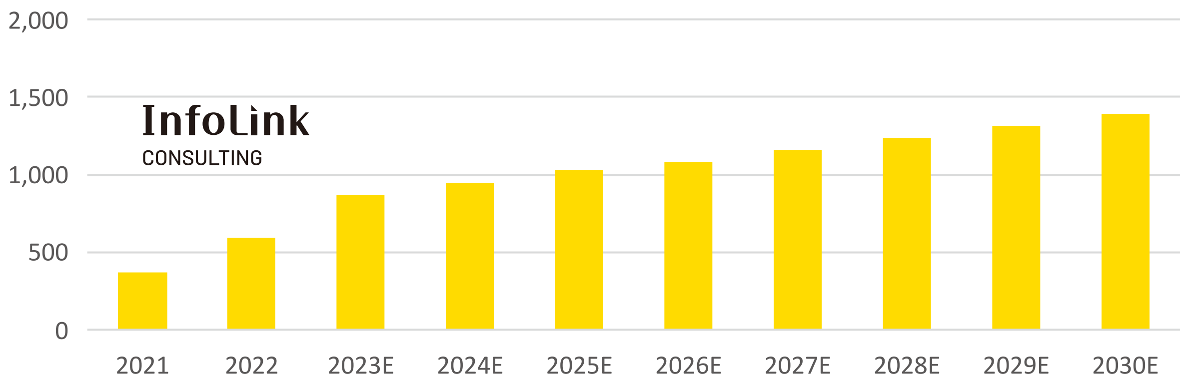


Figure 1.2-7. Wafer capacity forecast for 2021-2030, Unit: GW

The stable high profits of the wafer sector and vertically integrated manufacturers' active control over product formats gave rise to rapid production expansion during 2021 and 2022. As of the end of 2022, the annual wafer production capacity was nearly 600 GW, with an impressive annual growth rate of 62%. The release of huge new production capacities increased the demand for polysilicon and greatly affected its price trend in 2022. In 2023, the expansion of wafer production slows down due to the large production capacity in 2022, with an annual growth rate of around 46%. The annual production capacity is expected to reach nearly 1,400 GW in 2030.

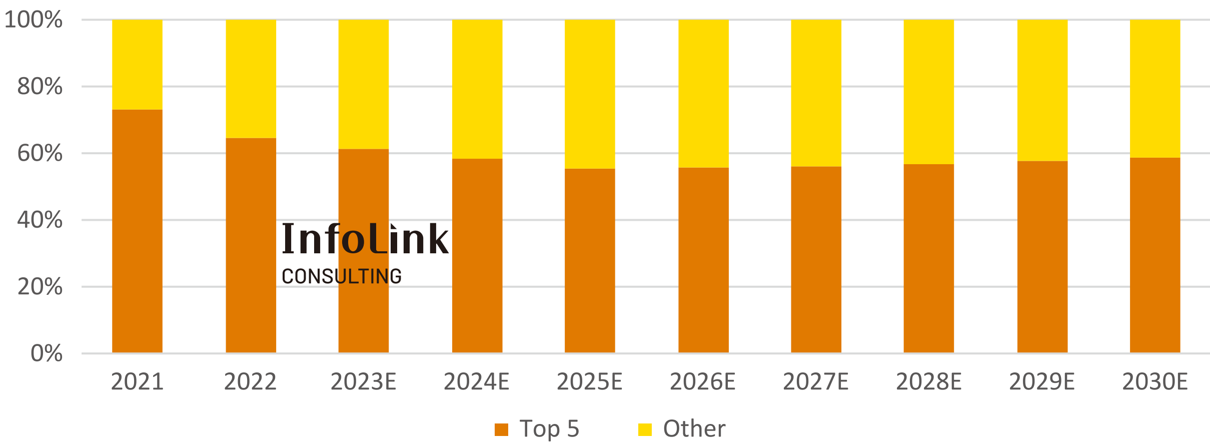


Figure 1.2-8. Market share of top 5 wafer manufacturers

In addition to existing vertically integrated manufacturers, such as GCL, Longi, and Zhonghuan, more and more professional wafer manufacturers have cross-sector production capacity from wafer to module in recent years. Vertical integration allows manufacturers to organize production plans and formats across the supply chain, enjoy lower production costs, create their own outlets, as well as mitigate the risk of external changes through self-sufficiency in times of short-term supply and demand mismatches. As of the end of 2022, the top 5 manufacturers[2] had 385 GW of annualized production capacity, accounting for 65% of market share. The percentage will slightly decrease as both vertically integrated and professional cell manufacturers plan to expand wafer production capacity.

Currently, China dominates the wafer sector with its cost advantage. As of 2022, China's annualized wafer production capacity reached 583 GW, representing up to 98% of the global capacity. Other production areas include Malaysia, Vietnam, Taiwan, and Europe. Some manufacturers are also considering setting up factories in the U.S. because of the government's incentive for domestic manufacturing, which deserves close attention in recent years. By the end of 2030, the global production capacity is projected to increase to nearly 1,400 GW, with China taking almost 95% of the global capacity, remaining the main source of raw materials for all PV markets.

The recent technological trend revolves around enlarging wafers and thinning them down. Meantime, n-type wafers will see a rapid increase in the share of production output between 2023 and 2025.

The cost per unit of large-format wafers is lower due to their bigger surface per unit, which in turn reduces the cost of cells and modules, improving LCOE. Hence, the wafer format has been shifting rapidly, from M2 (156.75mm), G1 (158.75mm), M4 (161.7mm), M6 (166mm) to the current M10 (182mm) and G12 (210mm). The change in format helps reduce production cost and increase module output, contributing to better LCOE performance. **Therefore, wafer format is the key to cost reduction over recent years.**

As the mainstream format changes, the cost advantage of large wafers became prominent in all sectors. In 2022, large wafers constituted over 80% of the total production as manufacturers raised the production proportion of M10 and G12. The M6 format saw a spiraling decline, taking up only 12% of the market share as of 2022. M10 became the mainstream format and held 63% of total module output, while the G12 format reached a market share of approximately 23%. Lately, vertically integrated manufacturers develop special formats to achieve higher module efficiency, such as G12R (210*182mm) rectangular wafers. InfoLink predicts that by the end of 2030, M10 will remain the mainstream format, accounting for 60% of the market share.

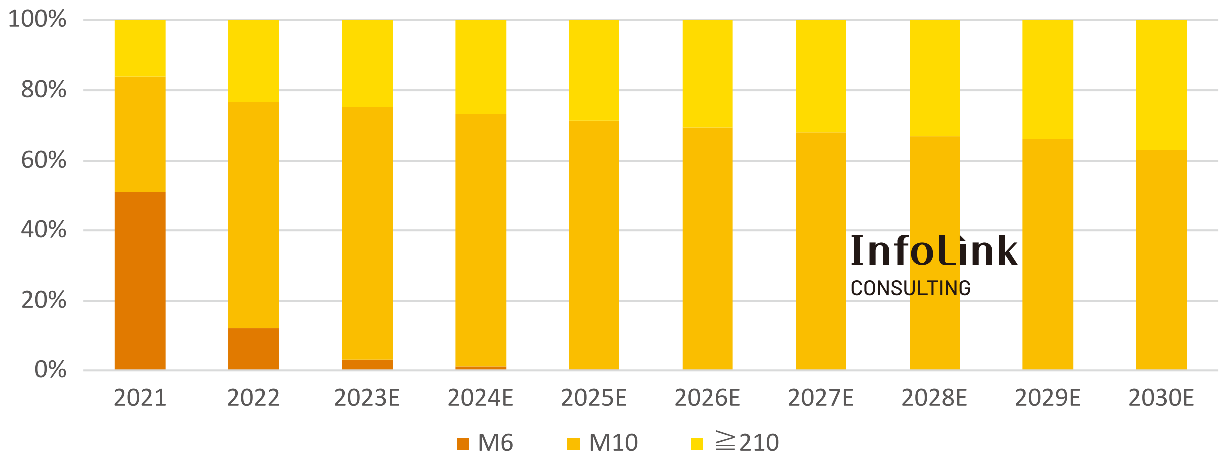


Figure 1.2-9. Market share of wafer formats

[2] The top 5 wafer manufacturers were Longi, Zhonghuan, Jinko, JA Solar, and Wuxi Shangji Automation (now HOYUAN Green Energy).

Most cell, module, and equipment manufacturers have production capacity for 220mm and 230mm wafers with backward compatibility to prepare for the future development of larger formats. 182mm and 210mm will coexist as the mainstream formats for a considerable period and not be replaced by newer, larger formats in the near future.

In terms of thickness, thinner wafers reduce polysilicon cost during wafer production significantly. Given high polysilicon prices, there is a breakthrough in mainstream thickness in 2022 and 2023. **The mainstream thickness of p-type M10 wafers dropped from 170μm in 2021 to 160-155μm in 2022, then 150μm in 2023.** The mainstream diameter of diamond wire core wires is 33-36μm. The A-grade rate of the M10 format lies between 92% and 97%. Meantime, **n-type wafer manufacturers reduce thickness more actively due to cost pressure. The mainstream thickness of n-type wafer dropped from 160-170μm in 2021 to 150-160μm in 2022, approaching 130μm in 2023.** In 2024, after polysilicon prices fall back to a more reasonable level, wafer thickness will stabilize again at 150μm for p-type wafers and 120-130μm for n-type ones.

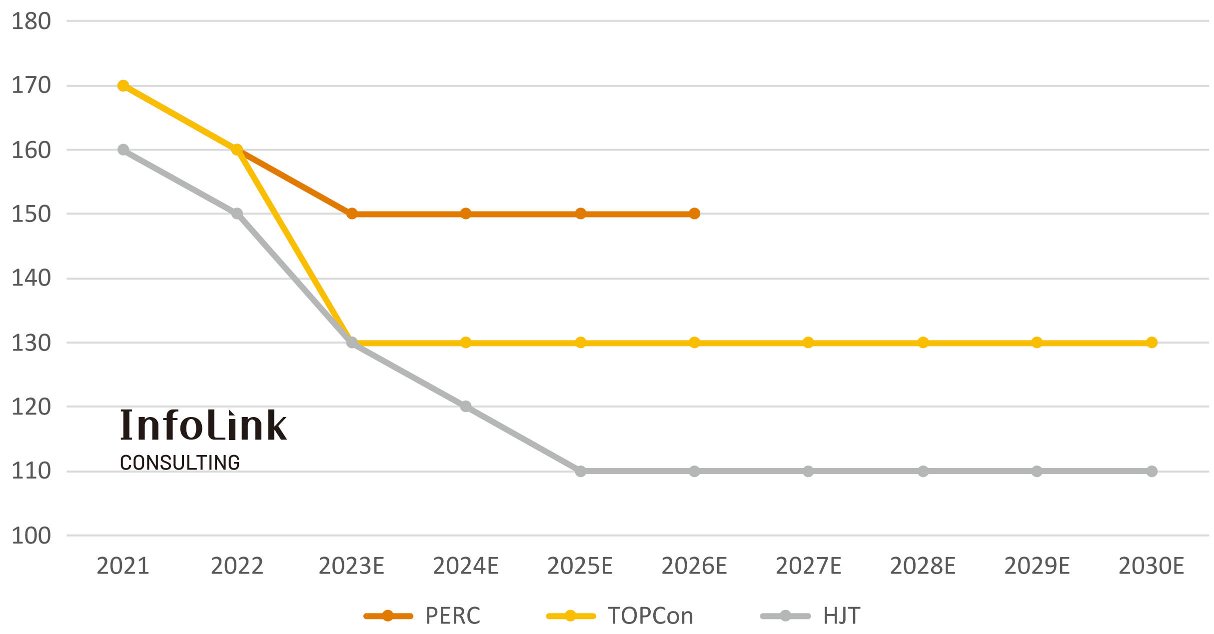


Figure 1.2-10. Wafer thickness trend, Unit: μm

Wafer manufacturers are also complementing on replacing conventional diamond wires with tungsten diamond wires to pare down the wire gauge because a smaller gauge reduces kerf-loss effectively. During a time of higher polysilicon prices, tungsten diamond wire is a better choice, owing to its greater breaking force, despite higher likelihood of wire breakages due to the smaller gauge. Even when prices for regular diamond wires and polysilicon drop, tungsten diamond wires can maintain their competitive edge through price declines and further wire gauge reduction. However, the development and application of thinner wafers hinge on polysilicon prices. If polysilicon manufacturers expand their production substantially, polysilicon prices will decrease over the years, reducing motivation for cost reduction for wafers and slowing down the thinning progress.

Since 2022, the advancement of TOPCon has driven up the market share of n-type wafers from the originally stagnant 3% to 5%. The transition from p-type to n-type hinges on the shift in the cell sector as well as the downstream acceptance. The transition does not require major adjustments so there is no technical challenge along the way. The progress of n-type will be discussed in depth in the following cell section.

Cell sector

Since the cell sector is positioned between the upstream and midstream sectors, and vertically integrated companies have enormous in-house production capacities, cell gross margin experiences less fluctuation than the upstream and downstream sectors.

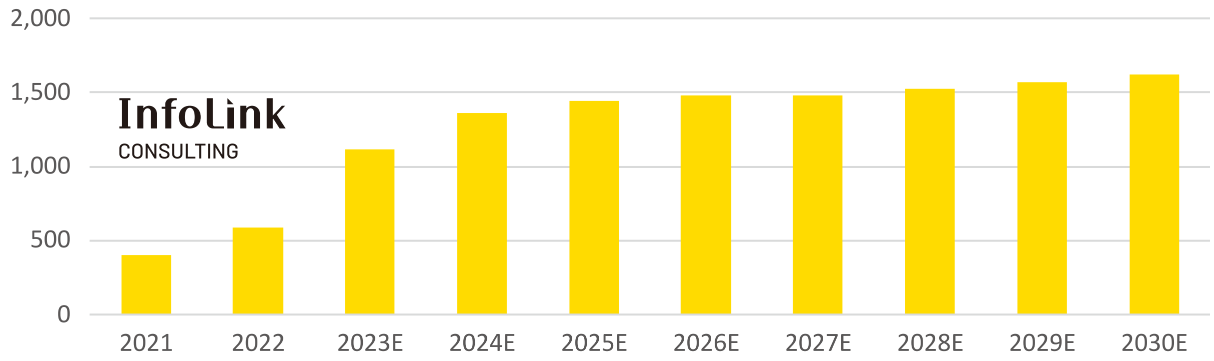


Figure 1.2-11. Cell capacity forecast for 2021-2030, Unit: GW

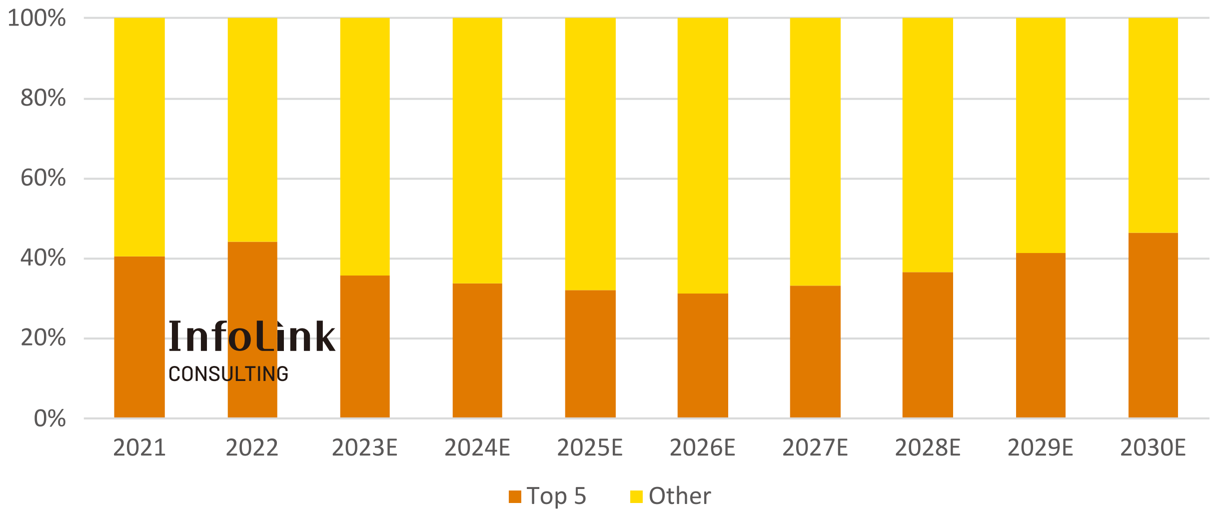


Figure 1.2-12. Market share of the top 5 cell manufacturers

As of the end of 2022, the annual production capacity of cells reached 590 GW, a 46% increase compared to 404 GW in 2021. The ample capacity will increase by over 80% due to another wave of technological advancement during 2023 and 2024. The TOPCon cell capacity will start edging out that of the mainstream PERC products. If proceeding smoothly in 2023 and 2024, the expansion of TOPCon cell capacity will slow down afterward, reaching slightly above 1,600 GW by 2030, a compound annual growth rate of 15%.

After cell giant Tongwei expands business into the module sector, the top 5 cell manufacturers comprise solely vertically integrated companies with module production, which together amass 260 GW of production capacity as of the end of 2022, accounting for 44% of the total capacity. The figure may reach 750 GW by the end of 2030 as the market share of vertically integrated companies increases, and the industry becomes more concentrated.

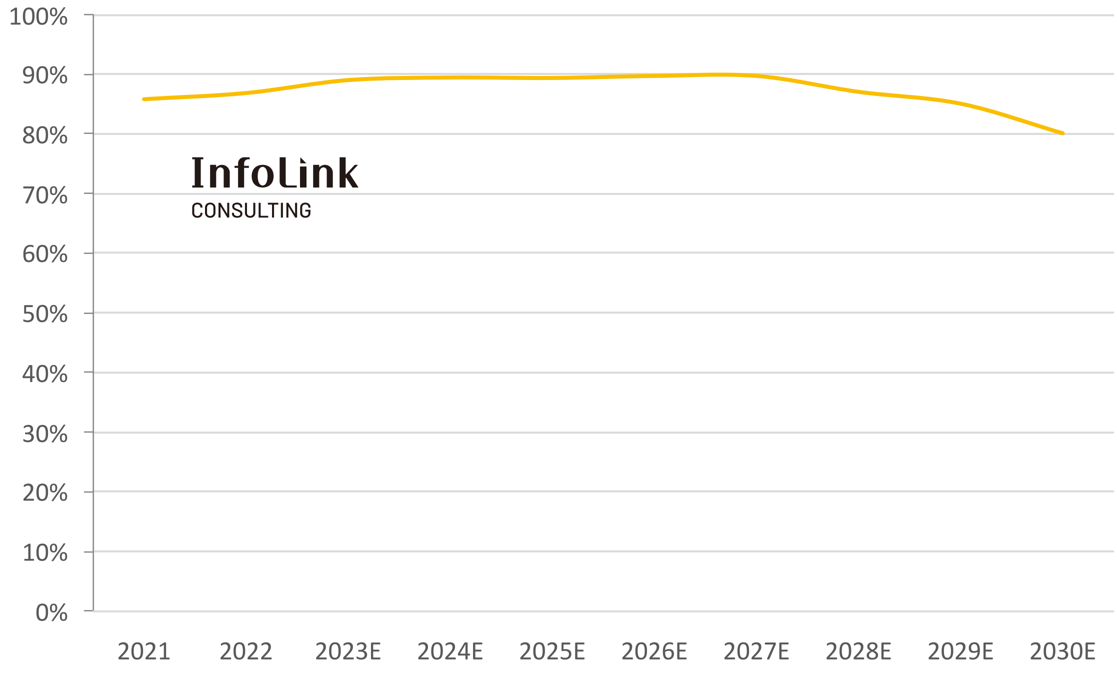


Figure 1.2-13. Share of China cell capacity in the world

The cell sector's barrier to entry is relatively low, compared with the polysilicon and wafer sectors. Combined with its lower share of electricity in production costs and impacts of the previous trade war, cell production is widespread in the Asia-Pacific region and scattered in Europe and the Americas. China continues to possess the largest scale of production. Its cell capacity hit 510 GW as of the end of 2022, taking up 87% of the global total. But the market share is expected to decrease to 80% in 2030 as some regions adopt protectionist policies.

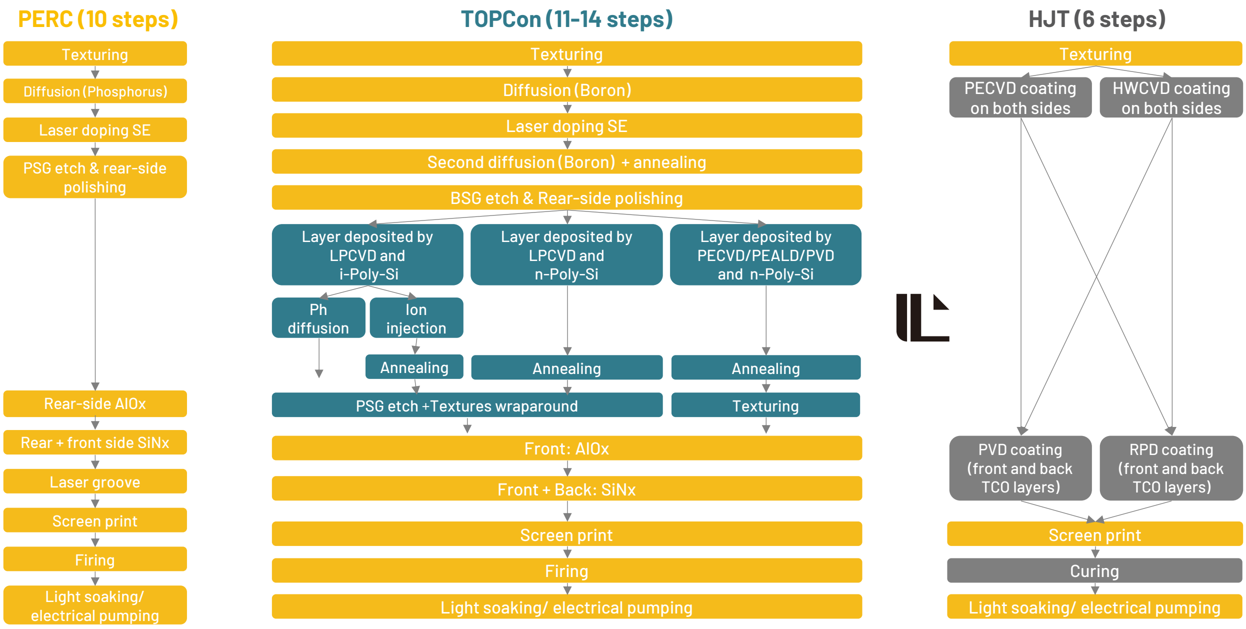


Figure 1.2-14. Comparison of cell process flow

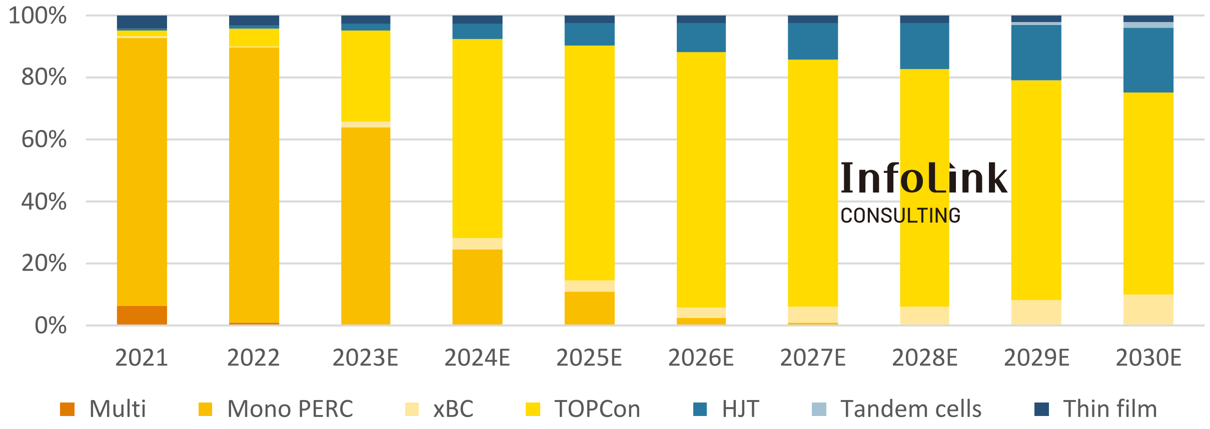


Figure 1.2-15. Share of high-efficiency cell capacity by technology (2021-2030)

The cell sector played a critical role in enhancing power generation performance and conversion efficiency. From multi-Si to mono-Si PERC technology and from p-type to n-type, the cell sector makes every effort to increase conversion efficiency during its R&D and manufacturing process. **As of 2022, mono-Si PERC remained the dominating technology, but the market share of n-type cells boosted from the stagnant 3-5% to 7%, marking the start of their growth. In 2023, the market share of n-type cells is expected to increase rapidly to 30%. The market share of multi-Si cells dropped to 1% in 2022 and may be phased out completely in 2023.**

Cell technologies ready for mass production include n-type TOPCon, HJT and back contact (xBC). As p-type PERC gradually reaches its theoretical maximum efficiency while TOPCon manufacturers have been actively working on cost reduction, the TOPCon technology emerges with high efficiency, relatively mature technology, and production costs nearly as low as that of PERC. In 2023, the industry has shifted from a wait-and-see approach to regarding TOPCon as the next mainstream technology. During 2022 and 2023, the capacity of n-type TOPCon cells is expanding rapidly, increasing to 81 GW as of the end of 2022 from 10 GW in the previous year, and are expected to exceed 400 GW in 2023. The total production is likely to be driven from 20 GW in 2022 to over 120 GW in 2023.

HJT technology is a very simple cell manufacturing process with better temperature coefficient. It has higher theoretical efficiency and bifaciality compared with TOPCon. Besides, it is a low temperature-based process with less carbon footprint, making it a potential hit in the low-carbon market. Nevertheless, its mass production efficiency has yet to surpass that of TOPCon, while production costs remain substantially higher. These factors present challenges in securing orders and, in turn, profitability. To reduce costs, HJT manufacturers must monitor the prices of paste, target materials, and production equipment.

Without busbars in the front, back contact cells eliminate shading losses on the metallic electrode and have better aesthetic appearance. In addition, the structure allows higher efficiency and better cell performance. The IBC technology can be integrated with p-type and n-type TOPCon and HJT technologies, producing HPBC, TBC, and HBC cells. The challenge facing this technology is its complex and expensive manufacturing process, limited ability to produce thin cells, and unsuitability for glass-glass modules. Future development of the IBC technology hinges on achieving expected production costs and yield rates.

With rapid production expansion, TOPCon is likely to replace PERC as the mainstream cell technology, enabling n-type cells to outperform p-type cells in market share in 2024. In 2030, as TOPCon and HJT gradually near efficiency limits, perovskite-integrated technology will be ready for mass production. The market is expected to see small volumes of perovskite and perovskite-silicon tandem cells emerge in the market from 2027 onwards.

Crystalline module sector

Module manufacturing is the last assembly procedure before the final product is sold to end users, which involves the assembly, lamination, and encapsulation of raw materials such as glass, EVA, backsheets, and aluminum frames.

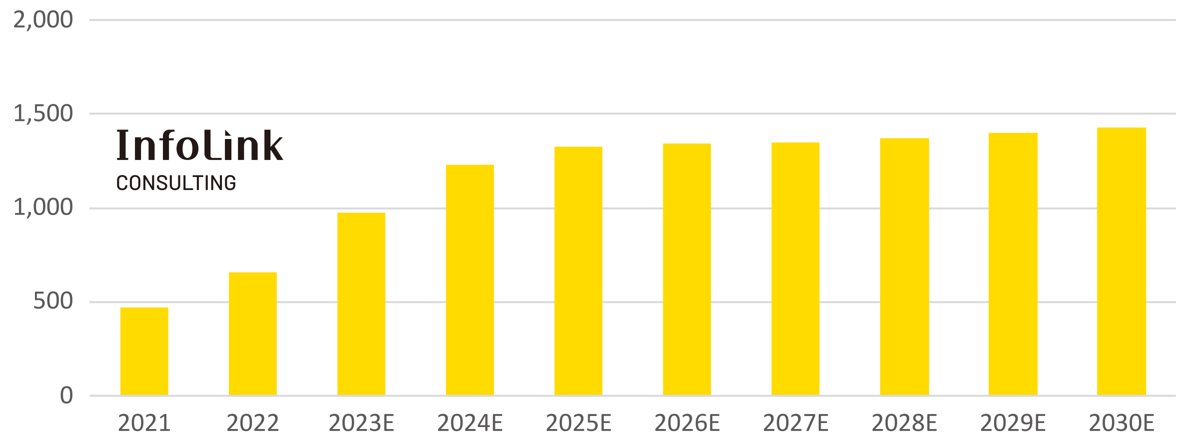


Figure 1.2-16. Module capacity forecast for 2021-2030, Unit: GW

Global crystalline module production capacity reached 660 GW in 2022, an annual increase of 40%, **the smallest among the four sectors despite lower barriers for capacity expansion.** This can be attributed to the fact that the industry had settled on the mainstream technology and format two to three years ago, and **professional module makers earn little profit under pressures from upstream sectors.** With ongoing capacity expansion, global module capacity is expected to exceed 1,400 GW by the end of 2030.

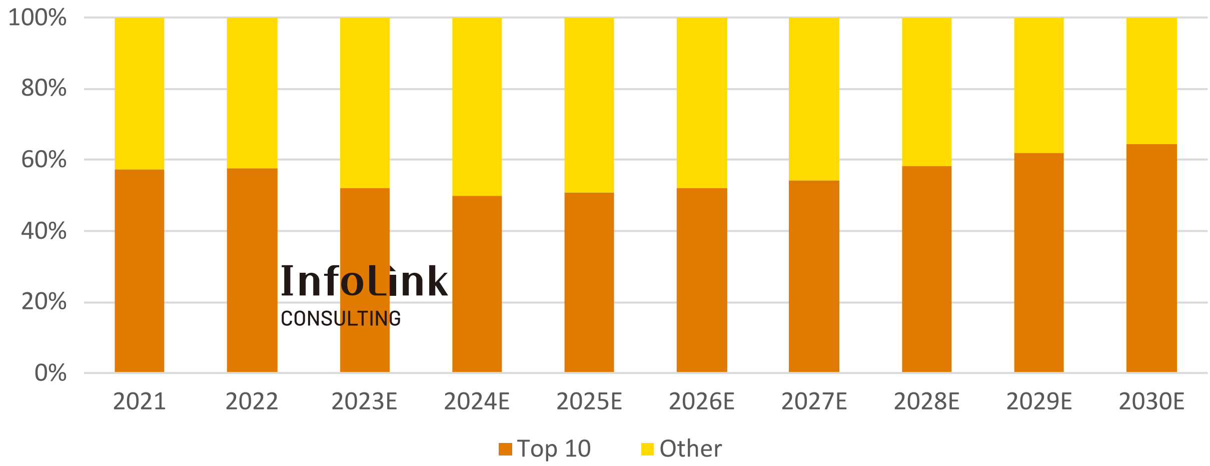


Figure 1.2-17. Market share of top 10 module makers

The top 10 module manufacturers[3] are the top 10 vertically integrated companies with wafer and cell production capacities. **As of 2022, their module production capacity reached 380 GW, accounting for 58% of the total capacity. But shipment volumes of the year suggested the top 10 securing over 85% of market share.** The module sector is up for grabs, with manufacturers focusing on gaining brand recognition and market share, since module is an end product, and the barrier to entry to the module sector is low. As the big stays big, competition will intensify among the top ten in terms of vertical integration and market layout. In 2030, capacity of the top 10 module makers will take up more than 60% of production capacity worldwide.

