Journal of Environmental Economics and Management 111 (2022) 102561

Contents lists available at ScienceDirect

Journal of Environmental Economics and Management

journal homepage: www.elsevier.com/locate/jeem

China's unconventional nationwide CO_2 emissions trading system: Cost-effectiveness and distributional impacts☆

Lawrence H. Goulder[a,*], Xianling Long[b], Jieyi Lu[c], Richard D. Morgenstern[d,e]

[a] Stanford University, Resources for the Future, and NBER, USA
[b] National School of Development, Peking University, China
[c] Yale University, USA
[d] Resources for the Future, USA
[e] Sichuan University, China

ARTICLE INFO

Keywords:
China climate Policy
Tradable performance standard
Cap and trade
Carbon pricing
Cost effectiveness
Distributional impacts

ABSTRACT

China is implementing what is expected to become the world's largest CO_2 emissions trading system. To reduce emissions, the nation employs a tradable performance standard (TPS), a rate-based instrument differing significantly from cap&trade (C&T) and a carbon tax, emissions pricing instruments used elsewhere. With matching analytically and numerically solved models, we assess the cost-effectiveness and distributional impacts of China's TPS for reducing CO_2 emissions from the power sector.

The TPS implicitly subsidizes electricity output, which limits the use of output-reduction as a channel for reducing emissions. It also gives power plants with especially low emissions-output ratios incentives to expand output relative to business-as-usual levels. These features compromise the TPS's cost-effectiveness relative to C&T. The use of differing benchmarks (emissions-intensity standards) also compromises cost-effectiveness by distorting relative production levels and by lowering the cost-reducing potential of allowance trading. In our central case simulations, the TPS's overall costs are about 34 percent higher than those of C&T.

Although the use of non-uniform benchmarks compromises cost-effectiveness, it can help serve regional distributional objectives. We assess the aggregate costs of customizing benchmarks in order to reduce the adverse profit impacts in provinces that otherwise would suffer a disproportionate cost from the TPS.

1. Introduction

China has embarked on what promises to be the world's largest carbon dioxide (CO_2) emissions trading system (ETS). When fully

☆ The authors are grateful to Richard Carson, Carolyn Fischer, Charles Kolstad, Mun Ho, Valerie Karplus, Joshua Linn, Ian Parry, Billy Pizer, Jeremy Schreifels, Rob Williams, Da Zhang, Junjie Zhang, and Xiliang Zhang for helpful advice; and to Eric Weiner for excellent research assistance. We gratefully acknowledge financial support from the Energy Foundation-China and the China Program of the Stanford Institute for Economic Policy Research. The authors have no known competing financial interests of personal relationships that could have appeared to influence the work reported in this paper.

* Corresponding author. Department of Economics, Landau Economics Bldg., 579 Jane Stanford Way, Stanford University, Stanford, CA, 94305, USA.

E-mail address: goulder@stanford.edu (L.H. Goulder).

https://doi.org/10.1016/j.jeem.2021.102561
Received 26 August 2020; Received in revised form 13 September 2021; Accepted 17 October 2021
Available online 12 November 2021

implemented, this nationwide multi-sector system will more than double the amount of CO_2 emissions covered worldwide by some form of emissions pricing.

China's ETS, which began operation in mid 2021, relies on a tradable performance standard (TPS) as its emissions pricing instrument for reducing emissions. The TPS differs in important ways from the emissions pricing instruments used in other countries, such as cap and trade and a carbon tax. The TPS is a rate-based instrument: compliance depends on the ratio of emissions to output. Accordingly, the number of emissions allowances granted to a facility in each compliance period is the product of its assigned "benchmark" (maximum allowable emissions intensity) and its level of output.[1] Since compliance depends on a facility's output, a facility can influence its allowance allocation through its choice of output during the compliance period. In contrast, under cap and trade (C&T), a covered facility's allocation of allowances is not influenced by within-period production changes. The dependence of the allowance allocation on within-period output significantly affects firms' production decisions and their levels of emissions abatement. This has important implications for the system's cost-effectiveness and distributional impacts.

This paper employs matching analytically and numerically solved models to evaluate China's new TPS, focusing on the impact on the nation's power (electricity) sector, the sector covered in the TPS's first phase.[2] The power sector includes more than 2000 coal-fired power plants and is critical to China's climate policy effort, as it accounts for over 40 percent of the country's total CO_2 emissions (Yang and Lin, 2016). While electricity prices historically had been set by the government, continual reform since the end of the state monopoly in 1985 has brought about considerable market-determination of electricity prices (Ho et al., 2017). Currently, about a third of electricity output is sold at market prices.

We apply the two models to assess the TPS's impact on output levels, production costs, and CO_2 emissions of power plants of differing technologies, as well as its implications for aggregate costs (lost producer and consumer surplus) and aggregate emissions reductions. We also examine how costs are distributed across different provinces. Throughout, we compare the TPS's impacts with those of a C&T program with similar coverage and achieving the same economy-wide emissions reductions.

Rate-based standards such as the TPS fall in two general categories. *Input*-oriented rate-based standards, such as fuel standards or clean energy standards, impose floors on the ratio of "clean" (low-polluting) to "dirty" (high-polluting) inputs to production. These standards implicitly subsidize the cleaner inputs and tax the dirtier ones. The subsidy component causes overall input prices to be too low in terms of efficiency; this compromises cost-effectiveness. Holland et al. (2009) and Holland et al. (2015) have explored the cost-effectiveness of clean fuel standards as part of climate policy in California and at the federal level, respectively. Fischer and Newell (2008), Parry and Krupnick (2011), and Goulder et al. (2016) have assessed the cost-effectiveness of clean energy standards imposed on purchases of renewable- and fossil-generated electricity by US utilities.

In contrast, China's TPS is an *output*-oriented rate-based standard: it imposes a limit on the ratio of a firm's CO_2 emissions to its output of electricity. Fischer (2001) shows that an output-oriented standard implicitly subsidizes output while it taxes emissions. The implicit subsidy reflects the fact that, at the margin, additional output increases the number of (valuable) allowances a facility will receive from the regulator. Fischer and Newell (2008), de Vries et al. (2014), and Zhang et al. (2018) find that, as a result of this subsidy, the TPS generally is less cost-effective than a mass-based alternative such as C&T.[3]

This paper extends the theory regarding the implications of a TPS relative to C&T. It also offers what we believe is the first quantitative assessment of China's new nationwide TPS that closely considers the TPS's incentives. Both the analytical and numerical models offer comparisons with C&T.

One contribution of our analytical model is to convey the implications of multiple (i.e., varying) benchmarks, a key feature of China's TPS. Multiple benchmarks can serve distributional goals, since higher (that is, less stringent) benchmarks can be assigned to facilities that otherwise would face especially high compliance costs. Our analytical model shows that greater variation of benchmarks, while addressing distributional goals, reduces cost-effectiveness (that is, raises the cost of achieving any given aggregate emissions-reduction target), other things equal. Greater variation increases costs because it alters the relative magnitudes of the implicit output subsidies across covered facilities and thereby distorts the relative outputs of these facilities. Under C&T the initial allocations of allowances also can involve significant variation in the allowances offered per unit of output. However, in contrast with the TPS, under C&T greater variation of this sort (holding fixed the total number of allowances allocated) does not reduce cost-effectiveness, assuming fluid allowance trading. Because a typical C&T program does not involve an output subsidy,[4] variation in allocations per unit of output does not affect decisions at the margin; such variation only has distributional consequences.

A second contribution of the theoretical model is to reveal that the TPS's implicit subsidy reduces the gains from allowance trading.

[1] The benchmarks are the assigned emissions-output ratios that covered facilities must not exceed, after adjusting for any emissions credits purchased on the allowance trading market. China's TPS design calls for allowance trading across all facilities and all covered sectors.

[2] Ultimately, the TPS is expected to cover nine major sectors. The cement and aluminum sectors are next in line to be covered, to be followed by iron & steel, nonferrous metals, petroleum refining, chemicals, pulp and paper, and aviation.

[3] Other studies of intensity standards include Newell and Rogers (2003), who examine the U.S. lead phasedown program, the first large scale US TPS; and Davis and Knittel (2019), who assess the impacts of US Corporate Average Fuel Economy (CAFE) standards. CAFE standards are akin to output-oriented rate-based standards: the numerator and denominator in the rate are gasoline use and miles, respectively. Burtraw et al. (2015) and Bushnell et al. (2017) analyze efficiency implications and coordination challenges related to US states' strategic choices between intensity standards and cap and trade as a way to comply with the Obama administration's Clean Power Plan. Fullerton and Metcalf (2001), Goulder and Parry (2008), Parry et al. (2016), and Metcalf (2019) survey the efficiency attractions and limitations of a wide range of climate policy instruments, including intensity standards and cap and trade.

[4] In Section 3 we address the case where C&T offers output-based allocation for certain covered facilities. In that case, greater variation in initial allocations influences cost-effectiveness.

Under C&T, covered facilities minimize their costs by trading allowances until their marginal abatement costs equal the common allowance price. This maximizes the cost-savings from trading, as it implies equality of marginal abatement costs across facilities. Under the TPS, in contrast, a facility will minimize costs by trading until its marginal abatement costs equal the *net-of-subsidy* allowance price. We show that the net-of-subsidy price generally differs across facilities, as it depends on technologies that differ across facilities. Thus, allowance trading does not achieve equality of marginal abatement costs across facilities, and gains from trades are compromised.

Two important channels for achieving compliance under the TPS or C&T are reductions in the emissions intensity of production and reductions in level of production. Our analytical model conveys how the TPS and C&T differ in their reliance on these two channels. While C&T generally[5] motivates all covered facilities to reduce output as a channel for reducing emissions, the TPS gives facilities with business-as-usual (BAU) emissions intensities below the benchmark incentives to *increase* output relative to BAU. Increasing output earns these facilities additional allowances which then can be sold to the high-emissions-intensity facilities. Only the relatively emissions-intensive facilities exploit the output-reduction channel. The analytical model indicates how the TPS's more limited engagement of this channel (and its associated greater dependence on the emissions-intensity channel) underlies its lower cost-effectiveness compared with C&T.

Our numerical model yields results consistent with the analytical model's predictions, supplementing the analytical model's qualitative results with a quantitative assessment.[6] Key findings of the numerical model are as follows.

First, the TPS involves considerably higher economy-wide costs than a C&T program of the same stringency and scope, a reflection of the TPS's implicit output subsidy.[7] Consistent with the analytical findings, in the numerical model the TPS causes many of the low-emissions-intensity units to expand output, while C&T induces most or all units to reduce output. The less efficient use of the output-reduction channel contributes to the TPS's higher costs. In our central case simulation, under a 3-benchmark TPS (an option given close consideration by the planners) the TPS would yield a 4.3 percent reduction in aggregate CO_2 emissions. This reduction could be achieved at 26 percent lower private cost under a C&T program with similar allowance allocations.

Second, the TPS's economy-wide costs rise substantially with the variability of benchmarks. The private cost per ton of emissions reduced under a 3-benchmark TPS is 16 percent higher than the cost per ton of a single-benchmark TPS achieving the same 4.3 percent (116.8 million ton) reduction in aggregate emissions. Greater variation of benchmarks implies higher costs by distorting the relative contributions of different facilities to emissions reductions.

Third, the distributional impacts of the TPS differ significantly from those of C&T. One difference is in terms of the relative impact on producers and consumers. As discussed, reductions in electricity output contribute a much smaller share to overall emissions reductions under the TPS than under C&T. The less extensive reductions in electricity supply under the TPS imply smaller increases in electricity prices[8] than under C&T. As a result, electricity producers (consumers) bear a larger (smaller) share of the overall economic burden under the TPS than under C&T. Indeed, in our central case, the sign of the producer surplus change differs between the TPS and C&T: it is negative under the TPS, positive under C&T.

Fourth, the TPS has very different cost-impacts across the Chinese provinces, reflecting differences in technologies and emissions intensities of the generators and the associated differences in compliance costs. Under the 3-benchmark central case specification for the TPS, generating units that would experience large profit losses have especially significant representation in certain provinces in the north, northeast, northwest, and southwest. We consider alternative, 4- and 5- benchmark policy specifications in which benchmarks are "customized" so as to lessen the cost-impacts in these provinces. In these cases, the technologies on which these regions disproportionately rely, and which involve especially high emissions intensities, are given less stringent benchmarks. Although such customizing reduces the adverse impacts in these provinces, it lowers profits in other regions of the country and increases aggregate policy costs.

Although the TPS is less cost-effective than C&T, it has important offsetting attractions. One is that, compared to an equally stringent C&T program, the TPS likely would yield less "emissions leakage" – offsetting increases in emissions stemming from shifts in production across jurisdictions. To the extent that regulation of China's pollution raises the prices of China's outputs relative to foreign goods, consumers could shift toward imports, potentially offsetting the pollution-reduction goals of the domestic regulation. Similarly, higher electricity prices can cause demand to shift away from the electricity sector and toward other domestic industries, causing leakage by increasing the emissions from those industries. Because the reduction in electricity supply is less extensive under the TPS than under C&T, the TPS induces smaller increases in electricity prices than does the equivalent C&T system. Thus it produces less emissions leakage.

A second attraction is that the TPS's rate-based structure causes the aggregate allocation of allowances to adjust in response to

[5] There are exceptions, as discussed in Section 4.

[6] This quantitative analysis complements a number of recent empirical studies of China's efforts to reduce CO_2 emissions through emissions trading. See, for example, Duan and Zhou (2017), Ho et al. (2017), Teng et al. (2017), Karplus and Zhang (2017), and Zhang et al. (2017). Our model differs from other numerical models of China's climate policy because of its sharp focus on the incentive effects of the TPS and its associated ability to yield a close comparison of the impacts of the TPS and C&T.

[7] Other factors can mitigate the potential disadvantages of rate-based approaches such as the TPS. Goulder et al. (2016) show that pre-existing distortionary taxes can reduce and sometimes eliminate the potential cost-disadvantage of a clean energy standard relative to cap and trade or an emissions tax.

[8] As noted earlier and discussed further in Section 4, a considerable share of China's electricity prices is now market-determined. Our models account for both government-controlled and market-determined prices.

current macroeconomic conditions. When the economy is booming and the demand for electricity is relatively high, the expanded output of electricity entitles generators to a larger number of allowances, since allowance allocations increase with output. Under C&T, although allowance prices can adjust, the total number of allowances in circulation is not a function of macroeconomic conditions. The TPS's direct connection between policy stringency – the aggregate supply of allowances – and macroeconomic conditions is an important source of flexibility.

