

Optimal Emission Reductions from the Chinese Power System, Considering Hydrogen, CCS and Resilience to Demand-Surge Events

Summary

This study used an updated version of the open-source Switch-China model¹ to assess options for deep decarbonization of China's power system, and how the preferred options and costs may change as different technologies are put on the table. The study focused on three questions:

1. How does the “right” level of abatement change when we update the Switch-China model with more realistic economic factors and improved risk management?
2. How important are hydrogen and CCS likely to be in achieving deep emission reductions in China's power system?
3. How would the system design change for stronger or weaker emission targets?
4. How does the resource plan change if we design for a higher level of robustness against sustained difficult weather such as heat waves?

This study made several preliminary findings in response to these questions. These are summarized here and discussed in more detail below.

1. With updated but realistic assumptions about the cost of capital and future costs of renewable power equipment and batteries, it appears that it would be cost-effective for China to achieve emission reductions around 93% below 2028 levels by 2048. This is significantly deeper than the 81% emission reductions found with the original Switch-China model.
- 2a. If hydrogen electrolyzers, fuel cells and hydrogen combustion are considered as options, the cost-effective level of emission reductions goes even deeper, to 97.5% below 2028 levels by 2048, with a slight reduction in power costs.
- 2b. If carbon capture and storage (CCS) is considered as an additional option, the cost of power in an optimally clean power system (a system designed based on a \$200/tCO₂ cost) falls by about 10% and the preferred level of CO₂ reductions in 2038 (under a \$100/tCO₂ carbon cost) rises from 58% to 89%. However the preferred level of CO₂ reductions in 2048 retreats slightly vs. the case with hydrogen but not CCS (to 94%). This is because when CCS is available, it becomes a preferred power source even at a low carbon cost, but then the additional cost per tonne to cut more deeply (via switching to renewables and possibly hydrogen) becomes higher. Since the economics appear to be favorable for CCS, it will be important to pin down its cost more accurately and to assess how widely it could be used and how soon. Attention should also be given to whether it is worthwhile to pursue this resource in light of the small cost savings it can deliver.
- 3a. With all options on the table, a least-cost system design ignoring CO₂ concerns would get roughly 30% of its power from solar, 40% from coal, and the rest from a mix of wind, hydro and nuclear (hydro and nuclear are at pre-specified levels in the model). For low reduction targets, the system would shift from coal to solar, until solar plateaus at about 35% of power generation. Additional reductions beyond that

¹ <https://github.com/switch-model/switch-china-open-model>

would come mainly from switching from direct combustion of coal to CCS if it is available. For deep reductions (more than 85% by 2048), it would be necessary to reduce CCS and use solar and batteries instead. For very deep emission reductions (beyond 95%), the optimal design would replace some of the last remaining coal with green hydrogen for seasonal balancing, reaching a maximum of 3% of the power supply in a fully decarbonized system.

- 3b. If CCS is taken off the table, then the main strategy to reduce emissions would be switching from coal combustion to solar, wind and batteries. For reductions beyond 90%, green hydrogen would also become attractive on a small scale.
4. It appears to require minimal changes to make a deeply decarbonized power system resilient against intense but rare heat waves. For events occurring for around 8% of the year every 3 years, the main changes would be to add additional direct-combustion coal capacity, which would be idle most of the time but used around the clock to supplement renewables and recharge batteries during these events. It is unlikely to be cost effective to add CCS plants for this purposes due to the high capital cost and small savings in CO₂ emissions. However, if natural gas plants or hydrogen fuel cells reach capital-cost parity with direct-combustion coal plants, they could take over as the preferred backup resource.

Future work should assess the robustness of these findings, i.e., use sensitivity studies to identify which conclusions are likely to be persistent despite uncertainties in the forecasts of loads and costs, and which depend more closely on the details of future economic conditions. In addition, it would be useful to use more realistic load shapes, driven by the same weather as the wind and solar profiles (Switch-China's loads are quite synthetic). It would also be a good idea to run the assessment using weather from many years, in order to be more sure of being resilient to the range of weather that has been experienced in past years.

Discussion and Figures

How does the “right” level of abatement change when we update the Switch-China model with more realistic economic factors and improved risk management?

For this work, I defined the “right” level of abatement as the amount that can be achieved at a marginal cost below \$200 per metric tonne of CO₂. This is close to recent estimates of the social cost of carbon² and the cost of direct air capture³. Either of these could set an upper limit on expenditure per tonne of CO₂ avoided: the social cost of carbon sets an economically efficient mitigation target, and direct air capture serves as a backstop option that would be preferred over more expensive mitigation in the electricity sector. As will be seen below, the vast majority of emission in the Chinese power sector could be avoided at a cost below \$200/tCO₂, but costs rise very quickly to avoid the last few percent of emissions from this sector. So \$200/tCO₂ also serves as a useful metric to identify the corner of the “hockey stick” shape of emission reduction costs, where further reductions rapidly become too costly to pursue. Because of this “hockey stick” shape, it appears unlikely that moderate changes in the cost threshold would cause large changes in the “right” amount of mitigation.