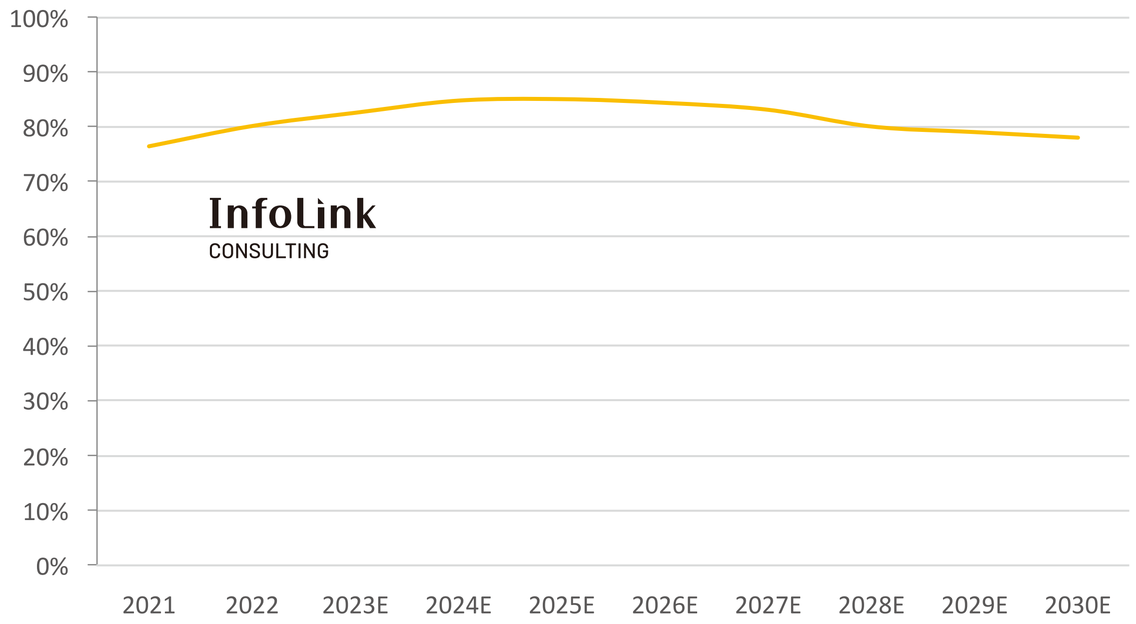


Figure 1.2-18. Share of China module capacity in the world

Module production sites are located across the five major continents, with China housing 528 GW of capacity in 2022, accounting for 80% of the global capacity. The percentage is likely to decrease below 80% by 2030 as the rest of the world introduces incentives to support domestic production.

Manufacturers have been making strenuous efforts to improve module efficiency while adhering to the same cell technology. The industry continues seeking technological breakthroughs for further cost reduction and efficiency improvement.

[3] The top 10 largest crystalline module makers are Longi, Jinko Solar, Trina Solar, JA Solar, Canadian Solar, Risen Energy, Chint Solar, Tongwei, Hanwha Q Cells and Yingli.

1.3 PV LCOE

The energy cost in this chapter refers to the levelized cost of electricity (LCOE), which measures the lifetime cost of a generating asset from project planning to the retirement of the facility and divide it by the total electricity generation to obtain the average cost per kWh.

LCOE formula:

$$\frac{\textit{Capex + Operation and Maintenance (O\&M)}}{\textit{Electrical Energy Generation}}$$

Factors affecting LCOE of PV systems

In addition to costs, the LCOE of a PV system is influenced by the power it generates over its lifetime, which is primarily determined by the sunshine hours of its location. The main influencing parameter in this chapter is the fluctuation of power station costs in the regional market, including hardware, financial, and system maintenance costs in capital expenditures.

The markets being calculated in this chapter are the world's three major PV markets: China, Europe (EU and the U.K.), and the U.S. The generation hours are calculated based on their respective average annual sunshine hours.

The lifespan of a PV power station introduced by mainstream companies is 25 to 30 years. Considering the degradation, the lifespan used in the calculation model in this chapter is 25 years.

Overview

Around 2022, the LCOE of PV systems was on a par with, if not lower than, that of fossil energy sources, such as coal and natural gas in many main regions, thanks to the sharp decline in hardware costs per unit.

In the initial capital expenditure of a PV system, the cost of hardware includes not only modules but also mounting equipment, inverters, and distribution feeders. In addition, there are non-system costs at the beginning of construction, such as land development and various administrative fees, as well as maintenance and operation costs throughout the lifespan of a system.

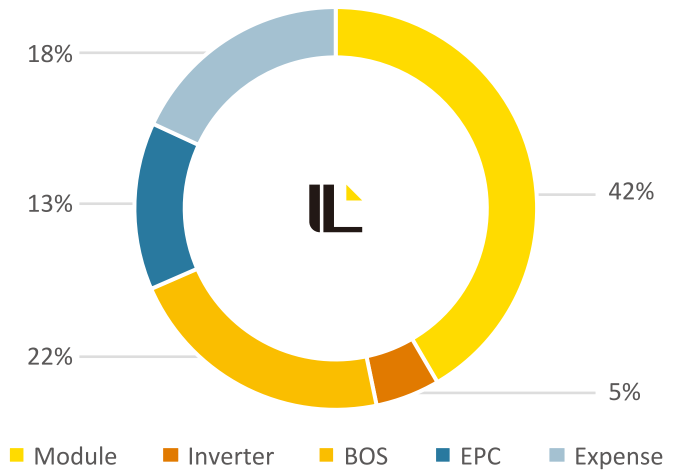


Figure 1.3-1. Average cost structure of PV systems worldwide 2022

Modules alone hold the largest share of hardware costs, ranging from 30% to 50%, depending on the region. Therefore, reducing module costs will significantly affect the LCOE.

Factors that drive costs down

As modules account for a great portion of the total PV system cost, reducing module cost is the key to bringing down LCOE. Currently, the industry focuses on the alteration of wafer format and thickness and cell technology innovation.

Larger wafers entail a larger power generation area of cells, which means higher generation per module and lower LCOE.

Changing wafer thickness involves using thinner diamond wires to produce more wafers with the same amount of silicon crystal ingot, reducing silicon costs in modules. However, changes in thickness can greatly affect the yield rate and cell conversion efficiency, so the changes had been slow until 2021 when polysilicon prices surged. To reduce polysilicon consumption, wafer manufacturers ramped up thinning process. Wafer thickness decreased from 170μm at the end of 2021 to 150μm at the beginning of 2023, and 140μm to 130μm for n-type wafers, significantly reducing the proportion of polysilicon costs.

Another key to effectively reducing the LCOE of the system is the evolution of cell technology. Early multi-Si cells only provide a maximum efficiency of 18.7%. P-type PERC technology, with outstanding cost-performance ratio, had been dominating the market over the past two to three years. After years of advancement, PERC cell efficiency reached 23.0% in early 2023, leaving scant room for further improvement. N-type technology can produce cells with higher cell efficiency. In 2022, after years of R&D efforts, more manufacturers start producing high-efficiency cells, such as TOPCon (efficiency of 24.2% to 24.9%) and HJT (efficiency of 24.3% to 25%), at large scale. N-type cells are superior in many aspects, such as a long lifespan, low light-induced degradation rate, small capture cross section, better weak light performance, better temperature coefficient, and high bifacial ratio.

With these advantages, n-type cells have higher theoretical efficiency. However, it was more expensive due to production costs and yield rates. Larger-scale production did not begin until 2022. 2023 finally ushers in another technological revolution. TOPCon stands out among n-type technologies with notable cost reduction, yield rate improvement, and efficiency enhancement. The efficiency is expected to see a yearly increase as the technology evolves, contributing to further reduction of PV power generation cost.

LCOE of major PV markets

With hardware costs declining rapidly, the LCOE of PV systems is on par with and even lower than that of fossil energy sources, such as coal and natural gas, in many parts of the world. There are two aspects of factors that affect the future trend of PV LCOE in major markets: supportive policies on the demand side and material price fluctuations on the supply side.

Supportive policies on the demand side include installation subsidies and tax incentives, which can effectively reduce purchase costs and tax expenses for end users. Subsidies may be provided by the central or local governments. One example of larger-scale incentives is the IRA, which was passed in the U.S. in August 2022.

On the supply side, China takes up more than 85.0% of global production capacity in polysilicon, wafer, cell, and module sectors, whilst being the biggest BOM manufacturing country. Therefore, China and international trade barriers wield much influence over global PV supply.

As mentioned, modules account for 30% to 50% of PV power station costs, with silicon being the major contributor. Thus, module prices are significantly subject to fluctuations in polysilicon prices.

Among rapid expansions across a PV supply chain, polysilicon capacity expansions are much slower due to the nature of the chemical industry. As a result, upstream and downstream capacities experienced a serious mismatch during the second half of 2020 and 2022. Polysilicon prices had been surging since the second half of 2020 – mono-grade polysilicon prices skyrocketed from USD 6.7/kg (RMB 59/kg) in June 2020 to USD 43.1/kg (RMB 300-303/kg) in August 2022, remaining high until the fourth quarter of 2022, when new production capacity of polysilicon started to come online.

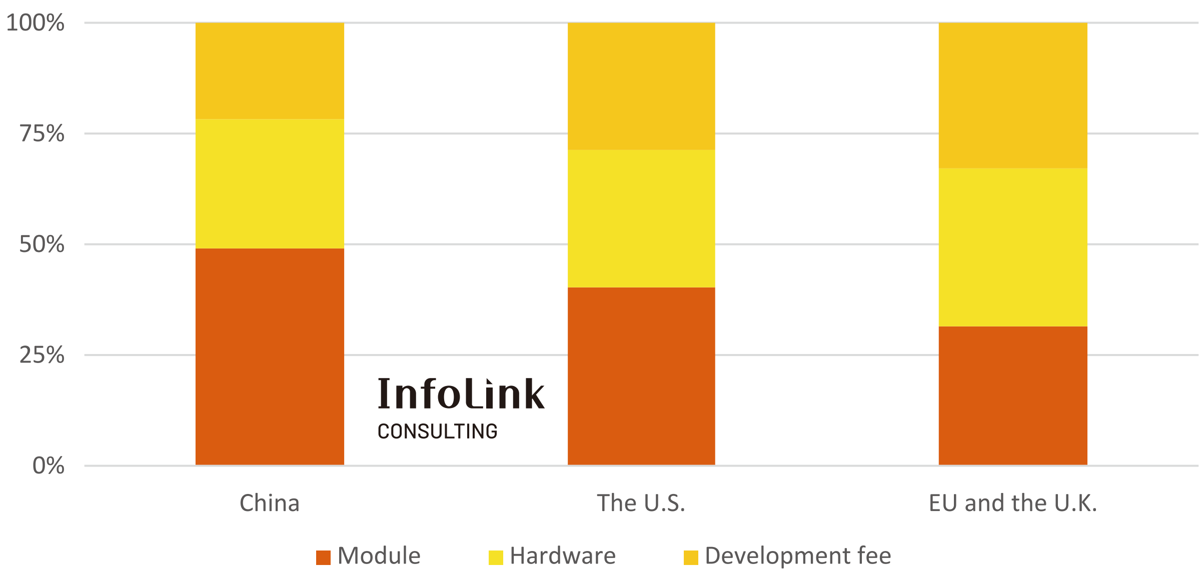


Figure 1.3-2. PV system cost structure

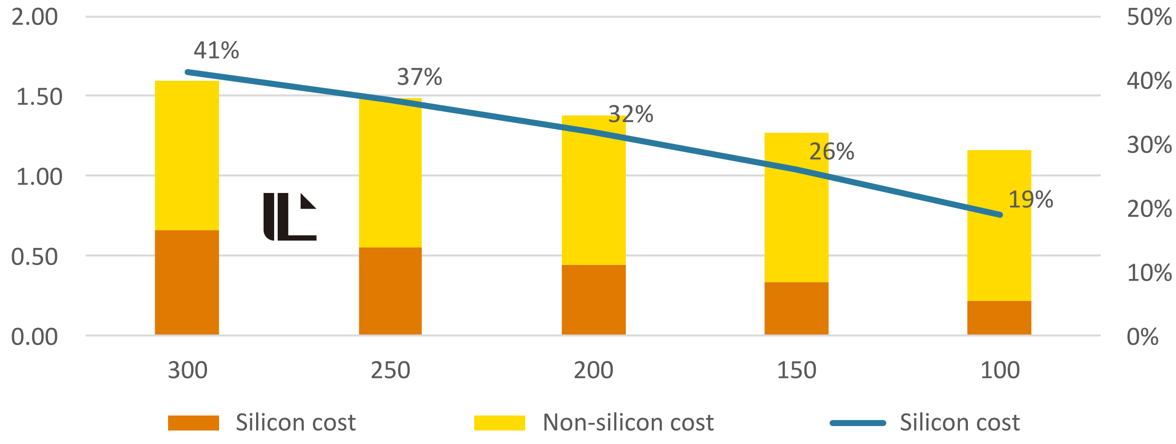


Figure 1.3-3. Module production costs, Unit: RMB/W

According to the chart, with other costs being unchanged, and polysilicon prices at the peak of USD 41.72/kg (RMB 300/kg) in 2022, silicon cost account for 40% of the total module production costs, pushing module costs beyond USD 0.21/W (RMB 1.6/W). Since polysilicon production capacity has increased substantially since the end of 2022, prices dropped to USD 30/kg (RMB 200/kg) in April 2023, reducing the share of silicon cost to 33%. With large-scale production expansions in 2023, excess polysilicon supply will replace short supply, resulting in price declines.

The LCOE calculations presented below are conducted under neutral conditions. **Since sunshine duration plays a crucial role in determining the LCOE, the calculations are based on the average sunshine hours in each region.** The calculations pertain to utility-scale power stations with a power output of 100 MW.

China

China has the most completed PV supply chain in the world and low construction costs of power stations. Solar power has reached grid parity in China. The central government ended subsidies, and only few local governments continue providing financial support.

Consequentially, with fewer variables on the demand side, the supply chain has a greater impact on the PV LCOE in China. Modules account for the largest share of system development costs. In 2021, based on average module prices of RMB 1.85/W for M10, modules constituted 49.0% of system development costs. Other cost contributors are inverters and other hardware and development fees, taking up 29.0% and 22.0%, respectively. **Provided that the average sunshine duration in China is 1,344 hours, the LCOE is USD 26.77/MWh (RMB 192.49/MWh) under neutral assessment.**

However, there was a serious mismatch between upstream and downstream production capacities in 2022, sending polysilicon prices surging continuously to USD 41.72/kg (RMB 300.00/kg) in August, resulting in price hikes across the supply chain. Meantime, commodity prices and the cost of power station equipment increased. In 2022, average module prices increased to RMB 1.97/W, and the PV LCOE is estimated to be USD 28.57/MWh (RMB 205.40/MWh), an increase compared to USD 26.77/MWh in 2021.

Other variables from the supply side include BOM required for module manufacturing and the hardware of power generation systems, both susceptible to changes in commodity prices. The administrative fees for power station development are also subject to local regulations. In general, the release time of new polysilicon production capacity, which constitutes a significant portion of module production costs, holds the key to reducing the LCOE of PV systems in China and the world. In recent years, high gross margin has attracted incumbent and upstart across the globe to expand production actively in the polysilicon sector. As a result, polysilicon prices will plunge during late 2023 and 2024, driving down module prices. **In 2023, average module prices are expected to come to RMB 1.66/W, while the PV LCOE drops to USD 26.49/MWh (RMB 190.44/MWh). InfoLink estimates that by 2025, with the commissioning of production capacity, polysilicon prices will fall to USD 22/kg (RMB 75/kg). By then, the silicon cost of module production will reduce significantly to RMB 1.31-1.37/W, bringing down China's PV LCOE to USD 24.74/MWh (RMB 177.91/MWh).**

On another note, n-type cells, with higher efficiency and lower degradation rate, will gradually become mainstream in the market in 2024. N-type cells provide higher power generation efficiency than PERC cells, allowing power plants of the same scale to produce more electricity within the same lifespan, spreading down the LCOE. **InfoLink projects PV LCOE in China to reach USD 23.2-23.92/MWh (RMB 155.6.00-172.00/MWh) in 2030, as production costs decline and power output increases.**

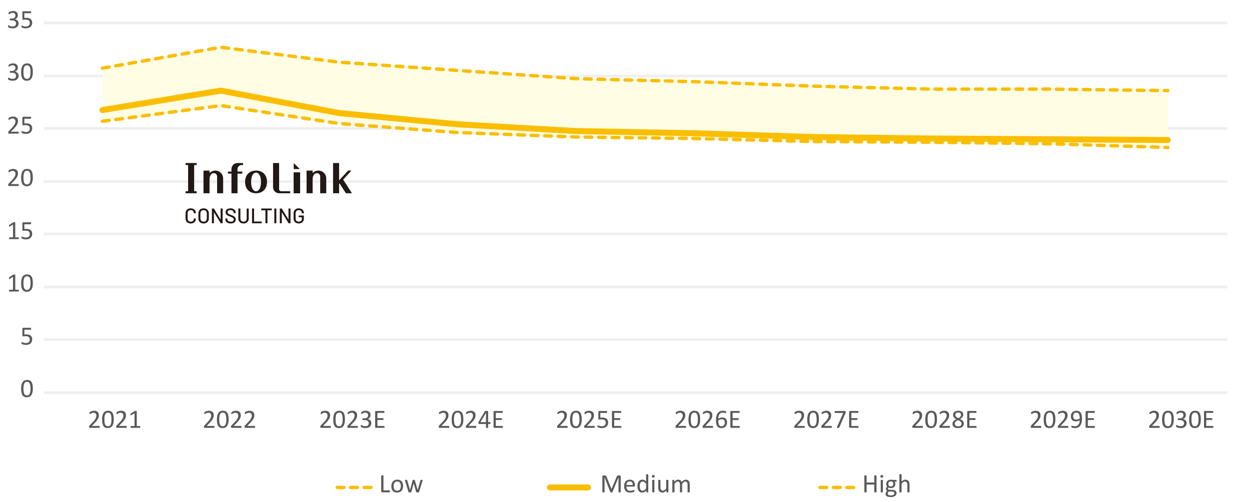


Figure 1.3-4. Developments of PV LCOE in China (2021-2030), Unit: USD/MWh

The U.S.

Unlike China, the U.S. does not have a complete PV industry supply chain, relying on module imports. Costs of other hardware are also higher than in China due to high commodity prices and labor costs. The U.S. currently imports modules from Southeast Asian countries, including Vietnam, Thailand, and Malaysia. The costs are slightly higher than that of China's supply chain, and there could easily be supply shortages because of tariff barriers.

Prices for modules in the U.S. are evidently higher than in other non-China markets due to the costs and industrial characteristics. In 2022, prices for large-format modules including shipping were USD 0.42/W, and even up to USD 0.5/W for domestically manufactured modules due to high labor, water, and electricity costs and less supply. Therefore, the overall cost of PV systems in the U.S. is higher than in other markets. The advantage of PV development in the U.S., however, lies in longer sunshine duration, which amounts to an average of 2,190 hours a year. Higher capacity factor and more electricity output effectively reduce the LCOE. The U.S. also benefits from government subsidies, such as the Investment Tax Credit (ITC), which has been stimulating local demand for the past few years. Since Biden took office, the U.S. has witnessed an accelerated energy transformation. This is most demonstrated by the IRA passed in 2022, which once again raised the ITC and added the Production Tax Credit (PTC). InfoLink's calculation of the LCOE in the U.S. for 2023-2030 is based on power stations with a power output over 1 MW and compliant with apprenticeship requirements (wages, employment, etc.) during construction, thus eligible to the ITC tax incentives.

In the U.S., given high labor costs, administrative fees, etc., modules also occupy the largest portion of PV system costs, only slightly smaller than in China. In 2022, subject to price hikes across the supply chain and rising commodity prices, average module prices increased to USD 0.42/W. The same happened to prices for other hardware such as inverters due to chip shortages. Calculated based on an ITC rate of 26.0%, the PV LCOE in the U.S. rose from USD 34.36/MWh in 2021 to USD 38.38/MWh.

In 2023, the Xinjiang issue and huge potential demand will keep module prices fluctuating between the high price range of USD 0.42-0.43/W, with estimated average prices at USD 0.423/W. Yet, the decline in commodity prices reduces other hardware costs of the PV system, thereby lowering the LCOE, **which is expected to drop to USD 34.58/MWh in 2023. The Xinjiang issue is anticipated to relieve in 2024. By then, module prices may start to decline. Doubled with the new ITC, the LCOE in the U.S. will fall to USD 30.48/MWh in 2025 under a neutral forecast.**

During 2026 and 2030, the LCOE in the U.S. will continue to dwindle as module costs decline. In addition, the IRA emphasizes the subsidization of domestic manufacturing. If a power generation system uses a certain proportion of U.S. content, it can receive an additional 10% ITC credit, resulting in an overall ITC subsidy of up to 40%. However, even though the tax incentives will stimulate the supply of U.S. content, manufacturers are not likely to surrender profits to power stations because of high costs. **Therefore, the LCOE in the U.S. will see a steady decline, falling to USD 25-28/MWh between 2025 and 2030. In a more optimistic scenario, the U.S. will be able to establish a more complete PV supply chain by 2028. If manufacturers are willing to give up profits to developers, the LCOE may drop faster to USD 25.22/MWh in 2030.**

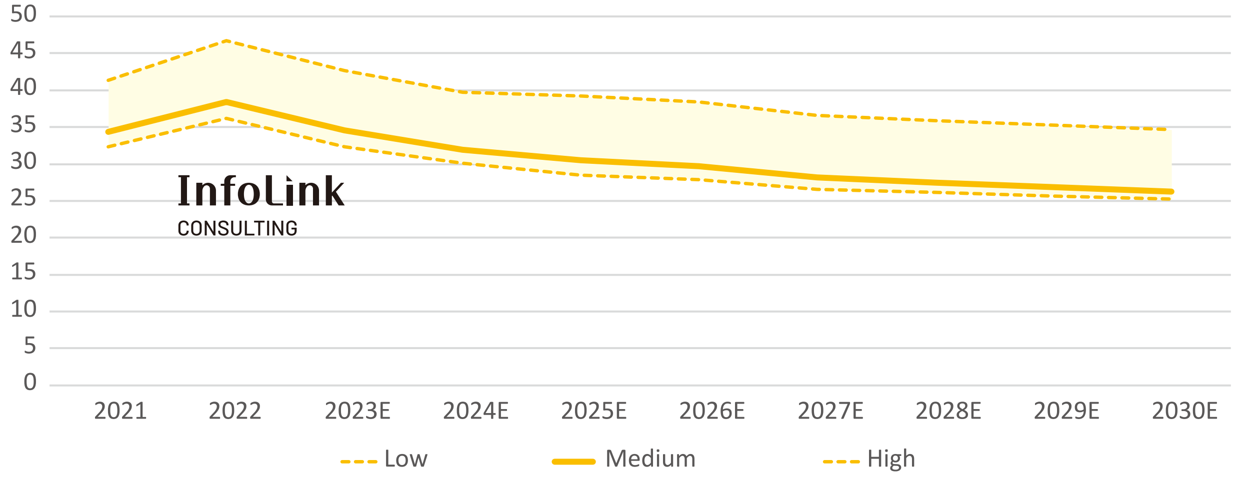


Figure 1.3-5. Developments of PV LCOE in the U.S. (2021-2030), Unit: USD/MWh

Europe (EU and the U.K.)

Europe is the world's most active region pursuing energy transition, with the EU and other European countries setting aggressive transition objectives, such as the EU's REPowerEU and EU Solar Energy. The EU aims to cumulate 320 GW and 600 GW of PV capacity by 2025 and 2030, respectively. With strong PV demand, Germany and France also set clear installation goals. In 2022, traditional energy supply ran short, and prices soared in Europe amid geopolitical conflicts, boosting demand for solar and other renewable energy sources. Despite substantial demand, the EU and other major European markets have yet to provide any solid subsidies for PV installations. Therefore, there are fewer variables on the demand side affecting the PV LOCE of the region. Still, compared with traditional energy, of which prices skyrocketed, solar energy is more appealing to end users.

Without a complete PV supply chain, Europe has yet to impose trade barriers on cells and modules, importing most of the content from China. Due to its pressing need for energy transition, Europe is currently the largest regional market for Chinese modules, importing 40.9 GW in 2021, and even 72 GW in 2022. The huge demand for Chinese products has made European suppliers immensely susceptible to the price trend in China.

Given the weather in Europe, the LCOE is calculated based on an average sunshine duration of 2,000 hours per year, slightly fewer than that of the U.S. Actively working towards energy transition, the European market is more receptive to high module prices, which are still lower than that in the U.S. In 2021, average module prices sit at USD 0.264/W in Europe, accounting for 35% of the total cost of hardware in PV systems. **In 2022, having no escape from the cross-supply chain price hikes, Europe saw average module prices increase to USD 0.311/W. Against this backdrop, the LCOE in 2021 was USD 31.22/MWh, and USD 37.11/MWh in 2022.**

The EU plans to establish a complete PV supply chain through the Green Deal Industrial Plan in the future, details remain scant, and legislation progress takes time. Therefore, China, with cost advantages, remains the major source of module supply in the short term, whilst supply chain price trend in China continues affecting Europe's PV LCOE. In the short and medium term, specifically before 2026, Europe's LCOE will decrease faster as module costs dwindle due to the commissioning of polysilicon capacity in China. **When prices for modules are lowered to USD 0.18-0.19/W in 2025, the LCOE will reach USD 31.31/MWh. After 2026, the LCOE will decline slowly, reaching USD 28.55/MWh if module prices in Europe fall to USD 0.17/W in 2030.**

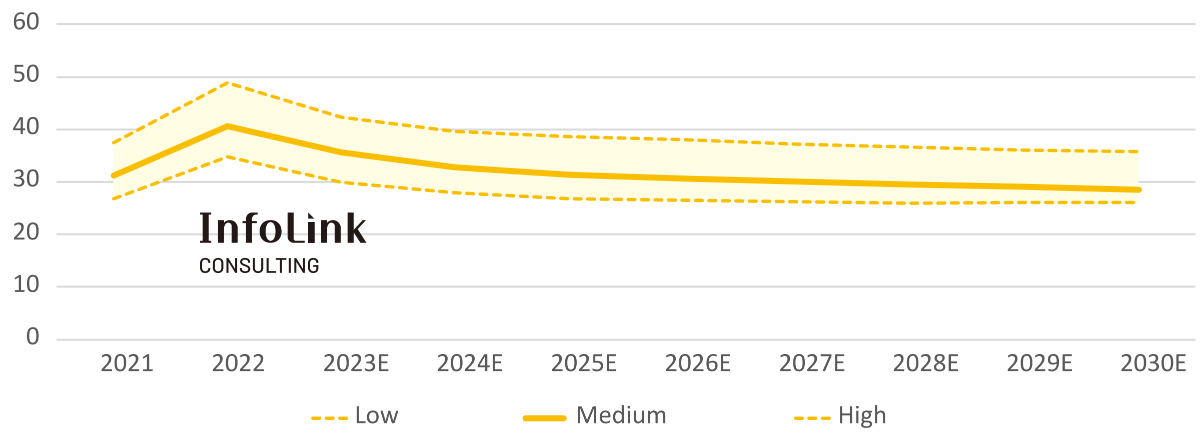


Figure 1.3-6. Developments of PV LCOE in Europe (2021-2030), Unit: USD/MWh

Conclusion

In China and Europe, where government has yet to provide subsidies for PV installations, LCOE mainly hinges on supply chain prices. Due to polysilicon production capacity, the LCOE in 2022 was higher than that in 2021. Significant declines are likely in the coming years as polysilicon capacity comes online, then are subject to the prevalence of high-efficiency products in the medium and long term.

In the U.S., module prices remain relatively high in recent years due to trade barriers. Still, under the IRA, the LCOE is likely to decrease evidently, despite more expensive PV content and higher hardware costs, as long as developers fulfill basic requirements to qualify for at least a 30% tax credit.

1.4 PV IRA

Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) was signed into law by President Biden on August 16, 2022, succeeding the Build Back Better Act (BBB) that failed to pass the Senate last year. The IRA will see USD 369 billion diverted to emission-reducing activities and investment into renewable energy technologies, projected to slash the country's carbon emissions by 40.0% by 2030 compared to the 2005 level.

The IRA's impacts on the US PV industry include stimulating installation demand and incentivizing domestic supply.

Demand

The IRA extends and increases tax credits of the Investment Tax Credit (ITC) and reinitiates the Production Tax Credit (PTC). Extended by 10 years, the two incentives are expected to bolster long-term PV demand in the U.S.

Investment Tax Credit (ITC)

The ITC provides project owners with income tax coverage based on the capital expenditure of the construction system.

Compared with the existing ITC (the extended version passed in 2020 by the House of Representatives that gradually steps down in 2023), the new ITC distinguishes between residential and non-residential projects, and projects that meet additional requirements can receive higher credits.

Residential projects

For residential projects, the base rate is 30.0%, with neither additional requirements nor means to earn bonus credits.

The IRA significantly extends the ITC and raises the credit rate for residential projects. The existing ITC provides a 26.0% of tax credit for residential projects until the end of 2022, which drops to 22.0% in 2023 and ends in 2024.

Under the IRA, credits for residential projects will begin to phase down in 2033 by 4.0% per year and end in 2035.

*Subsidy calculation starts upon the construction time of the project.
*Project capacity size ≥ 3 kWh

Figure 1.4-1. Investment Tax Credit (ITC) for residential under IRA

Non-residential projects

Non-residential projects include utility-scale, C&I distributed, community, and government projects. Projects with power output under 1 MW meeting several requirements are qualified for different adders.