A third attraction is the compatibility of the TPS's rate-based structure with China's international negotiation strategy, which has emphasized the need for economic growth. An agreement to achieve a future reduction in emissions intensity is not a commitment to any particular reduction in emissions levels. Hence it can be viewed as more compatible with economic growth.

Further, the TPS has the virtue of familiarity: its rate-based structure matches that of several of the country's previous provincial- and city-level pilot programs for reducing CO_2 emissions.

Our numerical model indicates that despite its higher overall economic costs relative to C&T, the TPS can generate significant aggregate gains once environmental benefits are accounted for. In our central case, the environmental benefits from the TPS (in terms of avoided climate-related damages) are about nine times the costs when emissions reductions are valued at 290 RMB (or about 44 U.S. dollars) per ton.[9] Accounting for the health effects from associated reductions in air pollution would further increase the benefit-cost ratio.

These issues have significance in other contexts. In many countries, policy makers are making the important choice as to whether to adopt a rate-based or a mass-based approach to pollution control. The results shown here for China are highly relevant to their choices.

The rest of the paper is organized as follows. The next section briefly describes key features of China's power sector. Section 3 then presents the basic structure of China's TPS program. Section 4 develops and applies an analytical model to assess qualitatively the firm- and aggregate-level impacts of the TPS, and compares these impacts with those under C&T. Section 5 lays out the structure, inputs, and solution method of the numerical model. Section 6 then applies the numerical model to assess the cost-effectiveness and distributional impacts of the TPS and C&T. Section 7 offers conclusions.

2. Key features of the electricity sector

In 2016 about 72 percent of electricity produced in China's power sector came from its fossil-based plants.[10] Table 1 groups these plants into three main technology categories – coal-fired units other than circulating fluidized be units, circulating fluidized bed units, and gas-fired units – and into 11 more specific technology classifications. The table also provides information on outputs, costs, CO_2 emissions intensities and emissions for the different technologies.[11]

Among these units, the 300 MW subcritical coal units account for the largest share of electricity production and CO_2 emissions. The 600 MW supercritical coal units, which operate at a slightly lower emissions intensity, are the second largest producers of electricity and CO_2 emissions. The quite limited gas-fired capacity has much lower emissions per MWh.

Almost every electric power plant sells some of its electricity at prices fixed by the central government and some at market prices. A three-tiered system determines the prices at which the output can be sold, with the government specifying the output levels that define where the tiers begin and end. Production in the first tier is sold locally and at a government-administered price. Production beyond the first-tier level and in the second tier is sold on a wider market and at a different government-administered price. Production beyond the second-tier level is sold at market prices – principally in a "residual local market," to which the generators in the unit's province are the main suppliers, and a "zonal" market, to which units in the several provinces in a given zone contribute. The main purchasers in the zonal market are grid companies.[12] As discussed further in Section 6, the market prices generally are below the fixed prices. Forward markets exist for both the residual local and the zonal markets.

A decade ago, nearly all production was in the first or second tier and therefore faced fixed prices. However, by 2018 almost a third of the electricity consumed in China was sold at market-clearing prices.[13] The increased importance of market prices reflects the gradual narrowing of the first and second tiers as well as the substantial growth in total electricity demand.

The current pricing features outlined above are captured in our models.

[9] The ratio does not take into account the costs that higher electricity prices could impose on other sectors. It is also worth noting that the ratio could decline in later years when policy stringency is expected to increase.

[10] See China Electricity Council (2018). About 20 percent, 4 percent, 4 percent, and 1 percent of electricity production is generated by hydropower, nuclear power, wind power, and solar power, respectively.

[11] This study relies on unpublished plant-level electricity and emissions data supplied by the Ministry of Ecology and Environment (2019). Because of some omissions in these data, total electricity production in this study is slightly below what emerges from aggregate data. Our data do not include renewables-generated electricity.

[12] Starting in 2017, some provinces allow private power retailers and large electricity consumers to enter the residual local markets and zonal markets. And as of 2018, consumers from coal, steel, non-ferrous, and building material sectors can purchase all of their electricity in the markets. For further details, see Kahrl et al. (2016) and Ho et al. (2017).

[13] See China Electricity Council (2019). Our models assume price-taking behavior by power generators. There is little good evidence of market power by generators, although electricity generators include the "big five" state-owned power generation firms that could employ some market power.

Table 1
Production levels, production costs, emissions intensities and emissions.

Technology Category	Technology Class	Number of Units	Annual Electricity Production (million MWh)	Mean Facility's Production Cost (million RMB)	Average Emissions Intensity (tCO_2/MWh)	Annual CO_2 Emissions (million tCO_2)
Coal-Fired Units						
	C1 - 1000 MW Ultra-supercritical Units	74	363.8 (11.6)	972.46	0.802	291.8 (10.7)
	C2 - 600 MW Ultra-supercritical Units	55	187.4 (6.0)	971.36	0.827	155 (5.7)
	C3 - 600 MW Supercritical Units	210	641.5 (20.5)	779.41	0.867	556.1 (20.4)
	C4 - 300 MW Supercritical Units	63	98.1 (3.1)	375.56	0.868	85.1 (3.1)
	C5 - 600 MW Subcritical Units	130	359.0 (11.5)	626.62	0.907	325.6 (11.9)
	C6 - 300 MW Subcritical Units	499	836.7 (26.7)	416.28	0.894	748 (27.4)
	C7 - High/Ultra-high Pressure and Lower Pressure Units (with installed capacity less than 300 MW)	930	353.3 (11.3)	96.00	1.006	355.4 (13.0)
Circulating Fluidized Bed Units						
	C8 - Circulating Fluidized Bed Units (with installed capacity greater than or equal to 300 MW)	57	71.1 (2.3)	340.00	0.971	69 (2.5)
	C9 - Circulating Fluidized Bed Units (with installed capacity less than 300 MW)	229	89.2 (2.8)	106.57	1.081	96.5 (3.5)
Gas-Fired Units						
	C10 – F-class Gas-fired Units	73	99.7 (3.2)	609.86	0.372	37.1 (1.4)
	C11 - Gas-fired Units with Pressure Lower than F-class	72	31.4 (1.0)	212.89	0.422	13.3 (0.5)
All Units		**2,392**	**3,131.1 (100.0)**			**2,732.9 (100.0)**

Note: In the fourth and seventh columns, the numbers in parentheses are percentages of the totals for each column.

3. Structure of the TPS

Allowance trading, a central feature of TPS and C&T programs, promotes a reallocation of abatement activity involving greater effort by facilities that can reduce emissions at lower cost. This helps reduce the economy-wide cost of achieving aggregate emissions reductions. China's current system allows for trading across provinces in the power sector. It is expected that the system will allow for intersectoral trading as well once it is extended beyond the power sector.

A key difference between C&T and China's TPS relates to the allocation of emissions allowances. Under C&T, in most cases the allocation to a covered facility is exogenous to the facility. To achieve compliance, a facility's emissions, minus any allowances it purchases from other facilities, must not exceed this allocation.[14]

In some exceptional cases, the allocation under C&T is endogenous. This occurs where C&T offers "output-based allocation" to certain facilities. In such cases a facility's allocation in a given period is the product of the benchmark and the facility's output in the previous period.[15] This makes the facility's allocation endogenous to the facility's output choices, but the impact on the allowance allocation comes with a lag. In practice, output-based allocation in other countries generally has been applied only to a small subset of covered firms and not to the power sector.[16]

In contrast with most forms of C&T, under China's nationwide TPS the allocation of allowances to each covered facility is endogenous within each compliance period; it depends on the product of the benchmark β_i assigned to each generator i and the level of electricity output q_i chosen by the generator in that period. Because the number of allowances allocated to each generator is

[14] Some ETSs include provisions that allow entities to borrow the allowances that it has been promised for future compliance periods, or bank some of its current allowances for use in future periods. In this case, aggregate emissions can exceed (if there is net borrowing) or fall short of (if there is net banking) the sum of currently issued allowances. When there are provisions for intertemporal borrowing or banking of allowances, the effective cap is on cumulative emissions, and this cap is equal to the sum of the allowances introduced over time.

[15] Haites (2003), Böhringer and Lange (2005), Fowlie (2012), Fischer and Fox (2012), Bushnell and Chen (2012) and Fowlie et al. (2016) offer discussions of output-based allocation.

[16] In the C&T systems in the European Union, California, and a few other countries, output-based allocation has been applied to firms designated as the most "emissions-intensive trade-exposed" and thus especially vulnerable to import-competition. It is a way of helping these firms compete internationally: it effectively subsidizes output, since additional output leads to larger allocations of allowances. Neither California's ETS nor the EU ETS employs output-based allocation in the power sector.

endogenous, the aggregate emissions associated with the government-chosen benchmarks is endogenous as well. Thus, unlike C&T, China's regulator will not know the total number of allowances to be issued and the aggregate level of emissions until the end of the compliance period, after all production during the period has occurred.[17]

China allocates allowances through a two-step process. At the start of the compliance period, a covered facility receives an initial allocation equal to the product of its designated benchmark emissions-output ratio, β, an "initial allocation factor", υ, and some measure of output, q_0 (e.g., a recent level of production). The second step in the process comes at the end of the compliance period, at which time a covered entity receives the quantity of additional allowances needed to bring its total allocation into conformity with its actual output during the period.[18]

The extent to which China's program will reduce CO_2 emissions depends crucially on the choice of benchmarks. Recently, the planners considered employing three or four benchmarks for the power sector. We focus on the three-benchmark case, in which each benchmark applies to a technology *category*. Table 1 indicates the three categories: coal-fired, circulating fluidized bed (CFB), and gas-fired units. We use the term "technology *class*" to refer to more specific technology types. The Ministry of Ecology and Environment distinguishes the 11 technology classes and the three technology categories shown in Table 1. We distinguish these classes in the numerical simulations below.

4. Impacts of the TPS: an analytical treatment

In the presence of the TPS, managers of a generating unit need to make several interconnected decisions. One is whether to remain in operation or shut down. Generators that remain in operation also need to decide on how much to exploit the two main channels for achieving emissions reductions: (a) reductions in emissions per unit of output and (b) reductions in output. These decisions depend on the stringency of the benchmark applied to the generating unit, the price of emissions allowances, and the administered and market prices of electricity.

The analytical model considers these elements. Distinctive features of this analysis are its attention to multiple benchmarks, its recognition of administered pricing of some electricity sold, and its attention to the implications of generator shutdowns. These features account for significant differences between the TPS's impacts and those of C&T.

For simplicity, the analytical model does not distinguish between the tier 1 and tier 2 administered prices; it considers a single tier, and "tier production" here refers to production on that tier, which faces administered prices. Output beyond that tier is sold at market prices. Also, this model does not separate the residual and zonal electricity markets. The key insights from this model are preserved in the results from the more disaggregated numerical model.

4.1. Net revenue, conditional on remaining in operation

Let:

$q_{ij} \equiv$ total end-of-period electricity output of generator i in technology class j

$\overline{q}_{ij} \equiv$ tier production of generator i in technology class j.

$e_{ij} \equiv CO_2$ emissions by generator i in technology class j

$C_{ij} \equiv$ total cost of production by generator i in technology class j

$\overline{p}_{ij} \equiv$ administered wholesale price applying to electricity output by generator i in technology class j below the generator's tier production level.

$p_{ij} \equiv$ market equilibrium wholesale price applying to electricity output by generator i in technology class j at or above the generator's tier production level

$\beta_j \equiv$ benchmark emissions-output ratio assigned to generators in technology class j

$t \equiv$ market price of emissions allowances.

Consider first the choices of a generating unit conditional on its remaining in operation. The generator's[19] choice variables are q and e. Net revenue π for operating generator ij is given by:

$$\pi_{ij} = \overline{p}_{ij}\overline{q}_{ij} + p_{ij}\left(q_{ij} - \overline{q}_{ij}\right) - C\left(q_{ij}, e_{ij}\right) - t\left(e_{ij} - \beta_j q_{ij}\right) \tag{1}$$

The first right-hand term in (1) is the revenue from production of electricity up to $\overline{q}_{ij}$, the highest level of output subject to the

[17] Although firms receiving output-based allocation in a C&T system can affect their allocations through changes in output, such changes do not alter each period's aggregate allocations. The aggregate cap remains exogenous: the increased allocations to these firms correspond to reduced allocations to other firms.

[18] In fact, each province has the option of reducing the allocation of allowances to facilities within the province if it wishes to make the program more stringent locally. The Ministry of Ecology and Environment sets national benchmark emissions-output ratios, but the provincial government can reduce them. Also, the central government has been contemplating offering "reserve allowances" to governments in some low-income provinces, additional allowances that these governments can allocate according to their own chosen criteria.

[19] For brevity, we will let "generator" refer to both the physical unit and the unit's decision-maker (manager). The intended reference will be clear from the context.

administered price $\overline{p}_{ij}$. The second right-hand term is the revenue from electricity output in excess of $\overline{q}_{ij}$. The third and fourth terms refer to production cost and the expense or revenue associated with allowance purchases or sales. We assume $\partial C_{ij}/\partial q_{ij} > 0$ and $\partial C_{ij}/\partial e_{ij} < 0$. We also assume that each generator's objective is to maximize net revenue.[20] For simplicity of exposition, equation (1) and subsequent equations in this section reflect the assumption that $q_{ij} > \overline{q}_{ij}$. This is the most frequent case in our data. In the rare cases where $q_{ij} < \overline{q}_{ij}$, $\overline{p}_{ij}$ replaces p_{ij} throughout.[21]

The endogeneity of q_{ij} in the far-right term in (1) is critical to the impact of the TPS. To be in compliance, the generating unit's ultimate (end-of period) allocation of allowances $\beta\, q_{ij}$, plus (minus) any allowances it purchases (sells) on the trading market, must be at least enough to justify its emissions during the period. The far-right term in (1) represents compliance cost, the additional needed purchases (or potential sales) of allowances consistent with compliance.