² https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf, p. 3

³ <https://www.iea.org/reports/direct-air-capture-2022/executive-summary>

For this study, “more realistic economic factors” includes the following changes from the original Switch-China model:

- Allow power plants to retire early to avoid fixed operation and maintenance (O&M) costs (full capital outlay must still be recovered).
- Switched from 8% real finance rate for renewable energy projects (corresponding to about 10% nominal) to 4% real (~6% nominal). This is closer to the 3-4% nominal cost of capital for renewable projects in China.⁴
- Switched from 8% real discount rate to 3% , which is closer to recent forecasts of long-term GDP growth of 2–3%.⁵
- Switched from 2010 dollars to 2022 dollars.
- Adopted the declining forecasts of future renewable equipment costs from the National Renewable Energy Lab Annual Technology Benchmark, in place of the nearly flat forecasts previously used in Switch-China.
- Switch to 10-year investment stages and extend the model to 2077, to include the full life and possible stranded cost of coal plants built before the system moves to deeper emission reductions around 2050.

“Improved risk management” consists of the following changes from the original model:

- Enforce a spinning reserve margin at all times. This was omitted from the original Switch-China model, possibly by mistake. The study reported here uses the “3+5” standard from NREL's 2010 Western Wind and Solar Integration study, which requires spinning reserves equal to 3% of loads plus 5% of renewable production at all times, to compensate for unforeseen changes in load and renewable production that may occur too fast for new plants to be turned on.
- Adopt a new planning reserve method designed to address sustained high-load events such as heat waves. These events could exceed high-renewable systems’ energy-delivery capacity even if they don’t exceed their peak power capability, e.g., there could be too little wind and solar power to charge batteries and serve high loads for several weeks, even if there is enough capacity to meet peak loads. This method consists of identifying the two sample days in each study period that are most difficult to serve with an all-fossil or all-renewable system, then modeling each of them as if loads could be 10% higher than the sample data and could continue at this level for two weeks straight every three years. This is designed to ensure the system can respond to unusual, sustained high load levels that do not appear in the sample data. When using these margins, the previous rating-oriented reserve margin was turned off. This avoided problems where coal capacity could be deemed eligible to meet planning reserve margins, even in very low or zero carbon scenarios, where it wouldn’t be allowed to be turned on.

Figure 1 summarizes the design and operation of a least-cost power system with all the changes above. This system was designed with a carbon cost that starts at \$0/tCO₂ in 2028 and rises

⁴ <https://www.irena.org/Publications/2023/May/The-cost-of-financing-for-renewable-power>

⁵ <https://carnegieendowment.org/chinafinancialmarkets/89466>

linearly to \$200/tCO₂ by 2048. This could be regarded as a carbon tax or carbon cap that results in this credit price.

This system steadily phases out coal over the 2028–48, replacing it and serving load growth with solar power, and to a lesser extent wind power. There are also significant investments in batteries, which are not shown in Figure 1. As a result, this optimized system achieves emission levels of 415 MtCO₂ by 2048, 93% below 2028 levels, with a levelized cost of electricity (LCOE) in 2048 of \$83/MWh.

These costs and emissions are much lower than the original Switch-China model, which would reach 1,157 GtCO₂ by 2048, 81% below 2028 levels, with a LCOE of \$114/MWh (see Table 1). These differences are mainly due to the use of a lower discount rate, lower interest rate and forecasts for renewable equipment costs that decline over time.

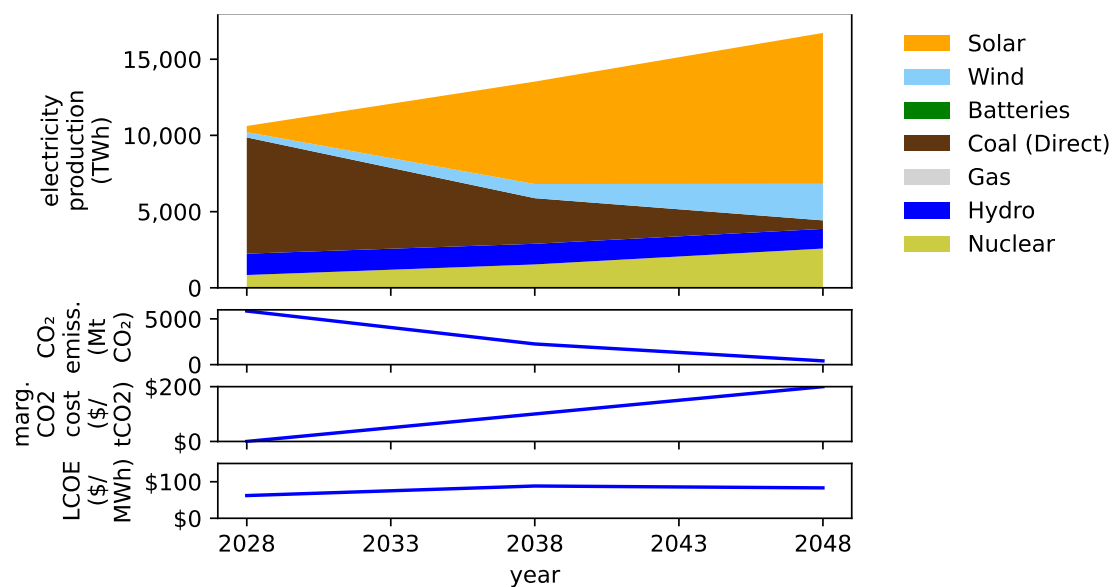


Figure 1. Summary plot for least-cost power system with carbon cost rising to \$200/tCO₂, without hydrogen or carbon capture options