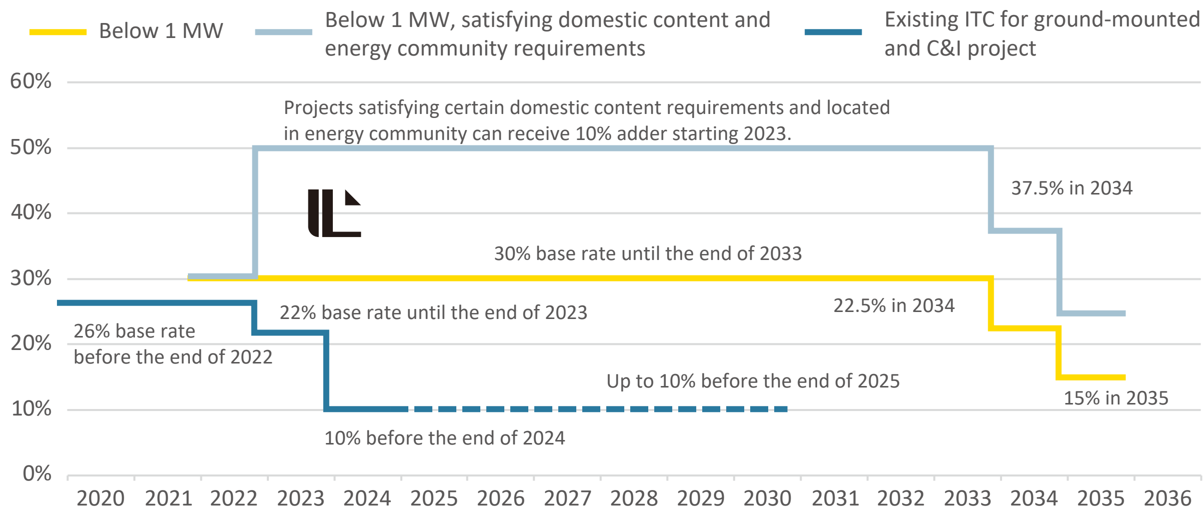
Projects under 1 MW

Projects with a maximum net output less than 1 MW can apply for 30.0% of base rate. A 10.0% adder is given each to projects meeting certain domestic content requirements or located within an officially designated "energy community." Another 10.0-20.0% adder is available for facilities that are part of qualified low-income projects. Earning this adder is more challenging, given the difficulty in participating in low-income projects and the annual capacity limitation. It is more feasible to obtain 50.0% of tax credits, namely the base rate and adder credits from meeting domestic content requirements and locating projects.

Projects with a maximum net output less than 1 MW	
Base rate	30%
Satisfying certain domestic content requirements	+10%
Located in an energy community	+10%
Work with low-income projects	+10 – 20%

Domestic content requirements:

Any steel or manufactured product must be produced in the U.S.
By the end of 2024, domestic content shall be account for 40% of the cost structure, 45% by 2025, 50% by 2026, and 55% by 2027.



*Subsidy calculation starts upon the construction time of the project.
*Bonus credit amount is applicable for projects that start operation in 2023.

Figure 1.4-2. Investment Tax Credit (ITC) for projects with a maximum net output less than 1 MW

Projects above 1 MW

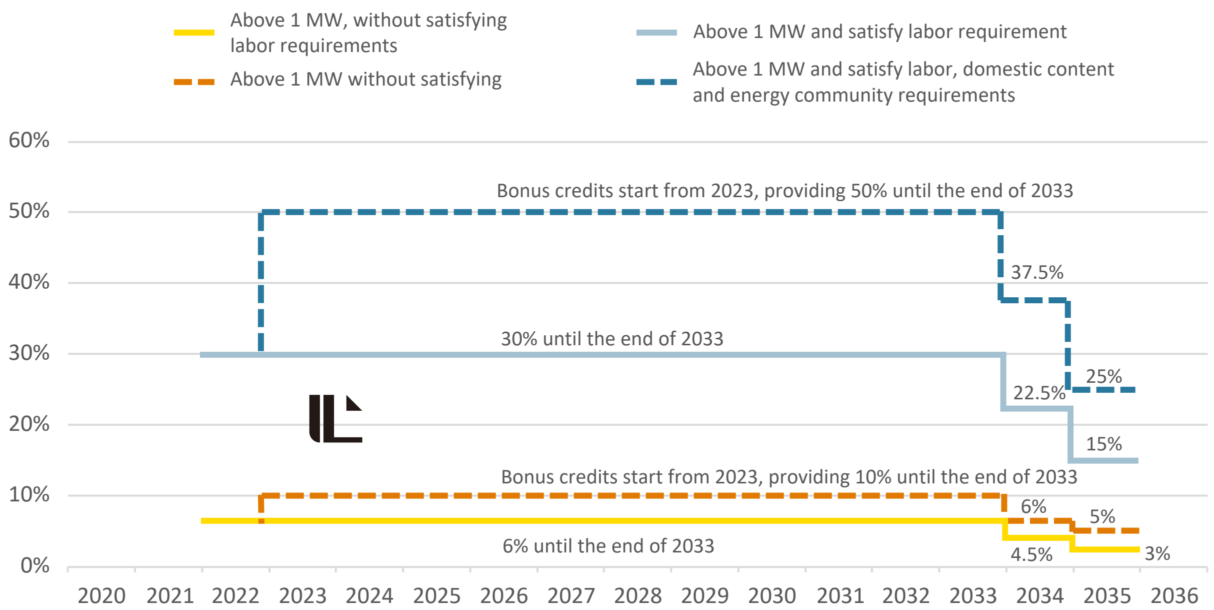
Facilities with a maximum net output over 1 MW shall satisfy more requirements to be eligible for higher credit rates. For those failing to satisfy apprenticeship requirements, the base rate and adder credits are much lower.

Basic apprenticeship requirements involve fair wages and the employment of qualified apprentices. Failure to meet these requirements results in a significant decrease in the base rate from 30.0% to 6.0%, and a reduction in adders of meeting the energy community and domestic content requirements from 10.0% to 2.0%. Facilities with a maximum net output of more than 1 MW participating in low-income projects are eligible for a 10.0-20.0% adder credit as well.

Since the tax rate for facilities not meeting the apprenticeship requirements is five times lower, project owners will make every effort to fulfill them. Meantime, the difficulty in participating in low-income projects will motivate project owners to strive for the 30.0-50.0% credit.

For non-residential projects, the ITC will start phasing down in 2034 by 25.0% per year and end in 2036.

Projects with a maximum net output more than 1 MW		
Satisfy apprenticeship requirements:	Yes	No
Base rate	6% + 24%	6%
Have certain ratio of domestic content	2% + 8%	+2%
Situated within energy community	2% + 8%	+2%
Work with low-income projects	+10% - 20%	+10% - 20%
Apprenticeship requirements cover minimum wage and employment of registered staffs.		



*Subsidy calculation starts upon the construction time of the project.
*Bonus credit is applicable for projects that start operation from 2023.

Figure 1.4-3. Investment Tax Credit (ITC) for facilities larger than 1 MW

In addition to the ITC, which provides tax credits in accordance with installation costs, the IRA re-initiates the Production Tax Credit (PTC), allocating subsidies based on the electricity generation (kWh) of solar systems. The credit amount of the ten-year PTC subsidy is subject to inflationary adjustments. Projects with domestic content or located within energy communities will have a 10.0% adder for each. The allocation varies for projects with a maximum output under or over 1 MW.

For projects with a maximum output under 1 MW, the base credit amount is USD 0.015/kWh. Manufacturers can receive an additional 10.0% credit each by satisfying domestic content and energy community requirements. Projects with a maximum output exceeding 1 MW must comply with the same apprenticeship requirements of the ITC to receive the USD 0.0150/kWh subsidy. If not, there will be only 20.0% of the credit amount, that is USD 0.0030/kWh, and adders of domestic content and energy community requirements will be lower. (Adders are calculated based on the base credit amount).

The PTC is subject to inflationary adjustments and will step down in 2034 by 25.0% per year until it ends in 2036.

Table 1.4-1. Estimated PTC under IRA, Unit: cents/kWh

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Below 1 MW	PTC base credit		1.53	1.56	1.59	1.62	1.66	1.69	1.72	1.76	1.79	1.83	1.87	1.43	0.97
	Satisfy domestic content and energy community location requirements		1.84	1.87	1.91	1.95	1.99	2.03	2.07	2.11	2.15	2.19	2.24	1.71	1.16
Above 1 MW, satisfying labor requirements	PTC base credit	1.50	1.53	1.56	1.59	1.62	1.66	1.69	1.72	1.76	1.79	1.83	1.87	1.43	0.97
	Satisfy domestic content and energy community location requirements		1.84	1.87	1.91	1.95	1.99	2.03	2.07	2.11	2.15	2.19	2.24	1.71	1.16
Above 1 MW, without satisfying labor requirements	PTC base credit	0.30	0.31	0.31	0.32	0.32	0.33	0.34	0.34	0.35	0.36	0.37	0.37	0.29	0.19
	Satisfy domestic content and energy community location requirements		0.37	0.37	0.38	0.39	0.40	0.41	0.41	0.42	0.43	0.44	0.45	0.34	0.23

*Inflationary adjustments are made based on inflation rate of 2%. Official statistics shall prevail.
After the inflationary adjustment, the PTC base rate was USD 0.005/kW in 2022 and
USD 0.026/kW for project satisfying apprenticeship requirement.

Supply

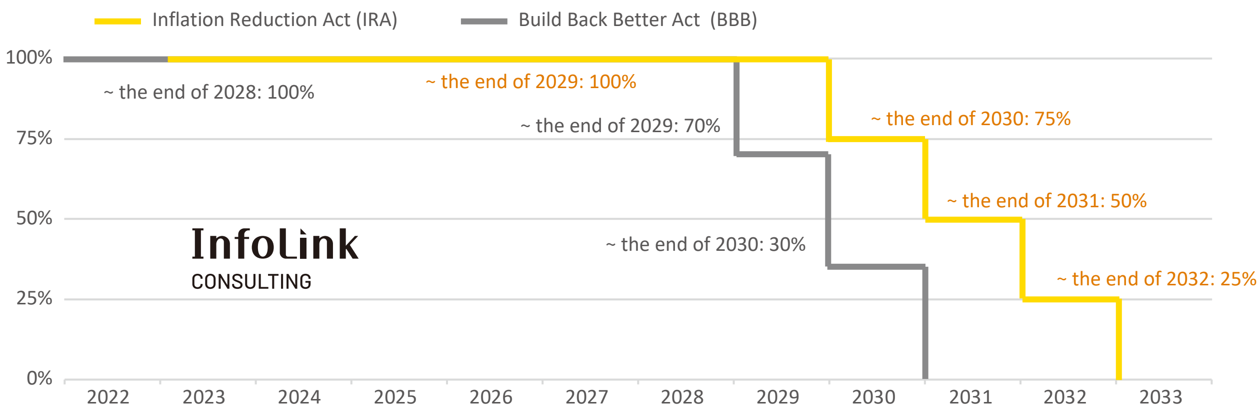
To establish a complete PV supply chain, the IRA provides PTC for domestic manufacturing, covering upstream and downstream sectors and BOM production. Additionally, there is the 6.0% ITC, which is increased to 30.0% for projects that satisfy apprenticeship requirements. Manufacturers shall choose either the PTC or the ITC.

Table 1.4-2. Subsidy amount and item for domestic PV manufacturing

	Item	Subsidy	Note
Advanced manufacturing production credit	Effective date	Products made and sold after Dec. 31, 2022.	The Act does not specify the maximum subsidy amount. Details remain to be published.
	Polysilicon	3 USD/kg	For polysilicon with purity higher than 8N.
	Wafer	12 USD/m²	Subsidy amount translation (including poly-Si and thin film) USD 0.329/piece for the M6 format USD 0.396/piece for the M10 format USD 0.529/piece for the G12 format
	Cell	0.04 USD/W	For both crystalline and thin film cells.
	Module	0.07 USD/W	For both crystalline and thin film cells.
	Backsheet	0.4 USD/m²	
	Inverter	Central inverter 0.0025 USD/W Utility inverter 0.015 USD/W Commercial inverter 0.02 USD/W Residential inverter 0.065 USD/W Microinverter 0.11 USD/W	Central inverter (>1 MW) Utility inverter (>125kW, <1MW) Commercial inverter (>20kW, <125kW) Residential inverter (<20kW) Microinverter (<650W)
	Tracking & mounting system	Torque tube 0.87 USD/kg Structural fastener 2.28 USD/kg	
Extension of the advanced energy project credit	Factory construction, equipment (Re-equipped, expanded, or build new facility)	By laws will be stipulated 180 days after the announcement of the Act. The subsidy will be applicable for projects that are placed in service after Jan. 1, 2023 and projects must commission within two years after receiving approval. The subsidy is capped at USD 10 billion, of which less than USD 6 billion is applicable for projects building in unqualified energy community, but the subsidy is in the form of tax credit instead of direct payment. Minimum subsidy is 6%. Projects that meet prevailing wage and labor requirements can receive 30%.	

*The subsidy is for domestic manufacturing and products sold to the third party only.
*Subsidy for products is given in accordance with actual production output.
*Projects can only receive either ITC or PTC.

Tax credits phase out later and more slowly under the IRA than the BBB. Under the BBB the credits will start stepping down in 2029 to 70.0%, then 30.0% the next year, and ends in 2031. Under the IRA, credits start phasing down in 2030 by 25.0% every year and do not end until 2033, making it a stronger support than the BBB.



*Applicable to products made and sold after Dec. 31, 2022.

Figure 1.4-4. Subsidy for domestic PV manufacturing

Provided with the PTC and 1. a complete supply chain, 2. wafer, cell, and module production capacity, or 3. cell and module production capacity, the production cost of US manufacturing may be able to contend with that in Southeast Asia.

Discussions around US manufacturing heat up, but not so much for upstream sectors, as polysilicon and wafer production are not as automated as that of cells and modules.

Polysilicon production capacity needs 18 to 24 months of construction period. Projects that begin construction in early 2023 will not enter operation until the second half of 2024. Expensive electricity in the U.S. is another concern, as it makes up 40.0% of polysilicon production costs. Therefore, most production capacity additions during 2022 and 2023 come from re-initiations of existing production plants. Polysilicon production expansions are still limited in overseas markets.

The establishment of wafer production capacity in the U.S. is subject to the quality of labor since wafer production has yet to be fully automated. Ingot growing and slicing require high-quality labor forces. Ingot growing, seeding, and slicing are much dependent on manpower.

The success of US manufacturing hinges on various factors including basic requirements, construction costs, and earnings yield. However, high production costs and sales prices continue to be a major challenge. As a result, the U.S. is still some time away from completing its supply chain in the short term.

Overall impact of IRA

The passing of the IRA is certainly welcome news for the US PV development in terms of both demand and supply. The increase of credit rates will boost demand, whilst the extension of the subsidies allows more flexible installation schedules, mitigating market uncertainties, such as price fluctuations and short supply. The ITC encourages distributed generation project developers the most, for they can receive higher credit rates by locating their projects in energy communities or low-income communities.

The ITC and the PTC are sure to boost installed PV capacity in the U.S. But in the short term, the UFLPA restricts the import of Xinjiang-made products. As a result, the U.S. is still some time away from completing its local supply chain, with Southeast Asia remaining a major source of modules in the recent one to two years.

Subsidies for factory construction, equipment purchases, and product manufacturing will make up for the high production costs in the U.S., attracting overseas manufacturers to expand production capacity in the country, completing the local supply chain, increasing local supply, and easing shortages resulting from the lack of imports amid trade disputes. The PTC encourages local manufacturers to reconsider production expansion, while attracting investors overseas to build production capacity in the U.S. Some investors have been assessing the feasibility of production in the U.S., with some already discussing purchases of module production equipment. Yet, on top of labor, water, electricity costs, and tax credit regulations, the unpredictable China-U.S. relationship deters investors, leading to a wait-and-see attitude among most Chinese manufacturers. Over time, increasing local supply will allow project owners to receive more subsidies, creating a positive cycle between incentives and demand, benefiting the long-term development of the US PV industry.

The IRA is not expected to have a significant impact on short-term PV demand in the U.S. This can be ascribed to three reasons: 1. The UFLPA bars products Tier-1 Chinese module makers made in Southeast Asia. Presently, module shortage in the U.S. can be attributed to political issues, incomplete upstream material tracing, and longer time for approval. 2. Despite enticing incentives the IRA provides for constructing production plants and manufacturing in the U.S., the local supply chain will not be well-developed without one to two years, for manufacturers need more time to assess and build production plants. Meantime, the nation’s reliance on raw materials from China pushes up transportation costs, while its labor cost is already higher than in other regions. In the short term, high production costs and high sales prices will persist in the U.S. 3. The ITC and the PTC take effect in 2023, and thus had little impact on installations in 2022.

02 WIND

DEMAND

In 2022, the world added 91.36 GW of wind power capacity, with onshore wind accounting for approximately 90% (82.01 GW), and offshore wind accounting for approximately 10% (9.35 GW).

InfoLink estimates global installed wind capacity to increase more than double from 834.75 GW in 2021 to 1839.77 GW in 2030. The share of onshore wind power is expected to decrease from 93% in 2021 to 85% in 2030, while the that of offshore wind power rising from 7% in 2021 to 15% in 2030.

The onshore wind sector will see the Chinese market expanding faster than the U.S. and Europe, with a CAGR of 15% from 2021 to 2030. In the offshore wind power sector, the U.S. is poised for rapid growth with the support of the Inflation Reduction Act of 2022, aiming to increase its capacity from 45 MW in 2022 to 30 GW in 2030.

SUPPLY CHAIN

In the first half of 2022, the average price of wind turbines from Siemens Gamesa increased by 20% to 30% compared to 2021, while Vestas saw an increase of approximately 10% to 20%. In the third quarter, both companies further raised prices for onshore wind turbines, which reached EUR 1.06 million/MW. Despite the adjusted prices, Siemens Gamesa and Vestas still experienced deficits.

The average power output of offshore wind turbines during 2021 and 2022 ranged from 6 MW to 9.5 MW. Leading wind turbine manufacturers such as Vestas, Siemens Gamesa, and GE introduce larger turbines with power outputs of 14-15 MW, which will be used in wind farms scheduled for completion during 2025 and 2026. InfoLink expect 17-18-MW offshore wind turbines to become mainstream gradually by 2030.

The offshore wind vessel market faces two challenges: the scaling up of wind turbines and the rapid market growth. Factoring out the Chinese market, there were only two kinds of wind turbine installation vessels (WTIVs) capable of installing 15-MW turbines in 2022.

LCOE

In 2022, the LCOE of offshore wind power in the three major markets under standard conditions were as follows: China at USD 70.01/MWh, the U.S. at USD 92.41/MWh, and Europe at USD 111.17/MWh. For onshore wind, the LCOE was USD 29.66/MWh in China, USD 23.68/MWh in the U.S., and USD 51.51/MWh in Europe.

Currently, onshore wind power in the three markets, as well as offshore wind power in Europe and the U.S., have achieved grid parity. In China, due to the low cost of coal-fired power generation in China, offshore wind power is not expected to reach grid parity until 2027. The recent interest rate hikes and inflation will lead to an increase in LCOE, which will ease after 2024.

IRA

Under the IRA, InfoLink expects the LCOE of offshore wind power in the U.S. to decrease by 22%, and that of onshore wind power by 31%. This will give rise to the expansion of wind farms into regions with lower capacity factors or higher construction costs.

Additionally, the IRA provides a 10% tax credit for offshore wind turbine components and offshore wind-specific installation vessels, allocates USD 100 million for the research of interregional transmission and distribution, and revises the Outer Continental Shelf Lands Act to accelerate offshore wind development.

2.1 WIND DEMAND

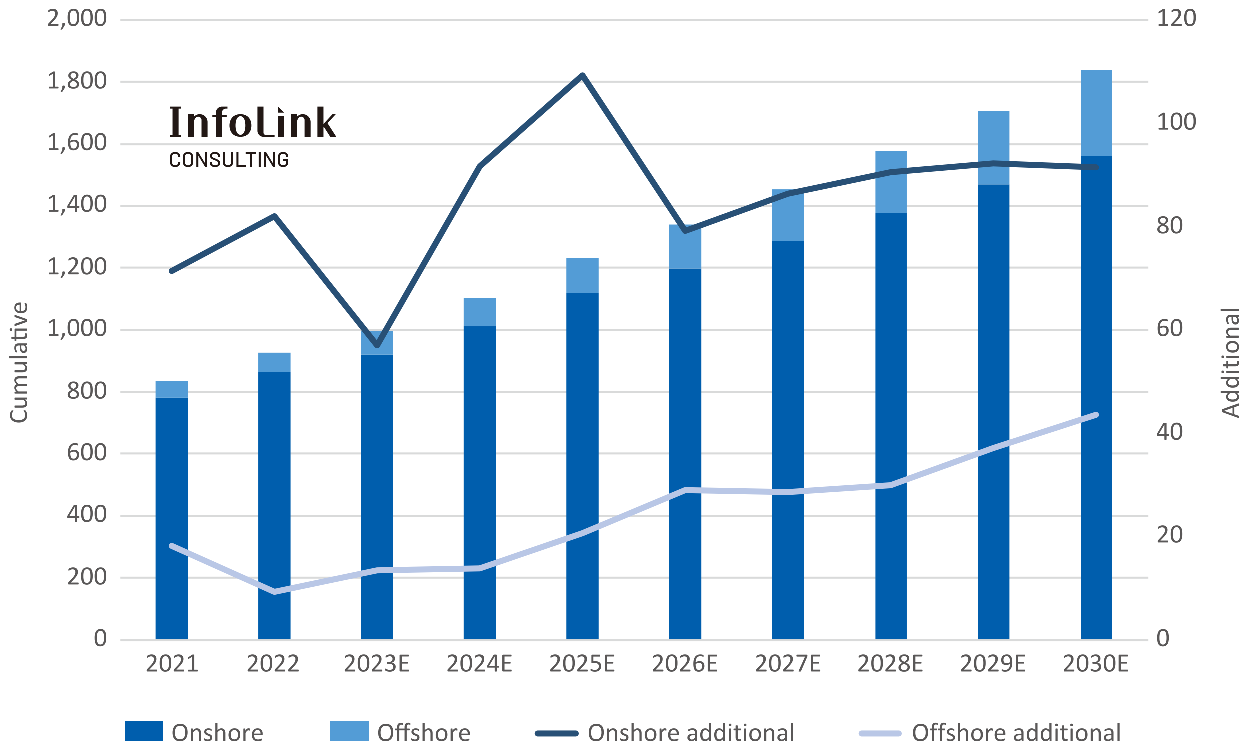


Figure 2.1-1. Onshore and offshore wind installed capacity 2021-2030, Unit: GW

Wind energy has experienced buoyant development over the recent decade. **Demand from onshore and offshore installations will increase from 834 GW in 2021 to 1,839 GW in 2030, translating to a compound annual growth rate (CAGR) of 9.18%. The world added 89.60 GW of wind power capacity in 2021 and 91.36 GW in 2022.** China added far less offshore wind capacity in 2022 after an installation rush in 2021. Making up for that, in the onshore wind industry, Europe and China added 4 GW to 5 GW more in 2022 than a year earlier, whilst other markets showed some growth.

In 2023, additions of onshore wind power capacity will decrease marginally to 70.41 GW, largely due to the initial expiration of the Investment Tax Credit (ITC) for onshore wind in 2021. The original ITC provided USD 0.015/kWh of tax credits for wind farms constructed no later than the end of 2021 and more credits for wind farms constructed even earlier. Since the construction of an onshore wind farm only takes a year, there will be no incentives for the US onshore wind industry from 2023. Yet, as the U.S. introduced the Inflation Reduction Act (IRA) in 2022, the extended Production Tax Credit (PTC) under the IRA will revitalize the industry again.

Onshore wind remains the major driving force behind the increase of installed wind capacity, with China being the strongest growing market. China accounted for 39% of installed wind capacity worldwide in 2021 and will maintain a 10% CAGR in the coming decade to take up 45% of global installed wind capacity by 2030. The booms are attributed to the fact that China's onshore wind power has reached grid parity, and that authorities push up installation targets. The European market, being closer to its saturation wind power potential, lacks momentum. Streamlining wind farm approval processes is a prerequisite for Europe to achieve policy goals.

Given the saturation of onshore wind, the energy share of onshore wind will decline over the coming decade, dropping from 93% in 2021 to 85% in 2030. Offshore wind, on the other hand, is still an emerging industry for markets other than Europe. The U.S.' ambitious goal to cumulate 30 GW of installed offshore wind capacity within the recent ten years drives the rapid growth of the industry. The relatively matured European market is still expected to see 17% of CAGR over the coming decade, given REpowerEU and the offshore wind target of the U.K. that boost offshore wind installation in Europe. Meantime, the EU is working to shorten wind farm approval process. The following paragraphs shed light on the growths of wind capacity in China, Europe, and the U.S.

China

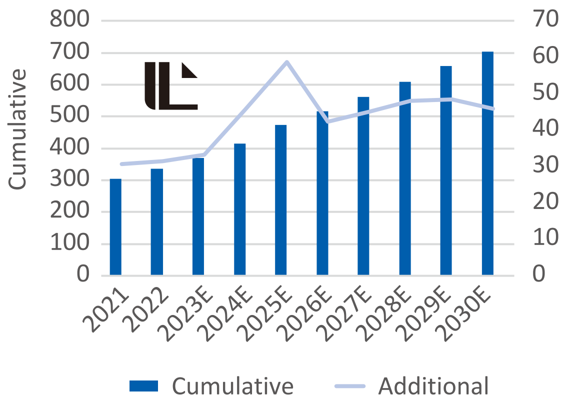


Figure 2.1-2.
China installed onshore wind capacity, Unit: GW

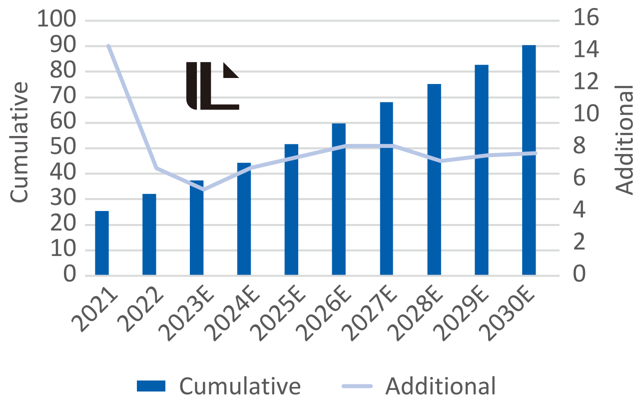


Figure 2.1-3.
China installed offshore wind capacity, Unit: GW

China's stretching coastline is optimal for the development of offshore wind energy. According to the China Wind Energy Association (CWEA), China's saturation wind power potential is around 3,500 GW —— 500 GW in waters 20m in depth, 1,100 GW in waters 20m to 50m in depth, and more than 2,000 GW in waters 50m to 100m in depth with floating or fixed foundations. In China, major power-consuming cities are located near the coast. Offshore wind saves more loss during long-distance transmission, compared with onshore wind farms in northeastern, northern, and northwestern China.

China's offshore wind energy is on its way to reach grid parity. **As all offshore wind farms eligible for FIT payment are required to be connected to the grid by the end of 2021, an installation rush occurred, adding more than 14.4 GW of offshore wind capacity, pushing cumulative offshore wind capacity from 10.9 GW in 2020 to 25.3 GW in 2021, a 230% growth.** Since then, China has cumulated more offshore wind capacity than all offshore wind farms in Europe combined. As the government phased out central subsidies, the pressure of allocating financial aids falls upon local governments.

During 2023 and 2025, local governments will continue their efforts to attain goals for the 14th Five-Year Plan, which covers the years 2021 to 2025. Guangdong Province set a target to add 17 GW of offshore wind capacity during the 14th five-year period, whilst Jiangsu Province aims to add 9 GW, pushing cumulative offshore wind capacity to 15 GW from 6 GW in 2021. Most provinces, such as Fujian, Zhejiang, Shandong, and Liaoning, plan to add 4 GW to 5 GW of offshore wind capacity during the 14th five-year period. With plans of some provinces remaining scant, InfoLink estimates that China will add more than 50 GW of offshore wind capacity during the 14th five-year. Under the 13th Five-Year Plan, the rates of achievement of targets set by provinces were 70% to 80%. Given that and more challenges when developing offshore wind than onshore wind, InfoLink expects China to attain targets of the 14th Five-Year in 2026.

As infrastructures and supply chains complete, and with no additional incentives, China will see 7 GW to 8 GW of offshore wind capacity added every year during 2026 and 2030, accumulating 88.4 GW of offshore wind capacity in 2030, attaining in advance its goal to have 71 GW by 2035.

The development of onshore wind energy in China is earlier than offshore wind. China began experimenting with onshore wind in the mid-1980s. But it wasn't until 2003 did production costs start to decline, due to its reliance on equipment imported overseas and the uneven quality of locally made ones. Lofty costs mire the progress of large-scale development, making cost reduction even more difficult.

Afterward, China promoted onshore wind by introducing wind power "concession policy" programme and "approval policy" programme. Under the concession policy, the government designates potential farm sites for businesses to bid for ownership and operation right in open tenders. Bid winners sign with the government contracts, which set out details such as the operation period and the purchase price of electricity during the operation period. When an operation period ends, the ownership and the right of operation are returned to the government free of charge. The concession policy was in effect during 2003 and 2007. In 2004, China introduced the approval policy, under which wind farm developers attain subsidies upon approvals. From 2009 onwards, only wind farms meeting certain requirements may receive subsidies.

With FIT and subsidies, China mitigates the uncertainties lie in wind farm investments, supporting local turbine manufacturers, and finally seeing its onshore wind industry prosper. From 2005 to 2018, China's installed onshore wind capacity rose from 1.3 GW to 179.8 GW. **In 2018, China's onshore wind power reached grid parity. In 2019, the National Energy Administration issued a notice requiring all onshore wind farm tariffs to be set via tendering process, and all power generated to be connected to the grid at a price equal to local coal power in 2021, achieving grid parity officially,** giving rise to an installation rush in 2020, during which China added 74 GW of onshore wind capacity.

Chinese onshore wind industry maintained a strong momentum after the installation rush in 2020. In 2021, the government announced the first batch of large-scale wind and solar projects with a total capacity of 97 GW, among which 13.6 GW were wind projects, and 61.6 GW were wind and solar projects. The projects are expected to be completed sometime during 2022 and 2023. In 2022, China announced the second batch of large-scale wind and solar projects with a total capacity of more than 450 GW. Against this backdrop, China's onshore wind capacity will keep increasing with a CAGR of 7% during 2021 and 2030. For now, China aims to add 200 GW of onshore wind capacity during the 14th Five-Year period, a target InfoLink expects China to attain timely in 2025. In 2026, China could add 516 GW of installed onshore wind capacity. The addition may increase to 600 GW afterward as the nation strives to achieve the goal of cumulating 1,200 GW of solar and wind capacity together by 2030. Factoring in installed solar capacity, that goal may be achieved in 2025 or 2026.

The U.S.