Define a facility's total cost as its pure production cost $C\,(q,\, e)$ plus its compliance cost (the far-right term in (1)). The compliance cost can be rewritten as

$$t \cdot (e\,/\,q - \beta) \cdot q \tag{2}$$

The TPS's impacts on a covered facility differ depending on whether, under business as usual (BAU), the facility's emissions-output ratio e/q is above or below the applicable benchmark β. Consider first a facility with $e/q > \beta$ under BAU. In the absence of adjustments to the TPS, this facility would be out of compliance. To be compliant, this facility will need to purchase sufficient allowances to cover the gap between e/q and β. From (1), it can reduce its required allowance purchases by reducing its emissions intensity, e/q, and/or by reducing its output, q.[22] To maximize profit, the facility will choose the optimal combination of reduced emissions intensity and output reduction, and purchase whatever allowances are necessary to fill the remaining gap between e/q and β.

The situation is different for a facility with $e < \beta q$ under BAU. Such a facility has excess allowances: more than it needs for compliance. It will benefit from selling these allowances, since they have no other beneficial use for the facility; selling them involves no opportunity cost.[23] Moreover, facilities in this category can increase profits by expanding output and augmenting the number of excess allowances.[24] As indicated earlier, the potential for a TPS to cause some firms to expand output underlies its disadvantage relative to C&T in terms of cost-effectiveness.

4.2. The shutdown Decision

Shutdowns are a significant source of the differences between the impacts of the TPS and those of C&T. As indicated below, the TPS tends to imply smaller increases in electricity prices than does C&T – a consequence of the fact that the TPS induces a less extensive reduction in electricity supply. The relatively low electricity prices under the TPS lead to more shutdowns than under C&T, and shutdowns account for a more significant share of emissions reductions under the TPS than under C&T.

In considering whether to shut down, the generator will compare the revenue from continued operation with the revenue associated with shutting down. In the case of shutting down, the revenue consists solely of the liquidation value[25] of the abandoned capital. The generator's owners cannot earn additional revenue by selling any of the allowances it was allocated at the beginning of the compliance period; such allowances must be returned to the government.

It is useful to rewrite (1) as:

$$\pi_{ij} = p_{ij}q_{ij} + \left(\overline{p}_{ij} - p_{ij}\right)\overline{q}_{ij} - C\left(q_{ij,}e_{ij}\right) - t\left(e_{ij} - \beta_j q_{ij}\right) \tag{3}$$

This expression divides the gross revenue from electricity production into$p_{ij}q_{ij}$, a component that depends on the level of production q_{ij}, and $(\overline{p}_{ij} - p_{ij})\overline{q}_{ij}$, a fixed component.[26] The fixed component is the revenue associated with output up to the maximal level to which the administered price applies. This revenue is inframarginal. It affects the level of profit and the shutdown decision, but because it is

[20] This assumption holds both for the approximately 30 percent of electricity production from privately owned units (Chen, 2019) and for the production from state-owned units, for which the central government has declared net profit as the primary economic performance target (State-owned Assets Supervision and Administration Commission, 2019).

[21] Thus, when $q_{ij} < \overline{q}_{ij}$, the equation for net revenue reduces to $\pi_{ij} = \overline{p}_{ij}q_{ij} - C(q_{ij}, e_{ij}) - t(e_{ij} - \beta_j q_{ij})$. This squares with the fact that in this case $\overline{p}_{ij}$, not the endogenous price, is the price that applies to each unit of electricity sold.

[22] The reduction in q would not lower compliance costs if it were associated with a fully offsetting increase in emissions intensity. In general, one would expect emissions intensity to be a non-decreasing function of q, implying that the reduction in q will not raise emissions intensity.

[23] There would be an opportunity cost if the system included provisions for intertemporal allowance trading. However, the TPS in its current design does not include such provisions. See National Development and Reform Commission (2017) and Ministry of Ecology and Environment (2020). As a result, the allowances available to generators needing additional allowances are restricted to the excess allowances offered by the generators with $e < \beta q$.

[24] Although China's TPS does not cover renewable sources of electricity such as wind and solar, it encourages production from these sources as well by increasing the relative cost of supplying fossil-based generated electricity.

[25] In discussions with the ETS planers, we have learned that the market for abandoned electricity generation capital is quite limited, so that the liquidation value is very low. In this one-period model, the relevant "liquidation value" is the avoided one-period rental on the capital that is no longer employed.

[26] Note that p_{ij} as well as $\overline{p}_{ij}$ and $\overline{q}_{ij}$, are exogenous to the individual generator.

inframarginal it does not affect the optimal level of production (or revenue) for firms that do not shut down.[27]

A generator will shut down if net revenues are lower than the liquidation value of facility. From the expression for profit (equation (3)), it follows that shutdown occurs if and only if

$$pq + (\overline{p} - p)\overline{q} - C(q, e) - t(e - \beta q) < L \tag{4}$$

where L represents the liquidation value (subscripts have been suppressed for convenience). Several elements in this inequality are functions of the price p. Appendix A shows that there is a critical value of p such that the facility will shut down if the electricity price applying to the facility is below this value. Calculation of the critical value recognizes that other variables in the inequality are functions of the electricity price.

Equation (4) can be rewritten as

$$pq + (\overline{p} - p)\overline{q} - C(q, e) - L \;\; > \;\; te - t\beta q \tag{5}$$

Define $\widehat{t}$ as the critical value of allowance price t that equates the left-hand and right-hand sides of (5):

$$\widehat{t} = \frac{pq + (\overline{p} - p)\overline{q} - C(q, e) - L}{e - \beta q} \tag{6}$$

The generator will shut down or remain in operation depending on whether the allowance price is above or below this value. Other things equal, $\widehat{t}$ will be lower for generators facing a lower (more stringent) β: they will shut down first.[28]

4.3. Equilibrium conditions

4.3.1. The allowance price

Let e_{ij}/q_{ij} represent the emissions rate of the *ith* a generator in technology class j, where the rate is that which applies after responding to the TPS. Let RP_j refer to the set of generators in technology class j that *remain* in operation and *purchase* allowances – the generators in technology class j with $(e_{ij}/q_{ij}) > \beta_j$ (or equivalently $e_{ij} > \beta_j q_{ij}$) for which condition (5) above is satisfied. Then the total market demand for allowances, $D(t)$, is expressed by

$$D(t) = \sum_j \sum_{i \in RP_j} \left(\left(e_{ij} / q_{ij} \right) - \beta_j \right) q_{ij} \tag{7}$$

Demand is a function of the allowance price t because this price influences the number of generators that remain in operation (the number for which t is below $\widehat{t}$). The allowance price also affects demand through its influence on the output levels and emissions intensities of the generators that remain in operation.

The supply of allowances to the trading market comes from generators that remain in operation and have excess allowances to sell. Let RS_j represent the set of generators in technology group j that *remain* in operation and *sell* allowances – the generators in technology group j for which $(e_{ij}/q_{ij}) < \beta_j$.[29] The total supply of allowances in the emissions trading market is:

$$S(t) = \sum_j \sum_{i \in RS_j} \left(\beta_j - \left(e_{ij} / q_{ij} \right) \right) q_{ij} \tag{8}$$

The allowance price affects allowance supply by influencing the electricity production levels of the generators with $e/q < \beta$: this affects the number of excess allowances they have to sell. This price also affects supply by influencing the emissions intensities of these generators.

The market equilibrium price of allowances is the price t that satisfies $D(t) = S(t)$.

4.3.2. Electricity prices

Generators whose production does not exceed $\overline{q}$ face only the administered electricity price $\overline{p}$, while generators that produce more than $\overline{q}$ face both the administered price $\overline{p}$ and the market price p for production beyond $\overline{q}$. The equilibrium market price equates total supply with total demand.

4.4. Cost-Effectiveness considerations

Under cap and trade, the profit function is

[27] Recall that the equations in this section assume $q_{ij} > \overline{q}_{ij}$. When $q_{ij} < \overline{q}_{ij}$, the corresponding profit equation is $\pi_{ij} = \overline{p}_{ij} q_{ij} - C(q_{ij}, e_{ij}) - t(e_{ij} - \beta_j q_{ij})$ and $\overline{p}_{ij}$ is the price at the margin.

[28] Under cap and trade, the expression for profit is $\pi = pq - C - t(e - a_0)$, where a_0 represents the facility's allocation of (free) allowances. From this it follows that under cap and trade, $\widehat{t}$is equal to$(pq - C - L)/(e - a_0)$. A larger initial allocation of free allowances raises $\widehat{t}$.

[29] Recall that the emissions intensity e_{ij}/q_{ij} is endogenous. We assume that generating units in the group RS_j undertake expenditure to reduce emissions intensities to the extent that this will increase net revenue (by increasing the number of excess allowances).

$$\pi = pq + (\overline{p} - p)\overline{q} - C(q, e) - t(e - a_0) \tag{9}$$

where subscripts have been suppressed for simplicity. This function matches the profit function under the TPS (equation (3)) except for the presence of a_0, which represents the allowance allocation under C&T and replaces $\beta\, q$ in the last term of the TPS profit function. The key difference from equation (3) is that in contrast with the TPS case, this last term is exogenous, which implies a difference in first-order conditions.[30] The first-order conditions for profit-maximization under cap and trade are:

$$\partial\pi / \partial e : -C_e = t \tag{10}$$

$$\partial\pi / \partial q : p = C_q \tag{11}$$

Equation (10) indicates that cost-minimization calls for equating the marginal cost of emissions reduction with the marginal benefit (the reduced allowance cost associated with the marginal reduction in emissions). Equation (11) indicates the requirement that marginal costs of production be equated to the price of output.

Under the TPS, the first-order conditions are:

$$\partial\pi / \partial e : -C_e = t \tag{12}$$

$$\partial\pi / \partial q : p = C_q - \beta t \tag{13}$$

Equations (10) and (12) are identical, since under both the TPS and C&T, an increase in emissions involves a marginal cost of t, the allowance price, other things equal. Equations (11) and (13) are different, however. The -$\beta\, t$ term on the right-hand side is the implicit subsidy to output under the TPS. The subsidy arises from the fact that under the TPS, each unit increase in output increases by β the number of allowances the firm is allocated. This contrasts with C&T, under which an increase in output does not yield a larger allowance allocation.

The implicit subsidy implies that the marginal cost of increasing output is lower under the TPS than under C&T. Importantly, the opportunity cost of *reducing* output (a key channel for coming into compliance) is higher under the TPS, since reducing output implies a reduction in emissions allowances received. As a result, producers' incentives to achieve emissions reductions through reduced output are weaker than under an equivalent cap-and-trade system. Moreover, as discussed above, generators with BAU emissions intensities below their benchmarks have incentives to increase rather than reduce output. Appendix B considers this issue in further detail. The combination of the implicit subsidy and the fact that some facilities are encouraged to expand output accounts for the lower cost-effectiveness of the TPS relative to C&T.

In a setting involving pure competition and without other market distortions[31], the first-order conditions under C&T match those of a social planner aiming to achieve a target reduction in emissions at the lowest social cost (Tietenberg, 1985). The implicit subsidy under the TPS implies that the cost of achieving a given target will be higher under the TPS than the (minimum) cost under C&T. Given the first-best nature of C&T, it follows that from an efficiency point of view, the TPS does not induce covered facilities to make sufficient use of output-reduction as a channel for reducing emissions. Instead, they must rely more on reduced emissions intensities as a mechanism for achieving the emissions reductions. This underlies the lower cost-effectiveness of the TPS relative to C&T.

The difference in the impacts of the TPS and C&T depends importantly on the price elasticity of output supply. This difference becomes smaller, the lower the elasticity. To see this, note that C_q is inversely related to this elasticity, implying that as C_q approaches infinity as the supply elasticity approaches 0. Suppose that q satisfies the TPS first-order condition. Since $\beta\, t$ is a constant, as C_q approaches infinity (or as the supply elasticity approaches zero) the change in q needed to satisfy the C&T first-order condition becomes infinitely small. In the limiting case of a zero supply elasticity, optimal q is in the same for the TPS and C&T, and since the first-order conditions for optimal emissions are also the same, both policies are the same in terms of cost-effectiveness. A comparison of equations (3) (for the TPS) and (9) (for C&T) indicates that with a zero supply elasticity the two policies will also have identical distributional consequences so long as the initial allowance allocations $\beta_j q_{ij}$ (for the TPS) and a_0 (for C&T) are the same. In our numerical simulations below, we consider the sensitivity of the differences in costs of the TPS and C&T to different values of supply elasticities.

4.5. The significance of benchmark variation

Maximal cost-effectiveness requires that the marginal cost of production equal marginal revenue, or price. Equation (13) shows that the TPS's benchmarks create a wedge between marginal cost and price. Note that when producers face a common electricity price at the margin, the use of multiple benchmarks can limit cost-effectiveness by causing the marginal net revenue ($p - C_q$) to differ across producers: for producers facing higher benchmarks C_q will be higher, and marginal net revenue lower. Thus, relative to the uniform-benchmark case, the use of multiple benchmarks compromises cost-effectiveness by distorting the generators' relative production levels.

Uneven benchmarking can serve distributional goals, however. Higher (less stringent) benchmarks can be applied to generators that otherwise would suffer especially high costs of compliance or be forced to shut down. In Section 6 we consider numerically the cost-effectiveness implications of multiple benchmarks as well as the trade-offs between cost-effectiveness and the achievement of

[30] This assumes the firm in question is not receiving output-based allocation.

[31] Specifically, two required assumptions are that there are no distortions from pre-existing taxes and that firms have perfect information.

certain distributional goals.[32]

4.6. Gains from allowance trading

With a perfectly fluid market for allowance trading, managers of generating units will reduce emissions to the point where the private marginal costs of abatement equal the private marginal benefits. To consider this, we examine the *total* derivative[33] of the TPS profit expression (3):

$$d\pi = pdq - \frac{\partial C}{\partial e}de - \frac{\partial C}{\partial q}dq - tde + t\beta dq \tag{14}$$

Dividing both sides by de yields:

$$\frac{d\pi}{de} = p\frac{dq}{de} - \frac{\partial C}{\partial e} - \frac{\partial C}{\partial q}\frac{dq}{de} - t + t\beta\frac{dq}{de} \tag{15}$$

Setting $d\pi/de$ to 0 and rearranging yields:

$$\underbrace{p\frac{dq}{de} - \frac{\partial C}{\partial e} - \frac{\partial C}{\partial q}\frac{dq}{de}}_{MB_e^{pvt}} = \underbrace{t\left(1 - \beta\frac{dq}{de}\right)}_{MC_e^{pvt}} \tag{16}$$

The left-hand side, MB_e^{pvt}, is the marginal private benefit from emissions (or marginal private cost of abatement), while the right-hand side, MC_e^{pvt}, is the marginal private cost of emissions (or marginal private benefit from abatement). The gains from trading are maximized when the marginal costs of abatement (left-hand side) are the same for all producers. This is readily accomplished under C&T, since (under fluid trading) firms equate these marginal costs to a common value: the allowance price, t. However, under the TPS, the right-hand side (marginal benefit from emissions abatement) will generally differ, since the $\beta\frac{dq}{de}$ element differs. In particular, the right-hand side will be lower (higher) for firms for which this element is higher (lower). Thus, trading doesn't lead to equality of marginal abatement costs. After the allowance market has cleared, society's costs could be reduced further if the high $\beta\frac{dq}{de}$ units were compelled to sell more allowances to the low $\beta\frac{dq}{de}$ units (though such additional trading would not be in the firms' private interests).

