Carbon Pricing in the Power Sector

Role and design for transitioning toward net-zero carbon development

WORLD BANK GROUP Climate Change

PMI PARTNERSHIP FOR MARKET IMPLEMENTATION

ESMAP Energy Sector Management Assistance Program

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ICAP International Carbon Action Partnership

Carbon Pricing in the Power Sector

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Foreword

Electricity is the lifeline for a modern economy. At the same time, the power sector is the world's main source of greenhouse gas emissions. Limiting the worst effects of a changing climate requires that the supply of clean electricity grows rapidly. This presents challenges as the power sector is technologically complex and requires costly infrastructure development. The sector is also highly regulated and dependent on domestic natural resources and fluctuating international commodity markets.

For policymakers, carbon pricing stands out as one of the most potent tools available to reduce emissions in the power sector. The EU and the UK are prime examples of how carbon taxes and cap-and-trade systems can help significantly advance the decarbonization of the power sector. However, the path to implementing carbon pricing in low- and middle-income countries is fraught with challenges, including financing obstacles, the urgent need to boost supply, and social priorities different from those of more advanced economies with more carbon pricing experience.

This report delves deep into the power sector value chain dynamics, demonstrating how well-designed carbon pricing instruments can be instrumental in helping low- and middle-income countries reach their decarbonization goals. Focusing on how decisions are made in diverse power sector models in several developing countries, our research establishes that the carbon pricing instrument must be carefully positioned at the right regulation point in the power sector's value chain—rather than merely adding a burden for the sector. Getting it right can influence everything from power generation options to investment decisions and customers' behaviors.

Carbon pricing, which generated a record $104 billion worldwide in 2023 alone, can provide governments with new income sources. Several developing countries, such as China, Colombia, and South Africa, are in the early stages of managing distributional impacts on the poorest while facilitating the adaptation of energy-intensive industries. The report builds on these early experiences.

Predictable carbon pricing can help attract private sector investment in cleaner technologies. In capital-intensive sectors like the power sector, both investors and policymakers need long-term plans for decarbonization based on clear and credible communication on carbon price evolution.

This report is a valuable resource to support policymakers in transforming their power sectors to be more reliable, green, and sustainable. The wealth of country experiences that it draws from can highlight the diversity of situations, national contexts, and carbon pricing implementations, empowering policymakers to make informed decisions and strengthening global knowledge on carbon pricing.

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Acronym list

CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CCfD	Carbon contract for difference
CDM	Clean development mechanism
CfD	Contract for difference
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COP28	28th Conference of the Parties
CPI	Carbon pricing instrument
CPS	Carbon price support
CPUC	California Public Utilities Commission
DPV	Distributed solar photovoltaic
EE	Energy efficiency
ETS	Emissions trading system
EU	European Union
EU ETS	European Union Emissions Trading System
EUAs	EU allowance units
FiP	Feed-in premium
FiT	Feed-in tariff
G20	Group of 20
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatt
HIC	High-income country
Hz	Hertz
ICAP	International Carbon Action Partnership
IEA	International Energy Agency
IPP	Independent power producer
IRENA	International Renewable Energy Agency
KEPCO	Korea Electric Power Corporation
kWh	Kilowatt hour
LIC	Low-income country
LTC	Long-term contracts
MIC	Medium-income country
MRV	Monitoring, reporting, and verification
MW	Megawatt
MWh	Megawatt hour
NDC	Nationally Determined Contributions
Nersa	National Energy Regulator of South Africa
NOx	Nitrogen oxide
NPV	Net present value
OCGT	Open cycle gas turbine
$PM_{2.5}$	Particulate matter 2.5
PM_{10}	Particulate matter 10
PMI	Partnership for Market Implementation
PMR	Partnership for Market Readiness
PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable energy
REC	Renewable energy certificate
SDG	Sustainable Development Goal
SO_2	Sulfur dioxide
SOE	State-owned enterprise
t	Ton (metric ton)
tCO_2	Ton of carbon dioxide
tCO_2e	Ton of carbon dioxide equivalent
ToC	Theory of Change
ToU	Time-of-use
UK	United Kingdom
US	United States
USD	US dollar
WACC	Weighted average cost of capital