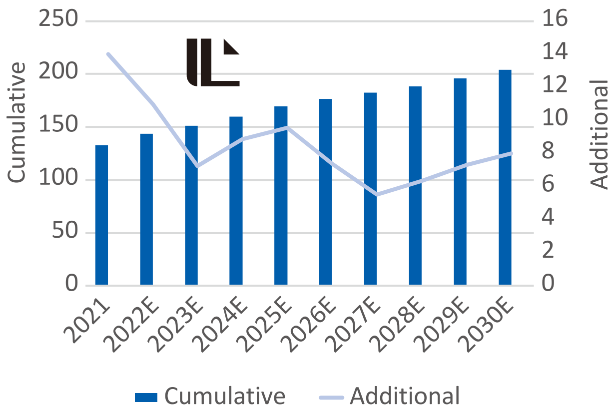


Figure 2.1-4.
US installed onshore wind capacity, Unit: GW

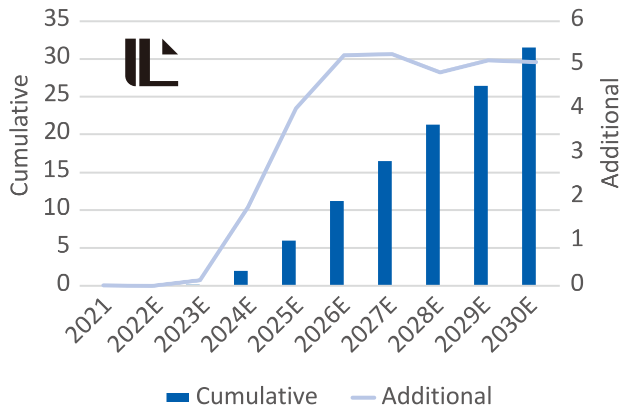


Figure 2.1-5.
US installed offshore wind capacity, Unit: GW

With many places of plentiful land, sparse population, and abundant wind resources, the U.S., especially the Midwestern states, are perfect fit for developing onshore wind power. In 2021, the average capacity factor of onshore wind farms in the U.S. was 35%. States including Iowa, Colorado, Texas, Wyoming, etc. rely heavily on onshore wind. Besides ideal natural conditions, strong government support, such as the PTC, drives the growth of U.S. onshore wind industry. For now, the White House focuses more on offshore wind, setting no specific targets for installed capacity and cost reduction of onshore wind energy. **During 2012 and 2021, the U.S. posted stellar performance with a CAGR as high as 22.5%, translating to 8 GW of average addition per year.** Initially ending in 2021, the PTC boosted onshore wind installation of the year, pushing cumulative capacity to 133 GW.

Since the PTC previously expired in 2021, InfoLink expects the U.S. to see the growth of onshore wind installation slowing down during 2022 and 2023. In August 2022, the IRA came into force, introducing the technology-neutral tax credits with 100% PTCs, reviving onshore wind development. Given that, installed capacity will increase in 2024 and 2025 as wind farms come online, then stabilize after 2026. From 2022 to 2030, the U.S. may install 8 GW of onshore wind capacity per year on average. As the US market has reached maturity, there may not be significant growth despite the incentives due to limited land space. Still, the PTC will push cumulative onshore wind capacity up 3.6% by 2030.

Offshore wind power had not received much attention in the U.S. before. This can be attributed to three major reasons.

First, the initial investment cost of developing offshore wind farms was high. With easier, more economical alternatives, such as onshore wind, solar, or biomass and geothermal energy that have great potential, the U.S. saw no necessity to work on offshore wind energy.

Second, government supports were inconsistent. The Republicans were not completely against renewable energies. However, to attract developers, the U.S. requires massive investment, FIT, and other incentives. Given the attitude of former president Donald Trump toward offshore wind and changeable incentive policy trajectory, developers chose the Asia-Pacific market over the U.S. after the European market saturated.

The third reason is the Energy Management Inc.'s (EMI) failure of the Cape Wind Project. Spoiling the waterfront view when developing Cape Wind, the lawsuit-ridden EMI finally put an end to the 16-year struggle. The ill-fated project provides valuable lessons yet undermines the confidence of developers in the US market.

The Biden administration has set new policy goals, including **cumulating 30 GW of offshore wind capacity by 2030, an ambitious goal compared with the 42 MW grid-connected capacity in 2021. The new target may attract developers' attention to the US market.**

The U.S. is a perfect fit for developing offshore wind energy, given continuous coastlines, abundant wind sources on both east and west coasts, and rich experiences in oil and natural gas industries. In addition, the new ITC under the IRA provides a 30% investment tax credit for offshore wind power, a strong financial incentive.

However, some potential challenges for the U.S. include insufficient infrastructure to support wind farm construction, inadequate port hinterland and carrying capacity for turbine manufacturing, and shortages of underwater foundation installation and turbine installation vessels.

To add to that, in April 2022, the U.S. Customs and Border Protection (CBP) issued a ruling regarding the Jones Act. According to the ruling, a foreign installation vessel may operate lawfully on US projects, provided none of the components are transported from a US point, for the crew is not considered passengers, and the components not goods, thus not violating the Act. For now, an approved alternative method is to transport components with a U.S.-flagged tugboat manufactured in the U.S., while leaving turbine and foundation installation vessels on the farm site. However, this process is less efficient and carries additional risk when transferring components from tugboats to installation vessels under adverse weather conditions.

The Jones Act will be the biggest obstacle for the U.S. to accelerate offshore wind farm development. Most ship owners remain cautious, given factors such as upscaling turbines, inflation, and interest rate hikes. Additionally, production costs in the U.S. are 50% higher than in international markets. For now, only Dominion Energy's Charybdis meets the requirements of the Jones Act. However, to meet the policy target, the market needs at least six turbine installation vessels.

Furthermore, **the Biden administration proposed to cumulate 15 GW of floating wind power capacity and reduce LCOE by 70% by 2035.** This target was set mainly for the West Coast and the State of Maine, where water depth rapidly increases, making the regions unsuitable for fixed underwater foundations. The advancement of floating technology will benefit the development of offshore wind power in California, Oregon, and Maine.

Factoring in policy targets and existing wind farms' estimated annual capacity additions from 2023 to 2030, InfoLink estimates the U.S. to add 4 GW to 5 GW of offshore wind capacity annually from 2025 onwards. Many states have set their offshore wind goals, such as Massachusetts, Connecticut, Maryland, Virginia, and North Carolina, with a combined target to cumulate 16.8 GW of installed offshore wind capacity by 2030. New York and New Jersey aim for 16.5 GW by 2035.

The U.S. did not commission any new offshore wind farms in 2022. The South Fork Wind Farm in Massachusetts, currently under construction, is expected to be connected to the grid in 2023, providing 132 MW of offshore wind capacity. The U.S. will not see explosive growth in offshore wind capacity until 2025. In 2025, Massachusetts will have nearly 3 GW of wind farms beginning commercial operation, whilst New Jersey will commission a 1.1-GW wind farm. From 2026 to 2030, wind farms in Massachusetts, Delaware, New Jersey, and New York will come online, with an average annual grid-connected capacity of around 5 GW, enabling the U.S. to reach its 30-GW policy goal by 2030.

Europe (EU and the U.K.)

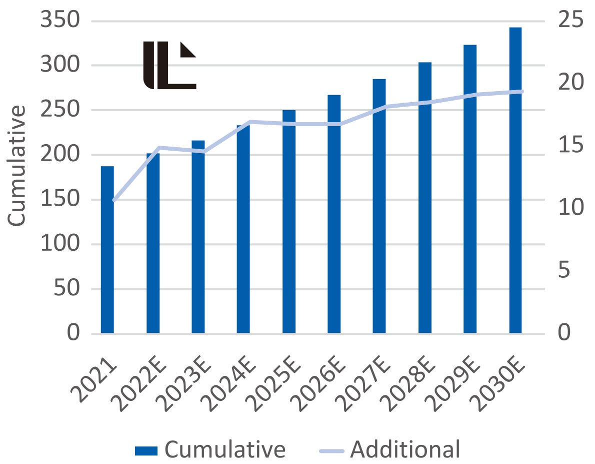


Figure 2.1-6.
Europe installed onshore wind capacity, Unit: GW

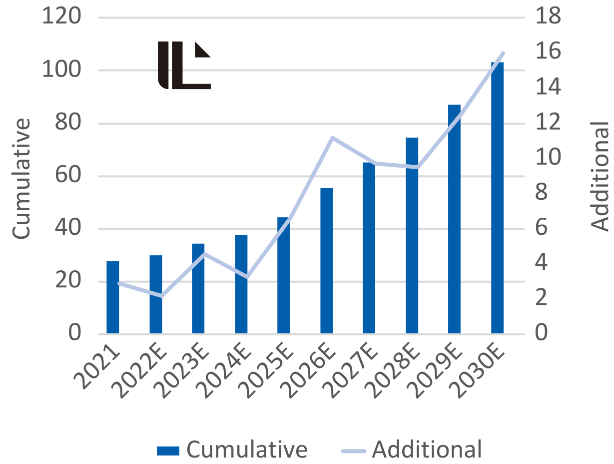


Figure 2.1-7.
Europe installed offshore wind capacity, Unit: GW

In 2019, the EU introduced the European Green Deal, a financial incentive plan aiming to boost renewable energy development, attract investments, mitigate impacts of the Covid-19 pandemic, and facilitate the recovery of global economics. To achieve net zero by 2050, the bloc needs to reduce greenhouse gas emissions by at least 55% by 2030 compared with the 1990's level. In 2021, the EU revised the plan, raising the target share of renewable energy in the overall energy mix from 32% to 40%.

In 2022, Russian troops set foot on Ukrainian soil, prompting the EU to reflect upon its reliance on fossil fuels and natural gas from Russia. In response, **the EU launched the "REPowerEU" initiative, designing three core strategies: energy conservation, expedited integration of renewable energy, and reduction in fossil fuel consumption across transportation and industrial sectors. The EU aims to wean itself off Russian fossil fuels by 2027 and raises again the target share of renewable energy in the overall energy mix to 45%, with 510 GW of installed wind capacity. Among which, 421 GW shall come from onshore wind, with 28 GW of average increase per year, and 89 GW from offshore wind, with 10 GW of average increase per year.**

Germany, the Netherlands, Belgium, and Denmark set their own offshore wind targets for 2030 respectively at 30 GW, 10.7 GW, 5.8 GW, and 12.9 GW, respectively. In 2022, the four countries jointly announced a large-scale offshore wind power target to cumulate 65 GW by 2030, which was 5.6 GW higher than the original goal. In the U.K., wind power is currently the most important source of electricity. With roll-out policy targets, the country aims to double its total onshore wind power capacity from 15 GW in 2021 to 30 GW by 2030, and 35 GW by 2035. As for offshore wind, it plans to cumulate 50 GW of capacity, including 5 GW of floating wind power capacity.

In terms of onshore wind, Europe's REPowerEU plan and the U.K.'s policy targets are very challenging. Based on past installation capacity targets, there is estimated to be 15.8 GW of average annual increase in new installations during 2022 and 2025 in the EU and the U.K. combined, even with incentives in place. Given the time it takes to construct a wind farm, the growth in installed capacity during this period will be limited, despite incentives. From 2026 to 2030, the EU and the U.K. are expected to work on streamlining the approval process to accelerate grid connection, adding an average of 18.4 GW of onshore wind capacity per year. However, both the EU and the U.K. are projected to fall short of their capacity addition goals between 2022-2025 and 2026-2030, due to sluggish approval procedures that have hampered progress. The two regions must solve this issue, otherwise the 2030 target will be left unattained.

In the U.K., offshore wind projects approved for development will be connected to the grid by 2027, adding 28 GW of capacity to the mix. Moreover, the sector is projected to witness 4.5 GW to 6 GW of annual growth between 2028 and 2030. Given that, the country is poised to achieve an impressive 43 GW of cumulative capacity by 2030, nearing its initial policy objectives.

As of 2021, the EU has accumulated 12 GW of installed offshore wind capacity, mainly in Germany, the Netherlands, Belgium, and Denmark. To meet their collective target of 65 GW by 2030 would require an annual addition of 5.9 GW, presenting a formidable challenge. Current project schedules indicate approximately 3 GW of wind farms to be connected to the grid in 2022 and 2023. However, the development may slow down in 2024, as the Netherlands and Denmark will not approve new projects in 2022. To achieve the policy target, the four countries will concentrate their efforts on development between 2028-2030, aiming to add over 20 GW of installed capacity, which is still shy of the initial target.

Meanwhile, new markets are emerging in Europe, with Poland's first offshore wind power project set to be connected to the grid in 2026, bringing 1 GW to 2 GW of growth to the EU between 2026 and 2027. The cumulative offshore wind capacity in the EU is expected to reach 64 GW by 2030, or 107 GW when including the U.K.

2.2 WIND SUPPLY CHAIN

Offshore wind market

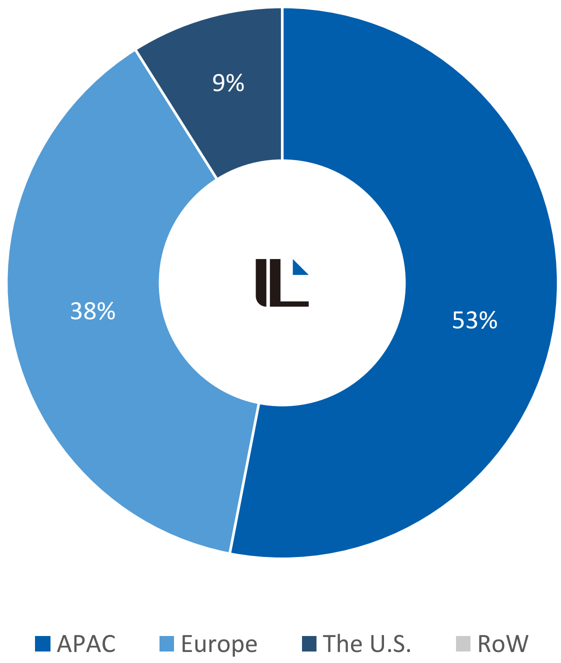


Figure 2.2-1. Share of wind turbine production by region in 2021

In recent years, the Asia Pacific has witnessed a rise of the offshore wind power market, as evidenced by the proportion of wind turbine production across the regions. By 2021, up to 53% of wind turbine production was concentrated in Asia Pacific, led by China, which saw an installation rush that year, followed by Europe at 38% and the U.S. at 9%. Seeing the growing potential in Asian countries, such as Taiwan, Japan, South Korea, and Vietnam, wind turbine manufacturers have started to establish plants in the region. One example is Siemens, which built a wind turbine assembly plant in Taiwan in September 2022 and planned to start production of 14 MW direct-drive wind turbines in 2024, which is expected to provide about 2 GW of installed capacity annually. Other markets of interest include India and China. India has the fourth largest installed wind capacity in the world, reaching nearly 38 GW by 2020, while China's onshore and offshore wind sectors are developing at a steady pace and will supply the Asia-Pacific region in the future.

In terms of the prices of wind turbines, after declines in previous years, prices rebounded in 2022 as wind turbine manufacturers faced significant pressure from inflation and a global supply chain disruption. Steel, constituting nearly 80% of the total weight of a wind turbine (up to 90% if including the underwater foundation), has been increasing in price in the U.S., Europe, and China since 2020. Compared to the 2019 low, steel prices in the U.S. more than tripled in 2022, while those in Europe rose by two to three times. China, on the other hand, saw a relatively modest increase of 40% to 50%. In addition, the price per container of the China Containerized Freight Index (CCFI) escalated from about EUR 1,000 in 2020 to EUR 5,000 in early 2022. Despite the recent fall in steel and shipping prices, previous increases have forced turbine manufacturers to raise turbine prices and included risk sharing clauses in re-negotiations with buyers to deflect inflationary pressures.

The prices for wind power purchase agreements increased by about 18% in the first half of 2022 compared to pre-pandemic levels, which Siemens said would bring wind turbine prices back to 2017 levels. Compared to 2021, average wind turbine prices increased by 20% to 30% in the first half of 2022 for Siemens and by 10% to 20% for Vestas, whose onshore wind turbine prices rose again in the third quarter to EUR 1.06 million/MW. **However, even with the price adjustments, Siemens and Vestas still suffered losses, with gross margins for Siemens' core business at -5.9% and Vestas at -3.2% over the first quarter to the third quarter period.**

Differences in wind turbine technology

In 2021, double-fed induction generators remained the dominant technology adopted, with a market share of 55%, followed by direct-drive permanent magnet generators with a market share of 22%. Double-fed and direct-drive generators differ in the main components of a wind turbine, such as the generator and inverter. The main difference between these two generators is that the double-fed type employs a gearbox, while the direct-drive type does not.

Direct-drive generators operate through connecting the generator to the impeller. Since the gearbox is prone to overload and damage in megawatt-level wind turbines, the direct-drive type is less likely to fail than the double-fed type, thus reducing operation and maintenance costs.

In addition, direct-drive turbines have no speed limit at low wind speeds. However, their power devices and cooling equipment tend to consume more power due to the high power loss of the full power inverter, which has three times the capacity of the doubly-fed type. Despite the absence of a speed limit, the amount of wind energy a wind turbine can absorb is proportional to the third power of the wind speed, making the amount of wind energy available at low wind speeds very limited. Companies that employ the direct-drive technology include Siemens Gamesa and Goldwind.

Although double-fed turbines are currently the dominant technology, their small capacity is not conducive to the trend towards larger turbines. Moreover, their complex construction results in higher failure rates and maintenance costs. With the high requirement on reliability of offshore wind turbines and decreases in price, it is expected that the outlook for double-fed generators is moderate. Representative manufacturers of double-fed generators include Vestas, General Electric, Sinovel, Ming Yang, Shanghai Electric, etc.

The semi-direct-drive generator combines the advantages of both the direct-drive and double-fed types. It has a low failure rate, requires less maintenance, costs less, which is suitable for offshore wind power and can satisfy the future demand for large wind turbines, making it possible to become a mainstream technology in the industry. Some wind turbine developers have adopted semi-direct drive technology, such as Ming Yang Smart Energy.

Large-sized wind turbine

Blades with larger diameters can sweep over a larger area, allowing wind turbines to capture more wind and generate more power, even in areas with little wind. Since around 2000, there has been a progress in the size of wind turbines. The average size of offshore wind turbines from 2021 to 2022 is 6 MW to 9.5 MW; meanwhile, leading wind turbine manufacturers, such as Vestas, Siemens Gamesa and General Electric, have started to introduce large 14 MW to 15 MW wind turbine technologies for wind farms to be completed around 2025 to 2026. InfoLink expects 17 MV to 18 MW offshore wind turbines to gradually become mainstream by 2030, with an average size of 15 MW.

Table 2.2-1. Size of large offshore wind turbines

	2021 - 2022	2023 - 2026	2027 - 2028	After 2029
Fan size, Unit: MW	6 - 9.5	14 - 16	17 - 18	20
Blade diameter, Unit: m	150 - 164	222 - 236	240 - 250	250 - 300

The purpose of larger turbines is to increase the ability to capture wind energy by increasing the area the turbine sweeps. When the length of the blades doubles, the area covered becomes four times larger, enabling the manufacturers to increase the rated capacity of the turbine.

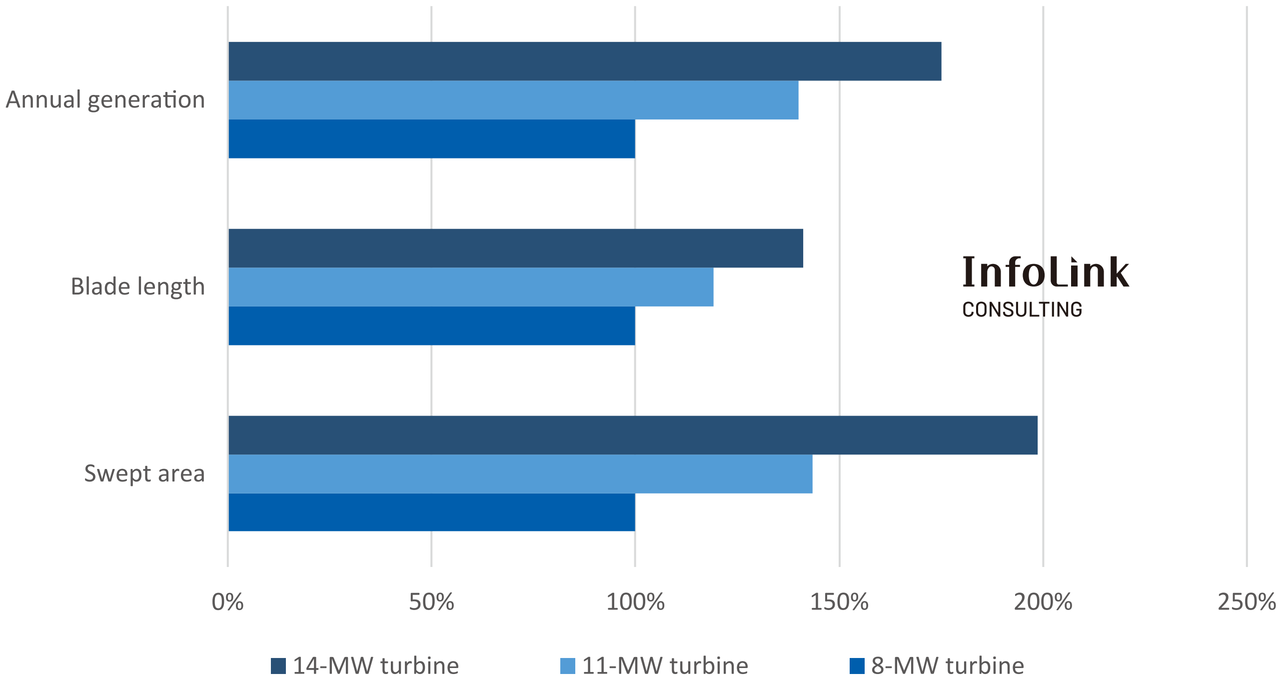


Figure 2.2-2. Offshore wind turbine performance by size (Based on Siemen's 8-MW turbines)

Taking Siemens Gamesa as an example. Its 11-MW wind turbine has 43% more swept area and generates 40% more annual electricity than its 8-MW counterpart, while its 14-MW turbine has nearly twice the swept area and generates 75% more annual electricity than its 8-MW counterpart. It is expected that the Siemens Gamesa's 14 MW wind turbine, Vestas' 15 MW wind turbine and Ming Yang's 16 MW wind turbine will be in commercial production; while the General Electric's 14 MW prototype, which has been in operation in the Netherlands since October 2021, will soon be installed at the Dogger Bank C wind farm off the UK coast.

Larger wind turbines not only facilitate the acquisition of wind energy, but also help to reduce costs. Despite the higher cost per unit, the use of larger turbines on sites of the same size will save more money for balancing systems (e.g., underwater foundations) due to the fewer number of turbines required, thus reducing the levelized cost of energy.

Wind turbine installation vessel market

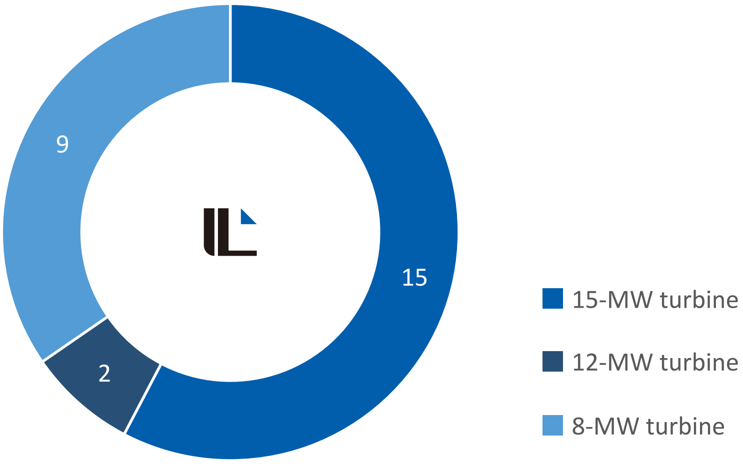


Figure 2.2-3. Share of WTIV lifting capacity by turbine size in 2025, Unit: vessel
WTIV* = wind turbine installation vessel

The wind turbine installation vessel (WTIV) market is facing two challenges: the trend of larger wind turbine and the rapid growth of offshore wind power market. Due to the increased nacelle height, tower height, and underwater foundation weight of new large turbines, the lifting hook height of wind turbine installation vessels and the lifting capacity of underwater foundation installation vessels may not be sufficient for the new 14- and 15-MW turbines. For example, an 8-MW wind turbine has a minimum lifting height of about 140 meters and a lifting capacity of about 600 tons, while a 15-MW wind turbine requires a lifting height of 175 meters and a lifting capacity of at least 1,300 tons. In this case, only two existing WTIVs in 2022 meet the requirements, namely Jan de Nul's Voltaire and Fred Olsen's Upgraded Bold Tern.

Voltaire has a lifting height of 187 meters and a lifting capacity of 3,000 tons to take on both underwater foundation installation and wind turbine installation, while Upgraded Bold Tern was upgraded in Singapore in 2021 to support new 15-MW wind turbines. There are another 18 vessels compatible with 15-MW wind turbines that are expected to become operational within the next five years. While this number may seem impressive, it is likely that there will be a shortage of supply after 2025 if there are not enough WTIVs putting into service, as the larger wind turbines will push inadequate vessels to retire or be upgraded.

Underwater foundation installation vessels also require greater lifting capacity, ranging from 1,500 to 2,000 tons, in response to the larger size of wind turbines. According to available data, **there will be about 45 vessels worldwide capable of installing underwater foundations by 2025, with 15 of them having a lifting capacity of only 1,500 tons, and another 15 also capable of installing 15-MW turbines.** Therefore, despite the seemingly sufficient vessels compatible with underwater foundation installation of 15-MW wind turbines by 2025, some of them may have to share capacity with wind turbine installation. If necessary, foundation installation vessels that are not dedicated to offshore wind power (i.e., heavy lift vessels used by the oil and gas industry) may be used as an alternative, but these types of vessels are more expensive and will drive up the cost of wind farm development.

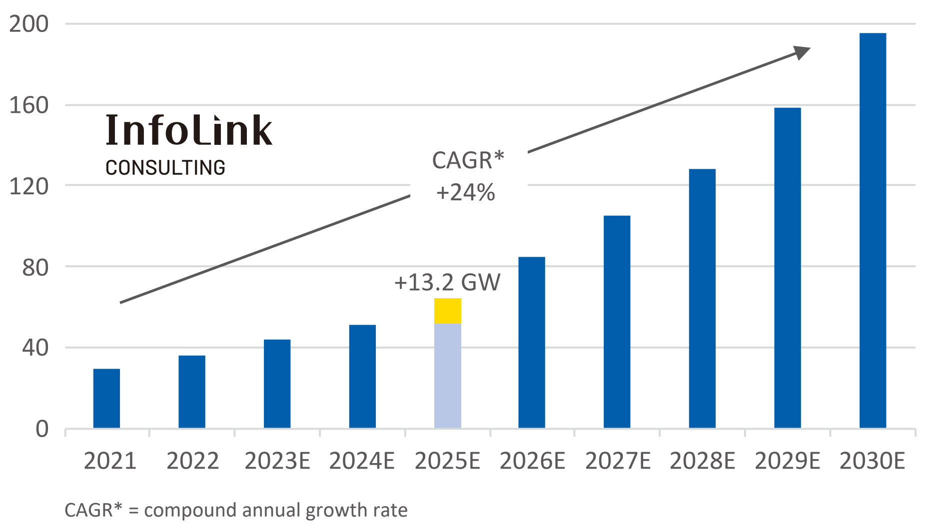


Figure 2.2-4. Global cumulative offshore wind installed capacity (excluding China), Unit: GW

Wind turbine manufacturers are joining the race to upgrade their equipment as larger wind turbines can significantly improve power generation efficiency and save costs. Siemens, for example, took three years to go from commercial production of 8 MW to 11 MW wind turbines, and only two years to go from 11 MW to 14 MW ones. While some believe that wind turbine manufacturers may stop at 15 MW, there is no doubt that once someone sizes up turbines to 20 MW, others will follow suit. This has raised concerns among shipowners and underwater foundation builders about whether wind turbines will scale up faster than expected, making previous investments worthless or requiring upgrades.

On the other hand, the explosive growth of the global offshore wind market has put considerable pressure on the supply chain, and the shortage of WTIVs could become a bottleneck that hinders growth of the industry. InfoLink estimates that, excluding China, the compound annual growth rate (CAGR) of global offshore wind capacity additions from 2021 to 2030 will be 27%, with global (excluding China) additions reaching approximately 13.2 GW in 2025. Based on data from 2021, the average annual installation capacity of each WTIV is approximately 500 MW (about 60 turbines), which means 27 WTIVs would be required to meet the demand. By 2025, production of the new 14- and 15-MW turbines will begin at commercial scale, bringing the average installed capacity of a single turbine to 12 MW, up from 8 MW in 2021. If the number of turbines that each WTIV can install remains at 60 per year, the installed capacity that each vessel could handle would rise to 720 MW per year.

Estimate by the 13.2 GW of new installations, the global market (excluding China) will need 19 WTIVs after 2025. **The number of installation vessels available is estimated to be 26 in 2025, with only 15 capable of lifting 15-MW turbines. Most of these 15 vessels will be built between 2022 and 2025, and if the rest of the vessels are not upgraded, the supply will fall short of demand.** In addition, as it takes about four years to build installation vessels, coupled with a surge in steel prices in 2021 and interest rate hikes by central banks in 2022 to curb global inflation, shipowners are delaying the start of construction, which will add to the shortage of WTIV supply.

2.3 WIND LCOE

Calculation

The calculation of offshore wind generation costs is based on the levelized cost of energy (LCOE), which presents the cost per unit of generation plants as well as costs of project investment, financing, and maintenance. Europe and the U.S.' models, calculating with 2021 benchmark, are mainly composed of capital expenditure, maintenance costs, capacity factor, and fixed charge rate. China, on the other hand, is calculated on a yearly basis as its onshore and offshore wind involve complex tax costs. China's model is calculated by using feed-in tariff rate as a reference for tax costs, covering capex, maintenance costs, capacity factor, the income tax policy of "3-year exemption and 3-year half payment,"[4] the value-added tax policy of "50% refund-upon-collection," and degradation of wind turbines.

[4] China's offshore wind enjoys the "3-year exemption and 3-year half payment" policy, under which eligible companies are exempt from income tax for the first year to the third year of its operation, and 50% reduction from the fourth to the sixth year of operation. The government also provides offshore wind businesses "50% refund-upon-collection." The refund excludes the urban maintenance and construction tax and education surcharge attached to the original value-added tax.