Equation (16) indicates that the greater the variation in $\beta\frac{dq}{de}$ across firms, the greater the gap between the costs after trades and the costs that would result if the additional trading needed to equate society's marginal abatement costs took place. Note that even if all facilities were to face the same β, the benefits from allowance trading often will be compromised, since the gap depends on both β and dq/de, and the latter will often differ across generators. The implication of greater variation in the β 's for this gap depends on the extent to which greater variation of the β 's induces an increase or decrease in the variation of the dq/de's.

These considerations indicate that C&T has an advantage over the TPS in terms of the cost-reductions from allowance trading. Under C&T, the right-hand side element in the $MB = MC$ expression (16) is simply t, which implies (in the absence of impediments to trading) that all units equate their marginal private benefits from emissions (marginal private costs of abatement) to the same value, leading to maximal trade-related cost-reductions.

Thus, under any given benchmark specification, under the TPS the presence of the benchmarks limits the gains from allowance trading by preventing equality of marginal abatement costs after trades. This applies even in the case of a single benchmark.[34]

4.7. Attractions of the TPS

It is important to recognize the various attractions of the TPS, as noted in the introduction. Because of its smaller impact on output prices, the TPS would likely contribute less to emissions leakage.[35] Second, as described earlier, the TPS's rate based structure implies

[32] The analogue to uneven benchmarks under the TPS is uneven free allocation of allowances relative to output under C&T. As noted in the introduction, this does not affect marginal conditions under C&T. It only compromises cost-effectiveness insofar as it affects shutdowns, which depend on profit levels rather than marginal conditions.

[33] In contrast with the partial derivative conditions shown in expressions (10–13), the total derivative considers at one time the impact of changes in both q and e on profit.

[34] It is not necessarily the case that the gains from trade will be lower in a uniform benchmark system than in one with multiple benchmarks. The reason is that a multiple benchmark system might involve smaller gaps, on average, between covered facilities' BAU emissions intensities and the benchmarks: that is, the various benchmarks could be customized so that the benchmarks were not far from the BAU intensities of the facilities facing that benchmark. This applies especially to facilities with relatively high or low BAU emissions intensities, for which the gap between their BAU intensities and the benchmark would be large in a one-benchmark system. Thus, the potential gains from trade can be lower in a multiple benchmark system because, across the facilities that face a given benchmark, the average discrepancy between the BAU emissions intensity and the benchmark is smaller and there are fewer potential gains from trade.

[35] This issue is particularly significant for industries that are especially import-competing and/or carbon-intensive. It is not a major issue for producers in China's power sector, since relatively little domestically produced electricity is sold internationally. The issue will be more important once the TPS expands to major industries in China's manufacturing sector.

that the aggregate supply of allowances responds directly to macroconomic conditions, whereas the aggregate supply (the emissions cap) under C&T does not change when macroeconomic conditions change. Two other attractions are the consistency of the TPS's rate-based structure with China's international negotiations strategy and its familiarity to China's planners. These attractions apply to the TPS program in its first, power-sector only phase as well as in its broader later phases.

The analytical model has brought out several features of the TPS that compromise its cost-effectiveness relative to C&T. Its lower cost-effectiveness stems from both its implicit output subsidy (which limits the attractiveness of output-reduction as a channel for reducing emissions) and the incentive it gives to especially low emissions-output ratios to expand output. This model also shows that the implicit subsidy lowers the potential of allowance trading to reduce policy costs, and indicates that greater variation in the benchmarks compromises cost-effectiveness. The results from our numerical model reinforce these analytically derived findings and provide estimates of the magnitudes of the analytical model's predicted qualitative impacts.

5. A numerical model

5.1. Overview

The model considers the 2392 generating units and 11 technology classes of Table 1. The numerical model's structure aligns with that of the previously described analytical model, although this model has more detail regarding elements of producer cost. The model also considers each generator's production capacity, which in some cases will constrain the unit's total production. We calibrate the numerical model so that its solution under baseline (status quo) conditions matches the data in terms of costs, production levels, emissions and electricity prices.

TPS policies are defined by the benchmarks applied to different generators, while C&T policies are defined by assumed initial allocations of emissions allowances to the different generators. All generators within a given technology class receive the same benchmarks under the TPS and the same initial allowance allocations under C&T.

Under each policy, profit-maximizing managers of generating units determine whether to shut down or remain in operation and, conditional on continuing to operate, the optimal level of production, the extent of effort to reduce emissions intensity of production, and the number of allowances to purchase or sell. Under each policy, the model solves for the equilibrium allowance price and the equilibrium prices of electricity in each provincial and zonal (regional) market. The equilibrium allowance price equates the aggregate supply of allowances with the aggregate demand. The equilibrium electricity prices pertain to the electricity produced in excess of the quantities facing administered prices. Such excess electricity is sold either to residual local electricity markets or to regional grid companies.[36]

The data show that a given generating unit will often sell its electricity in the local market and zonal market at different prices. Transactions costs help explain the difference in equilibrium prices of electricity, a homogenous product. We model transaction costs as increasing in the quantity of electricity that a given generator sells to the zonal market. We calibrate the parameters of the transactions cost function so that sales to the zonal market in the baseline simulation match the observed data. In both baseline and policy simulations, the equilibrium market price of electricity in the local market equals the price in the relevant zonal market net of the marginal transactions cost.

5.2. Optimal choices of heat rates and output

Under BAU, the cost of production is expressed by:

$$C(q,h) = p_f \frac{h}{\xi} q + (\varphi_0 + \varphi_1 q^{\varphi_2}) \tag{17}$$

The choice variables determining cost are the output level q and the heat rate h[37]. The heat rate is the required energy input (often measured in BTUs) per unit of electricity generated. The two terms on the right-hand side represent fuel costs and operation and maintenance costs, respectively. The fuel cost is the product of the unit price of fuel (p_f), the required amount of fuel per unit of output (h/ξ), and the level of output (q). ξ indicates the energy associated with a unit of fossil fuel input. Thus, dividing h by ξ yields the required fuel per unit of output. Per-unit fuel costs are an increasing function of the heat rate. φ_0, φ_1 and φ_2 are parameters of the operation and maintence cost function.

As indicated in the analytical model of Section 4, for a given generator the revenue outlay for the allowance purchases needed for compliance is $t(e/q - \beta)q$, where t, e, and β are defined as before. Generators with $e/q > \beta$ need to purchase sufficient allowances to fill the gap between e/q and β. These generators reduce the number of allowances they need to purchase through a combination of reducing the emissions intensity (e/q) and reducing electricity output. In the numerical model, the emissions intensity is $h \cdot \psi$, where ψ is emissions per unit of energy for the fuel used by the unit in question. The annualized cost of lowering the heat rate from its BAU value

[36] In a few unusual cases, the overall demand for electricity at the administered price is less than the guaranteed hour level of output. In this case, the equilibrium quantity produced is less than the GH output level and all electricity is sold at the administered price.

[37] According to the National Development and Reform Commission (2014), managers can reduce heat rates of generating units via technical adjustments and operation improvement. Technical adjustments can include replacing blades and sealing elements in the steam turbines. Operation improvements can include adjustments to the air flow rate and air/coal ratio, as well as changes in coal fineness to optimize boiler combustion.

h_0 to the lower value h is given by the function $\gamma\left(\frac{\alpha}{1+\alpha}\right)\left(h_0^{\frac{1+\alpha}{\alpha}} - h^{\frac{1+\alpha}{\alpha}}\right)$, adopted from Linn et al. (2014). The paratmeter α represents the elasticity of the heat rate to fuel prices, and γ is a scale parameter that differs across generating units with the same capacity. The optimal change in the heat rate balances the costs of lowering the heat rate with its benefits in terms of reducing per-unit fuel costs.

Generators with $e/q < \beta$ under BAU have excess allowances. These generators also maximize profits through a combination of a change in output and in the heat rate, but as indicated in Section 4 it is optimal for them to increase rather than reduce output.

Because the marginal revenues and marginal benefits from choices of q and h are interdependent, the choices must be made simultaneously. Appendix C indicates the conditions for optimal choices and the solution method.

5.3. Producer heterogeneity

Our data on production costs consist of *average* total costs for each of the 11 technology classes shown in Table 1. We allow for cost heterogeneity within technology classes by assuming that the parameter φ_0 in the operation and maintenance cost function differs across the units within a class according to a beta distribution. Since φ_0 is a constant term in that function, it does not affect the first-order conditions for optimal q or h. However, it does affect the level of profits and thus, under any given policy scenario, it influences whether profits for a given unit are positive and whether the unit shuts down. Because the values of φ_0 are distributed according to the (continuous) beta distribution, the number of units that shut down is a continuous function of policy parameters and the allowance price.[38]

5.4. Equilibrium conditions

We adopt the following approach to solve for the market equilibria under the TPS and C&T policies. Let V represent a vector consisting of an allowance price and a set of province-level and zonal electricity prices. For any given V, the model calculates each generator's net-revenue-maximizing quantity of output and optimal heat rate (which determines emissions intensity), conditional on remaining in operation. For some units – particularly those with emissions-output ratios above the applicable benchmark – production costs can be sufficiently high to imply negative profits. These are the units with exceptionally high values of φ_0 within the distribution of this parameter for the technology class in question. These units will shut down.

The production decisions of individual generators determine the aggregate demand and supply of allowances and they affect the supply and demand for electricity in both the residual local market and the six zonal markets. The model's solution algorithm continually alters both the allowance price and the electricity prices in V until three sets of equilibrium conditions are satisfied: (1) the aggregate allowance supply equals the aggregate allowance demand; (2) for each province, the supply of electricity to the local market equals the demand in that market; and (3) for each zonal market, the sum of provinces' supplies to that market equals the electricity demand in that market. The equilibrium allowance and electricity prices are closely connected, since electricity prices affect allowance supply and demand through their impact on electricity production, and the allowance price affects electricity supplies through its impact on compliance costs.[39]

5.5. Data and calibration

Here we summarize the data and calibration methods; details are provided in Appendix D.

5.5.1. Data

The data are for the year 2016. Table 1, referred to previously, presented the data on generators' outputs, production cost, and emissions by technology class. We assume that, for a given technology class, the emission intensity is the same across provinces. Output levels are the total outputs over the year. Annual output is below the level that would apply if units operated at capacity at all times.[40]

Table A1 of Appendix D offers detail on baseline administered and market electricity prices, organized by province. Overall, 68.3 percent of electricity is sold at administered price, 94.3 percent of which is coal-fired electricity. For coal-fired electricity, the generation-weighted administered price of guaranteed-hour electricity sold within the province is 0.364 RMB, which is 10.2 percent higher than the local market price. For gas-fired electricity, the generation-weighted admininistered price at the local level is 0.727

[38] Using a continuous probability distribution function to incorporate heterogeneity within broad technology classes causes the model's aggregate demand functions for allowances to be continuous. This facilitates solving the model.

[39] The solution method obtains equilibrium electricity prices for 29 province-level residual electricity markets, equilibrium electricity prices for six zonal markets, and one equilibrium price for the national allowance market. We solve for the 36 equilibrium prices by minimizing the differences between supply and demand in each market through gradient descent.

[40] Output below capacity reflects several factors. First, units need to go offline during parts of the year for maintenance. In 2016, the average hours due to regular maintenance and unintended outage are 582 and 674 for coal-fired and gas-fired units in China, respectively. Second, some generation units that are used to meet peak and intermediate load do not produce at capacity at every hour of the day. Third, during some parts of the year, electricity prices and fuel prices might not justify capacity-level production. Fourth, to the extent that marginal production costs increase as production levels approach capacity, current electricity prices will not always justify production at capacity. Our model is unable to address each of these factors explicitly. As described in Appendix C, we adopt a reduced-form approach that aims to capture the overall difference between actual output and capacity-level production.

RMB, 120.2 percent above the local market price.

Table 2 indicates the sources of data for several other key variables.

5.5.2. Parameters

In our central case, we assume a short-term wholesale-level price elasticity of demand for electricity equal to −0.202, based on results from the meta-analysis of Labandeira et al. (2017). As detailed in Appendix E, we first obtain the demand elasticities for electricity in each of the sectors: agriculture, commerce, resident, and industry. We then obtain the overall price elasticity of demand as an electricity-consumption-weighted average of the four demand elasticities.

Remaining parameters are obtained via calibration. We sketch the approaches here; details are in Appendix E.

For each technology class in each province, we identify the parameters φ_1, and φ_2 of the cost function, along with $\varphi_{0\text{mean}}$, the mean value of the cost function's constant term φ_0, through a calibration procedure that imposes requirements on the average generator in each technology class.

The requirements are based on 2016 and 2019 business-as-usual data. The $\varphi's$ are calibrated such that the net revenue equals the net revenue from the data, and that the net-revenue maximizing level of output matches the business-as-usual output level. A further step is to specify the distribution of the constant term φ_0 in the cost function of each technology class. As mentioned, we employ a beta distribution, which involves finite bounds for the parameter, and we assume the distribution is symmetric.

The parameters α and γ of the heat-rate cost function are obtained as follows. The values for α for each generator are based on the responsiveness of power-sector emissions intensities to prices in the general equilibrium model of the China economy of Long et al. (2021). Given the $\alpha's$ we calibrate γ such that the net-revenue maximizing level of heat rate matches h_0.

6. Numerical results

Our central case TPS policy involves three benchmarks: $\beta_{GF} = 0.382$, $\beta_{CF} = 0.848$, and $\beta_{CFB} = 1.002$, where the units are tCO_2/MWh and the subscripts refer to the three technology categories indicated in Table 1: gas-fired generators, coal-fired (other than circulating fluidized bed) generators, and circulating fluidized bed generators. We also introduce alternative benchmark specifications that differ in terms of the number, variation, and stringency of the benchmarks.