Table 1. Summary statistics for updated model, with and without hydrogen and CCS options

	CO ₂ emissions (Mt/y)			LCOE (\$/MWh)		
	2028	2038	2048	2028	2038	2048
Original Switch-China	5,974	3,340	1,157	64	106	114
Updated economics and reserves	5,862	2,262	415	62	88	83
Add hydrogen options	6,057	2,562	151	59	87	80
Add CCS option	6,060	685	346	59	74	72

How important are hydrogen and CCS likely to be in achieving deep emission reductions in China's power system?

To answer this question, I defined additional technology options as follows:

- Allow construction of hydrogen electrolyzers, liquefiers, storage tanks and fuel cells and allow retrofitting of coal power plants to burn hydrogen from these sources.
- Allow retrofitting or augmentation of coal power plants to add carbon capture and sequestration (CCS) technology. This uses a fairly aggressive (low-cost, high-efficiency) design.⁶

Figure 2 below shows the model from Figure 1, with the additional option of producing hydrogen via electrolysis and using it to operate fuel cells or as a fuel for retrofitted coal plants.

Adding the hydrogen option has two contradictory effects: (1) by providing an end-of-life option for coal plants, it makes new coal more viable in the early years, slightly increasing use of coal in 2028 and 2038; (2) on the other hand, it provides an option for deeper emission reductions at a cost below \$200/tCO₂ in 2048 and later, slightly decreasing the use of coal then.

As a result, if hydrogen is available, emissions from the optimal system design rise by 195 MtCO₂ (3.3%) in 2028 and fall by 264 MtCO₂ in 2048. The net result is a very clean power system in 2048, with emissions of 151 MtCO₂, 97.5% below the 2028 level (see Table 1). Both of these effects reduce costs in 2028 and 2048, so the LCOE drops by \$3/MWh in both years. It may also be worth noting that in this system, CO₂ emissions continue to decline as the early coal investments age out, eventually reaching no emissions at all by 2068.

⁶ Yuan Jianget al., "Energy-effective and low-cost carbon capture from point-sources enabled by water-lean solvents," *Journal of Cleaner Production*, Volume 388, 2023, 135696, <https://doi.org/10.1016/j.jclepro.2022.135696>.

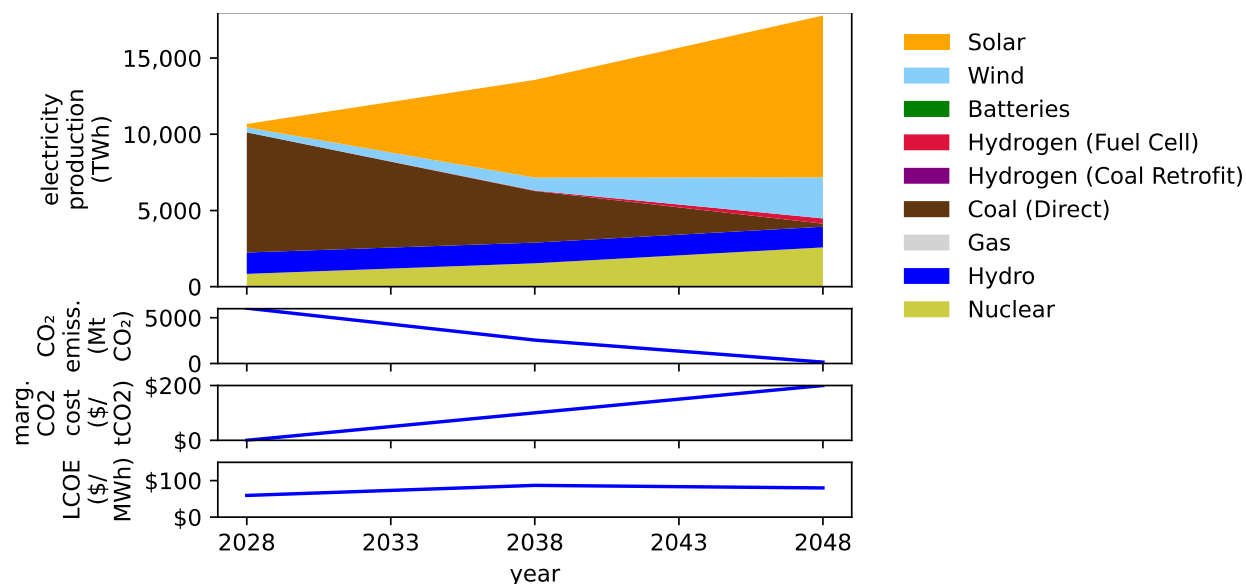


Figure 2. Summary plot for least-cost power system with carbon cost rising to \$200/tCO₂, with hydrogen options but without carbon capture