Industry overview

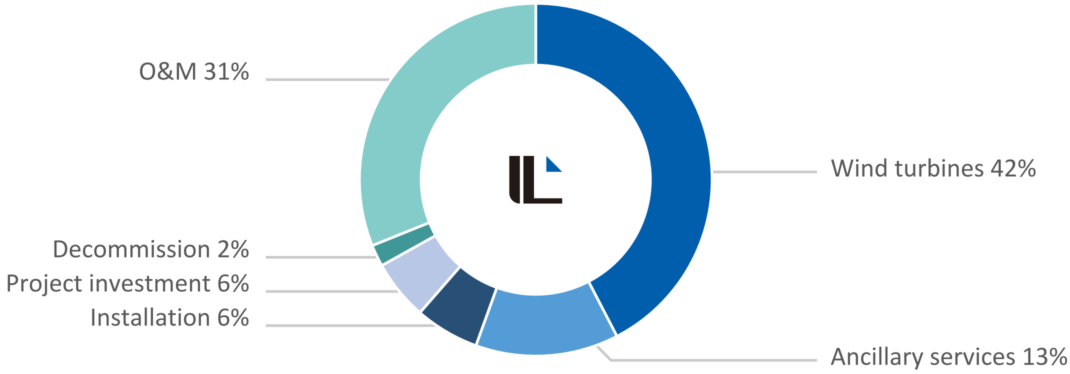


Figure 2.3-1. Cost structure of onshore wind

Onshore wind generation cost estimate is calculated based on 200-MW wind farm (Consisting of 73 turbines with 2.8 MW capacity each). The capex takes up 68.9% of total costs, while operation and maintenance accounts for 31.1%. Of the capex, wind turbines are the costliest, accounting for up to 42% of the total, followed by ancillary services, which represent 13%.

Note: Fixed charge rate (FCR) is used for annualized capex and take into account debt, shareholder equity, and project life cycle.

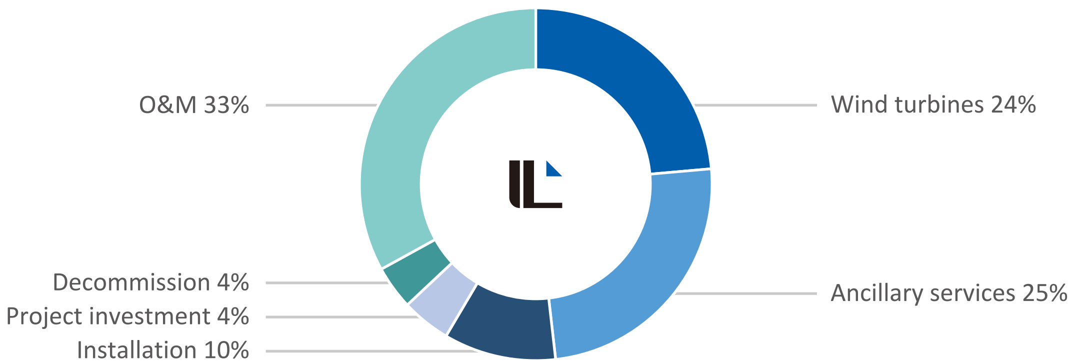


Figure 2.3-2. Cost structure of offshore wind

Offshore wind has far higher requirement on capital and technology compared with other green technologies such as onshore wind and solar PV. This is because the costs for offshore wind infrastructure including underwater foundation, turbines, and offshore substation are high, and it requires special vessels and skilled workers to construct a wind farm. Moreover, the administration process of wind farm development is complicated. These factors set a high bar compared with most renewable energies. A 1,000 MW wind farm consisting of 100 10-MW turbines sees its capex account for 78% of the total cost, while O&M expenditure accounts for 22%. Turbines take up the highest percentage of the total capex, accounting for 21%, followed by auxiliary equipment that represents 15%, which is the same of onshore wind. The cost structure of offshore wind is more evenly distributed than that of onshore wind, and the cost is also higher given offshore construction is more difficult.

Factors that drive costs down

From a cost structure perspective, turbines account for the highest percentage of costs for both offshore and onshore wind. Therefore, technology advancement in sizing up and improving turbines is the major factor driving down offshore wind costs. **Between 2021 and 2022, the global weighted average levelized cost of electricity (LCOE) for onshore wind increased by 2.3% from USD 33.85/kWh to USD 34.64/kWh, while that of offshore wind increased by 3.2% from USD 89.03/kWh in 2021 to USD 91.86/kWh.** 2022 was a tough year for both onshore and offshore wind sectors. Clogged supply chain and congested freight caused by recovering economy in 2021 had persisted into the first half of 2022, driving up steel prices, which witnessed an increase of 40% at its peak. As a result, manufacturing costs of turbines and underwater foundation surged, forcing large manufacturers including Siemens, Vestas, and Norde to raise prices to offset their cost pressure. InfoLink estimates that the sales prices of turbines have increased by 10% to 20%, pushing up capex of wind farms in Europe and the U.S. further.

In the long run, wind power generation will gradually mature. With complete technology, process flow, and manufacturing equipment, as well as competition in the supply chain, turbine prices will gradually decline. Yet, prices of major raw materials such as steel, fiberglass, resin, and plastics are prone to turbulation caused by inflation and trade barrier. Moreover, maintenance and installation costs for turbines and cable reduce as the number of turbines required for a wind farm of the same size decreases. These factors drive wind turbine manufacturers to develop larger turbines, such as Siemens Gamesa’s 6.6-MW onshore wind turbine and 14-MW offshore wind turbine; Vestas’ 4.5-MW onshore wind turbine and 15-MW offshore wind turbine; and General Electric’s 12-MW offshore wind turbine, to name a few.

Advanced turbine technology, higher turbine hub height, and longer blade contribute to larger swept area, therefore increasing capacity factor. The capacity factor of onshore and offshore wind turbines worldwide has grown year on year as turbines size up. However, the onshore wind sector has become saturated while the wind speed condition less ideal compared with the previous years, making the capacity factor growth from 2021 to 2030 lower than the past decade. In light of this, the capacity factor in the three largest onshore wind markets is estimated to increase 1% to 3%. Offshore wind, on the other hand, is less saturated, and therefore is estimated to see 3% to 4% of increase in capacity factor from 2021 to 2030.

In the offshore wind industry, ships and port infrastructure are unable to catch up with the rapidly developing turbine size. Currently, there are only two vessels in the world that can install 15-MW turbines. The shortage of installation vessels could hinder the development of large turbines.

Another factor driving costs down is cheap capital. The key of LCOE estimate is weight average cost of capital (WACC), which is mainly determined by the risk and interest rate of invested projects, as well as returns required by stakeholders. The wind industry is benefited from the monetary policy of central banks, with hot money flows pressing down the loan interest. For example, financing rate in Europe had sustained at 0% from mid-2016 to mid-2022, allowing interest rates of many onshore wind farms to keep below 2%. The WACC of wind farms could be reduced to 3% to 4% and even 1% to 2% in countries with lower risks such as France and Germany, helping drive down capex. However, as central banks in Europe and the U.S. raised interest rates to keep inflation, the US base rate had reached 4% in early November 2022, while the main refinancing operations came in at 2% in Europe, meaning that wind farms have no longer enjoyed cheap capital. Based on the previous risk premium, the loan cost of a new wind farm may rise to around 4%, which is expected to persist into 2023. Interest rate movement would affect the cost estimates of developers and even the signing of PPA of new wind farms. For instance, Avangrid, a subsidiary of Iberdrola, requested Massachusetts to halt the investigation of PPA in October 2022 due to rising interest rates and other factors.

Other factors contributing to cost reduction include clear policy that can encourage the supply chain to scale up investment, the establishment of logistics, and the economies of scale of wind farms. The competition between operation and maintenance (O&M) teams, newly developed O&M strategies, and the economies of scale also drive down O&M costs.

Offshore

China

Under the standard scenario, China's LCOE is USD 72.49/MWh (RMB 521.30/MWh) in 2021 and USD 70.01/MWh (RMB 503.47/MWh) in 2022, a decrease of 3.5%. Since 2022, the central government subsidy for offshore wind power in China has been withdrawn in favor of subsidies from local governments and a gradual move toward grid parity. For local government subsidies, Guangdong and Shandong are the only two provinces that have introduced subsidy programs, both of which are relatively inadequate.

Guangdong, for example, provides subsidies ranging from USD 69.52/kWh to USD 208.59/kWh (about RMB 500/kWh to RMB 1,500/kWh) depending on the time of grid connection, compared to the original feed-in tariff of USD 0.12/kWh (RMB 0.85/kWh). With the goal to reach grid parity, the entire offshore wind supply chain is under tremendous pressure to reduce costs, with wind turbines bearing the brunt.

One example is the Zhejiang Taizhou-1 offshore wind project in 2022, where the price of a wind turbine, including the tower, is only USD 493.38/kW (RMB 3,548/kW), nearly half of the average price of USD 973.41 (RMB 7,000) per kW for a wind turbine in 2020. Although the alarming rate of reduction may be a temporary phenomenon for manufacturers to compete for market share, the technological advancement of wind turbines, such as larger wind turbines, longer blade lengths with carbon fiber composite materials replacing glass fiber, supply chain localization in China, and economies of scale in the wind turbine industry, have accelerated the reduction of wind turbine costs. While other projects (e.g., underwater foundations, electrical equipment, etc.) are not subject to such a large cost reduction pressure, InfoLink projects that there will also be a 20% to 30% price decrease in cables and power plant auxiliary equipment to achieve the goal of grid parity.

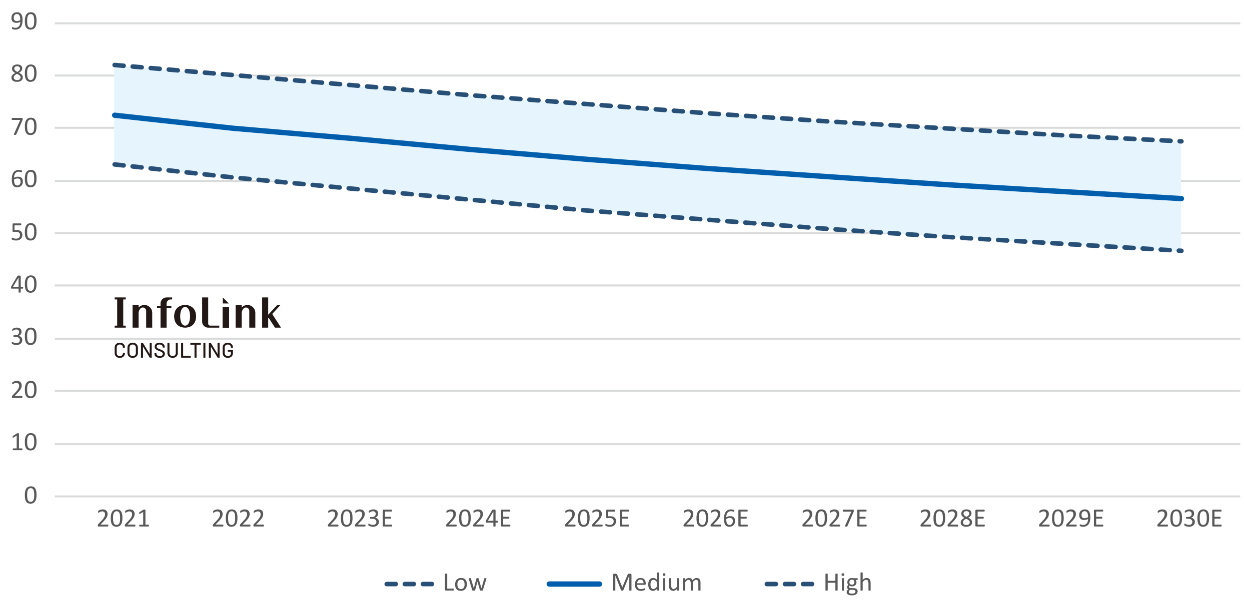


Figure 2.3-3. LCOE developments in China's offshore wind sector (2021-2030), Unit: USD/MWh

Under the standard scenario, assuming a system degradation rate of 1.6% for wind turbines, a project period of 25 years, an internal rate of return (IRR) of about 6% to 8%, and taking into account China's value-added tax (VAT), income tax, and related tax incentives (i.e., 50% VAT rebate and income tax reduction), Infolink estimates that by 2025, the LCOE will fall to USD 64.11/MWh (RMB 461.03/MWh) by 2025 and steadily decline to USD 56.68/MWh (RMB 407.61/MWh) by 2030.

In this scenario, InfoLink assumes that **the cost reduction in the past is not only due to competition for market share by wind turbine manufacturers, but a normal path following the learning curve with technology development and large-scale, specialized production, so that the cost will not rebound** and will keep falling until 2030. Among the reduction in capex, wind turbines and towers account for 48%, representing the main driver of LCOE reduction in China's offshore wind sector. As large wind turbines enter the market, the capacity factor is expected to grow steadily at an annual rate of about 1%. Additionally, provinces with higher wind speeds, such as Fujian located near the Taiwan Strait, are expected to be the first to achieve grid parity.

A conservative scenario assumes that the reduction in wind turbine prices is driven by competition for market share. To ensure reliable operation, the ideal price for wind turbines and towers in 2021 would be approximately USD 695.30/kW (RMB 5,000/kW), with a system degradation rate 0.2% higher than in the standard scenario and an LCOE of USD 67.43/MWh (RMB 484.92/MWh) in 2030. Only a few provinces are able to achieve grid parity, as they adopt higher coal-fired guidance price, such as Guangdong.

An optimistic scenario, on the other hand, assumes that the cost reductions occur naturally due to economies of scale in the industry. The previous subsidy policy obscured the actual prices of wind turbines and towers. After the subsidies were withdrawn, fierce competition in the supply chain allowed the cost of wind turbines to drop to half of the previous level, with the annual system degradation rate 0.2% lower than that in the standard scenario. The LCOE in 2030 would be USD 46.61/MWh (RMB 335.20/MWh), with most provinces achieving grid parity.

The U.S.

The US offshore wind market did not receive enough attention until early 2021 when the Biden Administration set a target of 30 GW of offshore wind capacity by 2030 and 110 GW by 2050, which accelerated the development of offshore wind on the East Coast of the U.S., such as New York, Massachusetts and Delaware. In addition, the new target set in September 2022 to reach 15 GW of installed floating wind capacity by 2035 and reduce costs by 70% is expected to stimulate the development of floating wind power on the West Coast, where the seabed has been rapidly deepening, such as California, Maine, and Oregon, leading to another wave of growth for offshore wind power in the U.S.

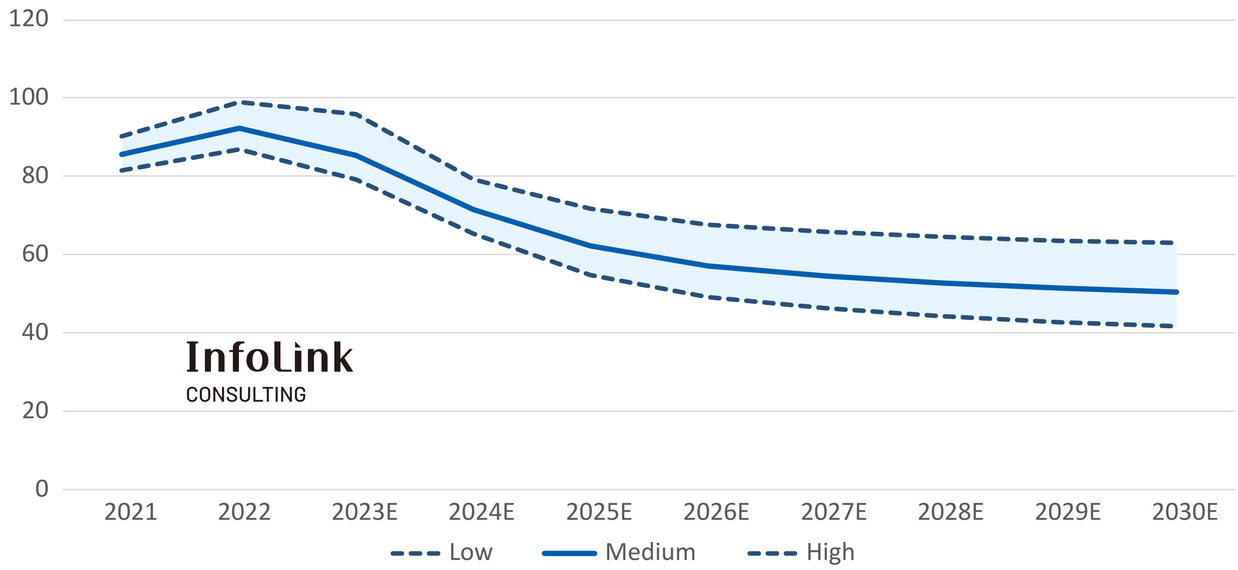


Figure 2.3-4. LCOE developments of offshore wind sector in the U.S. (2021-2030), Unit: USD/MWh

On the other hand, the IRA of 2022 extended the application of 30% the ITC for offshore wind power until the power sector greenhouse gas emission reduction target is met, which should benefit offshore wind farms that are scheduled to start construction before Jan. 1, 2026. After 2023, the Act is expected to help reduce the LCOE by more than 10%, estimated Infolink. For example, the winning bid for Mayflower Wind's 800 MW project in Massachusetts is USD 77.76/MWh, and then the electricity is sold for USD 70.26/MWh after the bill was introduced, allowing US residents to enjoy more affordable offshore wind power.

In the standard scenario, the LCOE for offshore wind farms in the U.S. would **fall from USD 85.68/MWh in 2021 to USD 62.25/MWh in 2025 and reach USD 50.42/MWh in 2030. Due to fluctuations in interest rates and raw material prices in 2022, the LCOE increased by approximately 8% to USD 92.41/MWh in 2022 compared to 2021. Therefore, InfoLink adjusted the capex and weighted average cost of capital (WACC) for wind farms in 2022 and 2023.**

As steel makes up nearly 90% of the weight of the wind turbine and the underwater foundation, the pressure of rising costs due to the surge in steel prices and supply chain disruptions from 2021 to the first half of 2022 will be reflected in the wind farms built during 2022 and 2023. InfoLink estimates that capex for wind farms will increase by 9.55% in 2022 compared to the original scenario due to higher wind turbine prices, and that increase will narrow down to 4.83% in 2023. The LCOE must also include the increase in borrowing costs due to interest rate increases, resulting in a 6.25% increase in 2022 and a 3.21% increase in 2023 compared to the original estimate.

However, if looking at the long term, the construction cost will continue to decline from USD 4,095.52/kW in 2021 to USD 2,904.08/kW in 2025 and USD 2,378.50/kW in 2030. This is because specialized production of wind turbines and underwater foundations, as well as competition in the supply chain, have allowed for significant cost reductions. Specifically, 25% of the estimated reduction in capex comes from the development of large wind turbines and the specialization of manufacturing, which represent the majority of all factors. Moreover, the capacity factor is growing at a rate of 0.85% to 1.41% per year due to the development of large wind turbines and a lower incidence of unexpected shutdowns, allowing for more power production per unit of capex.

In terms of O&M, the economies of scale achieved by the concentration of nearby wind farms reduces the unit cost of O&M, which is estimated to fall from USD 125.15/kW in 2021 to USD 88.74/kW in 2025 and USD 72.68/kW in 2030. As a result, with reduced capex and O&M expenses, the LCOE is USD 62.25/MWh in 2025 and USD 50.41/MWh in 2030. Both the optimistic and pessimistic scenarios take into account the growth rate of capacity factor due to progress of large turbine development, capex due to supply chain learning and specialization, and the reduction level of O&M cost as the US industry develops. Ultimately, the LCOE is expected to fall to USD 41.64/MWh in 2030 under the optimistic scenario, and USD 62.96/MWh under the pessimistic scenario.

Europe (EU and the U.K.)

The war between Russia and Ukraine has significantly impacted the European energy markets, resulting in skyrocketing energy prices and inflation. This has led to **a 9.6% increase in capex in 2022 compared to the original estimate, and a 6.8% increase in the LCOE from USD 104.07/MWh (EUR 102.43/MWh) to USD 111.17/MWh (EUR 109.42/MWh) compared to 2021. While the LCOE remained high from 2022 to 2023,** it is expected to decline in 2024 when the inflation eases and steel prices fall. Wind farms in Europe tend to sign PPAs as the market is mature. Most of the wind farms to be connected to the grid between 2023 and 2025 have already sealed PPAs (e.g. the Dogger Bank project in the U.K.), with the LCOE expected to fall to the level of corporate power purchase price. In 2026, as technological innovations make 14 MW wind turbines widely available in Europe, along with achievement of economies of scale, the LCOE will fall slightly.

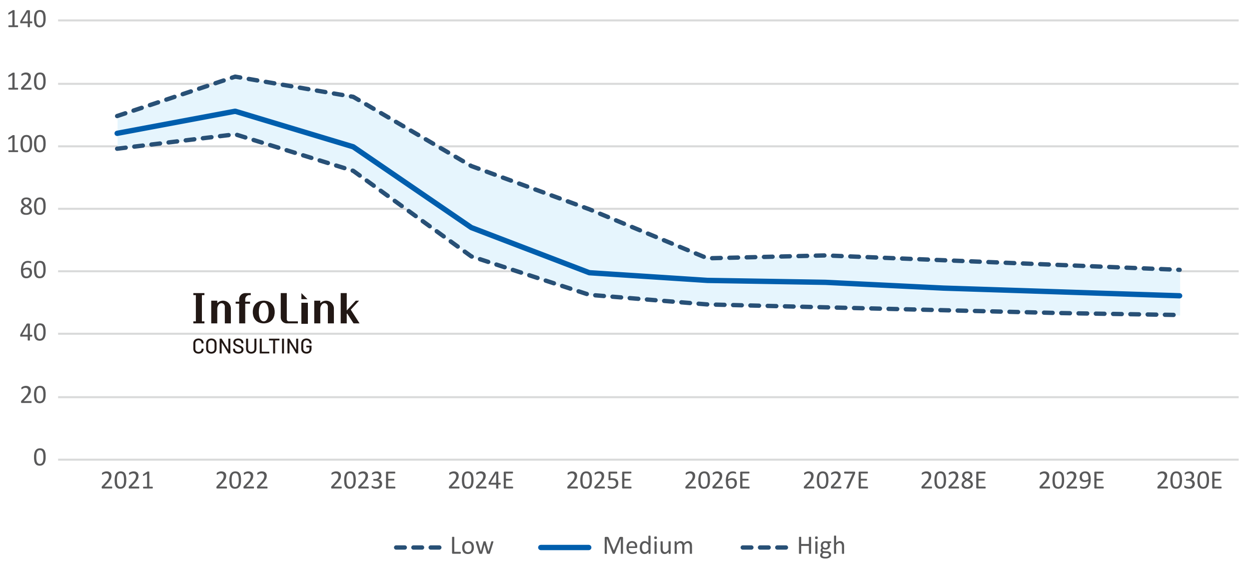


Figure 2.3-5. LCOE developments of offshore wind sector in Europe (2021-2030), Unit: USD/MWh

InfoLink projects that raw material prices will gradually decline in 2023, and LCOE will steadily decrease from 2023 to 2025, and is expected to fall below USD 60/MWh (EUR 58.55/MWh) in 2025. However, demand for renewable energy in Europe will rise between 2025 and 2026 in response to each country's net zero emissions target, driving up PPA prices and significantly constraining the reduction of LCOE. As a result, the LCOE in 2030 is estimated to be around USD 52.27/MWh (EUR 51.44/MWh).

In a pessimistic scenario, if the impact of the war between Russia and Ukraine continues for several years, the LCOE in Europe will start to drop significantly in 2025. In addition, demand for renewable energy will continue to rise in 2027, which pushes up the PPA price and thus reduces the pressure of cost reduction. Meanwhile, countries such as **Germany and the Netherlands will start to adopt "negative bidding," where the government will charge fees for developing wind farms, resulting in a 2.7% to 18.8% increase in capex** (depending on how negative bidding is implemented) and a 1.1% increase in the LCOE in 2027 compared to 2026. However, technological innovations such as large wind turbines will leave room for capex to decline after 2027, with an estimated LCOE of USD 60.64/MWh (EUR 59.69/MWh) for 2030.

Onshore

China

Since 1986, China has been exploring the utilization of onshore wind energy. The State Council of the People's Republic of China set a target in 2021 to achieve at least 1,200 GW of cumulative installed capacity of solar and wind together by 2030. As of 2021, the cumulative installed capacity has reached 320 GW.

China has established a domestic supply chain of onshore wind, spanning turbine manufacturing, O&M, components, and modules, allowing its levelized cost of energy to drop rapidly. Between 2010 and 2020, China's LCOE of onshore wind decreased by 36% and reached grid parity in 2021. The wind curtailment rate stayed high from 2011 to 2018, averaged at 12.9% over the eight years and impacted the willingness of wind farm development. However, the situation has significantly improved in recent years, with curtailment rate keeping under 10% after 2019.

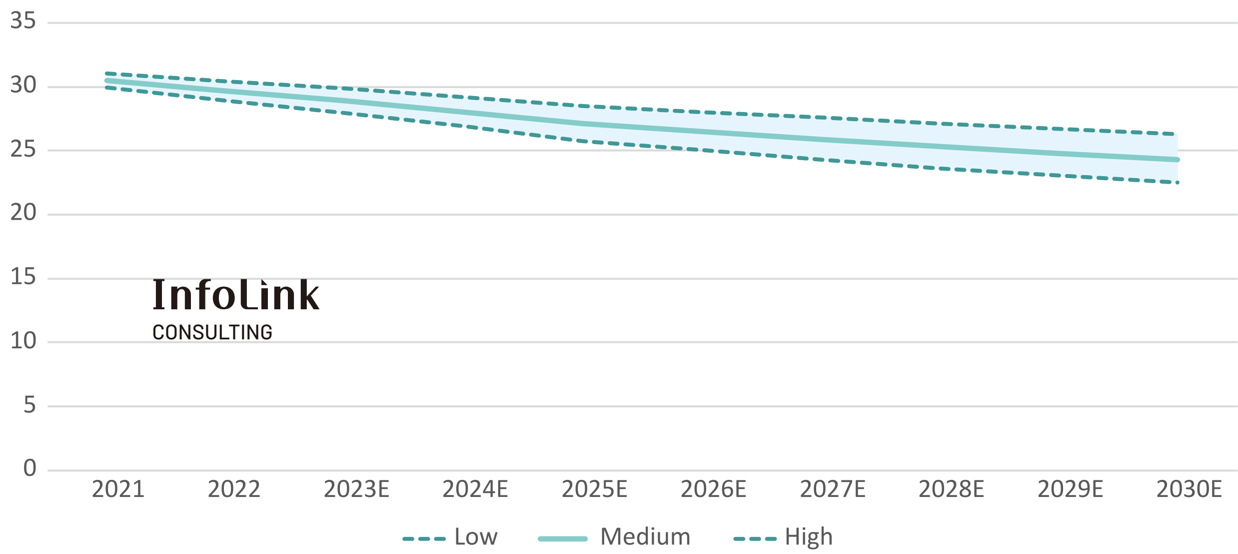


Figure 2.3-6. LCOE developments of onshore wind sector in China (2021-2030), Unit: USD/MWh

In 2022, the LCOE of onshore wind energy in China was USD 29.66/MWh (RMB 213.31/MWh), down 2.69% from USD 30.48/MWh (RMB 219.21/MWh) in 2021. Different from Europe and US' turbine prices that are pushed up by geopolitical factors and inflation, China's onshore wind turbine prices have declined steadily from 2021 to 2022. The winning bid prices for turbines (excluding tower) stood at RMB 2,000/kW in early 2022, and then declined to RMB 1,700-1,800/kW in the middle of the year, and manufacturers have no intention to renegotiate prices to pass on pressure from inflation. This can be ascribed to China's successful localization of turbine components, which safeguards them from geopolitical impacts and surging international freight rates. The force of fierce competition between turbine manufacturers and cost reduction brought by larger turbines goes beyond price increases in the supply chain.

InfoLink estimates LCOE of onshore wind under three scenarios in which China's installed onshore wind capacity exceeds 700 GW in 2030 and with the same condition of lower capex owing to local supply chain and installation and equipment cost reduction brought by larger turbines. Under the standard scenario, **China's LCOE will decline to USD 27.12/MWh (RMB 195.2/MWh) in 2025 and come down further to USD 24.32/MWh (RMB 174.93/MWh) in 2030, down 21% from 2021 and far lower than China's coal-fired electricity price of USD 51.8/MWh (RMB 370/MWh).** Under a conservative scenario, the LCOE will reach USD 26.32/MWh (RMB 189.26/MWh) in 2030 provided that annual system degradation is higher and improvement rate is lower and considers capacity factor growth. Under an ideal scenario, rapidly development of larger turbines brings down installation cost further, with LCOE coming in at USD 22.49/MWh (RMB 161.73/MWh) in 2030.

The U.S.

Presently, the U.S. focuses on the offshore wind development, while there's no specific installation or cost reduction target for onshore wind as the sector has reached maturity. Supply chain pressure and technology maturity result in little room for cost reduction, while price increases in raw materials such as steel and higher logistics costs after Covid-19. Against these backdrops, turbine manufacturing costs will rise slightly. Yet, overall capex will break even as projects scale up despite higher turbine costs. Wind farms with more than 200 MW of capacity see the most significant cost reduction driven by economies of scale.

Under the IRA introduced by the Biden administration, the PTC for onshore wind is extended until 2033. The old PTC was scheduled to expire on Dec. 31, 2021, with projects starting construction from 2021 eligible for a full credit of 60%. The new PTC provides full credit from 2022 to 2033, meaning that projects that begin constructed during 2022 and 2030 will enjoy PTC, allowing LCOE to drop markedly. As per IRA, the base credit amount for wind projects is 0.3 cents/kWh and is worth 1.5 cents/kWh if the Wage and Apprenticeship Requirements are met (subject to applicable inflation adjustments). The PTC after inflation adjustment in 2021 is 2.5 cents/kWh. InfoLink estimates LCOE after 2021 based on an annual inflation rate of 2%.