We also consider C&T policies. For comparability with the TPS policies, under the C&T policy (free) allowances are allocated to generators so that each generator's share of the total allocation matches that generator's initial share under the TPS. Since C&T leads to differences in electricity outputs relative to the TPS, under C&T we scale the allocations by a common factor so that the aggregate emissions reduction is the same (116.8 million tons) under both policies.

6.1. Central case results

6.1.1. Prices, costs, emissions, and outputs

Table 3 displays the results in our central case. With the central-case benchmarks, the TPS prompts a reduction in emissions of 116.8 million tons, or 4.3 percent. An allowance price of 117 RMB (or about 18 U.S. dollars) brings the supply of excess allowances by the $e/q < \beta$ generators into balance with the demand for allowances by the $e/q > \beta$ generators. In the allowance market, the $e/q > \beta$ generators purchase 71.1 million tons of allowances from the $e/q < \beta$ generators.

Shutdowns account for an emisions-reduction of about 10 million tons, or about 8 percent of the overall reduction. The generators that remain in operation contribute to about 107 million tons of emissions-reductions through lowered emissions intensities and (for the $e/q > \beta$ units) through reduced electricity production. The units that increase electricity output reduce emissions by 74 million tons since the emissions reductions from lower emissions intensities outweigh the emissions increases from higher output. .

The TPS causes aggregate electricity supply to decline by about 0.10 percent. The reduction in supply by $e/q > \beta$ units – those that shut down and those that remain in operation – exceeds the increase by $e/q < \beta$ units. In keeping with the goal of reducing emissions, the benchmark applied to each technology category is below the average emissions intensity of the technology classes included in the category. Correspondingly, more than half of electricity production tends to be from generators with $e/q > \beta$. The reduction in aggregate electricity supply makes necessary an increase in electricity prices to achieve equilibrium in the electricity markets. The output-weighted-average price of electricity rises by 0.11 percent, reflecting higher prices in both the local residual and the zonal markets. (Administered electricity prices do not change.)

The private cost of this central case TPS policy, measured as the negative of the change in producer and consumer surplus, is about 3.59 billion RMB, or 30.71 RMB per ton. About 35 percent of the private cost is borne by consumers: a significant fraction of the cost is shifted to consumes in the form of higher electricity prices.

Although assessing the climate-related environmental benefits from emissions reductions involves great uncertainties, it is worth considering how climate-related benefits from the TPS might compare with these estimated costs. The Interagency Working Group on the Social Cost of Carbon (2016) arrived at a central value of about $44 (or 290 RMB) per ton in the benchmark year (2016) for the social cost of carbon. Applying this value to the estimated 116.77 million ton reduction in CO_2 emissions yields a climate-related benefit of 33.86 billion RMB, approximately 9.4 times the estimated costs.

6.1.2. Comparison with cap and trade

Table 3 includes results under C&T. The emissions responses by generators under this policy differ significantly from those under the TPS. While the TPS induces some generators to expand output, C&T causes all generators to reduce output. And while the TPS leads

Table 2
Data sources.

Capacity	Source
Electricity output	Ministry of Ecology and Environment (2019)
Capacity	
Emissions-output ratio	
Production costs	Liu and Zhang (2018); Liu et al. (2016); Zhang (2013); Chen and Chen (2012); Zhang (2011); Zhu (1987)
Electricity prices	National Development and Reform Commission (2015b)
	National Energy Administration (2018)
	Electric Power Development Research Institute (2018)
Fuel prices	National Development and Reform Commission (2015a)
	China Coal Market (2016)
Emissions factors	Jiang et al. (2013)
	IPCC (2006)
Price elasticity of demand for electricity	Labandeira et al. (2017)

Table 3
Impacts of the TPS and C&T – the central case.

	Baseline	TPS	C&T
Benchmarks (tCO_2/MWh)			
– Coal-fired (technology classes 1–7)		0.848	Allowance Allocations
– CFB (technology classes 8 and 9)		1.002	Matching TPS
– Gas-fired (technology classes 10 and 11)		0.382	Allocations
Emissions (million tCO_2)	2,732.88	2,616.10	2,616.10
– change from baseline		−116.77	−116.77
– change from units that shut down		−9.52	0
– change from units that remain and increase supply		−73.7	−0.28
– change from units that remain and reduce supply		−33.55	−116.49
– percentage change from baseline		−4.27	−4.27
Allowance Price (RMB)		117.30	67.67
Allowances Traded (million tCO_2)		71.05	55.73
Aggregate Electricity Supply (million kWh)	31,31,149	31,28,057	30,60,397
– change from baseline		−3,091	−70,752
– change from units that shut down		−9,436	0
– change from units that remain and increase supply		21,345	4,266
– change from units that remain and reduce supply		−15,000	−75,018
– percentage change from baseline		−0.10	−2.26
Electricity Price (RMB/kWh)			
Average Electricity Price	0.3774	0.3778	0.3936
– marketed electricity in intraprovincial market	0.3305	0.3319	0.3816
– administered electricity in intraprovincial market	0.3852	0.3853	0.3852
– marketed electricity in interprovincial market	0.3719	0.3735	0.4219
– administered electricity in interprovincial market	0.435	0.4351	0.435
Private Cost (million RMB)		3,586	2,670
– change in Consumer Surplus		−1,258	−48,215
– change in Producer Surplus		−2,327	45,545
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)		30.71	22.84
Environmental Benefit (million RMB)		33,863	33,863

to shutdowns of some facilities, in our central case simulations of C&T there are no shutdowns.

The differences in shutdowns stems from differences in the policies' impacts on electricity prices. C&T leads to more pronounced reductions in electricity supply, as no generators increase output. The larger reductions in electricity supply give rise to higher electricity prices. As indicated in Table 3, the national average electricity price (output-weighted, and encompassing all local and zonal prices) rises to .394 RMB/kWh, as opposed to .378 under the TPS. The higher electricity prices under C&T generate rents to electricity producers, preventing the need for shutdowns. Indeed, with free allocation of emissions allowanes, C&T leads to an increase in producer surplus, as indicated in the table. This result is in keeping with earlier studies that show how 100 percent free allocation of emissions allowances can create large rents or windfalls for producers.[41] The large rents stem from the significant reduction in electricity output under C&T, which boosts electricity prices and creates rents in the same way that a cartel's restriction in output would.

[41] See Bovenberg and Goulder (2001), Parry (2003), Palmer et al. (2006), Fullerton and Karney (2009), Goulder et al. (2010), and Stavins (2020). In the present study, 100 percent of the allowances under C&T are given out free. Previous studies indicate that freely allocating a significantly smaller share of the allowances would be sufficient to prevent a loss of profit. See, for example, Goulder et al. (2010).

Table 4 shows that the units that shut down under the TPS are in technology classes C5, C6, and C7 (within the coal-fired category) and classes C9 and C11 (within the circulating fluidized bed and natural-gas categories, respectively). These are the units with original emissions intensities above the benchmarks for their categories.

The two pie charts in Fig. 1 further illustrate the significant differences between the TPS and C&T in terms of their reliance on the different channels for emissions reductions. The charts decompose the overall reductions into those due to reduced electricity production, changes in the relative outputs among generating units, and reductions in emissions intensity.[42] The differences are dramatic. Under the TPS, reduced electricity output accounts for only about 6 percent of the emissions reductions, as compared with about 57 percent under C&T. Reductions in emissions intensity account for about 91 percent of the reductions under the TPS, as compared with about 38 percent under C&T. The combination of the implicit output subsidy and the fact that $e/q < \beta$ generators have incentives to expand output causes the TPS to make insufficient use of output reduction as a channel for reducing emissions and leads to excessive reliance on reduced emissions intensities to achieve compliance.

These differences underlie the TPS's higher costs of achieving given aggregate emissions reduction targets. The combination of the implicit output subsidy and the fact that $e/q < \beta$ generators have incentives to expand output causes the TPS to make insufficient use of output reduction as a channel for reducing emissions and leads to excessive reliance on reduced emissions intensities to achieve compliance. As indicated in Table 3, the overall private cost is 34 percent higher under the TPS than under C&T.

The equilibrium allowance price under C&T is 42 percent lower than under the TPS. Because C&T makes more efficient use of the output-reduction channel for achieving emissions reductions, generators' needs for emissions allowances to achieve compliance are reduced. Thus, the demand for allowances at any given allowance price is lower, giving rise to a lower equilibrium allowance price.

6.1.3. Regional impacts

The numerical model incorporates benchmark data on the geographical locations and electricity production levels of each technology class. Using this information, the model calculates how the policy costs experienced by each technology class are distibuted across provinces and regions. Regional differences in the profit impacts reflect differences in the composition of units by technology class as well as differences across provinces in the production costs of units in a given technology class.

Fig. 4 and the first pair of columns in Table 5 show how the costs to producers under the TPS are distributed across provinces and regions of the country in the central case. The Northern, Northwestern, Northeastern, and Southwestern provinces experience overall losses of producer surplus, with the largest losses in percentage terms applying to Shandong in the North and Heilongjiang in the Northeast. Table 6 shows that the average BAU emissions intensities for the generators in these provinces are significantly higher than their average benchmarks. This reflects their reliance on coal-fired technology classes C6 and C7, which face the most stringent benchmark for the general coal-fired category. In some provinces the overall profit impact of the TPS is positive. This is the case for provinces, such as Fujian and Anhui, where a large fraction of generators are in technology categories with BAU emissions intensities below the applicable benchmark.

In our central case, the larger costs fall on the less developed western and northern provinces, such as Qinghai, Gansu, and Heilongjiang. This signals potential trade-offs between the important goals of cost-effectiveness and regional economic development. We explore further the regional distributional impacts in the discussion of subcategorization below.

6.2. Impacts under Alternative benchmark scenarios

Here we explore the sensitivity of policy impacts to alternative benchmark specifications.

6.2.1. Impacts of spread of benchmarks

We first consider how the benchmark "spread" – the range between the high and low benchmarks – affects the results. Fig. 2 displays the overall costs under different specifications for the spread. The one-benchmark case, where the same benchmark applies to all 11 technology classes, is the limiting case of zero spread. The single benchmark is the output-weighted average of the three central case benchmarks, and is scaled so that the number of allowances allocated matches the allowance total from the 3-benchmark case. In the other benchmark cases, the three central-case benchmark categories apply, but the benchmark values are different. To obtain these values, we expand or shrink the spread across the three benchmarks while preserving total emissions.[43]

Fig. 2 shows that the private cost per ton increases with spread. This is in keeping with the implication of equationn 13 that greater

[42] In the pie charts, the contribution from reduced electricity output is the emissions reduction that would occur from the differences between output in the policy case and the baseline, if emissions intensities and sector composition remained the same as in the baseline. The contribution from lowered emissions intensities is the reduction that would occur if the emissions intensities changed but industry production levels remained at baseline levels. The contribution from changed sector composition is the reduction that would occur if the only change from the policy were in the shares of production from the different technology classes.

[43] More specifically, for each of the three central-case benchmarks, we calculate the difference between the central-case benchmark and the benchmark in the 1-benchmark case. Let d_j denote the difference for technology category j. The new category-j benchmark is the value in the uniform-benchmark case plus the product of d_j and a scaling factor. We employ scaling factors of smaller than one and greater than one to produce benchmarks with less and more spread. Note that applying a scaling factor of 0 recreates the 1-benchmark case; applying a scaling factor of 1 reproduces the central-case benchmarks. After applying the scaling factor, we then scale up or down all benchmarks by the same percentage so that the total end-of-period emissions match the central case.

Table 4
Impacts on generators' market status – the central case.

Technology Category	Technology Class	TPS				C&T			
		Initially in Compliance?	Policy Response (percentage of generators in each category)			Initially in Compliance?	Policy Response (percentage of generators in each category)		
			Shut Down	*Operate and Purchase Allowances*	*Operate and Sell Allowances*		*Shut Down*	*Operate and Purchase Allowances*	*Operate and Sell Allowances*
Coal-Fired Units									
	C1	Y	0	0	100	Y	0	0	100
	C2	Y	0	0	100	Y	0	0	100
	C3	N	0	0	100	N	0	0	100
	C4	N	0	0	100	N	0	9.52	90.48
	C5	N	0.04	99.96	0	N	0	100	0
	C6	N	0.02	96.78	3.21	N	0	100	0
	C7	N	2.27	97.73	0	N	0	100	0
Circulating Fluidized Bed Units									
	C8	Y	0	0	100	Y	0	0	100
	C9	N	1.21	98.79	0	N	0	59.83	40.17
Gas-Fired Units									
	C10	Y	0	0	100	N	0	0	100
	C11	N	0.10	99.90	0	N	0	100	0

spread increases the discrepancies across generators in the marginal net revenue from electricity output. Such discrepancies compromise cost-effectiveness.

As shown in Table 7, in the most cost-effective case – the one-benchmark case – the private cost per ton is about 14 percent lower than in the central 3-benchmark case. The central case offered higher (less stringent) benchmarks to the coal-fired and circulating-fluidized-bed generators, whose emissions-intensities are higher than those of natural gas-fired generators. In the 1-benchmark case, coal-fired and circulating-fluidized bed generators face lower benchmarks and their profits are reduced by considerably more.

Table 8 shows the extent to which allowance trading lowers costs relative to a scenario involving the same benchmarks but no provisions for trades. The presence of trading reduces policy costs by 84 percent in the 1-benchmark case and by 78 percent in the 3-benchmark central case. Recall that in the 1-benchmark case, the benchmark was set at the output-weighted average of the benchmarks in the 3-benchmark case. For many generators, the discrepancy between their BAU emissions-output ratios and the benchmark is considerably higher in the 1-benchmark case than in the 3-benchmark case, where the benchmarks are customized to address differences in initial intensities. As a result, and as indicated in the table, the potential gains from trade are especially high and the gains from trade in percentage terms are higher than in the 3-benchmark case.