Figure 3 below shows the model from Figure 2, with the additional option of adding a high-performance, low-cost CCS system to new or existing power plants. When this option is available, the least-cost design shifts radically, almost completely phasing out direct coal combustion by 2038. However, it also adopts coal combustion with CCS on a very large scale, continuing to amount to about 50% of the 2028 coal level in 2048. This is paired with a commensurate reduction in solar and wind capacity. In the previous system designs, coal acted in a niche role to provide backup power on difficult weather days after 2048, but with the CCS option, coal moves back to a major role in the generation portfolio.

Comparing emissions and costs (Table 1), the CCS option has a minimal effect in 2028. However, in 2038 and 2048, it reduces the LCOE by 10–15%. It also makes it cost-effective to significantly reduce emissions in 2038, from 2,562 MtCO₂ for the no-CCS system to 685 MtCO₂ when CCS is available. This indicates that CCS may make large emission reductions cost-effective at the \$100/tCO₂ carbon cost in effect in that year.

However, as a low-cost, low-carbon (but not zero-carbon) power source, the CCS option has a perhaps unexpected effect on emissions in later years: because power can be produced via CCS with a fairly low amount of carbon per MWh (nearly 10x lower than direct coal combustion), other mitigation options such as using more renewables or hydrogen become less cost-effective per tonne of carbon avoided. Consequently they are not pursued to as high a degree (if at all) when CCS is available, and the optimal design with CCS available has somewhat higher emissions in 2048 (346 MtCO₂, 94% below 2028 levels) than the optimal design with hydrogen and no CCS (151 MtCO₂). It should be noted however, that the higher emissions in 2048 are more than counterbalanced by the lower emissions that CCS makes possible in 2038.

The findings for the power system with CCS option raise several questions that merit further investigation: Are the low CCS costs used here realistic? CCS is not yet commercialized for power plants; would it be reasonable to adopt it as a centerpiece of China's mitigation strategy?

Is it possible to sequester the massive volumes of CO₂ that would need to be stored under this strategy (3,100 MtCO₂/y, roughly 50% of China's 2028 electricity emissions)? Given the uncertainties around CCS, is it worth pursuing in order to achieve the modest cost reductions (~10%) it can give in a deeply decarbonized power system?

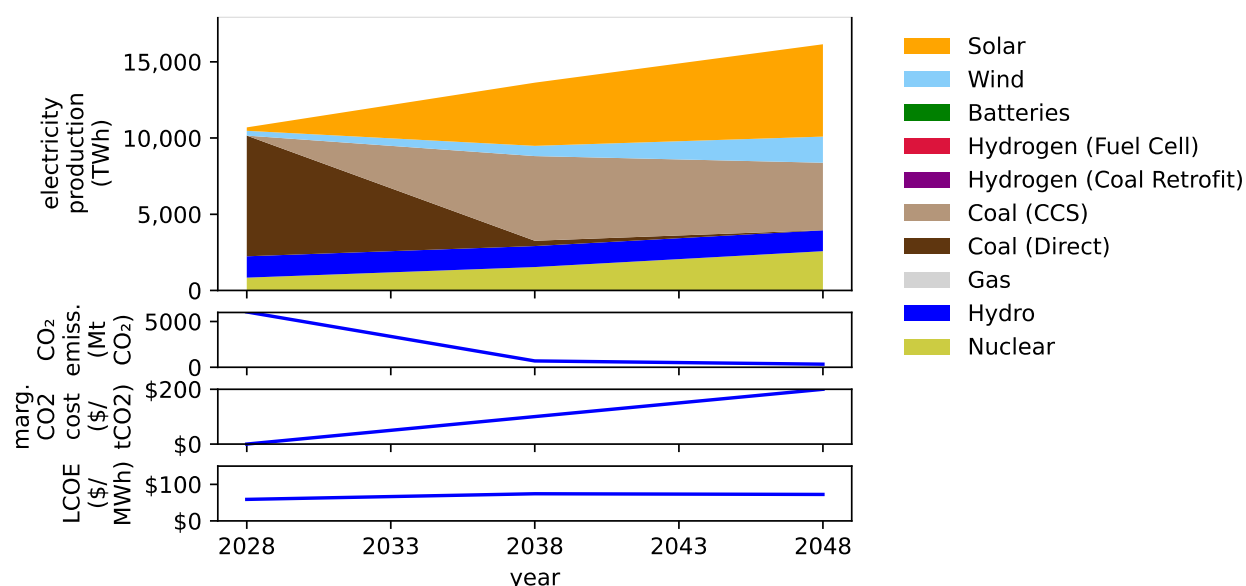


Figure 3. Summary plot for least-cost power system with carbon cost rising to \$200/tCO₂, with hydrogen and carbon capture options

How would the system design change for stronger or weaker emission targets?