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Executive summary

The number of countries that have announced some type of commitment to net zero emissions has increased very rapidly in recent years, from five in 2018 to over 145 in 2023. Many of these are middle-income countries (MICs) and low-income countries (LICs) (Net Zero Tracker, 2023), whose greenhouse gas (GHG) emissions are concentrated in the power sector. As domestic electricity demand grows, these countries must increase power generation while reducing carbon emissions to meet socioeconomic needs and align with the Paris Agreement's goal of limiting global temperature rise to 1.5°C. Therefore, the power sector must increasingly rely on low-carbon energy sources.

LICs and MICs are therefore considering introducing a range of policies to decarbonize their power sectors, and a growing number of them are considering carbon pricing instruments (CPIs), such as carbon taxes and/or emissions trading systems (ETSs) to transition to low-carbon electricity systems, as part of a broader policy mix. The international experience of applying CPIs across the world is substantial, and many lessons can be learned from it. However, while such initiatives commenced more than 15 years ago in advanced economies, the use of carbon pricing instruments is still very limited in LICs and MICs.

Power sectors in LICs and MICs vary substantially but share common acute challenges distinct from those faced by advanced economies. These include rapid growth in electricity demand, low levels of access and affordability, insufficient and insecure supply, and lack of affordable financing, among others. Such challenges require a different set of public policy choices compared to advanced economies. Thus, while much can be learned from international experience in deploying CPIs in high-income countries (HICs), the policy landscapes are substantially different in LICs and MICs.

A literature review confirms the gaps that exist in developing economies to introduce carbon pricing. This report aims to fill some of the identified knowledge gaps and assess the role that CPIs, specifically carbon taxes and ETSs, can play in supporting decarbonization of the power sector. The report also provides actionable recommendations for policy makers considering implementing a CPI in their countries.

Well-designed carbon pricing in the power sector could support

1. A shift toward lower-carbon generation capacities, including through decisions on investments and retirements of power sector assets, and improved energy efficiency and fuel adjustments in existing power plants (medium- and long-term impact).

2. A shift in dispatch toward lower-emissions power generation, including by changing merit order and accompanying flexibility resources (short-term impact).

3. A shift toward less carbon-intensive wholesale electricity purchase, including distributors, retailers, and/or large customers contracting the purchase of electricity from renewable energy producers (short- and long-term impact).

4. A shift toward less carbon-intensive consumption patterns, including by changing the time of consumption, investing in battery storage, reducing on-grid demand by improving efficiency, or adopting behind-the-meter renewables (short- and medium-term impact).

5. Raising new fiscal revenues, facilitating the transition to a lower-carbon power sector.

These insights are validated by 10 years' experience of the Partnership for Market Readiness and emerging evidence from the Partnership for Market Implementation, as well as consultations with various power sector and carbon pricing experts and specific case studies. The selected case studies include China (ETS), Colombia (carbon tax), Kazakhstan (ETS), and South Africa (carbon tax) and cover a series of characteristics and challenges frequently met in LICs and MICs (e.g., state-owned monopoly power utility, high coal reliance, issues with affordability, insecurity of supply, etc.).The findings also shed light on the specific role that carbon pricing can play within the wider energy transition happening in these countries.

MULTIPLE CPI OPTIONS FOR MULTIPLE POWER SECTOR STRUCTURES

The entire value chain of the power sector, composed of five main stages—fuel supply, generation, wholesale transmission and dispatch, distribution and retail, and consumption—contributes to the sector's emissions. System and network operators must maintain the continuous and reliable operation of the power grid by balancing generation, demand, and power flows in real time to ensure grid stability. Despite technological advancements that support system and network operators, including allowing distributed resources like solar rooftops to inject power at any point in the network, the power sector in LICs and MICs is still structured around five main stages. All these stages contribute to shaping the emissions of the sector. Consumer demand dictates the volume of electricity distributors purchase, guiding the system operator to decide on the order of the dispatch of available generators, which ultimately impacts the level of emissions in the sector.