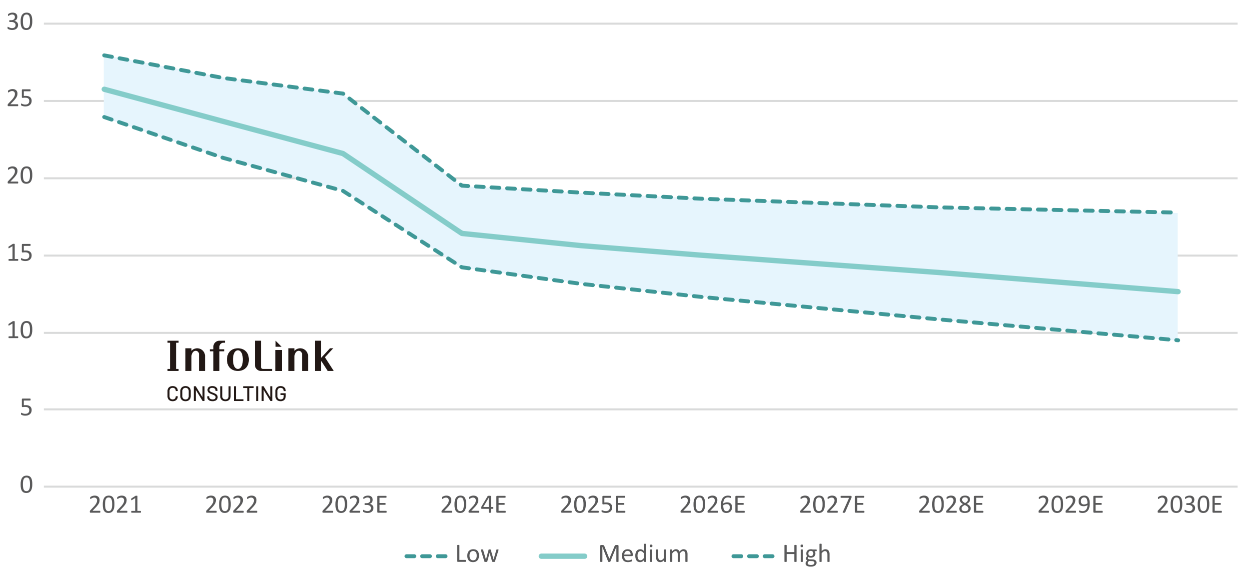


Figure 2.3-7. LCOE developments of onshore wind sector in the U.S. (2021-2030), Unit: USD/MWh

According to the U.S.' development plan for wind energy, the country aims to bring the installed onshore wind capacity to 204 GW by 2030. The LCOE is estimated based on the experience curve as onshore wind in the U.S. has reached maturity. In 2022, steel prices surged due to inflation, affecting prices for turbines and foundations. This led to an increase of 7.3% of total capex compared to the previous forecast. However, considering advanced turbine technology and larger size, there's increase of 1.0% in capacity factor. Between 2021 and 2022, LCOE declined slightly from USD 25.76/MWh to USD 23.68/MWh, down 8.1% from 2021. InfoLink projects that raw materials price increase may ease in 2023. Meanwhile, there will be more projects entering construction due to extended PTC. Given the land use has become saturated, the site and wind speed of wind farms are less ideal than before. As a result, capacity factor will have no more than 0.5% of growth from 2025 onwards and stabilize in 2029. It's estimated that LCOE will reach around USD 14.65/MW in 2025 and decline to USD 12.67/MW in 2030.

Under a pessimistic scenario, the impact of raw material price increases will persist into 2023. On the conditions that capacity factor starts declining from 2024 to 2025 because the improvement rate is lower, LCOE sits at USD 26.68/MWh in 2022, and the impact of poor wind farm conditions is greater than the positive impact brought by larger turbines and advanced technology, it's estimated that the LCOE will sit at USD 19.31/MWh in 2025 and USD 18.17/MWh in 2030.

Europe (EU and the U.K.)

Wind power has become a key source of electricity in Europe. To achieve a 55% reduction in greenhouse gas emissions by 2030, the EU aims to accumulate an onshore installed capacity of 343 GW by 2030. With maturing technology and the scaling up of wind turbines, competition in onshore wind farm bidding intensifies. In 2021, Spain saw a bidding price of USD 20.32/MWh (EUR 20/MWh). Although lackluster reviewing process slowed down the growth of onshore wind in Europe in 2021, the Russia-Ukraine conflict in 2022 will prompt European countries o accelerate wind farm reviews to address the electricity shortfall.

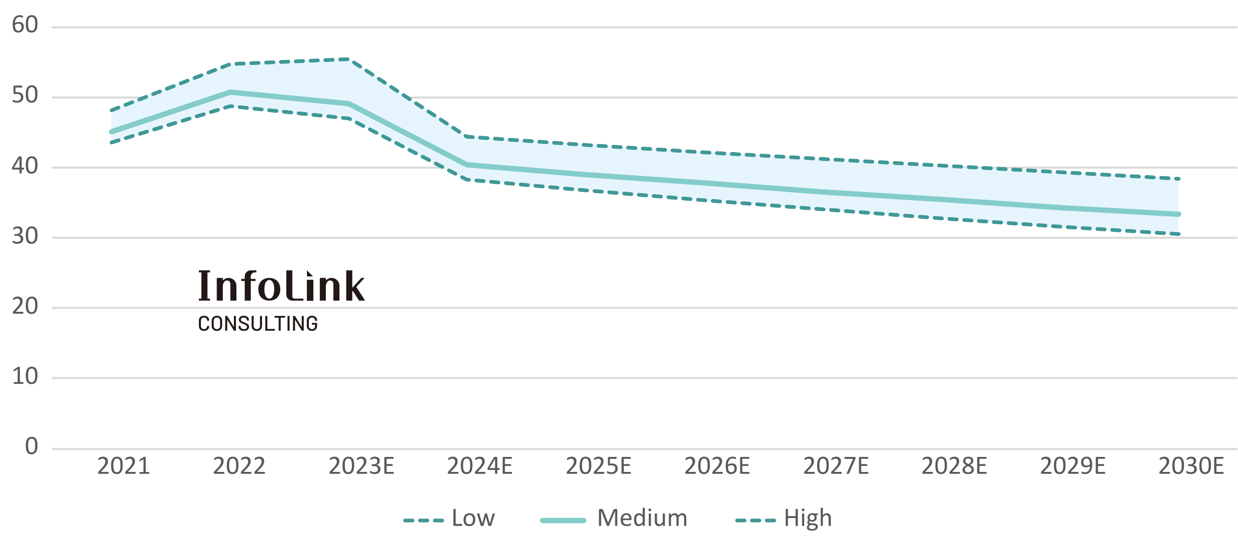


Figure 2.3-8. LCOE developments of onshore wind sector in Europe (2021-2030), Unit: USD/MWh

The average LCOE in 2021 was USD 45.73/MWh (EUR 45.06/MWh), and it rose to USD 51.51/MWh in 2022 driven by rising raw materials prices during 2021 and the first half of 2022. This impacted the prices for turbines and foundations. Under a standard scenario, **InfoLink estimated that raw materials price increase led to an increase of 10.39% in capex in 2022, and 5.40% in 2023. If factors in rising loan costs due to increased interest rates,** the LCOE in 2022 and 2023 would end up higher by 7.77% and 4.09%, respectively, than the original forecast. Although the increase in capex narrows in 2023, InfoLink projects that Europe will raise main refinancing operations again to narrow the interest rate spread between the Federal Reserve System, and thus the LCOE will increase by a certain level.

InfoLink estimate LCOE under three scenarios in which the installed onshore wind capacity in Europe will near 342.51 GW in 2030, wind farms enjoy higher capacity factor, longer life cycle, and fewer use of cable, infrastructure, and substation after using larger turbines, and nearby decommissioned onshore wind farms can replace with new type of turbines. Under the standard scenario, **the LCOE for onshore wind in Europe will decline to USD 39.63/MWh (EUR 39.03/MWh) in 2025 and USD 33.86/MWh (EUR 33.23/MWh) in 2030, down 26% from 2021.** Under a conservative scenario, in which capacity factor growth and improvement rate are lower, the LCOE is estimated to sit at USD 38.45/MWh (EUR 37.85/MWh) in 2030. Under an optimistic scenario in which larger turbines drive down installation costs further, the LCOE is estimated at USD 30.52/MWh (EUR 30.05/MWh) in 2030.

2.4 WIND IRA

The PTC and ITC allows owners and developers of wind energy facilities to claim income tax credit. The IRA extends the PTC and ITC for wind projects through at least 2033. The IRA also introduces the new "technology neutral" PTC and ITC for projects that generate electricity and yield zero greenhouse emissions. These tax credits will apply to facilities placed in service after 2025. Therefore, wind projects that satisfy the new prevailing wage and apprenticeship requirements can receive 2.6 cents/kWh of PTC and the rate is adjusted annually for inflation, while 30% tax rate for ITC. These credits begin to phase out for projects that start construction after 2033 or after certain emissions targets are achieved, meaning that projects can only receive 75% of the original tax credits, 50% in 2035 and 0% in 2035, and in the case of ITC, the credit will decrease to 22.5% from the original credit of 30%. The timeline will be rediscussed if the emissions targets are not met.

For purpose of the apprenticeship requirement, wind projects must 1) pay prevailing wages at the local rate in accordance with Subchapter IV of Chapter 31 of Title 30 of the United States Code for the construction of the facility and any repair of alteration of the facility during the entire construction period, within five years after commissioned (projects receiving ITC), or the 10-year PTC period, and 2) ensure that no less than the applicable percentage of total labor hours is performed by qualified apprentices.

Projects that begin construction prior to the date that is 60 days after the Internal Revenue Service (IRS) publishes guidance with respect to the prevailing wage and apprentice labor requirements are qualify for the 100% PTC (2.6 cents/kWh) and 30% ITC.

Table 2.4-1. Percentage of apprentice labor hours

Project	Percentage of apprentice labor hours
Projects beginning construction before Jan. 1, 2023	10%
Projects beginning construction after Jan. 1, 2023	12.5%
Projects beginning construction on or after Jan. 1, 2024	15%

The Act contains measures for correcting failures to comply with the wage and labor rules, so the 100% PTC can be reserved. The corrective measures include payments to the laborer for the difference between the prevailing wage and the wage paid, plus interest, and a USD 5,000 per-laborer penalty to be paid to the IRS. If the new rules are disregard on purpose, the penalty is increased to USD 10,000 per laborer. Failure to employ apprenticeship laborers has similar corrective measures, including a USD 50 per-labor-hour penalty, or USD 500 per-labor-hour penalty if the failure was an intentional disregard.

There are two separate 10% credit adders for projects for projects with domestic content, and projects located in energy communities. See below table for domestic content requirement:

Table 2.4-2. Percentage of domestic content

Project	Percentage of domestic content	Percentage of domestic content (in the case of offshore wind facilities)
Construction before Jan. 1, 2025	40%	20%
Begin construction during 2025 and before Jan. 1, 2026	45%	27.5%
Begin construction during 2026 and before Jan. 1, 2027	50%	35%
Begin construction during 2027 and before Jan. 1, 2028	55%	45%
Begin construction during 2028 or later	55%	55%

An additional 10% credit is offered for projects that are located within an “energy community” or low-income community. Based on the USD 2.55/MWh rate after inflation adjustment (USD 2.5/MWh in 2021 and an estimated annual inflation rate of 2%) in 2022, a project can receive up to USD 3.2/MWh PTC.

In the case of offshore wind, ITC helps encourage the investment. The old ITC provides tax credit for offshore wind projects that begin construction before Jan. 1, 2026, but the IRA extends the phaseout to at least 2033, when greenhouse gas emissions from the electric generation industry are reduced by at least 75% of the annual 2022 emission rate. Under the new ITC, developers can receive 6% of base rate and they need to satisfy the registered apprenticeship and prevailing wage requirements to qualify for 30% PTC. A 10% PTC adder applies for wind projects placed in service after Dec. 31, 2022, that satisfy a new domestic-content requirement.

To support the emerging offshore wind, **the IRA creates 10% credits for wine energy components and offshore wind vessels and allocates USD 100 million for R&D in regional transmission and distribution of electricity. Also, the IRA revises the Outer Continental Shelf Lands Act to allow offshore wind leasing** in the waters adjacent to Puerto Rico, Guam, American Samoa, the U.S. Virgin Islands, and the Commonwealth of the Northern Mariana Islands, and to grant offshore wind leases for areas off the coasts of North Carolina, South Carolina, Georgia, and Florida.

In addition, the IRA requires the Department of the Interior (DOI) not to issue a lease for offshore wind development during the ten-year period after IRA enactment unless it has held an "offshore lease sale" in the preceding year and offered at least 60 million acres in oil and gas lease auctions. Such a restriction is to win key vote from Senator Joe Manchin[5]. In the schedule proposed by the Bureau of Ocean Energy Management, such requirement is not likely to be met under certain situations, thus posts potential threat to offshore wind development. Moreover, developing offshore wind projects in the U.S. may face lawsuits and lengthy administration procedure, to which the IRA does not offer a clear solution.

[5] Senator Manchin worries that such fiscal spending will worsen the government deficit and is concerned about the offshore wind will compete with oil fields for development site, as the IRA would shift the structure of the fossil fuel industry to renewables. To win his vote, the IRA ensures the right to auction drilling permits for fossil industry and support upgrades to coal and natural gas facilities.

03 ESS

DEMAND

New global electrochemical storage capacity additions hit 44 GWh in 2022, of which 70% came from the FTM sector. China, the U.S., and Europe (EU and the U.K.) together dominated 85% of the global total.

Cumulative global installed storage capacity was 56.7 GWh in 2021; the figure is projected to grow 32.5 times over a decade to hit 1,900 GWh in 2030. China alone installed 15.8 GWh in 2022, surpassing the U.S.' 12.18 GWh for the first time. China is expected to become the largest energy storage market after 2023.

FTM sector accounts for 90% of China's energy storage market; 75% in the U.S.; 50% in Europe. The three countries are expected to reach 437 GW/855 GWh, 175 GW/508 GWh, and 65 GW/245 GWh of cumulative installed capacity by 2030, respectively.

SUPPLY CHAIN

Surging cell and raw materials prices during 2021 and 2022 led to growing awareness of domestic supply chain among Europe and the U.S. InfoLink expects the share of Chinese cell capacity in the world to decline from 70% to 52% from 2022 to 2030, while that of Europe to rise from 14% to 27% and the U.S. to grow from 6% to 18%. Global cell capacity is forecast to increase from 2022's 1,400 GWh to 6,000 GWh in 2030, a compound annual growth rate of 20% over the nine-year period.

Europe and the U.S. will mostly rely on cell imports before 2025. After the two regions begin mass production in 2025, prices for LFP and NMC battery pack are estimated to come in at USD 93/kWh and USD 113/kWh and reach USD 82/kWh and USD 98/kWh in 2030. Such a price decline will impact the levelized cost of storage.

LCOE

In 2022, the average LCOS of utility-scale storage in China, the U.S., and Europe sat at USD 0.10, USD 0.12, and USD 0.16, respectively. China enjoys cheaper storage prices due to advantages of supply chain, labor, and location. Europe and the U.S. both see higher battery, land and development costs.

Global cell supply is likely to balance demand after 2025 as manufacturers are ramping up capacity. The LCOS in China, the U.S., and Europe is expected to decline to USD 0.04, USD 0.05, and USD 0.06 by 2030, respectively.

IRA

Before the IRA, energy storage needs to integrate with solar to receive subsidy. The IRA extends the subsidy to include standalone BESS. C&I storage can apply for 6% to 70% of subsidy depending on the requirements it met, while residential storage can receive 30% to 70% of subsidy. The IRA will boost the ratio of solar systems integrated with storage and the development of long-duration storage.

The IRA provides PTC for domestic manufacturing, including USD 35/kWh for cells, USD 10/kWh for battery pack, and 10% of the costs of cell or mineral costs. Localization of cell supply chain is happening worldwide.

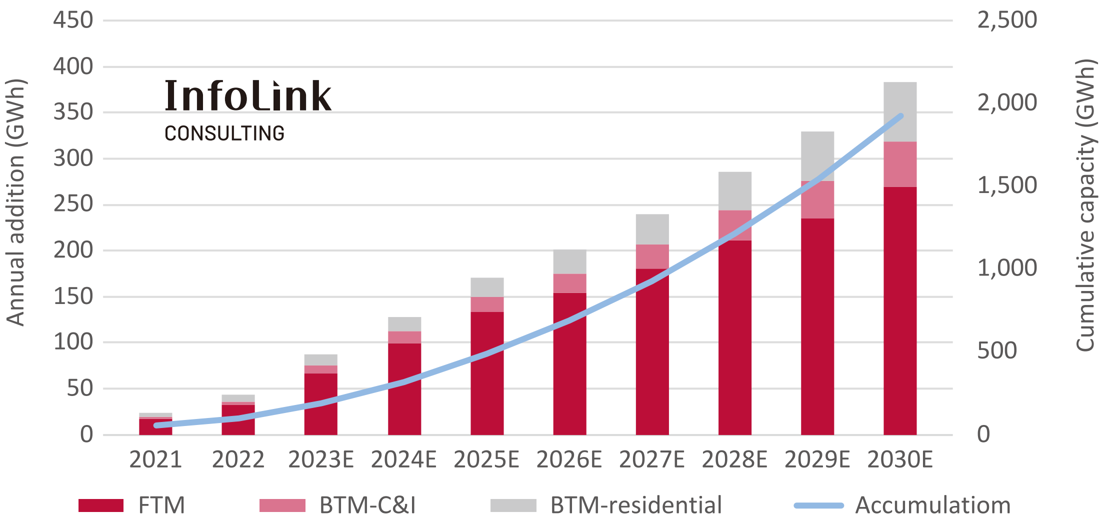
3.1 ESS DEMAND

The race to halve emissions by 2030 and achieve net zero by 2050 has never been more urgent. Flexibility of electric power system is one crucial element to accelerate net zero. Energy storage started to rise rapidly worldwide in 2018 along with the increasing share of renewable energy installation and their fluctuating nature. There are three major applications of energy storage, namely front-of-the meter (FTM), behind-the-meter (BTM) C&I and BTM-residential. FTM-storage can solve the intermittency problem, reduce solar and wind curtailment rate, and stabilize the grid, helping reduce energy loss and improve safety and lifespan of power grid. BTM-storage, on the other hand, not only can arbitrage through the peak-to-valley price difference or FIT payment, but also realize self-consumption to reduce the risk of power outrages caused by disasters.

In 2022, global energy storage installation exceeded 44 GWh for the first time, with cumulative installed capacity reaching 43 GW/100 GWh. FTM-storage accounted for more than 70% of the total. As of 2022, the countries that have deployed the most energy storage are China, the U.S., and Europe, which together made up around 85% of the world's total storage installation.

According to InfoLink's database, **the world added 21 GW/44 GWh of installed electrochemical energy storage capacity in 2022, of which China contributed around 34%, the fastest among all. Followed by the U.S., Europe, Japan, South Korea, and Australia.** The newly installed storage capacity in these countries accounted for more than 90% of total installations that year, bringing the cumulative installed capacity of electrochemical energy storage to 46 GW/100 GWh in 2022. Of which, 16 GWh to 17 GWh are integrated with solar systems. InfoLink expects the share of solar-plus-storage to increase year by year, driven by policy and renewables development. By 2025, when cell manufacturers finish ramping up capacity, energy storage installation, which is already doubling each year, will accelerate on decreasing cell prices, bringing the global electrochemical storage market size to exceed 500 GWh. Optimistically, the global cumulative installed storage capacity may hit 2,000 GWh by 2030.

The following section provides more details on the world's largest storage markets – China, the U.S., and Europe.



Source: InfoLink Consulting

Figure 3.1-1. Global electrochemical energy storage market size

China

China's cumulative installed storage capacity stood at 12 GW/25 GWh in 2022 and added 7 GW/15 GWh of new capacity in 2022. So far, FTM-storage accounts for 90% of the ESS market in China. Rationale behind includes higher power and capacity of FTM-storage as well as provincial mandate. As of the first half of 2022, China has released 27 regulations that bode well for storage, requiring new renewables facilities to pair with battery-storage equivalent of 10% to 20% of their power generation in average, with one to two hours of duration. In Inner Mongolia, new renewables facilities must pair with storage equivalent of 15% of their power generation, with four hours of duration, the longest among all provinces. Anhui and Chengmai County of Hainan province have the highest energy storage ratio requirement, mandating a bundling of 27% and 25% of energy storage capacity for new renewables projects relative to their generating capacity, with two hours of duration. Moreover, around ten provinces have set energy storage target for 2025, which could bring the cumulative installed capacity to beyond 80 GW by 2025 if all targets are met.

Under regulation, China's FTM market is thriving. From 2022, several provinces started introducing policies that mandate or encourage the incorporation of energy storage with distributed generation PV. For instance, Zhuji city in Zhejiang mandates at least 8% of energy storage in distributed generation solar projects. While the BTM-C&I storage installation doubled in installations during 2020 and 2021, its size still fell far behind from the FTM market. Such development is mainly ascribed to China's low electricity costs and unmature business module, meaning that the BTM market will not see much progress unless there's strong policy in place.

For now, China's policy focuses on the generation and grid sides. In 2021, solar-plus-storage systems accounted for nearly 50% of total storage installation. As a large solar market in the world, China's share of storage installation will increase along with solar growth. InfoLink expects the share of solar-plus-storage to grow gradually to around 70% by 2030. Although there's no specific regulation designed for storage safety and recycling, demand will be huge in the future as the market continues to develop. Moreover, the application of shared energy storage is another trend in the future. **The installation in China surpassed the U.S. for the first time in 2022 and become the world's largest energy storage market. By 2030, China's electrochemical storage market is expected to hit 330 GW/855 GWh.**

The U.S.

The U.S.' cumulative installed energy storage capacity in 2022 stood at 11 GW/29 GWh. The country developed storage market earlier than others and used to have the highest ESS installations of the world by 2021. In 2022, the U.S. added 4.8 GW/12 GWh, accounting for 27% of the world, only second to China. FTM storage application dominates the US storage market, accounting for more than 85%.

The rapid growth of energy storage is highly correlated to the Investment Tax Credit (ITC) introduced by the Federal government. The Inflation Reduction Act approved in August 2022 also extends the incentive for ten years and cover not only C&I and residential storage but standalone energy storage. This enables energy storage facilities built during 2022 and 2032 to enjoy 30% ITC, which will gradually phase down from 2033. Moreover, the U.S. invests huge funds to conduct research on new form of energy storage. In 2019, the country approved the Better Energy Storage Technology (BEST), under which USD 60 million will be allocated to grid upgrade and energy storage R&D per year from 2020 to 2024. The research includes technologies to advance energy storage recycling facility infrastructure and critical mineral recycling and reuse of lithium, cobalt, nickel, and graphite. The Act requires the United States Department of Energy to establish at least five demonstration programs for grid-scale energy storage systems by the end of 2023. Many states also set target for energy storage capacity. Massachusetts, Nevada, and Michigan all set goals to build 1 GW of energy storage by the end of 2025. New York set the highest target among US states, aiming to reach 1.5 GW by the same year.

Due to the independent nature of grid in the U.S, each region has its own independent utility companies. It is relatively difficult to dispatch electricity between various companies, which provides the country with high potential in the FTM market to dispatch the electric power system. **In 2022, around 50% of the solar systems installed in the FTM market are coupled with energy storage facility. InfoLink projects the penetration rate and ratio of storage in solar will increase year on year in the U.S.** The application of energy storage varies from state to state. The California Independent System Operator (CAISO), a non-profit system operator serving California, mainly utilizes energy storage in renewable energy integration to strengthen the reliability of the grid. Therefore, it prefers to use energy storage system with long duration hours (four hours in average) instead of pursuing high power. PJM Interconnection, a regional transmission organization operates mainly in Pennsylvania, New Jersey, and Maryland, mostly uses energy storage for frequency regulation, which requires the system to fast response. Therefore, the energy storage systems it uses feature shorter duration hours (45 minutes in average) but higher power.

The BTM-storage market only accounts for 25% in the U.S. The difference between the size of BTM-C&I and BTM-residential storage is minor and thus is often neglected compared with the FTM market. Yet, spacious land and extreme climate in some regions make it suitable to build energy storage in many places. Maine and Hawaii, for example, introduced policies for BTM-storage in recent years to spur the development of residential storage. Hawaii, aiming to achieve 100% renewables by 2045, introduced the Battery Bonus program to encourage customers to install battery capacity for their rooftop PV systems, with a rebate ranging from USD 500-850/kW depending on the time of submission, which should be done before June 20, 2023. The program is capped at 50 MW. As one of the states that developed energy storage earlier, the policy is expected to drive more battery installation among solar system users.

With supportive policies, California and Texas are two states that are most active in deploying energy storage in recent years. California initiated the Self-Generation Incentive Program (SGIP) in 2001 and included energy storage in 2011 for its USD 2/W subsidy. The scheme was extended for 10 years in 2018 to encourage deployment of distributed energy storage, with USD 613 million of funds earmarked for low-income and medically vulnerable customers at highest risk of fire-prevention power outages. California also provides USD 100 million to California of its USD 1.2 billion Self-Generation Incentive Program budget to help low-income communities.

In Texas, its large amount of energy storage installation can be ascribed to the significant growth of solar installation in recent years, dispose of regular generators, and old electric grid. Moreover, the snowstorm hitting Texas in 2021 caused state-wide blackout. The blackout rose awareness of energy storage, prompting Tesla to introduce a virtual grid project to ease grid burden by installing home solar and energy storage facilities. Meanwhile, Tesla also calls for the Electric Reliability Council of Texas (ERCOT) to change the profit mechanism for users participating in electricity generation. If the request is approved, Tesla will launch an electricity plan for home within a year, paving way for the development of BTM-storage in the state. **In the long run, the U.S. has a great potential for BTM-storage market, which will grow rapidly along with booming solar energy. It's expected that the total electrochemical energy storage capacity in the nation will hit 175 GW/508 GWh by 2030.**

Europe (EU and the U.K.)

Europe has accumulated 12 GW/20 GWh of energy storage capacity in 2022, and added 5 GW/10 GWh in 2022, with the installation volume increasing by more than 100% compared with the preceding year. Different from China and the U.S., Europe's power grids are interconnected by cross-border lines, and thus its demand for FTM-storage is less urgent than other countries. Moreover, with surging electricity prices, large peak-to-valley electricity difference, and mature business model, home users have high willingness to install energy storage. Currently, the ratio of FTM and BTM-storage is around 1:1.

The U.K. dominates more than 50% of FTM-storage in Europe. At present, more than 60% of energy storage plants under construction are larger than 30 MW in size. Of which, around 65% are paired with renewable energy, while 35% for ancillary service to help stabilize the island country's independent power grid. After experiencing several major blackouts, the U.K. also introduced several business models for the grid, including the Mandatory Frequency Response (MFR) and Frequency Containment Reserve (FCR), as well as the Dynamic Containment (DC), a service to contain frequency launched in 2022. These provide grid-scale energy storage with higher flexibility in terms of application and profiting in the U.K. In addition, the country's amendment to the Electricity Act in 2017 well establishes the position of energy storage in the power system. In 2020, the country lifted barriers on energy storage projects over 50 MW, allowing large-scale projects to proceed without approval through the national planning regime. It then removed the 'double charging' for energy storage facilities, meaning that declared storage assets are exempt from import charges of the Balancing Services Use of System (BSUoS). These policy changes help spur the development of large energy storage projects.

In terms of BTM-storage, Germany accounts for more than 60% of the market, with its share far higher than Italy, the runner-up. Germany has long been developing renewable energy: the public's acceptance for clean energy is high, the government has offered generous subsidy and tax incentive, and banks has introduced low-interest loan – all of which pushes the development of BTM-storage. For instance, Berlin introduced a subsidy scheme in 2020 to fund new solar and storage installations with up to EUR 300 per usable kWh stored. Bavaria, in 2021, launched a subsidy scheme for residential solar-plus-storage installations, providing EUR 500 for storage facilities paired with solar of at least 3 kWh and a further EUR 100 for each additional 1 kWh for up to 30 kWh. Also, German state-owned bank kfW offers low-interest loan (annual rate of 1.03% and a EUR 50 million line of credit) and repayment subsidies for new solar installations incorporating battery storage system. Numerous incentives and subsidies have boosted the adoption of energy storage, with nearly half of solar utilities built in Germany are paired with storage, pushing up the penetration rate of solar-plus-storage in the residential sector.

Amid energy crisis and skyrocketing energy prices driven by Russia-Ukraine war, European public come to be aware of the importance of self-consumption. To make Europe independent from Russian fossil fuels, the European Commission proposed the REPowerEU plan on May 18, 2022, rolling out the EU Solar Energy Strategy to boost solar energy capacity and mandate solar installation on new public, commercial and residential buildings. These policies, indirectly, promote the development of energy storage. **If the price of electricity continues to rise and policies remain, the electrochemical energy storage market size is likely to reach 95 GW/345 GWh by 2030 in Europe.**

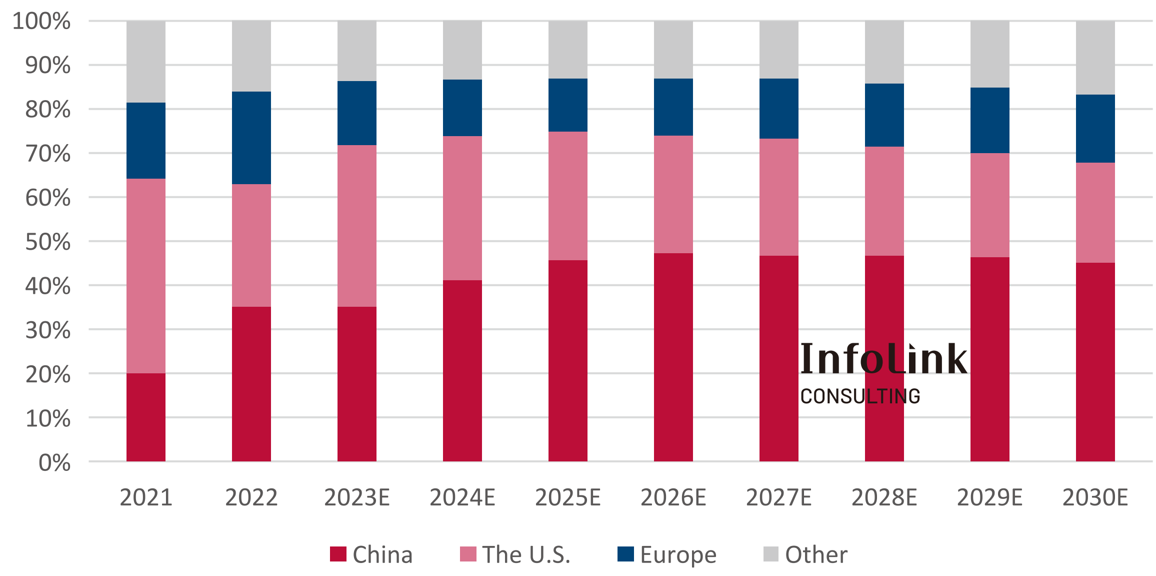


Figure 3.1-2. Annual additions of energy storage installation

Conclusion

To sum up, China is still in the early phase, but has a great potential to grow rapidly in the future due to strong policies for FTM-storage and high solar-plus-storage ratio, whereas its BTM-storage sector shows no sign of development due to cheap electricity prices and it will remain so unless there's mandatory policy. The U.S., despite being a pioneer in energy storage, saw inconsistent attitude, resulting in a huge gap in installed capacity between states. Yet, the nation's independent grid system, severe climate events, and the government's promotion of renewables provide a large room for both FTM and BTM storage development. Europe, where the BTM-storage has economies of scale due to liberalized electricity, has the most developed BTM-storage so far. In the future, the share of FTM-storage will also increase as the government works toward net-zero emissions and promotes renewables. Indeed, the more mature an electricity market is, the more developed the BTM-storage.

The three regions discussed above show that demand for energy storage so far is mainly driven by policies, which, coupled with booming solar energy, the penetration rate of storage will increase year by year. Subsidies provided by governments are usually the bigger driver behind installing energy storage facilities. Moreover, liberalization of electricity, net-zero emissions-related policies, and renewables targets, as well as investments in R&D are keys to acceleration of storage development.