The preceding analysis focused on systems designed to achieve the most mitigation possible with a marginal cost below \$100/tCO₂ in 2038 or \$200/tCO₂ in 2048. In this section, I look at how the system design would change with different levels of ambition in the emission reductions. For the scenarios in this section, I applied a carbon cap that began at a benchmark level of 4,856 MtCO₂ in 2028 and then reached a level from 100% to 0% of this by 2048. The transition from the starting to ending target was linear in each case. The 2028 benchmark was based on the original level in the Switch-China model, which corresponds to a nearly unconstrained system for that year.

No hydrogen or CCS. Figure 4 below shows the range of designs that would be preferred in 2048 for emission reductions of 0% to 100% below the 2028 baseline. This uses a different x-axis from the previous plots: Figure 4 shows the same scenario as Figure 1, but with the year held constant at 2048, and the emission target allowed to vary from very loose (left) to very clean (right).

For a nearly unrestricted system (left side), the least-cost plan would get about 7,000 TWh of power from coal in 2048, nearly equal to the total amount of coal in 2028 without a carbon cost (see the left edge of Figure 1 above). However, all the load growth between 2028 and 2048 is met by solar and wind power, making up about 5,000 TWh by 2048. Pre-planned nuclear and hydro make up the remaining 3,000 TWh. This indicates that even a least-cost system with no

carbon cap would obtain about 50% of its power from non-emitting sources. (I tried additional scenarios with carbon caps up to 200% of the baseline and the least-cost system remained close to 100% of the baseline, i.e., 0% reductions, as shown on the left edge of Figure 4. This is also reflected in the near-zero marginal mitigation cost at the left edge of Figure 4.)

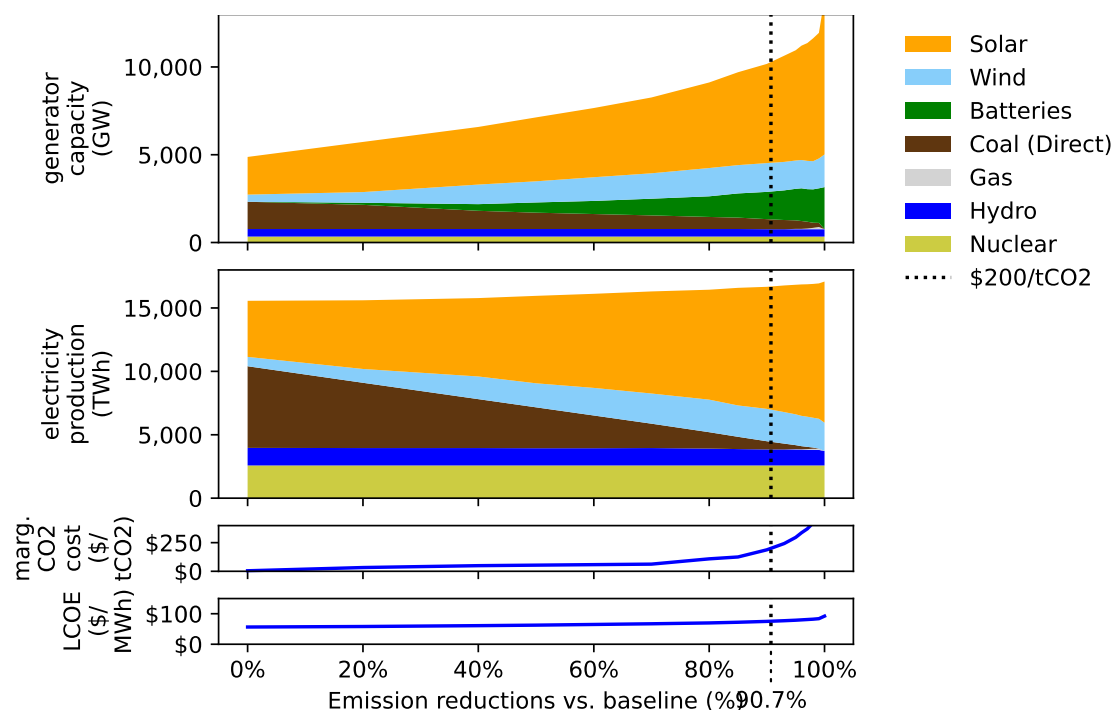


Figure 4. Generating portfolio, production plan, marginal cost of CO₂ abatement and levelized cost of electricity in 2048, for emissions ranging from 0% to 100% below 2028 levels, with no hydrogen or CCS options

As the CO₂ target in 2048 is reduced below the 2028 baseline (moving right in Figure 4), coal is phased out and replaced with wind and solar, complemented with batteries. For emission reductions deeper than about 80%, natural gas begins to replace coal to a very limited extent. Above 80%, investments in wind also plateau, and the main switch is coal to solar+batteries.