Power sector reforms in developing countries have led to varied and diverse structures, ranging from fully state-owned utilities to competitive markets. Since the 1980s, many LICs and MICs reformed their power sectors by liberalizing and unbundling to encourage private sector participation and introducing competition to increase efficiency, reducing political interference and subsidies, and attracting private capital. The outcomes of these reforms varied significantly among HICs, LICs, and MICs. For example, privatization and liberalization in developing countries were less successful than in Organisation for Economic Co-operation and Development countries, due to higher investment risks. In the 2000s, many developing countries reformed their market regimes again to create safer and more stable regulatory environments, such as through long-term contracts between new and existing producers and retailers (Roques & Finon, 2017). As a result, LICs and MICs now have diverse power sector structures, ranging from fully integrated state-owned public utilities to fully competitive markets, as shown in Figure ES1.

The structure of a country's power sector significantly influences the economic agents at each stage of the value chain and their decision-making priorities, leading to variations in the policies and instruments, including carbon pricing, used to reduce emissions.

International experience shows that ETSs and carbon taxes can be designed to target different groups of stakeholders at different points of regulation along the value chain. As outlined in Figure ES2, a CPI can apply at the supply, generation, dispatch, distribution, or consumption stage.

When a CPI is applied at the generation stage, electricity generation companies either surrender emission allowances or pay a carbon tax based on their direct emissions.[1] This leads to an additional operational cost for higher-emitting plants. Examples include the South African carbon tax and the ETSs in China and Kazakhstan.[2] In contrast, the California Cap-and-Trade program applies a carbon price to both generators and importers of electricity.

A CPI, at the dispatch stage, as seen in the South Korea ETS, includes the carbon price either as a separate cost or in the cost curve submitted by generators, affecting the merit order.

At the distribution stage, distribution and/or retail companies pay a carbon price proportional to the carbon content of the electricity they procure, encouraging contracts with low-carbon sources, as seen in the California Cap-and-Trade program. This regulation incentivizes companies importing electricity to purchase from lower-carbon sources.

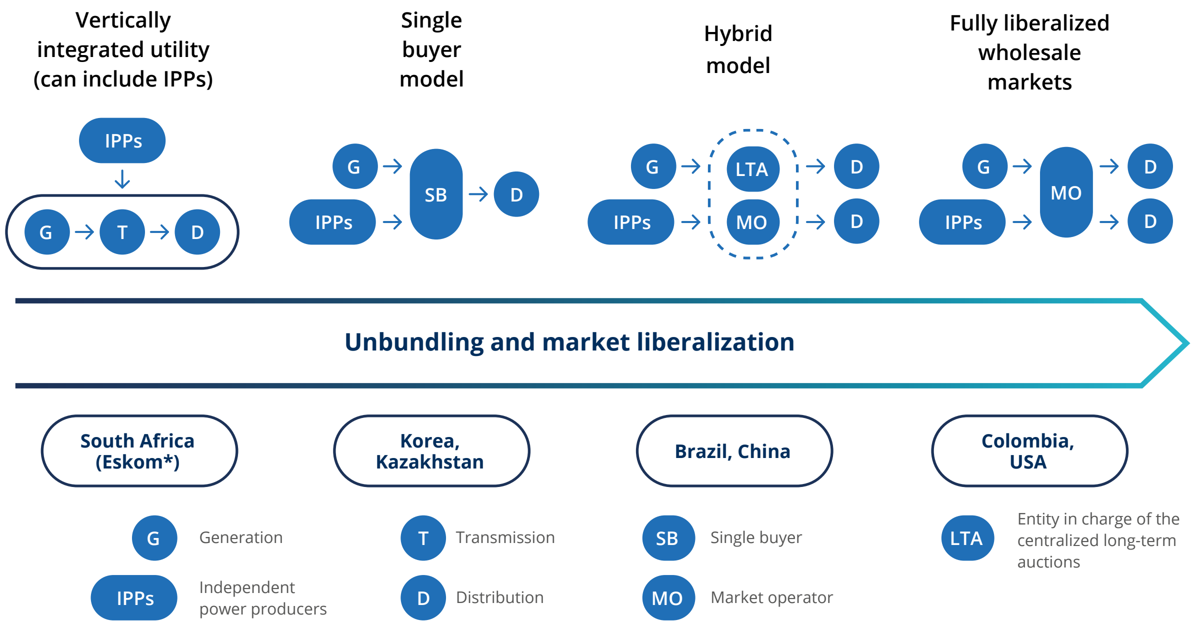
Lastly, at the consumption stage, a CPI is applied to the consumer's electricity bill based on the consumption-weighted emission factor of the grid. This can be done through an ETS, with caps based on a consumer's Scope 2 emissions