6.2.2. *Impacts of stringency of benchmarks*

To assess how the overall stringency of the benchmarks alters policy costs, we scale up or down each of the three central-case benchmarks by a common factor. This alters stringency while maintaining the relative sizes of the benchmarks. In the central case, the benchmarks lead to an aggregate reduction in emissions reduction of 4.3 percent. Fig. 3 displays policy costs in the central case and in cases of lower or higher stringency. We consider cases where all benchmarks are either 1.74 percent lower or 1.73 percent higher than in the central case. In the high benchmark (low stringency) case, aggregate emission reductions are 41 percent smaller, and costs are 65 percent smaller, than in the central case. The convexity of the lines in the figure indicates that costs per ton rise with stringency, in keeping with increasing marginal costs of abatement.

6.2.3. *Subcategorization of benchmarks to achieve distributional objectives*

To explore the potential costs of achieving further distributional goals, we perform alternative simulations in which we expand the number of benchmark categories to four or five from the original three, thereby customizing the benchmarks more closely to particular economic circumstances. This particular "subcategorization" involves subdividing the original coal-fired generator category.[44] It is guided by the objective of reducing the adverse impact on the provinces that otherwise would experience the largest percentage loss of producer surplus. As was noted, Heilongjiang and Shandong provinces experience the largest percentage losses of producer surplus in the central scase, a reflection on their heavy reliance on coal-fired generation – particularly on technology classes C6 and C7 within the broader "coal fired units" category to which to one of the central case's three benchmarks applies.

In one alternative simulation, we split the coal-fired generation category into two subcategories depending on whether a unit's nameplate capacity is higher or lower than 300 MW,[45] with one applying to technology classes C4, C6 and C7 ($\leq$ 300MW) and the

[44] Prior studies that consider the distributional impacts of alternative choices for intensity targets include Zhang et al. (2016) and Pizer and Zhang (2018). The Pizer-Zhang study points out that subcategorization can lead to shifts in production toward "dirtier" sectors and thereby cause emissions to increase in those sectors.

[45] This is consistent with the rule in the Ministry of Ecology and Environment (2020).

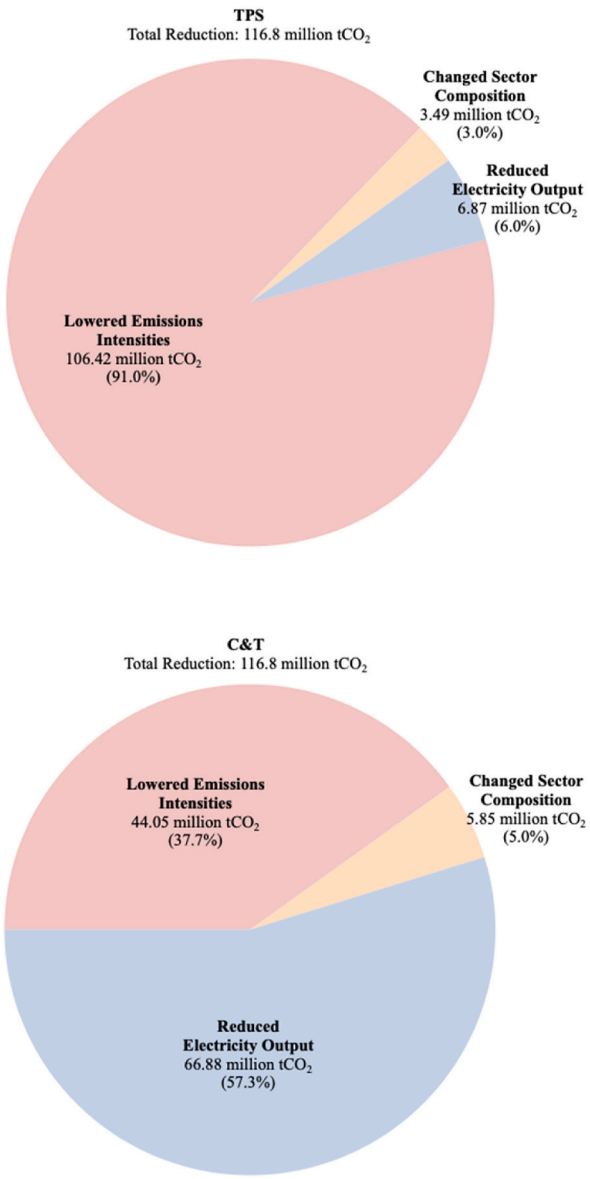


Fig. 1. Sources of emissions reductions under the TPS and C&T.

other applying to the other technology classes (>300 MW) within the coal-fired category. Relative to the original benchmark, we scale up (loosen) the benchmark for the new C4/C6/C7 subcategory and scale down the benchmark for the other new (C1/C2/C3/C5) subcategory by an amount sufficient to prevent the percentage loss of profit from exceeding four percent[46] in any province. The scaling is also such as to assure that the output-weighted average benchmark for the overall coal-fired-generator category is maintained at the same level as in the central case.

In a second alternative simulation, we divide the original coal-fired generator category into three subcategories, which allows for a further tailoring of the benchmarks to the particular technological composition of the two provinces. The three subcategories in this case cover the following three groups of technologies: (1) C1; (2) C2, C3, and C5; and (3) C4, C6, and C7. The subdivision among C1, C2, C3 and C5 relative to the four-benchmark case allows us to tighten C2/C3/C5 to a smaller degree than C1, so as to reduce the profit losses of provinces that have significant share of output from C2/C3/C5. We loosen the benchmark for the C4/C6/C7 subcategory and tighten the benchmarks for the two other subcategories such that the percentage profit loss of any province being smaller than 3.1

[46] This threshold, 4 percent, is the minimum percentage loss of profit that the 4-benchmark case can accomplish.

Table 5
TPS profit impacts by region and province.

Region/ Province	3-Benchmark (Central) Case		4-Benchmark Case		5-Benchmark Case	
	Change in Profit (million RMB)	*Change as Pct of Baseline Profit*	*Change in Profit (million RMB)*	*Change as Pct of Baseline Profit*	*Change in Profit (million RMB)*	*Change as Pct of Baseline Profit*
East	**821**	**0.66**	**−432**	**−0.35**	**−2191**	**−1.77**
Anhui	385	1.9	44	0.22	−113	−0.56
Shanghai	220	1.48	135	0.90	−171	−1.15
Jiangsu	39	0.11	−302	−0.81	−872	−2.34
Jiangxi	143	1.78	8	0.11	72	0.91
Zhejiang	32	0.07	−318	−0.73	−1107	−2.55
North	**−2400**	**−2.83**	**−2079**	**−2.45**	**−1493**	**−1.76**
Beijing	−22	−0.84	−17	−0.64	−15	−0.58
Tianjin	17	0.34	−17	−0.33	−105	−2.06
Shanxi	−237	−1.85	−210	−1.64	−72	−0.57
Shandong	−1275	−4.34	−965	−3.29	−883	−3.01
Hebei	−417	−2.74	−231	−1.52	−15	−0.10
Inner Mongolia	−464	−2.38	−636	−3.27	−401	−2.06
Central	**9**	**0.04**	**−49**	**−0.18**	**−174**	**−0.65**
Hubei	24	0.35	33	0.46	34	0.48
Henan	−15	−0.08	−82	−0.42	−208	−1.06
South	**383**	**0.68**	**−118**	**−0.21**	**−746**	**−1.33**
Guangdong	206	0.47	−90	−0.21	−751	−1.70
Guangxi	10	0.5	−47	−2.29	−32	−1.56
Fujian	180	2.36	−35	−0.47	−46	−0.61
Hainan	−14	−0.68	55	2.66	84	4.02
Southwest	**−204**	**−0.86**	**−424**	**−1.78**	**−282**	**−1.19**
Chongqing	51.0	0.68	3.0	0.05	−75.0	−1.00
Sichuan	−132	−1.53	−166	−1.92	−100	−1.15
Guizhou	−96	−1.74	−209	−3.79	−103	−1.86
Yunnan	−26	−1.25	−52	−2.49	−4	−0.20
Northwest	**−346**	**−1.04**	**−248**	**−0.74**	**−155**	**−0.46**
Shaanxi	−219	−2	−346	−3.17	−251	−2.29
Gansu	−48	−0.73	51	0.77	109	1.65
Ningxia	42	0.57	44	0.59	1	0.02
Qinghai	−16	−3.05	0	0.05	6	1.26
Xinjiang	−105	−1.34	2	0.03	−21	−0.28
Northeast	**−590**	**−2.36**	**−417**	**−1.67**	**−162**	**−0.65**
Heilongjiang	−424	−5.53	−308	−4.00	−234	−3.05
Jilin	−73	−1.03	−5	−0.08	72	1.01
Liaoning	−92	−0.91	−103	−1.02	0	−0.01
Total	**−2327**	**−0.62**	**−3770**	**−1.01**	**−5206**	**−1.39**

percent and, again, the output-weighted average benchmark for the coal-fired category is the same as that in the central case.[47]

Table 5 displays the cost impacts in the central cases and the two subcategorization cases. The percentage reduction in profit in Heilongjiang is 4.0 percent in the 4-benchmark case and 3.1 percent in the 5-benchmark case, as compared with 5.5 percent in the central case. The percentage reduction in profits in Shandong is also reduced. Several provinces that would experience profit increases in the central case have lower profits under this alternative TPS policy, a consequence of the tighter benchmarks applied to technology classes 1, 2, 3 and 5. The burden shifts from the North, Northeast, and Northwest in the central case to the Central, East, South, and Southwest in subcategorization cases. As indicated in the final row of Table 5, compared with the 3-benchmark case the overall loss of profit is about 62 percent greater in the 4-benchmarks case, and 124 percent greater in the 5-benchmark case. Reducing adverse impacts in the worst-off provinces compromises cost-effectiveness by increasing the variability in the marginal cost of production across generators. Fig. 5 displays the trade-offs between the goals of cost-effectiveness and reducing exceptionally adverse profit impacts in particular provinces.

[47] In the first alternative simulation, the central case benchmark for the coal-fired generators is 0.848 tCO_2/MWh. Meeting the two "scaling" conditions requires changing the benchmarks for C1/2/3/5 and C4/6/7 to 0.814 tCO_2/MWh and 0.889 tCO_2/MWh, respectively. Given the particular groupings of technologies in the first simulation, the benchmark levels needed to meet the scaling conditions are uniquely defined. In the second alternative simulation, the additional subcategory implies that there is not unique set of benchmarks that meets the scaling conditions. However, alternative benchmarks have very little impact on aggregate private cost, so we present results from one particular set of benchmark values. The benchmarks are 0.709 tCO_2/MWh for C1, 0.826 tCO_2/MWh for C2/3/5, and 0.907 tCO_2/MWh for C4/6/7.

Table 6
Correspondences between profit impacts and the business-as-usual "emissions intensity gap".

Province	(1)	(2)	(3)	(4)
	Profit change in central case relative to baseline (%)	Weighted average emissions intensity (tCO_2/MWh)	Weighted average benchmark (tCO_2/MWh)	"Emissions intensity gap" (difference between (2) and (3))
Heilongjiang	−5.53	0.95	0.85	0.10
Shandong	−4.34	0.93	0.85	0.07
Qinghai	−3.05	0.91	0.85	0.07
Hebei	−2.74	0.91	0.86	0.06
Inner Mongolia	−2.38	0.91	0.86	0.05
Shaanxi	−2.00	0.90	0.85	0.05
Shanxi	−1.85	0.91	0.86	0.05
Guizhou	−1.74	0.89	0.85	0.04
Sichuan	−1.53	0.91	0.86	0.05
Xinjiang	−1.34	0.90	0.85	0.04
Yunnan	−1.25	0.90	0.86	0.04
Jilin	−1.03	0.90	0.85	0.04
Liaoning	−0.91	0.90	0.86	0.04
Beijing	−0.84	0.46	0.44	0.02
Gansu	−0.73	0.90	0.86	0.04
Hainan	−0.68	0.83	0.80	0.03
Henan	−0.08	0.87	0.84	0.03
Zhejiang	0.07	0.81	0.79	0.02
Jiangsu	0.11	0.87	0.84	0.03
Tianjin	0.34	0.85	0.82	0.03
Hubei	0.35	0.86	0.84	0.02
Guangdong	0.47	0.82	0.80	0.02
Guangxi	0.50	0.87	0.84	0.03
Ningxia	0.57	0.88	0.85	0.03
Chongqing	0.68	0.86	0.84	0.02
Shanghai	1.48	0.78	0.77	0.00
Jiangxi	1.78	0.86	0.86	0.01
Anhui	1.90	0.86	0.85	0.01
Fujian	2.36	0.86	0.85	0.01

Note: Provinces are ordered according to the percentage change in profit.

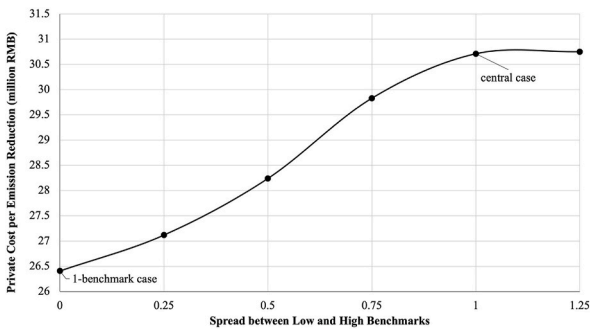


Fig. 2. Benchmark variation and cost per ton reduction in emissions under TPS

6.3. Further sensitivity Analysis

Table 9 indicates how alternative parameter values affect the results. The first two panels indicates the impacts of different values for the price elasticities of supply and demand for electricity. As noted earlier, the difference between the TPS and C&T directly depends on the price elasticity of supply. As indicated in the table and predicted by the analytical model, the two policies match when this elasticity is zero, and the differences in private cost expand with increases in this elasticity.

A higher absolute value for the demand elasticity reduces the overall economic cost of both the TPS and C&T, as it facilitates for both policies achieving emissions reductions through the output-reduction channel. A higher demand elasticity also affects the relative costs of the two policies. With a more elastic demand, the essential difference between the TPS and C&T – the output subsidy – gains importance. Hence the cost-effectiveness disadvantage of the TPS expands and the difference in the total private costs of the two policies increases with the elasticity of demand.

We also consider the sensitivity of results to the parameter α in the heat rate cost function (Equation A.25). This parameter represents a generator's elasticity of the heat rate to fuel prices. A higher absolute value for α leads to heavier reliance on reduced

Table 7
Impacts of the TPS – one-benchmark case.