As the target is tightened, the marginal cost of emission reductions (third panel of Figure 4) rises gradually at first, and then more rapidly. Around 91% below the baseline, the system reaches a marginal abatement cost of \$200/tCO₂, which is arguably as far as abatement should be taken before turning to other sectors and other solutions (see discussion above). This level is marked with a vertical dotted black line across all the plots. (Note: the “socially optimal” percent reduction here is different from the previous discussion partly because this scenario uses a linearly-adjusted cap instead of a linearly-adjusted carbon cost, and partly because this scenario uses a baseline of 4,856 MtCO₂ instead of ~6,000 MtCO₂.) Beyond 91% reductions, the marginal cost of emission reductions rises rapidly as the target approaches a 100% reduction.

Between 91% and about 99% emission reductions, there are no dramatic changes in the preferred design, but the last few GW of coal do begin to be replaced by gas. This reflects the fact that very high carbon costs are needed to make gas more attractive than coal in China. Above 99%, when *no* fossil sources can be used, it becomes necessary to adopt much more solar power. This

is an extreme system design, where no other backup resources are available for the most difficult days, with low wind, low sun and possibly high loads, so the only option is to add a large amount of solar just to serve these days.

The levelized cost of electricity in 2048 is about 20% higher with the deepest emission reduction targets (right) than in the unrestricted case (left). This suggests that very deep emission reductions could be achieved with minimal impact on the Chinese economy.

Hydrogen option. Figure 5 below summarizes system designs for a range of mitigation targets, with the option of building hydrogen infrastructure—using electrolyzers to make hydrogen, storing it in liquid form for long periods, and converting it back to electricity via fuel cells or combustion in former coal plants. This produces a similar design to the previous case, but with hydrogen replacing gas entirely and displacing coal as targets rise above 85% reductions. Hydrogen makes it cheaper to achieve deep emission reductions, so the “socially optimal” emission target rises to 96.8% reductions. There is also no spike in solar investment as the target reaches 100%, because it is possible to use hydrogen as a backstop for difficult weather days.

The levelized cost of electricity in 2048 in this case is similar to the case without hydrogen (Figure 4).

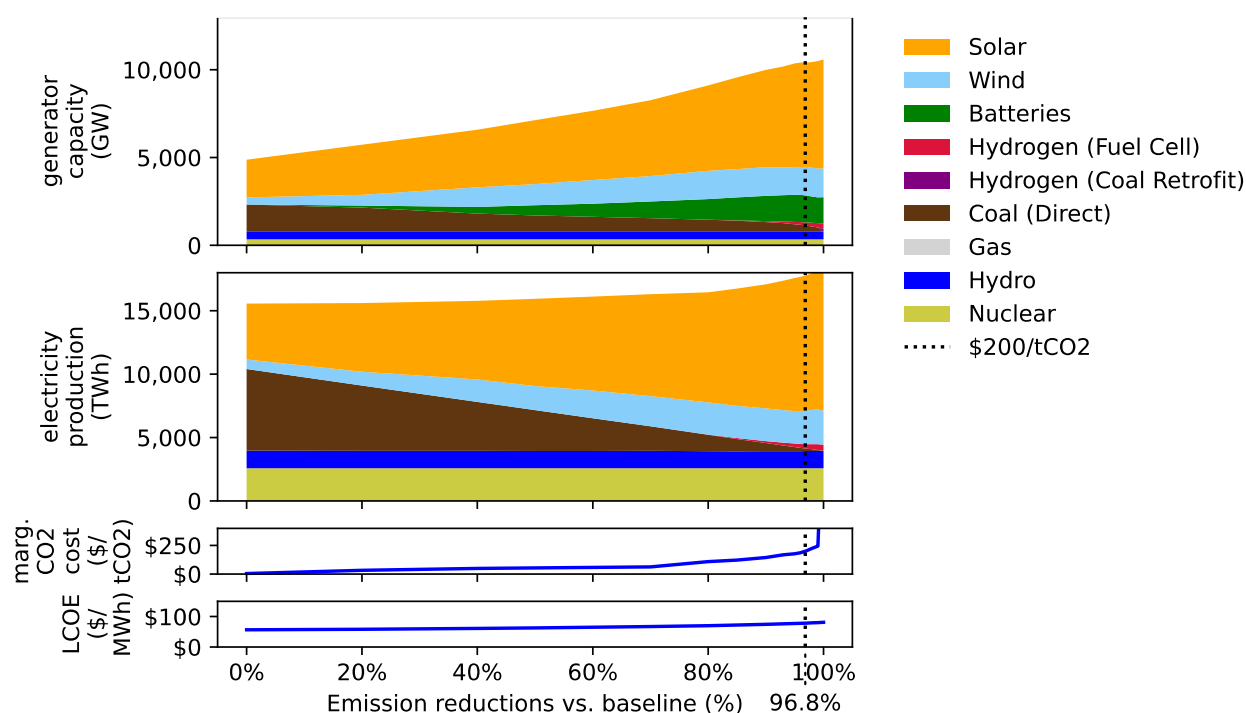


Figure 5. Generating portfolio, production plan, marginal cost of CO₂ abatement and levelized cost of electricity in 2048, for emissions ranging from 0% to 100% below 2028 levels, with hydrogen options but no CCS