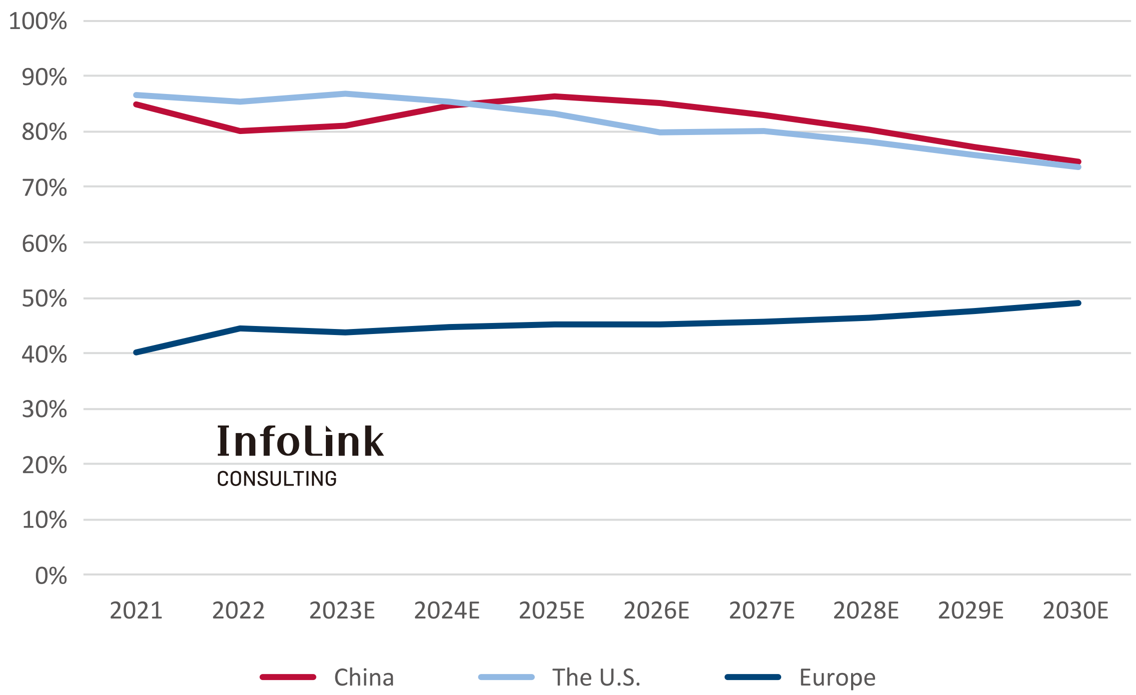
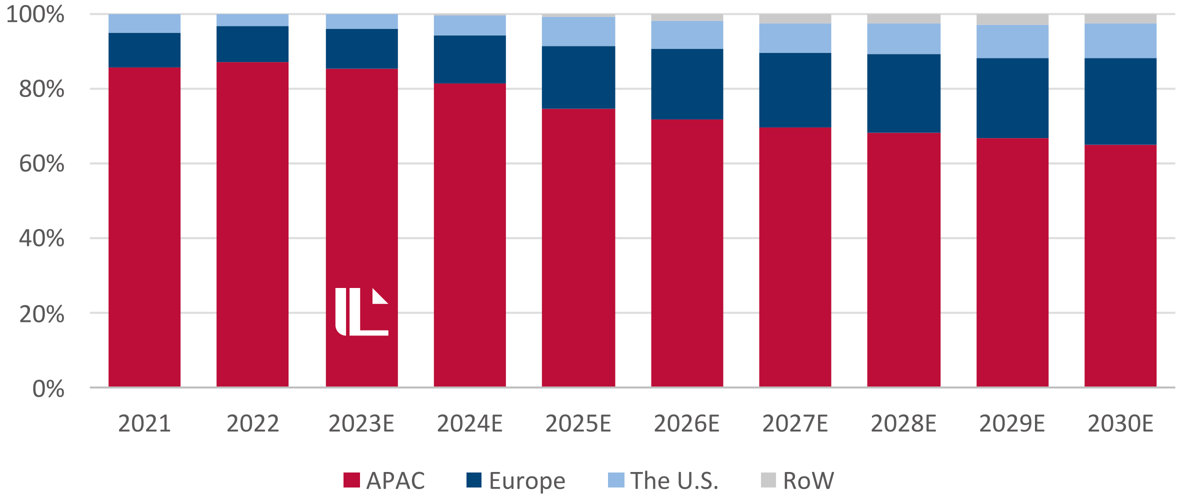


Figure 3.1-3. Share of FTM-storage market in China, the U.S., and Europe

3.2 ESS SUPPLY CHAIN



Source: InfoLink Consulting

Figure 3.2-1. Forecast for cell shipment by volume and region

At present, China, South Korea, and Japan dominate the manufacturing capacity for cell for energy storage. As the energy storage and electric vehicle industries boom in recent years, governments across the globe are finding ways to handle waste batteries. Policies mandating localization of cell supply also emerged after factoring energy security. Amid acceleration of cell development in Europe and the U.S., InfoLink predicts the share of cell shipment from Europe will gradually increase after 2023 to 2024, when new entrants such as Northvolt and Freyr bring capacity online and existing Korean manufacturers finish capacity expansion.

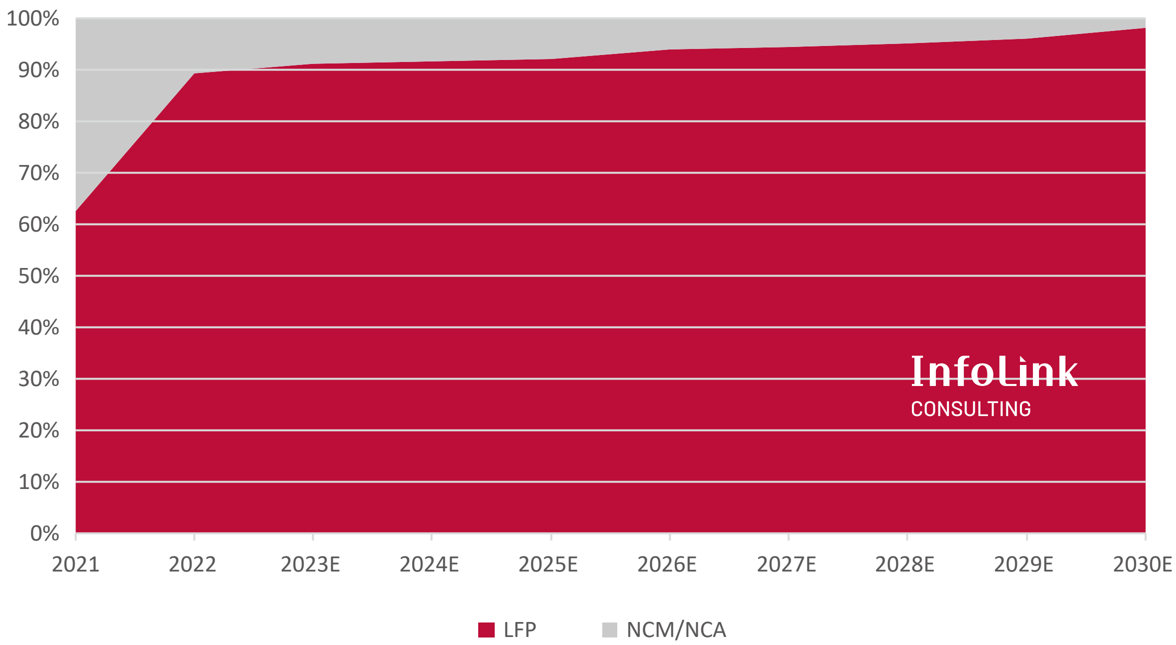
Cell production capacity is highly concentrated in Asia, while China's strict Covid-19 policy impacted the production plan and cell delivery during 2021 and 2022. In response, downstream energy storage system suppliers such as Fluence announced in the second quarter of 2022 that the company's supply chain management goal is to raise the share of non-China made cells to 30% in 2023, and 50% in 2024. In the U.S., large manufacturers such as LG Energy Solution, has announced plans to begin mass production of lithium-ion battery during 2023 and 2024, which, coupled with the government's policy for supply chain localization, are likely to change the supply chain landscape, turning the China-dominated supply to a certain share of local supply. **InfoLink expects the share of cell for energy storage in Asia to decline from 86% in 2021 to 65% in 2023, while the share of Europe and the US local supply will respectively grow from 6% and 3% in 2020 to 14% and 11% in 2023.**

Materials trends for ESS using lithium-ion battery

Table 3.2-1. Material trend for ESS using lithium-ion battery

Cell type	NCM, NCA	LFP
Operating voltage (V)	3.7	3.2
Energy density (Wh/kg)	240 ~ 280	150 ~ 170
Price (USD/kWh)	100 ~ 120	80 ~ 100
Cycle life (one time)	~ 2000	At least 3000
Thermostability	Moderate	Good
Safety	Moderate	Good
Application	Medium, high-grade EVs, electronic products	Affordable EVs, energy storage

At present, there are two types of lithium-ion batteries used by energy storage systems, namely LFP batteries and NCM/NCA batteries. China mostly uses LFP battery, while Japan and South Korea opt for NCM/NCA batteries. In general, NCM/NCA batteries have higher energy density (240-280 Wh/kg) but poorer safety, higher cost, and lower cycle life compared with LFP battery (150-170 Wh/kg of energy density; 20 to 30% cheaper costs than NCM/NCA).



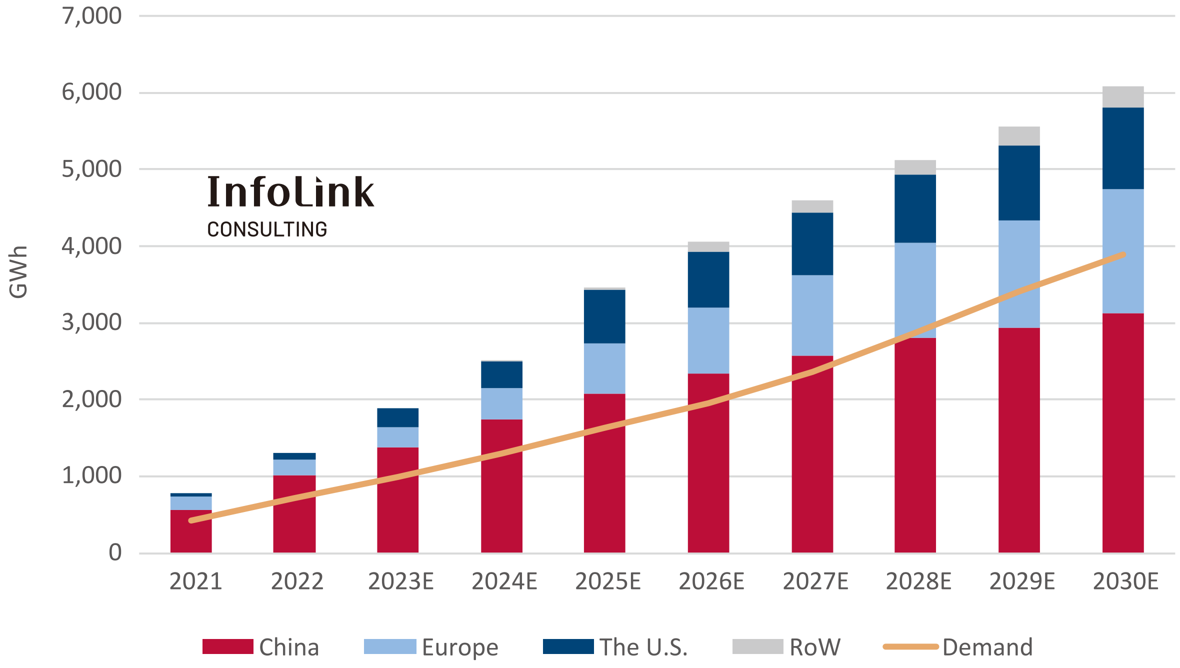
Source: InfoLink Consulting

Figure 3.2-2. Stationary storage chemistry

The share of LFP batteries in global energy storage facilities exceeded that of NCM/NCA for the first time in 2021. InfoLink estimates that the penetration rate of LFP batteries will rise continuously to 98% before 2030, while a small percentage of storage facilities will use NCM/NCA batteries due to regional supply factor and end user preference. Over the past decade, the mushrooming growth of EVs led to a lithium-ion battery cost reduction of nearly 90%. In the early phase of EV development, manufacturers mostly used NCM/NCA EV batteries to pursue higher energy density and performance. Energy storage that started developing in 2018 also adopted NCM/NCA batteries due to cost reduction brought by EVs. China, in particular, used mostly NCM/NCA batteries with longer recharge mileage and higher energy density to meet subsidy requirement.

However, as supply of NCM/NCA batteries gradually became tight, cost reduction slowed, China terminated subsidy, and supply of LFP batteries increased, LFP batteries started penetrating the share of NCM/NCA batteries in the energy storage and affordable EV markets from 2020, surpassing NCM/NCA for the first time in 2021. Since the patent for LFP materials expired in 2022, large Japanese and Korean manufacturers and some European start-ups also plan to engage in developing and producing LFP batteries. LG Energy Solution, for example, will start producing LFP batteries in its Michigan-based facility in 2023. ElevenEs plans to produce LFP batteries in Europe from 2023, while Freyr plans the same in Norway for 2024. Against these backdrops, **InfoLink expects the penetration rate of LFP battery in energy storage to rise continuously, whereas NCM/NCA batteries will be mainly used for power storage application (frequency regulation) and EVs.**

Forecast for global cell supply and demand



Source: InfoLink Consulting

Figure 3.2-3. Analysis of global cell capacity and demand

With solid demand for energy storage and EVs, global cell manufacturing capacity has been growing at a fast pace, and there's even concern of surplus. Based on the expansion projects of large cell manufacturers compiled by InfoLink, it's expected that global cell capacity will grow from 1,400 GWh in 2022 to around 6,000 GWh in 2030, with an annual compound growth rate of 20% between 2022 and 2023. With localization of cell supply under way, InfoLink projects that the share of China in global cell capacity will decline from 2022's 70% to 52% in 2030; Europe's share increases from 14% in 2022 to 27% in 2030; and the U.S.' share from 6% in 2022 to 18% in 2030.

3.3 ESS LCOE

Industry overview

Energy storage cost per kWh includes the costs of battery, PCS, EMS, EPC, and other items. Batteries account for 50 to 70% of the total cost, followed by PCS, EMS, and EPC, each making up 5 to 15% of the total cost. Other items include land, rental, development expenses, etc. The estimation here is based on an FTM energy storage system with 30 MW/120 MWh of power output and 90% of depth of charge and discharge. System cycle efficiency and battery life span will increase gradually over the years. The levelized costs of storage (LCOE) is calculated as followed:

$$\frac{\textit{Capex + \{Operation and Maintenance (O\&M)*Battery Life\}}}{\textit{Life used energy}}$$

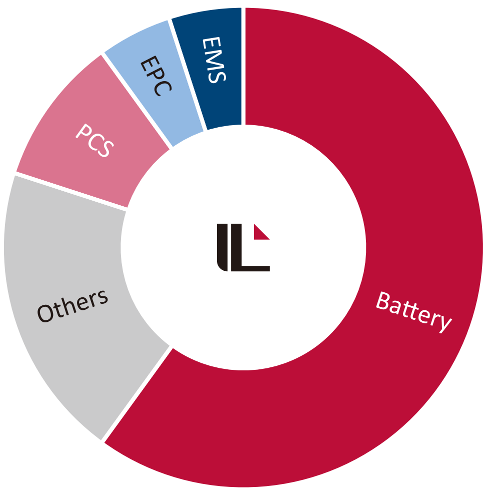


Figure 3.3-1. Cost structure of energy storage system

Factors that drive costs down

The cost of an energy storage system mainly consists of the costs of batteries, inverters, and installation, among which, inverter and installation costs will decline steadily as technology matures and the market expands. It is the cost of batteries that determines the cost of the entire energy storage system. Given battery is the major component of energy storage systems and the rise of EVs, the cost of energy storage is largely susceptible to cell price trend and the development of the EV market. The cost of lithium-ion battery has declined by 90% over the past decade, with energy density improving incessantly. For now, the world mostly uses LFP battery for energy storage systems because it is safer, thanks to its fair thermostability, and has cost advantage. In the recent two years, strong downstream demand for lithium-ion batteries and the rise of both energy storage and EV industries result in cell shortage. The supply-demand imbalance pushes up prices, affecting the cost of energy storage systems.

In 2021, demand weakened to lower-than-expected levels, due to chip and cell shortages and rising cell prices. If the shortages persist, demand will fall short of expectations in 2022. Although cell prices have been surging over recent years, the performance of lithium-ion battery improves every year, allowing the levelized cost of storage (LCOS) to decline steadily.

International cell manufacturers have been planning capacity expansion actively, with LG and CATL together amassing at least 600 GWh of target production capacity in 2023. Production output of the two companies can produce 9 to 12 million EVs in a year. The construction period of a cell manufacturing plant is around two years. After years of expansion, cell supply will catch up with demand from EV and energy storage industries. After 2026, as production capacity comes online and lithium-ion battery technology matures, a balanced supply-demand relationship will allow prices to drop gradually for lithium-ion batteries and energy storage systems.

InfoLink expects a balanced supply-demand relationship to occur sometime during the second half of 2023 and 2024. By then, cell prices will drop evidently. In 2022, the average prices of NCM/NCA batteries rose to USD 172/kW from 2021's USD 131/kWh, while LFP batteries rose to USD 131/kWh from USD 93/kWh. In the optimistic scenario, NCM/NCA batteries will drop to USD 113/kWh in 2025 and USD 98/kWh in 2030, while that for LFP batteries will decline to USD 93/kWh in 2025 and further to USD 82/kWh in 2030.

Besides EVs and cell supply that affect energy storage prices, the use of long-duration energy-type storage system helps reduce the LCOE of energy storage. Many countries have been developing long-duration energy storage. The U.S., for example, plans to bring down the LCOE of long-duration energy storage to USD 0.05/kWh by 2030.

LFP battery remains the top choice of many energy storage system suppliers, despite the technology has been reaching a limit of development. Compared with NCM/NCA battery, LFP battery has higher thermostability and cheaper prices. Therefore, many companies regard it as the top choice. Besides, LFP battery patents are due to expire during 2022 and 2023. By then, the market share of LFP battery may increase outside of China.

However, due to the maturity of LFP technology, in the long run, when NCM/NCA battery and solid-state battery improve to be safer, more efficient, and cheaper choices, there will be more types of batteries for the market, further reducing the cost of energy storage.

The following are the LCOE of an FTM energy storage system with 30 MW/120 MWh of power output calculated based on a neutral hypothetical battery capability. The cost of an energy storage system is subject to battery cycle life, depth of charge and discharge, and storage capacity.

LCOE comparison: China, the U.S., and Europe

China

China's LCOS was estimated at USD 0.10/kWh in 2022, lower than that of the U.S. and Europe. China has three advantages. First, Chinese cell manufacturers improve yield rates and lower production costs through large-scale production. Second, China is home to the cell supply chain, thus transportation and labor costs are lower for Chinese manufacturers. Third, most energy storage systems in China use LFP battery. In 2021, LFP battery price was USD 100-120/kWh, and NCM/NCA battery price was USD 130-150/kWh. Since cell cost accounts for more than half of the cost of an energy storage system, **Chinese manufacturers, with access to cheaper cells, can sell energy storage systems at significantly lower prices.**

Major Chinese cell manufacturers all have plans for production expansions. The expansions are astonishingly fast, thanks to supply chain advantages that allow manufacturers to reduce the cost of cells. In 2020, CATL only shipped 2.38 GWh. The figure quadrupled to 16.7 GWh in 2021, increasing rapidly to 59.8 GWh in 2022, and is expected to reach 500 GWh of total cell capacity after 2024, among which more than 125 GWh will be dedicated to energy storage. Presently, China accounts for 70% of cell market share around the globe. With massive production capacity, China could even wield direct influence over cell prices and cost of energy storage worldwide.

In 2021, surged cell demand led to shortages in the upstream. Doubled with metal raw material price hikes and Covid lockdowns, the originally expected price decline was challenged. Against these backdrops, the LCOE of energy storage sat at USD 0.1/kWh in 2022. Still, even in the most pessimistic scenario, InfoLink expects the cost of energy storage systems to be lower than USD 0.1/kWh by 2025.

If expansions of all major cell manufacturers in China stick to the schedule, the supply will be sufficient for not only the fast-growing EV industry but also the energy storage sector. In an optimistic scenario, prices for energy storage systems will drop to USD 0.05/kWh by 2025. After 2026, even if the pace of expansions is slower than expected, there will still be enough cells available on the market. By then, the battery and energy storage system prices will drop slower amid a balanced supply-demand relationship. The average price for energy storage systems is expected to come in at USD 0.04/kWh in 2030.

The U.S.

The US energy storage market is huge and mature, thanks to solar incentives and geographical and climate advantages. The nation's LCOE of energy storage was estimated at USD 0.12/kWh in 2022. Although fully developed, the U.S. has slightly higher LCOE than China. This can be attributed to China's use of the cheaper LFP batteries, while Europe and the U.S. mostly use NCM/NCA batteries, and the higher costs of development, labor, and installation in the U.S., which account for one-fifth of the total cost of energy storage. Such a condition changed in 2021, as the use of LFP batteries becomes more prominent than NCM/NCA ones. Tesla also announced to use LFP batteries partially, **underlining the dominance of LFP in the global cell market, which may accelerate the decline of LCOS.**

The U.S.' intention to localize its cell supply chain is clear. In 2022, President Joe Biden signed the Inflation Reduction Act (IRA) of 2022 into law, encouraging renewable energy suppliers to use U.S.-made products, providing generous subsidies for local cell manufacturers, and ITC for constructions of energy storage systems. To add to that, the EV industry's strong battery demand sent raw materials prices surging. Doubled with the pandemic-induced increases in freight rates, the cost of energy storage fluctuates, dissuading bank funding for developers. Against these backdrops, cell manufacturers consider localizing the supply chain to mitigate risks of international incidents.

However, the U.S. lacks natural raw materials. Even though a cell manufacturing factory can be constructed in two years, it takes more time to build a raw material plant. Therefore, in the short term, the U.S. still has to rely on cell imports. Additionally, the U.S. has yet to establish a comprehensive set of procedures to recycle batteries, making localization even more challenging.

InfoLink expects to see ample local cell supply catching up with demand in the U.S. after 2024, given that the IRA supports energy storage systems constructed after December 31, 2024, and that production expansions of cell and other upstream materials take time. In the neutral scenario, energy storage cost will drop to USD 0.10/kWh in 2023, excluding subsidies. By 2025, when the U.S. completes local supply chain and yields steady output, energy storage LCOE will drop to USD 0.078/kWh. Meantime, **the Department of Energy promotes long-duration energy storage actively, hoping to reduce LCOE to USD 0.05/kWh by 2030, reducing the cost of energy storage systems. In the optimistic scenario, energy storage LCOE can drop to USD 0.05/kWh by 2025.**

Europe (EU and the U.K.)

The U.K. has the highest installed FTM energy storage capacity in Europe, mostly for auxiliary services of the grid. **InfoLink estimates USD 320-530/kWh of construction cost of a utility-scale standalone power plant.** In a neutral scenario, the energy storage LCOE was USD 0.16/kWh in 2021. Like the U.S., Europe has higher LCOE since it still relies on cell imports. In Europe, LG Energy Solution, Samsung SDI, and SK Innovation have the greatest production capacities, which are mostly dedicated to the more expensive NCM/NCA batteries. **Additionally, higher costs of labor and land push up maintenance costs. Against these backdrops, Europe has the highest LCOE in the world. Doubled with the pandemic and logistics disruptions, Europe's energy storage LCOE is expected to stay elevated at USD 0.14/kWh in 2023.**

Despite having the highest LCOE in the world, Europe is a free electricity market that is highly susceptible to international situations. In recent years, given the endless electricity price hike and supportive policies for various power grid business models, many companies consider localizing supply chains. When exiting South Korean manufacturers expand production capacities in 2023, the share of local supply will increase rapidly. However, **InfoLink does not see Europe wean itself off cell imports until 2025 when LCOS is estimated at USD 0.1/kWh. After 2025, when cell manufacturing plants in Europe enter operation, cell supply may catch up, allowing prices to drop gradually. The LCOS in 2030 is estimated at USD 0.06/kWh.**

Conclusion

There are two types of energy storage systems, FTM energy storage systems, and BTM energy storage systems. Since the FTM capacity is bigger than BTM, the cost of FTM systems are also much cheaper. The LCOE in this white paper is calculated by FTM energy storage systems that has 30 MW/120 MWh of power output. Battery's cycle life is a decisive variable in calculating LCOE. Since batteries account for most of the total cost of an energy storage system, the choice of cells is a significant factor. For now, LFP batteries and NCM/NCA batteries are the main batteries used for energy storage systems. China, as the manufacturing hub of LFP batteries, has the lowest LCOS in the world.

The Covid-19 pandemic results in battery delivery delays and price hikes. Many international cell manufacturers plan production expansions in other places, reshoring cell supply chains. InfoLink expects cell supply to be sufficient for the huge demand from the EV and energy storage industry when major manufacturers complete expansion. As expansions make steady progress, **the construction cost of energy storage systems will stabilize,** coming in at USD 0.07/kWh in 2025 and USD 0.04/kWh in 2030.

3.4 ESS IRA

Energy storage

Before the IRA became law, an energy storage system was only eligible for the ITC if integrated with solar facility. Residential energy storage systems were only eligible if the batteries are charged 100% by solar, whilst FTM and C&I energy storage systems were only eligible if charged 75% from solar energy.

As shown in Table 3.4-1, an energy storage system could avail as high as 26% of ITC in 2021, and 19.5% if 75% pared with solar energy. **The IRA lifts these restrictions to include standalone energy storage assets, significantly affecting the development of energy storage industry.**

Table 3.4-1. ITC rate before the IRA

Percentage of being charged by solar	75%	80%	90%	100%
FTM, C&I ESS	19.5%	20.8%	23.4%	26%
Residential ESS	0%	0%	0%	22%

The IRA applies to energy storage facilities constructed after December 31, 2022. FTM and C&I energy storage systems must have a minimum nameplate capacity of 5 kWh, and residential ones of 3 kWh. As shown in Table 3.4-2, before the IRA, there are merely 26% of ITC for FTM and C&I energy storage systems in 2022, while that for residential ones was 22% in 2021. The ITC for FTM and C&I energy storage systems would start to phase out from 2023, while the ITC for residential facilities would end in 2022. Under the IRA, the 30% ITC is extended for another ten years, then start to step down gradually to 26% in 2033. For residential energy storage systems, the subsidy will end in 2035. FTM and C&I facilities will see ITC step down to 15% in 2035 and end in 2036.

Table 3.4-2. ITC before and after the IRA

ITC		2020	2021	2022	2023	2024	2025-2032	2033	2034	2035	2036
Before	**C&I**	26%	26%	26%	22%	10%	10%	10%	10%	10%	N/A
	Residential	26%	26%	22%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
After	**C&I**	26%	26%	30%	30%	30%	30%	26%	22.5%	15%	N/A
	Residential	26%	26%	30%	30%	30%	30%	26%	22%	N/A	N/A

FTM and C&I energy storage systems with net output lower than 1 MW are qualified for 30% of tax credit without meeting any labor and wage requirements, as long as they have a minimum nameplate capacity of 5 kWh. Facilities with net output larger than 1 MW must satisfy all labor and wage requirements to be eligible for the full bonus rate, otherwise, it only gets a maximum of 6% base credit. As shown in Table 3.4-3, if meeting certain domestic content requirements, a facility can avail 2% to 10% of extra credit. Another 2% to 10% of extra credit is applicable for facilities located in an "energy community." Namely, under different circumstances, an FTM or C&I facility can manage to attain an ITC of as much as 6% to 50%.

Table 3.4-3. ITC requirements under the IRA

	Net output > 1MW		Net output < 1MW
Labor requirements	Not satisfied	Satisfied	No need to satisfy
Base credit	6%	30%	30%
Certain domestic content requirements	2% - 10%	2% - 10%	10%
Located in energy communities	2% - 10%	2% - 10%	10%
Low-income communities (Below 5MW)	10% - 20%	10% - 20%	10% - 20%
Total credit	4% - 46%	30% - 70%	30% - 70%

Originally, energy storage systems are eligible for 5-year to 7-year MACRS depreciation schedule, depending on the ratio of integration with solar systems. Under the IRA, energy storage systems with at least 500 kWh of net output commissioned after Dec. 31, 2024 are categorized as 5-year property given natural wear and tear that result in the deterioration of performance and efficiency. Early in an equipment's lifetime, the MACRS factors in natural wear and tear proportionally to evaluate depreciation, allowing fixed assets to receive subsidies, and investors to collect returns as soon as possible, ramping up equipment upgrades. The IRA expands the scope of depreciation and leaves the administrative procedures unchanged.

The biggest impact of the IRA is that it includes standalone energy storage technology. In the past, BTM and C&I energy storage system must be paired with solar. Therefore, the time of charging and discharging is limited, making energy arbitrage impossible. Under the IRA, energy storage systems are not required to be connected to the grid, allowing more flexible business models.

In the residential market, before the IRA, energy storage systems must be connected to solar systems to receive tax credits. Therefore, solar projects in energy communities are not eligible for energy storage ITC. With the IRA, participants of these projects add standalone energy storage systems and receive the subsidy. The IRA boosts installed energy storage capacity in both FTM and BTM markets. Additionally, **the act helps reduce initial investment cost, boosting the development of the more costly long-duration energy storage facilities** and add flexibility to different application scenarios.

Cell supply chain

Introduced with the IRA, the Section 45X Advanced Manufacturing Tax Credit is a credit for manufacturers of certain components produced within the U.S. For battery cells, the credit amount is USD 35/kWh, for battery modules USD 10/kWh, and for materials and minerals, the credit amount is 10% of production costs. The Section 45X promotes the premium of "U.S.-made" and is applicable for every manufacturing step. Namely, manufacturers have tax credits at every stage of processing and assembling.