	Baseline	TPS
Benchmarks (tCO_2/MWh)		
— Coal-fired (technology classes 1–7)		0.836
— CFB (technology classes 8 and 9)		
— Gas-fired (technology classes 10 and 11)		
Emissions (million tCO_2)	2,732.88	2,616.1
— change from baseline		−116.77
— change from units that shut down		16.63
— change from units that remain and increase supply		57.27
— change from units that remain and reduce supply		42.88
— percentage change from baseline		−4.27
Allowance Price (RMB)		106.71
Allowances Traded (million tCO_2)		111.01
Aggregate Electricity Supply (million kWh)	31,31,149	31,26,256
— change from baseline		−4892
— change from units that shut down		−16,052
— change from units that remain and increase supply		32,132
— change from units that remain and reduce supply		−20,972
— percentage change from baseline		−0.16
Electricity Price (RMB/kWh)		
Average Electricity Price	0.377	0.378
— marketed electricity in intraprovincial market	0.331	0.333
— administered electricity in intraprovincial market	0.385	0.385
— marketed electricity in interprovincial market	0.372	0.375
— administered electricity in interprovincial market	0.435	0.435
Private Cost (million RMB)		3,084
— change in Consumer Surplus		−2,219
— change in Producer Surplus		−865
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)		26.41
Environmental Benefit (million RMB)		33,863

Table 8
TPS impacts with and without allowance trading.

	3-Benchmark Case		1-Benchmark Case	
	With Trading	Without Trading	With Trading	Without Trading
Percent Reduction in Emissions	−4.27	−5.68	−4.27	−7.99
Percent Increase in Average Electricity Price	0.21	0.93	0.27	1.59
Private Cost (million RMB)	3,586	22,039	3,084	35,786
— change in Consumer Surplus	−1,258	−8,853	−2,219	−16,174
— change in Producer Surplus	−2,327	−13,185	−865	−19,611
Private Cost per Ton of Reduced Emissions (RMB/tCO_2)	30.71	142.06	26.41	163.83
Gains from Trade				
— value (million RMB)	111.35		137.42	
— percent of no-trade private cost	78.38		83.88	

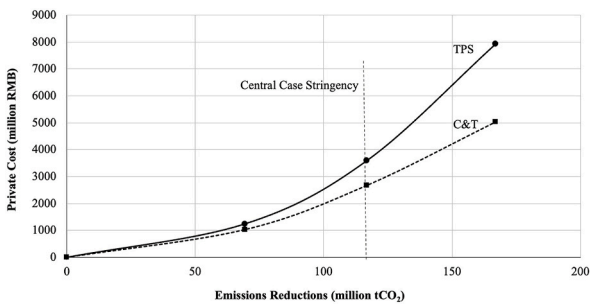
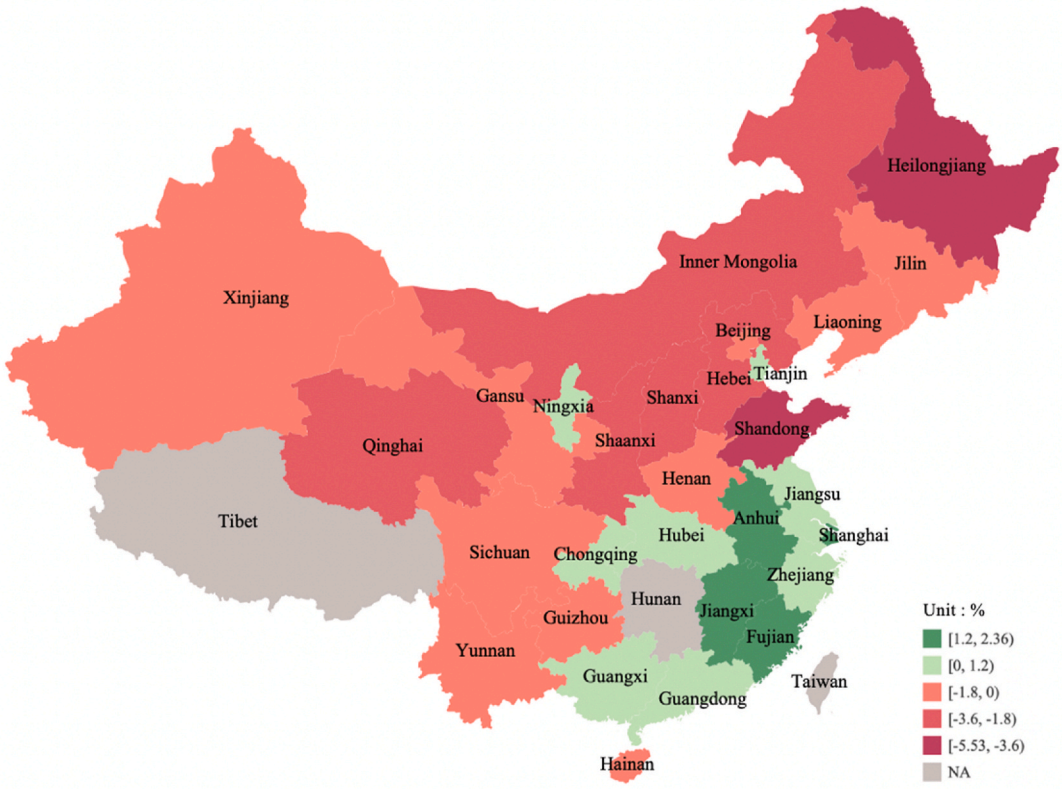


Fig. 3. TPS and C&T costs under varying policy stringencies.

emissions intensities as a channel for compliance. As a result, a higher elasticity reduces the private costs of both TPS and C&T.

Although the alternative parameter values affect the magnitudes of impacts, the qualitative differences between the policies in terms of their relative price impacts, relative costs, and distributional impacts are robust across these scenarios.



Note: Values applied to the key for this map are from the third column of Table 5.

Fig. 4. Percentage Loss of Profit Relative to Baseline by Province in the Central Case.

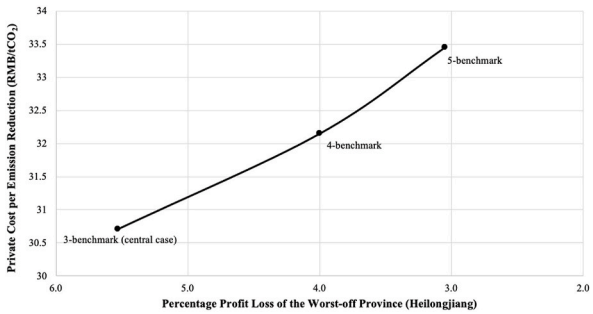


Fig. 5. Aggregate private cost under alternative distributional outcomes.

7. Conclusions

China's nationwide CO_2 emissions trading system, a tradable performance standard, has the potential to make a very substantial contribution to the world's efforts to confront global climate change. This paper assesses the cost-effectiveness and distributional consequences of alternative designs of this TPS during its initial power-sector phase, using matching analytically and numerically solved models. It also compares the TPS's impacts with those of a C&T program with the same coverage and stringency.

A key property of the TPS – inherent in its rate-based approach – is its implicit subsidy to production. The subsidy underlies important differences in the TPS's impacts relative to C&T. The subsidy causes the TPS to make less extensive and less efficient use of electricity output reduction as a way of reducing emissions. Instead, the TPS depends much more on reductions in emissions intensities. And while C&T induces nearly all covered power-generation facilities to reduce electricity output, the TPS's rate-based structure

Table 9
Impacts under alternative supply and demand elasticities.

	Supply Elasticity				Demand Elasticity			Heat Rate Elasticity		
	0	0.8684	1.7367 (central case)	2.6051	−0.101	−0.2020 (central case)	−0.303	−0.0339	−0.0484 (central case)	−0.0629
TPS										
Percent Reduction in Emissions	−4.47	−4.26	−4.27	−4.29	−4.22	−4.27	−4.31	−4.33	−4.27	−4.24
Percent Increase in Average Electricity Price	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Private Cost (million RMB)	3,811	3,661	3,586	3,524	3,588	3,586	3,584	4,150	3,586	3,322
— change in Consumer Surplus	−4,484	−1,022	−1,258	−1,482	−1,386	−1,258	−1,160	−2,439	−1,258	−610
— change in Producer Surplus	672	−2,638	−2,327	−2,042	−2,202	−2,327	−2,424	−1,711	−2,327	−2,711
Private Cost per Ton of Reduced Emissions (RMB/ tCO_2)	31.23	31.44	30.71	30.09	31.08	30.71	30.44	35.06	30.71	28.68
										C&T
Percent Reduction in Emissions	−4.47	−4.26	−4.27	−4.29	−4.22	−4.27	−4.31	−4.33	−4.27	−4.24
Percent Increase in Average Electricity Price	1.00	1.04	1.04	1.04	1.06	1.04	1.03	1.04	1.04	1.04
Private Cost (million RMB)	3,811	2,813	2,670	2,501	2,883	2,670	2,505	2,707	2,670	2,555
— change in Consumer Surplus	−4,484	−46,669	−48,215	−47,293	−65,494	−48,215	−35,933	−47,579	−48,215	−48,558
— change in Producer Surplus	672	43,856	45,545	44,791	62,611	45,545	33,427	44,872	45,545	46,003
Private Cost per Ton of Reduced Emissions (RMB/ tCO_2)	31.23	24.16	22.84	21.35	24.97	22.84	21.27	22.87	22.84	22.06

Note: Supply elasticity is implied by parameters associated with cost function. It is the baseline weighted average supply elasticity over all units. The 0.8684 and 2.6051 supply elasticities are 50% lower and higher than the central case respectively. The −0.1010 and −0.3030 demand elasticity are the 50% lower and higher in absolute value than the central case respectively. The −0.0339 and −0.0629 heat rate elasticity are 30% lower and higher than the central case respectively.

causes covered facilities with relatively low emissions intensities to increase electricity output and emissions relative to the levels under business as usual.

The subsidy reduces the extent to which emissions allowance trading can reduce costs. This arises from the fact that under the TPS, a cost-minimizing firm will aim to equate its marginal abatement costs with the net-of-subsidy allowance price applicable to that facility. Since the net-of-subsidy price generally differs across facilities, allowance trading will not bring about equality of marginal abatement costs across facilities; hence gains from trades are compromised. This limitation to the gains from trade does not occur under C&T. The subsidy further compromises cost-effectiveness when multiple benchmarks are employed. Multiple benchmarks add to costs by affecting the relative strength of the subsidy across different covered facilities, thereby distorting the relative contributions of different facilities to emissions abatement. The TPS's costs are about 16 percent higher in our central case's 3-benchmark system than in an equally stringent single-benchmark system.

These channels combine to produce the higher overall costs of the TPS. In our central-case numerical simulation, the costs of the TPS are about 34 percent higher than those of C&T. To our knowledge, this study is the first to consider together these three channels and quantify their impacts.

In addition to yielding different overall cost impacts, the TPS and C&T produce quite different distributional consequences. Because producers make less use of the output-reduction channel under the TPS, aggregate output is reduced less under the TPS than under C&T and electricity prices rise by a smaller amount. Hence electricity producers shift less of their compliance costs to consumers, and the share of the overall economic burden borne by consumers is smaller under the TPS than under C&T.

To address distributional concerns, China's TPS applies different benchmarks to different power plant technology classes. Coal-fired and circulating-fluidized bed plants, which tend to have higher emissions intensities, receive higher (less stringent) benchmarks in order to avoid what would be exceptionally high compliance costs if they faced the same benchmarks as natural gas-fired plants. Expanding the number of benchmarks beyond three allows for further customizing of benchmarks in ways that avoid exceptionally large adverse profit impacts in some provinces. At the same time, if aggregate emissions reductions are to be kept constant, such customizing increases the profit losses in other provinces and raises overall economic cost. We have applied the numerical model

to assess the distributional impacts and assess the sacrifices of cost-effectiveness associated with achieving particular distributional goals.

On cost-effectiveness grounds, economists have reason to applaud China's decision to reduce CO_2 through an emissions pricing instrument as well as its plan to move from a group of provincial or municipal pilot programs to an integrated nationwide program. The TPS may not be as cost-effective as C&T, but its reliance on emissions pricing and its wide geographical scope can help achieve emissions reductions on a broad scale at relatively low cost. Also, the TPS has certain attractions relative to C&T. Its rate-based structure implies that policy stringency adjusts automatically in response to changes in macroeconomic conditions. And the fact that it brings about smaller increases in electricity prices implies that it would cause less emissions leakage. The smaller price increases could also be an attraction in terms of fairness and political feasibility. Another potential attraction – at least to some interested parties – is the fact that Chinese planners are more familiar with intensity-based regulation.

Despite its higher costs than those of an equally stringent C&T system, the TPS can generate significant net gains once environmental benefits are counted. Our central case results indicate that the TPS's benefits in terms of avoided climate damages are several times the policy costs when CO_2 emissions reductions are valued at 290 RMB (or 44 U.S. dollars) per ton. In addition to reducing CO_2 emisions, the TPS will also reduce several air pollutants whose emissions are correlated with CO_2 emissions. Accounting for the reductions in air pollution and associated health benefits would raise the benefit-cost ratio considerably.

Some caveats are in order. First, although we have been fortunate to gain access to important data through our research and contacts in China, we still have faced some data limitations, and we have needed to calibrate or borrow others' estimates of important parameters rather than estimate them econometrically. Yet the robustness of our results leads us to believe that the key insights from this study would not change significantly with more comprehensive data. Second, ours is a one-period model. Hence it does not capture investment decisions and associated changes to capital stocks, though it accounts for shutdowns. We would expect that in a multi-period model, the results would show a similar pattern but be amplified. Specifically, we would expect that the use of multiple benchmarks would imply larger sacrifices of cost-effectiveness, as multiple benchmarks would not only distort relative output decisions across units (as captured in the current model) but also distort the relative levels of investment across units. We would also expect that incorporating investment decisions would widen the differences between the costs of the TPS and C&T, as the implicit output subsidy of the TPS would cause investment decisions to be less efficient than those under C&T.

This study brings out hitherto unrecognized channels of impact of the TPS and offers unique quantitative estimates of the wide-ranging impacts of China's planned TPS system as well as relevant comparisons with C&T. We believe the study's findings can significantly help Chinese planners in their efforts to arrive at designs for the TPS that can most successfully balance cost-effectiveness and distributional goals. The findings also should be of value to decision makers in regional and national jurisdictions outside China who currently are making important choices as to whether to employ rate-based, mass-based, or other ways to achieve reductions in emissions of CO_2 and other pollutants.