1 In the case of the European Union ETS, if emissions are captured at the point source of emissions and permanently stored in a way that meets jurisdiction requirements for sequestration or carbon capture and storage, then there is no need to redeem allowances or pay a carbon tax.

2 A CPI could also be placed upstream of electricity generators, where the companies distributing fossil fuel must surrender allowances or pay a carbon tax according to the carbon content of the fuels they sell in a determined jurisdiction. The fossil fuel distribution companies then pass on the cost to the purchaser of the fuel. Generation companies will then purchase coal or gas where the carbon price is already factored into the fuel price.

FIGURE ES1

Degrees of market liberalization and unbundling of power sector



• *Eskom is in the process of unbundling*

(i.e., those that result from the purchase of electricity consumption) or through a carbon tax based on the carbon content of the electricity consumed, prompting consumers to alter their usage patterns or invest in energy-efficient appliances.[3] If the carbon price applied to tariffs varies throughout the day based on the changing type of generation, consumers could also move part of their consumption to periods of the day when the generation of electricity is less carbon intensive. For the price signal to be efficient, it requires the installation of smart meters that can differentiate consumption periods accordingly. Before its national ETS in 2021, several of China's regional ETS pilots included indirect emissions from electricity consumption (International Energy Agency, 2020d).

The effectiveness of a CPI also depends on its interaction with existing incentives and regulations at each value chain stage, influenced by other policy challenges.

A CPI applied at one stage of the value chain can influence the decisions made either upstream or downstream of the regulation point, although the structure and regulation of the industry matters for the pass-through of incentives. A CPI applied at the point of electricity consumption, for instance, with a tax based on average carbon content, can influence consumption patterns. However, it does not directly impact dispatch or supply mix decisions—although it will eventually influence these by changing the shape and the size of the load

3 If the market structure allows, large consumers could also respond by signing bilateral power purchase agreement contracts with low-carbon electricity producers.

curve to be served and the marginal capacity to be dispatched. Conversely, applying the CPI at the fuel combustion stage in power generation sends a clear signal for investment and dispatch decisions. Depending on the structure and the regulation of the sector, this may be passed through to consumers, potentially influencing their consumption patterns and investments in energy efficiency.