Hydrogen option. Figure 6 below summarizes design options for a system with both hydrogen and CCS options. As discussed previously, this leads to significant adoption of CCS in preference to solar power. As in the previous two cases, reductions of less than 20% below the baseline are achieved mainly by switching from coal to solar power. For deeper reductions than

this, coal with CCS becomes a more cost-effective choice than solar power, and solar usage plateaus until the emission target exceeds about 85%. Above this level, it becomes necessary to phase out CCS and replace it with solar power, wind power and batteries. The “optimal” emission reductions in this case are around 95%, slightly less ambitious than with hydrogen alone, due to the effects discussed previously. For emission targets beyond this level (and only beyond this level), hydrogen begins to play a role, eventually replacing the last few GW of coal capacity when the target reaches 100%.

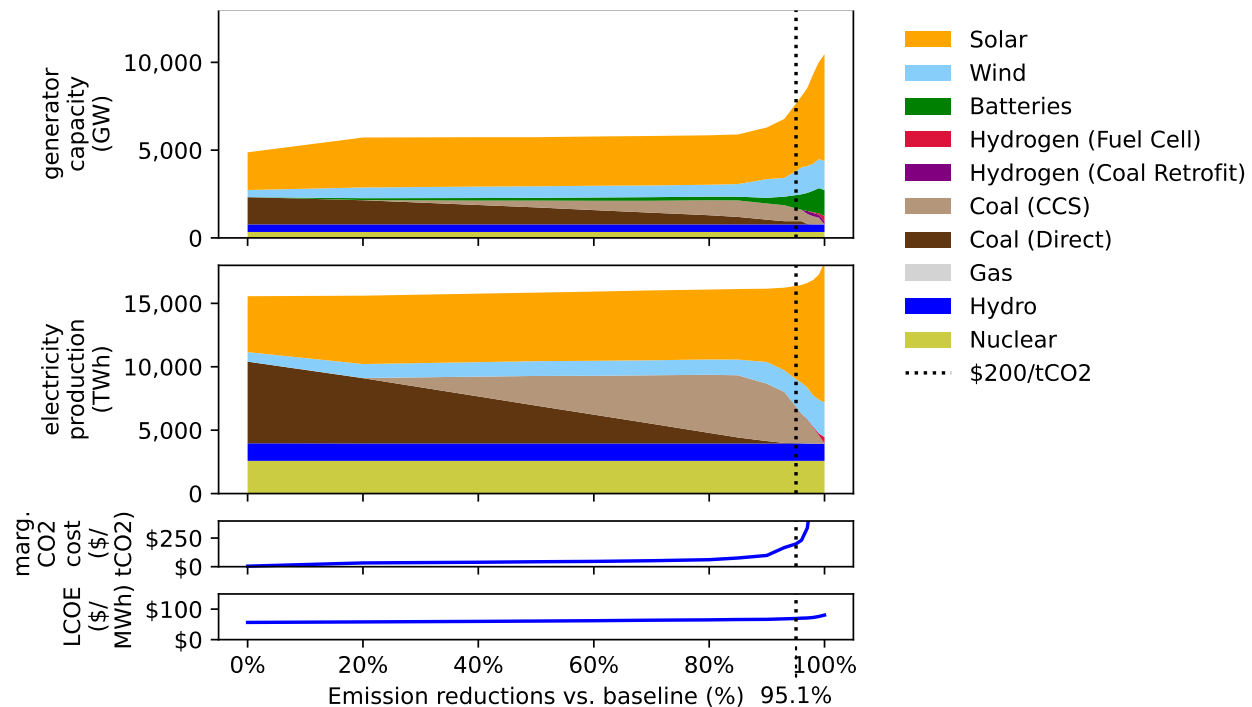


Figure 6. Generating portfolio, production plan, marginal cost of CO₂ abatement and levelized cost of electricity in 2048, for emissions ranging from 0% to 100% below 2028 levels, with hydrogen options but no CCS

How does the resource plan change if we design for a higher level of robustness against sustained difficult weather?

Figure 7 below shows power system designs optimized for a \$200/tCO₂ carbon price, with planning reserve margins ranging from 0% to 30%, and with access to hydrogen and CCS options. The 10% case is the same case as shown in Figure 3 earlier. Figure 7 focuses on conditions in 2048, when the system faces its highest carbon cost.

As noted above, planning reserves in this model are implemented by identifying the two sample days in each 10-year period that are most difficult to serve with an all-fossil or all-renewable system (i.e., highest-load day and highest net-load day). Then these are added back into the model with 10%–30% higher loads. These new, “difficult days” are weighted as if conditions continuing at this level for 15 days in a row every three years, making a total of 30 unusually difficult days every three years.