References

Böhringer, Christoph, Lange, Andreas, 2005. Economic implications of alternative allocation schemes for emission allowances. Scand. J. Econ. 107 (3), 563–581.

Bovenberg, Lans, A., Goulder, Lawrence H., 2001. Environmental Taxation and Regulation. National Bureau of Economic Research. https://www.nber.org/papers/w8458. (Accessed 15 March 2021).

Burtraw, Dallas, Palmer, Karen, Paul, Anthony, Pan, Sophie, 2015. A proximate mirror: greenhouse gas rules and strategic behavior under the US clean air act. Environ. Resour. Econ. 62 (2), 217–241.

Bushnell, James, Chen, Yihsu, 2012. Allocation and leakage in regional cap-and-trade markets for CO2. Resour. Energy Econ. 34 (4), 647–668.

Bushnell, James B., Holland, Stephen P., Hughes, Jonathan E., Knittel, Christopher R., 2017. Strategic policy choice in state-level regulation: the EPA's clean power plan. Am. Econ. J. Econ. Pol. 9 (2), 57–90.

Chen, Yun, 2019. "Enhance the Understanding of State-Owned Enterprise Development(深化对国有企业发展的认识)." *Economic Information Daily*. http://dz.jjckb.cn/www/pages/webpage2009/html/2019-11/11/content_58671.htm. (Accessed 24 March 2021).

Chen, Jianhua, Chen, Guowei, 2012. Analysis on operation cost of 9F gas-steam combined cycle power plants in jiangsu province (江苏省9F级燃气-蒸汽联合循环电厂运营成本分析). Electric Power Construction 33 (8), 99–102, 0.

China Coal Market, 2016. "Coal Prices by Province (地区煤炭价格)." *China Coal Market*. https://www.cctd.com.cn/list-148-1.html. (Accessed 5 August 2020).

China Electric Power Development Research Institute, 2018. Electricity Prices by Province. " *China's Electric Power Development Research Institute*. https://www.365power.cn/. (Accessed 5 August 2020).

China Electricity Council, 2018. Annual Statistics of China Power Sector 2016, 2016年电力统计基本数据一览表. https://www.cec.org.cn/detail/index.html?3-126874. (Accessed 16 March 2021).

China Electricity Council, 2019. An Analysis of National Electricity Trading in 2018, 2018年全国电力市场交易情况. https://www.cec.org.cn/guihuayutongji/dianligaige/2019-03-04/189190.html.

Davis, Lucas W., Knittel, Christopher R., 2019. Are fuel economy standards regressive? Journal of the Association of Environmental and Resource Economists 6 (S1), S37–S63.

de Vries, Frans, P., Dijkstra, Bouwe R., Mcginty, Matthew, 2014. On emissions trading and market structure: cap-and-trade versus intensity standards. Environ. Resour. Econ. 58 (4), 665–682.

Duan, Maosheng, Zhou, Li, 2017. Key issues in designing China's national carbon emissions trading system. Economics of Energy & Environmental Policy; Cleveland 6 (2). https://search.proquest.com/docview/2259798778/abstract/32123F8E0395476DPQ/1. (Accessed 6 August 2020).

Fischer, Carolyn, 2001. Rebating environmental policy revenues: output-based allocations and tradable performance standards. Resources for the Future.

Fischer, Carolyn, Fox, Alan K., 2012. Comparing policies to combat emissions leakage: border carbon adjustments versus rebates. J. Environ. Econ. Manag. 64 (2), 199–216.

Fischer, Carolyn, Newell, Richard G., 2008. Environmental and technology policies for climate mitigation. J. Environ. Econ. Manag. 55 (2), 142–162.

Fowlie, Meredith, 2012. The Design and Implementation of US Climate Policy *Updating The Allocation Of Greenhouse Gas Emissions Permits In a Federal Cap-And-Trade Program*. University of Chicago Press. https://chicago.universitypressscholarship.com/view/10.7208/chicago/9780226921983.001.0001/upso-9780226269146-chapter-11. (Accessed 6 August 2020).

Fowlie, Meredith, Reguant, Mar, Stephen, P., Ryan, 2016. Market-based emissions regulation and industry dynamics. J. Polit. Econ. 124 (1), 249–302.

Fullerton, Don, Karney, Daniel H., 2009. The allocation of permits in U.S. Climate change legislation. Econ. Voice 6 (12). https://www.degruyter.com/view/journals/ev/6/12/article-ev.2009.6.12.1636.xml.xml. (Accessed 6 August 2020).

Fullerton, Don, Metcalf, Gilbert E., 2001. Environmental controls, scarcity rents, and pre-existing distortions. J. Publ. Econ. 80 (2), 249–267.
Goulder, L.H., Parry, I.W.H., 2008. Instrument choice in environmental policy. Rev. Environ. Econ. Pol. 2 (2), 152–174.
Goulder, Lawrence H., Hafstead, Marc A.C., Dworsky, Michael, 2010. Impacts of alternative emissions allowance allocation methods under a federal cap-and-trade program. J. Environ. Econ. Manag. 60 (3), 161–181.
Goulder, Lawrence H., Hafstead, Marc A.C., Williams III., Roberton C., 2016. General equilibrium impacts of a federal clean energy standard. Am. Econ. J. Econ. Pol. 8 (2), 186–218.
Haites, Erik, 2003. Output-based allocation as a form of protection for internationally competitive industries. Clim. Pol. 3 (Suppl. 2), S29–S41.
Ho, Mun S., Wang, Zhongmin, Yu, Zichao, 2017. *China's Power Generation Dispatch*. Resources for the Future.
Holland, Stephen P., Hughes, Jonathan E., Knittel, Christopher R., 2009. Greenhouse gas reductions under low carbon fuel standards? Am. Econ. J. Econ. Pol. 1 (1), 106–146.
Holland, Stephen P., Jonathan, E., Hughes, Christopher, R., Knittel, Parker, Nathan C., 2015. Some inconvenient truths about climate change policy: the distributional impacts of transportation policies. Rev. Econ. Stat. 97 (5), 1052–1069.
Interagency Working Group on the Social Cost of Carbon, 2016. Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866.
IPCC, 2006. In: Eggleston, Simon, Buendia, Leandro, Miwa, Kyoko, Ngara, Todd, Tanabe, Kiyoto, et al. (Eds.), *2006 IPCC Guidelines For National Greenhouse Gas Inventories*. IGES, Japan (Japan).
Jiang, Lixue, et al., 2013. Life-cycle GHG emission factors of final energy in China. Energy Procedia 37, 2848–2855.
Kahrl, Fredrich, Dupuy, Max, Wang, Xuan, 2016. *Issues In China Power Sector Reform: Generator Dispatch*. Regulatory Assistance Project (March 15, 2021). https://www.raponline.org/knowledge-center/issues-in-china-power-sector-reform-generator-dispatch/.
Karplus, Valerie J., Zhang, Xiliang, 2017. Incentivizing firm compliance with China's national emissions trading system. Economics of Energy & Environmental Policy; Cleveland 6 (2). https://search.proquest.com/docview/2260013017/abstract/C14E989B02D0488CPQ/1. (Accessed 6 August 2020).
Labandeira, Xavier, Labeaga, José M., López-Otero, Xiral, 2017. A meta-analysis on the price elasticity of energy demand. Energy Pol. 102, 549–568.
Linn, Joshua, Mastrangelo, Erin, Burtraw, Dallas, 2014. Regulating greenhouse gases from coal power plants under the clean air act. Journal of the Association of Environmental and Resource Economists 1 (1/2), 97–134.
Liu, Hui, Zhang, Dawei, 2018. Gas consumption and cost calculation for gas turbine power generation in guangdong (广东燃气轮机发电用气量及成本测算). Petroleum & Petrochemical Today 26 (11), 43–46.
Liu, Zongkui, Xu, Xiaojing, Hu, Xuemei, 2016. Based on the generating cost, the optimal intelligent automatic generating system of 1030 Ultra supercritical unit (基于发电成本最优的1030超超临界机组智能发电系统). In: Yinchuan, Ningxia (Ed.), In China Power Generation Automation Technology Forum Proceeding 2016, vol. 1. China: Power Automation Committee of Chinese Association of Automation, Electric Power Magazine, p. 7.
Long, Xianling, Zhang, Da, Zhang, Xiliang, Goulder, Lawrence, Qu, Chenfei, Weiner, Eric, September 2021. General Equilibrium Analysis of Cost-Effectiveness and Distributional Impacts of China's Nationwide CO2 Emissions Trading System. Working paper, Stanford and Tsinghua universities.
Metcalf, Gilbert E., 2019. On the economics of a carbon tax for the United States. Brookings Pap. Econ. Activ. 2019 (1), 405–484.
Ministry of Ecology and Environment, 2019. Unpublished electricity sector data.
Ministry of Ecology and Environment, 2020. Implementation plan for the 2019-2020 national carbon emissions trading quota setting and allocation (power generation sector) (关于印发《2019-2020年全国碳排放权交易配额总量设定与分配实施方案（发电行业）》《纳入2019-2020年全国碳排放权交易配额管理的重点排放单位名单》并做好发电行业配额预分配工作的通知) (March 15, 2021). https://www.mee.gov.cn/xxgk2018/xxgk/xxgk03/202012/t20201230_815546.html.
National Development, Reform Commission, 2014. Action plan 2014-2020 for transforming the coal-fired power industry and upgrading energy conservation and emissions reduction (关于印发《煤电节能减排升级与改造行动计划（2014-2020年）》的通知) (March 15, 2021). https://www.mee.gov.cn/gkml/hbb/gwy/201409/t20140925_289556.htm.
National Development and Reform Commission, 2015b. Notice on the Reduction of On-Grid CoalElectricity Prices and General Industrial and Commercial Electricity Prices ([关于降低燃煤发电上网电价和一般工商业用电价格的通知(发改价格〔2015〕3105 号)]). https://www.ndrc.gov.cn/xxgk/zcfb/tz/201512/t20151230_963541.html. (Accessed 5 August 2020).
National Development and Reform Commission, 2015a. Notice on Lowering Non-ResidentialNatural Gas City Gate Prices and Advancing Market Price Reform (【关于降低非居民用 天然气门站价格并进一步推进价格市场化改革的通知(发改价格〔2015〕2688 号)】). https://www.ndrc.gov.cn/fzggw/jgsj/jgs/sjdt/201511/t20151118_1109917.html. (Accessed 19 August 2020).
National Development, Reform Commission, 2017. Guidelines of national carbon emissions trading system (power generation sector) (【关于印发《全国碳排放权交易市场建设方案(发电行业)》的通知(发改气候规(2017)2191号)】). https://www.ndrc.gov.cn/xxgk/zcfb/ghxwj/201712/t20171220_960930.html. (Accessed 19 August 2020).
National Energy Administration, 2018. National energy administration's report of the electricity prices in 2017（国家能源局关于2017年度全国电力价格情况监管通报）. http://www.gov.cn/xinwen/2018-10/09/content_5328808.htm. (Accessed 5 August 2020).
Newell, Richard, Rogers, Kristian, 2003. The market-based lead phasedown. Resources for the future. https://www.rff.org/publications/working-papers/the-market-based-lead-phasedown/. (Accessed 15 March 2021).
Palmer, Karen, Burtraw, Dallas, Kahn, Danny, 2006. Simple rules for targeting CO2 allowance allocations to compensate firms. Clim. Pol. 6 (4), 477–493.
Parry, Ian W.H., 2003. Fiscal interactions and the case for carbon taxes over grandfathered carbon permits. Oxf. Rev. Econ. Pol. 19 (3), 385–399.
Parry, Ian W.H., J Krupnick, Alan, 2011. Is a clean energy standard a good way to move U.S. Climate policy forward? Resources for the Future.
Parry, Ian, Shang, Baoping, Wingender, Philippe, Vermon, Nate, Narasimhan, Tarun, 2016. Climate Mitigation in China: Which Policies Are Most Effective?" IMF Working Paper WP/16/148. International Monetary Fund.
Pizer, William A., Zhang, Xiliang, 2018. China's new national carbon market. AEA Papers and Proceedings 108, 463–467.
State-owned Assets Supervision and Administration Commission of the State Council, 2019. Measures for assessment of the operational performance of persons in charge of state-owned key enterprises (中央企业负责人经营业绩考核办法). http://www.sasac.gov.cn/n2588035/n2588320/n2588335/c10652592/content.html. (Accessed 12 April 2021).
Stavins, Robert N., 2020. The future of US carbon-pricing policy. Environmental and Energy Policy and the Economy 1, 8–64.
Teng, Fei, Frank, Jotzo, Wang, Xin, 2017. Interactions between market reform and a carbon price in China's power sector. Economics of Energy & Environmental Policy; *Cleveland* 6 (2). https://search.proquest.com/docview/2260059029/abstract/76F8BAF58A4A4FB0PQ/1. (Accessed 6 August 2020).
Tietenberg, Thomas, 1985. Emissions Trading: an Exercise in Reforming Pollution Policy. Resources for the Future, Inc, Washington, DC.
Yang, Lisha, Lin, Boqiang, 2016. Carbon dioxide-emission in China's power industry: evidence and policy implications. Renew. Sustain. Energy Rev. 60, 258–267.
Zhang, Huaiyu, 2011. Technological and economic analysis of 350MW supercritical thermal power unit (350MW超临界火电机组技术经济性分析). Turbine Technol. 53 (4), 245–248+317, 0.
Zhang, Qiang, 2013. Comparing and analysis of 660MW ultra supercritical and supercritical unit (660MW机组超(超)临界与超临界分析比较). Guizhou Electric Power Technology 16 (1), 19–21, 0.
Zhang, Da, Springmann, Marco, Valerie, J., Karplus, 2016. Equity and emissions trading in China. Climatic Change 134 (1), 131–146.
Zhang, Junjie, Wang, Zhenxuan, Du, Xinming, 2017. Lessons learned from China's regional carbon market pilots. Economics of Energy & Environmental Policy; *Cleveland* 6 (2). https://search.proquest.com/docview/2260057752/abstract/75449ECAD9DF4729PQ/1. (Accessed 6 August 2020).
Zhang, Duan, Chen, Yihsu, Tanaka, Makoto, 2018. On the effectiveness of tradable performance-based standards. Energy Econ. 74, 456–469.
Zhu, Tai, 1987. Assessment of supercritical unit from the perspective of marginal power generation cost (按边际发电成本评价超临界压力机组). Electr. power (8), 27–29, 0.