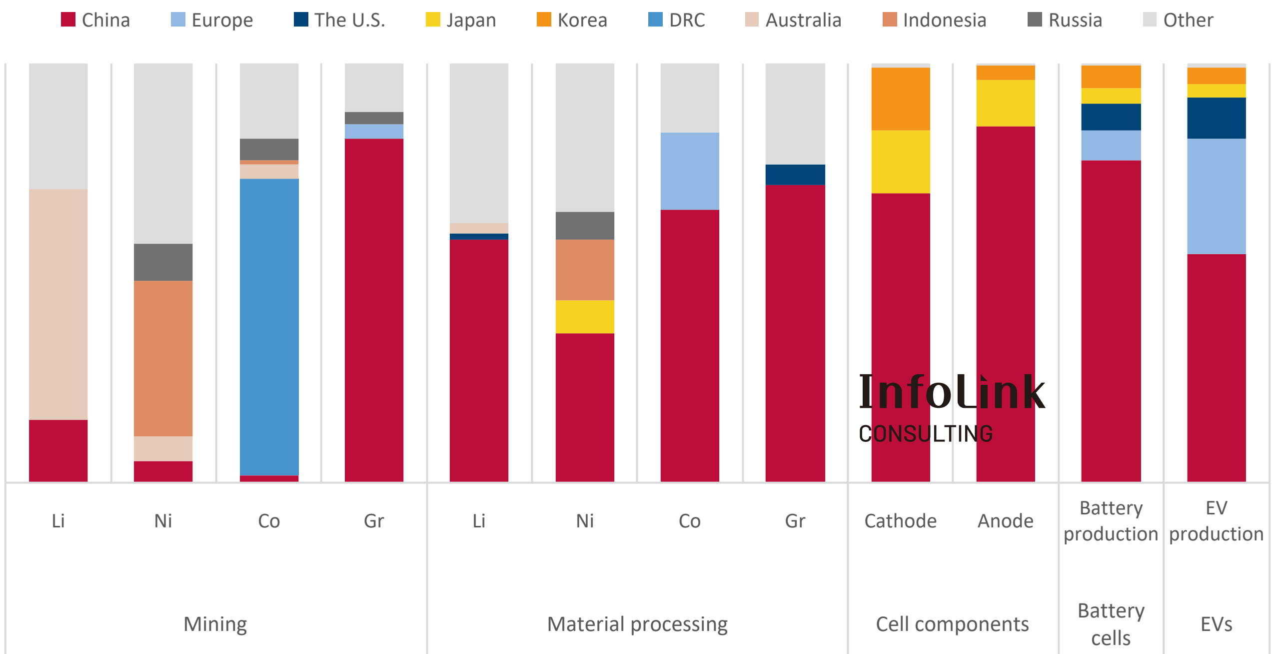
For downstream sectors, the IRA limits the cell supply chain by providing incentives to local EV manufacturers. As shown in Table 3.4-4, the USD 7,500 tax credit is split into two parts. The first USD 3,750 is allocated to manufacturers of batteries of which at least 40% of critical minerals are extracted or processed in the U.S. or free trade partners. The other USD 3,750 is for manufacturers of batteries of which at least 50% of battery components are manufactured or assembled in the U.S. or free trade partners. The percentage of value required will increase by 10% every year to 80% in 2027.

Starting from 2024, EVs with any battery components sourced from a foreign entity of concern, and from 2025, any battery with critical minerals sourced from a foreign entity of concern, will not be qualified for the tax credit, respectively. Given that, **the IRA is no doubt a major driving force for the localization of cell supply chains worldwide.**

Table 3.4-4. IRA EV tax credit, Unit: USD

	Credit amount	Income caps	MSRP caps	Vehicle cap	Requirement				
					2023	2024	2025	2026	2027
Previous EV tax credit	$7,500	N/A	N/A	200,000	N/A	N/A	N/A	N/A	N/A
IRA EV tax credit (effective from 2023-2032)	$3,750	Single filers: $150,000 Joint filers: $300,000	Vans: $80,000 SUVs, pickup trucks, and all other vehicles: $55,000	N/A	At least 40% of critical minerals are extracted or processed in the U.S. or free trade partners.	50%	60%	70%	80%
	$3,750	Single filers: $150,000 Joint filers: $300,000	Vans: $80,000 SUVs, pickup trucks, and all other vehicles: $55,000	N/A	At least 50% of battery components are manufactured or assembled in the U.S. or free trade partners.	60%	60%	70%	80%

The following chart from an IEA report titled Global Supply Chains of EV Batteries, illustrates the concentration of material processing capacity, cell component, and battery cell production capacities in China. Due to the concentration, other countries lack supply chains for related materials. As a result, it takes them much more time to assess, design, and build cell manufacturing plants. For instance, CATL constructed a cell factory within a year in China but spent more than three years in Germany. **The IRA will boost the localization of cell supply chains outside of China, especially those of free trade partners of the U.S. and cell manufacturers investing in the U.S.**

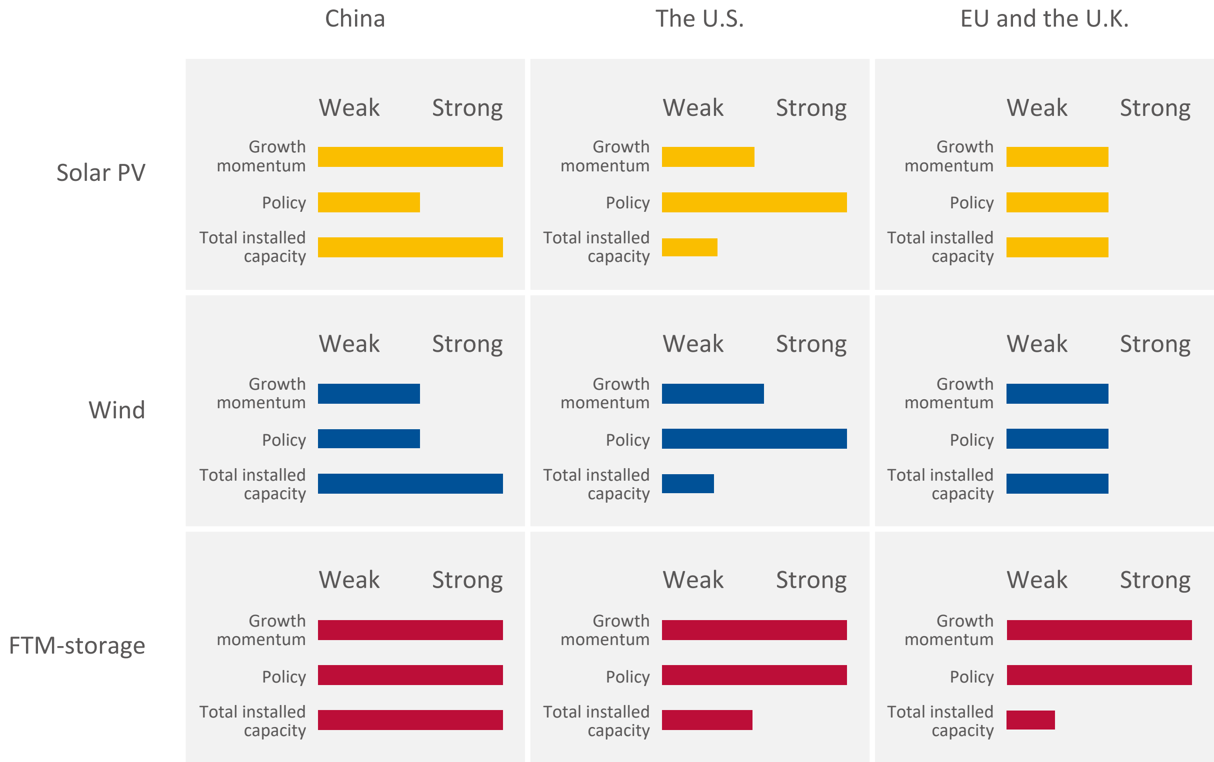


Source: IEA, 2022

Figure 3.4-1. Geographical distribution of the global EV battery supply chain

SUMMARY

Renewable energy installation growth



Growth momentum: Weak— CAGR< 10%; Moderate— CAGR 10~20%; Strong – CAGR >20% (In the case of wind: Weak – both onshore and offshore <10%; Moderate – either onshore or offshore >10%; Strong – both >20%)
Policy: Weak – no policy target; Moderate – have policy target but no strong incentive; Strong – clear supportive policy and incentives
Total installed capacity: The markets are ranked by strong, moderate, weak in accordance with the total installed capacity in 2030. Growth momentum, policy, and total installed capacity are compared market by market rather than cross comparison of renewable energy sources.

Figure S-1. Forecast for renewables development in three major regions

The above grid compares the renewable energy potential in the three major markets. China has witnessed the fastest overall growth rate. In 2021, the nation was the world's largest solar and onshore wind market, with a CAGR of 24% for solar installations, 10% for onshore wind, and 39% for energy storage from 2021 to 2030, the highest among the three. However, China's strong cost advantage makes it challenge for foreign companies to enter the Chinese market. Additionally, while offshore wind and energy storage still receive subsidies from some local governments, government subsidies for solar and onshore wind are no longer available. Therefore, entering the Chinese market currently would put companies at a relative disadvantage and limit their profit potential.

Among the three regions, the US market has the strongest subsidy policies. The Inflation Reduction Act (IRA) provides comprehensive subsidies for renewable energy such as solar, wind, and energy storage, which will significantly reduce the levelized cost of energy (LCOE) and levelized cost of storage (LCOS) and stimulate the growth of installed capacity, especially offshore wind. In the past, the development of offshore wind energy in the U.S. was hindered by alternative renewable energy options, abundant traditional energy sources, and development failures. However, with the Biden administration setting a target of 30 GW of cumulative installed capacity by 2030, the U.S. will become one of the fastest-growing markets in the world.

Energy storage also benefits from the IRA, which not only expands the scope of subsidy by including standalone storage but also accelerates the evaluation process. Additionally, IRA-driven solar installation and investment will also contribute to the growth momentum of energy storage.

The European market may not stand out in terms of total installed capacity and growth momentum and has no longer provided large-scale subsidy for solar and wind energy. Yet, the region enjoys relatively stable investment environment, and it is accelerating renewable energy and energy independence. Also, persistently high prices of fossil fuels have driven more residential solar installations. The urgency to deploy renewables and the consensus met by the governments and the public have stimulated the growth of solar installations in Europe and improved the issue of lengthy approval processes for wind farms.

LCOE

The calculation for solar and wind energy shows that the average LCOE of solar and onshore wind in China, Europe, and the U.S. had reached a level lower than the traditional energy sources in 2021. In Europe, the LCOE of solar and onshore wind sat at USD 30/MWh to USD 50/MWh; USD 20/MWh to USD 40/MWh in the U.S.; USD 25/MWh to USD 30/MWh in China. Europe saw the biggest gap between onshore, solar, and the traditional energy, with the difference between solar and natural gas reaching as far as USD 110/MWh to USD 120/MWh. Costs of fossil-fuel and natural gas energy generation surged due to Russia-Ukraine war – up 50% during 2022 and 2023 compared with the level in 2021.

In China, natural gas costs increased by 50% over the short term, but coal-fired energy prices experienced little impact as the country has coal mines and does not join the western sanction against Russia. Moreover, China and Russia have agreed long-term gas supply deal, consuming the natural gas originally provided to Europe. The U.S. also received minor impact, as the country produces shale oil and natural gas itself.

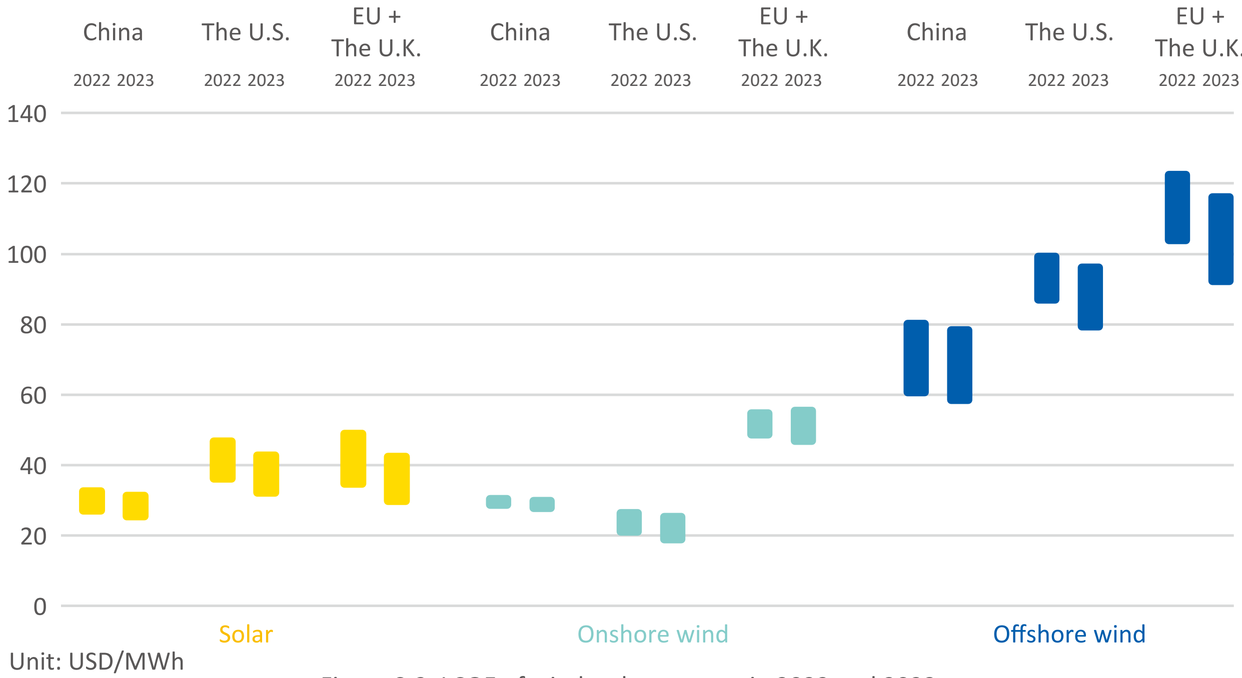


Figure S-2. LCOE of wind, solar, storage in 2022 and 2023

2022 is a unique year for renewable energy, for it marked a rare increase in LCOE of onshore wind and solar over the past decade. The rise in construction costs was driven by three factors. Firstly, the impact of the Russia-Ukraine conflict disrupted the renewable energy supply chains, affecting shipping and raw material availability. Secondly, inflationary pressures led central banks in various countries to raise interest rates, resulting in increased financing costs. Lastly, the accelerated energy transition in Europe led to increased demand, driving up prices.

For instance, solar project costs in Europe started to rise steadily from early 2022 and peaked in early 2023. China, the manufacturing hub of solar components, also experienced price increases driven by demand. However, this momentum started to fade in 2023. In light of this, InfoLink predicts a global decline in LCOE for solar energy in 2023.

The situation for wind energy is quite different between Europe, the U.S. and China. In Europe and the U.S., wind turbine manufacturers faced significant cost pressures due to surging raw material prices and hefty fines resulting from shipping disruptions. Unable to bear the losses, they gradually shifted the cost burden to developers. As a result, wind turbine prices increased by an average of 30% to 40% in early 2023 compared to 2021, significantly pushing up the construction costs for onshore and offshore wind power. Developers in Europe and the U.S. expressed objections to previously agreed Power Purchase Agreement (PPA) prices, saying that the current construction costs and interest rates might not support the construction of wind farms. While wind turbine prices are not likely to fall significantly in 2023, the drop in steel prices contributes to a decrease in construction costs for wind farms.

On the other side of the world, the competition among Chinese wind turbine manufacturers shows no sign of stopping. Prices of towers and wind turbines have been falling in 2022 and that decrease continued into 2023. Since China has a complete wind turbine supply chain and only requires imports of a few components, it was less impacted by shipping congestion compared to the European and US markets.

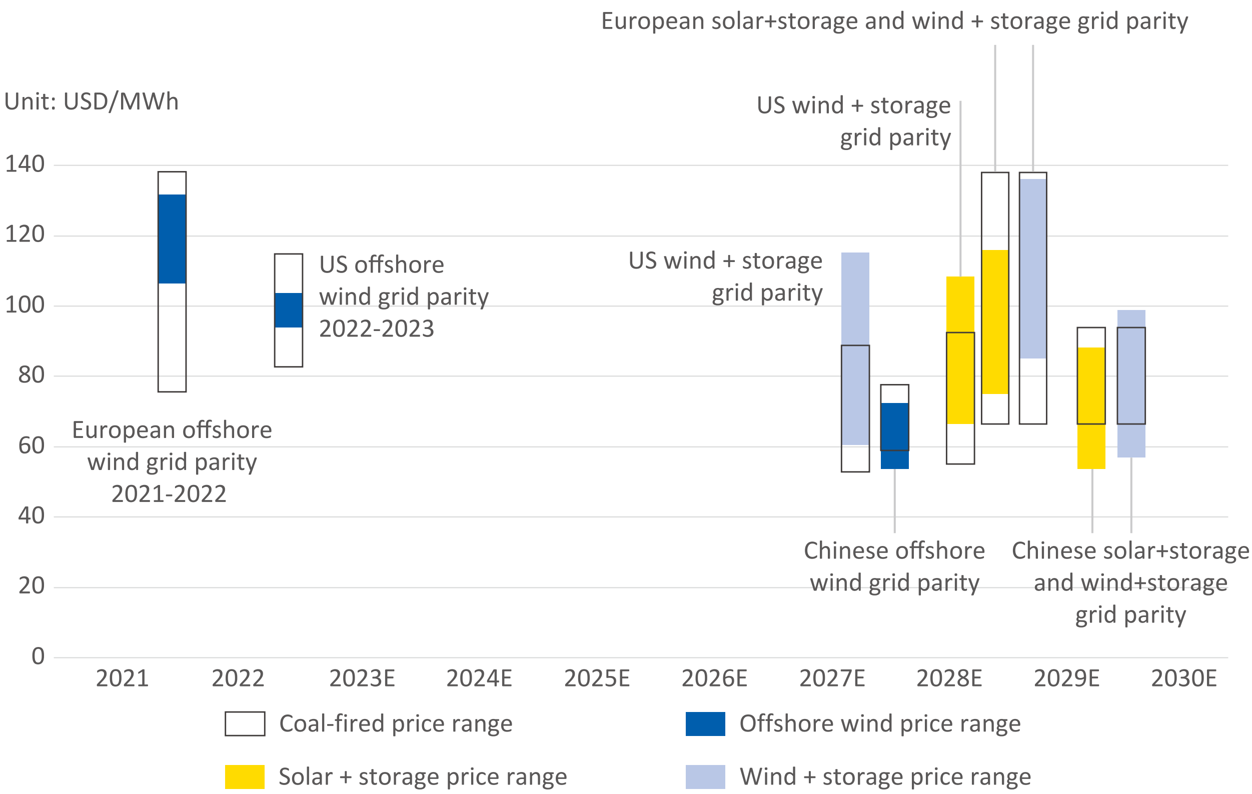


Figure S-3. The timeframe for offshore, wind-plus-storage, solar-plus-storage to reach grid parity in each region

InfoLink's research finds that the three largest markets will reach grid parity in the offshore and solar- and wind-plus-storage by 2030. As showed in the figure, offshore wind and wind-plus-storage and solar-plus-storage in Europe and the U.S. will achieve grid parity earlier than China. China will achieve grid parity for offshore wind five years later than the U.S. The following are the timeframes for reaching grid parity in different regions:

In Europe, the cost of offshore wind energy is already lower than that of coal-fired power generation, which surged due to the Russia-Ukraine conflict. However, the negative bidding to implement from 2027 will lead to an increase in capital expenditure, meaning that governments are shifting the cost burden of wind farm development onto developers, widening the cost gap between offshore and onshore wind power and solar energy. The costs of solar-plus-storage and wind-plus-storage are both expected to be lower than those of coal and natural gas between 2028 and 2029. This is primarily due to the decreasing costs of energy storage. InfoLink expects the supply and demand for energy storage in Europe will approach equilibrium in 2025, allowing for further cost reductions.

Offshore wind power in the U.S. is still in its nascent stage, but it enjoys lower LCOE theoretically owing to ITC, which, is estimated to reduce the LCOE by more than 20%, making it lower than coal-fired power generation between 2022 and 2023. Wind-plus-storage in the U.S. is expected to be lower than coal-fired power generation by 2027 due to onshore wind's low LCOE. With the Production Tax Credit (PTC) subsidy under the IRA, the LCOE of onshore wind power may approach USD 12.9/MWh. Solar energy has slightly higher LCOE than onshore wind, and thus solar-plus-storage is expected to be lower than coal-fired power generation around 2028 and 2029.

China is projected to achieve grid parity for offshore wind between 2027 and 2028, while wind-plus-storage and solar-plus-storage are expected to reach grid parity between 2029 and 2030. China lags behind Europe and the U.S. in achieving grid parity for wind-plus-storage and solar-plus-storage due to the relatively cheap coal-fired power generation in China. However, if excluding government subsidies, the LCOE of offshore wind, onshore wind, and solar energy in China are the cheapest among the three markets. Moreover, China has advantages in terms of large-scale production of energy storage equipment, localized supply chains, and the widespread use of LFP batteries, all of which contributing to lower costs.

Supply chain

The cost reduction of solar is driven by technology advancements in the supply chain. In the upstream sector, polysilicon capacity is expected to increase by 72% from 2022 to 2023. Such a surge in capacity will significantly lower the cost of polysilicon from 2023. Furthermore, as large wafers become mainstream, the process of wafer thinning continues to drive down costs.

Between 2023 and 2024, the rapid development of n-type cells should be monitored continuously. Such cells are expected to offer better price performance for it brings higher conversion efficiency and rear-side passivation. The era of n-type replacing p-type may arrive earlier than expected, potentially in 2024.

The scaling up of wind turbines is a key factor in reducing costs. Increasing the length of blades improves the swept area, allowing for a larger capture area. It also reduces the required length of array cables and the number of underwater foundations needed. As 15-MW turbines have been moving towards commercialization, InfoLink projects that by 2030, 17-18-MW offshore wind turbines will gradually become mainstream, with an average size of 15 MW.

The impact on the supply chain has led to losses for Siemens and Vestas. Siemens reported a core business gross margin of -5.9% in over the Q1-Q3 period of 2022, while Vestas had a profit margin of -3.2%. They were forced to raise turbine prices. In the first half of 2022, the average turbine price of Siemens increased by 20% to 30% compared to 2021.

Regarding energy storage, the mass production of cells driven by energy storage and electric vehicle demand has raised concerns of oversupply. InfoLink estimates an annual compound growth rate of approximately 20% from 2022 to 2030, and the production location will be slightly more dispersed from China to the U.S. and Europe. The rapid development of electric vehicles has also contributed to a nearly 90% decline in lithium-ion battery costs over the past decade. However, the types of batteries used are no longer limited to NMC batteries. LFP batteries are about 20% to 30% cheaper, and with the expiration of patents for LFP, Japan and South Korea also plan to invest in the development and production, which will help lower the construction cost of energy storage.

Inflation Reduction Act

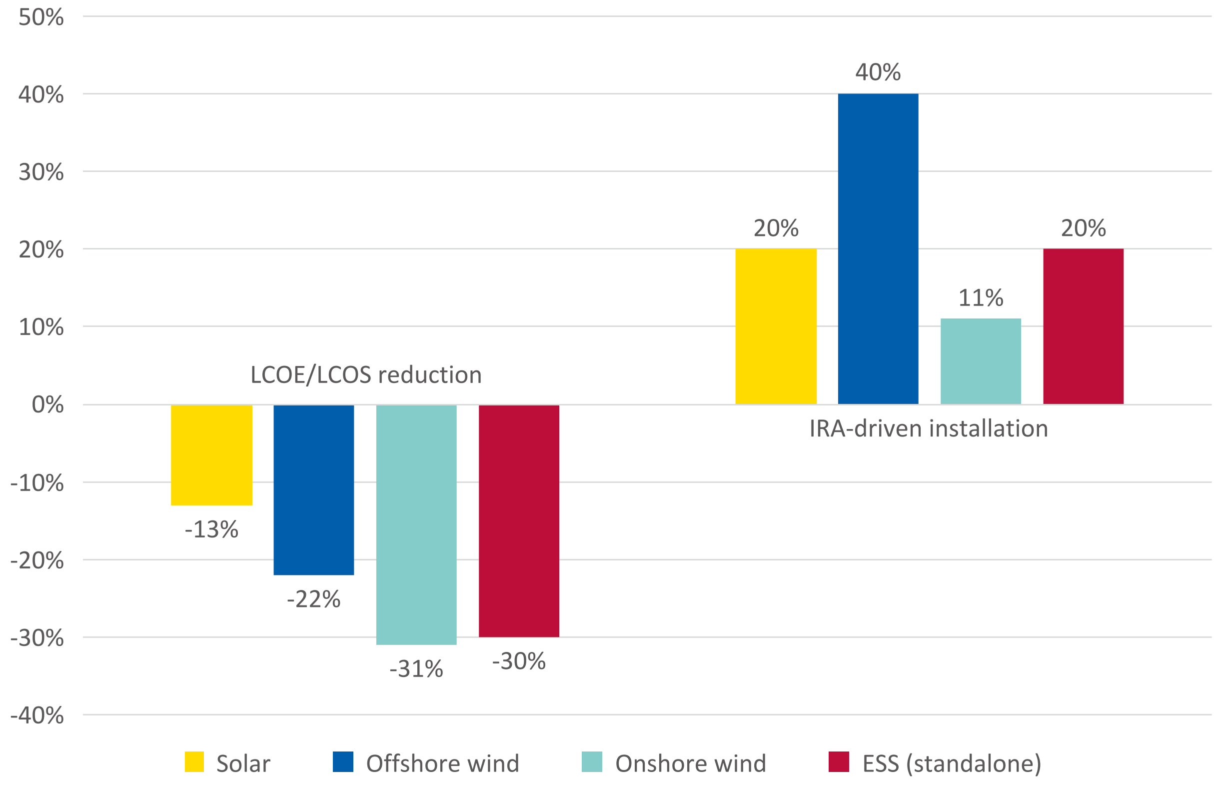


Figure S-4. Impact of IRA on installation and LCOE/LCOS

Overall, the IRA has a long-term impact on renewable energy. Firstly, it enhances investment incentives for renewable energy. A total of USD 369 billion has been allocated for climate solutions and environmental justice, along with ITC and ITC for renewable energy sources. InfoLink projects that the act will stimulate a 10% to 40% growth in solar, wind, and energy storage installed capacities, significantly reducing the LCOE of renewable energy and LCOS in the U.S. by 10% to 30%. Secondly, the IRA provides incentives for domestic manufacturing. Manufacturers that meet wage requirements and talent development plans can receive tax credits, and credit adders are available for meeting local content requirements, although this has raised concerns among European countries, fearing that the legislation may harm Europe's renewable energy manufacturing industry. Lastly, to mitigate backlash from the traditional energy sectors, the act offers additional tax credits for assisting energy communities[6] reliant on traditional energy sources in their transition. There are also tax credits available for carbon capture and storage technologies.

[6] Energy communities under the IRA include brownfield sites, coal communities and areas with a specific mix of employment and local tax revenue related to fossil fuels.

GLOSSARY

Bifacial technology

Bifacial technology generates electricity on both sides of a module as the rear side harnesses light reflected from the ground, increasing module power output.
For now, bifacial modules are increasingly favored in ground-mounted solar plants.

Feeder

A type of transmission line connected to the grid.

Grid parity

A point of time when a renewable energy source can generate power at a price that is less than or equal to the price of coal-fired electricity.

High-density assembly technology

High-density assembly technology increases the number of cells per package by minimizing cell spacing. The narrowed-spacing technology is the most prevalent due to its simplicity.

Inverter

An electronic device that changes direct current (DC) to alternating current (AC).

Investment Tax Credit (ITC)

The ITC scheme provides project owners income tax credit as a subsidy for system construction costs.

Levelized Cost of Energy (LCOE)

The average net present cost of electricity generation for a generator over its lifetime.

Multi-busbar (MBB) technology

Multi-busbar (MBB) technology reduces silver paste consumption and the shading area.

Production Tax Credit (PTC)

The PTC subsidy is allocated based on the actual amount of electricity generated by a PV system. The subsidy lasts for ten years, and the credit rate is subject to adjustment per inflation.

Split-cell technology

Split-cell technology reduces power loss and benefits the use of thinner large-format cells.
For now, half-cut cell technology is mainstream.

Uyghur Forced Labor Prevention Act

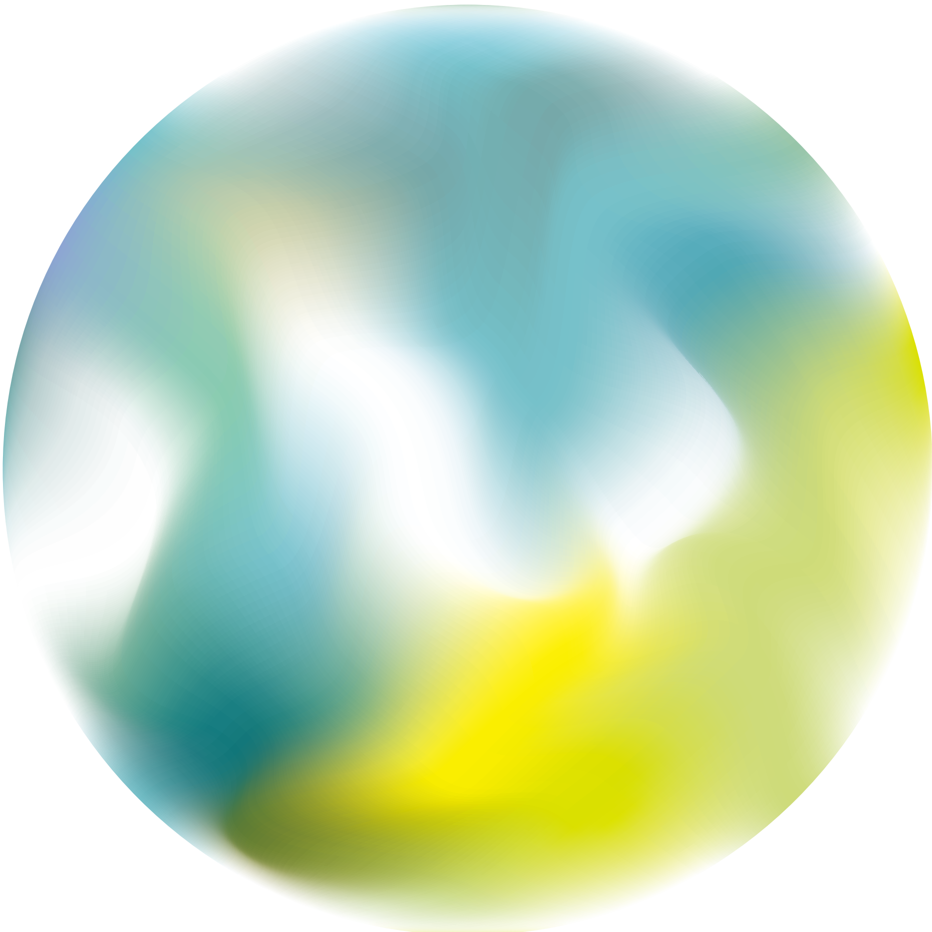
A U.S. federal law passed in 2021 banning products originated in Xinjiang.

LIST OF FIGURES

LIST OF FIGURES

LIST OF TABLES

ON THE ROAD TO NET ZERO



WHITE PAPER JUNE 2023

InfoLink CONSULTING

service@infolink-group.com