This method is designed to force the planned system to be reliable in the face of sustained high-load events such as heat waves. Traditional approaches to planning reserve margins focus on building extra peak *power* serving capacity, so that they can serve unusually high loads, or can continue to serve loads when an unusually large number of plants are on maintenance outages. This method works adequately for plants that mainly use conventional generators, which can run for as long as needed. However, in high-renewable systems, sustained difficult conditions can exceed high-renewable systems' *energy*-delivery capacity even if they don't exceed their peak power capability. For example, there could be too little wind and solar power to charge batteries and serve high loads for several weeks, even if there is enough battery and conventional generator capacity to meet peak loads. This problem is particularly acute in zero-carbon systems, where fossil plants (even with CCS) cannot be run at all, even for emergency days. The approach used in this study addresses this challenge by requiring the system to be able to meet these sustained difficult conditions without running short of energy.

The system designs optimized for each of these four planning reserve levels are shown in Figure 7. There is surprisingly little difference between the four cases. The additional planning reserve targets are met mainly by adding direct-combustion coal capacity (brown band in top panel), which is generally run at full power throughout the difficult days to meet the extra load. It is almost never run on other days. Installed direct coal capacity ranges from 4 GW in the 0% reserves case to 431 GW in the 30% case. Total production from this resource is very low, 1–90 TWh (barely visible in the second panel of Figure 7). This extra capacity has a moderate effect on overall costs, which rise from \$71/MWh in the 0% planning reserves case to \$75/MWh in the 30% case.

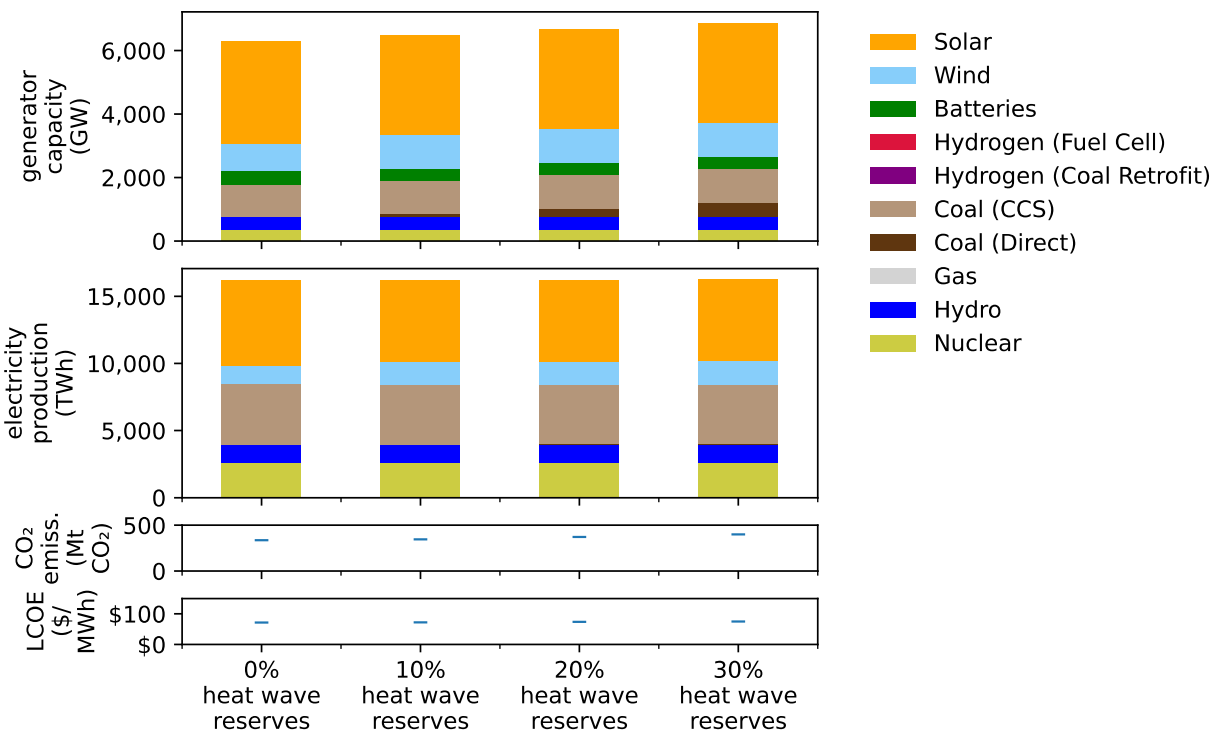


Figure 7. Generation portfolio, production plan, CO₂ emissions and levelized cost of energy in 2048, for power systems optimized for \$200/tCO₂ carbon cost, with 0%–30% planning reserve margins

For this low utilization rate, it does not appear to be cost-effective to install CCS plants, which have a much higher capital cost than direct-combusting coal. Consequently, the (synthetic) heat waves are met with direct coal combustion and cause relatively high emissions. Serving a 30% “heat wave” instead of a 10% wave raises emissions in 2050 from 346 MtCO₂/year to 400 MtCO₂/year in this example. The exact value in real future years would depend on the intensity and frequency of heat waves.

For this rarely used application, capital costs are the much more important than variable costs (fuel and CO₂). If capital costs for hydrogen fuel cells drop below direct-combusting coal plants, then they could instead become the preferred option for this application, but that was not the case in this study.