Finally, in certain cases, combining multiple CPIs along the value chain may be worth considering. Regulators often introduce regulations along the value chain to address market failures or to internalize specific public policy objectives,[4] which can create rigidities and hamper the pass-through of the carbon price signal to other stakeholders. As a result, multiple CPIs might be necessary at different points in the value chain to ensure **adequate incentives to all agents involved.**

FIGURE ES2

Regulation points along the value chain

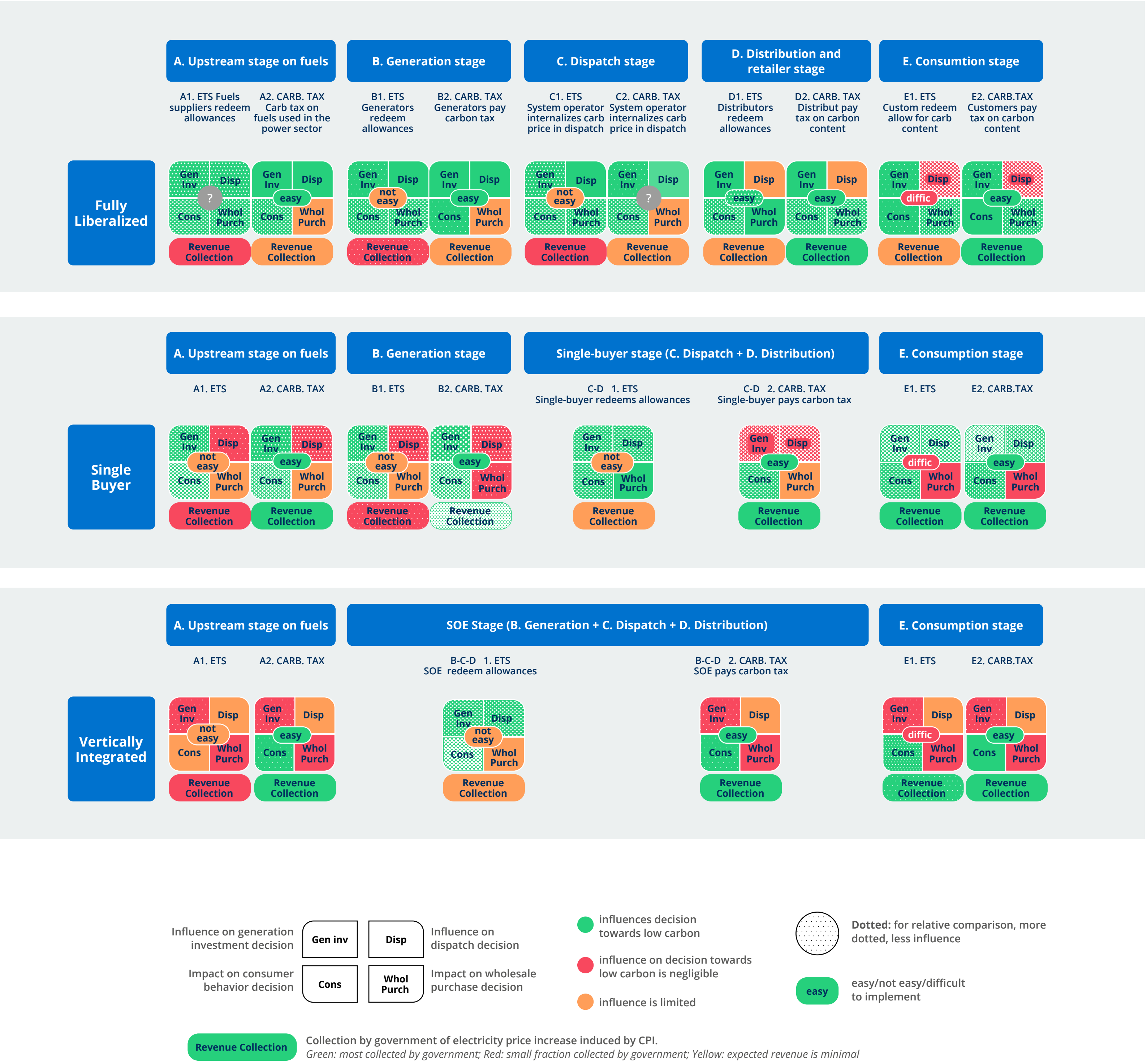
Power Sector Value Chain

Power sector value chain (bidirectional)	Fuel supply for the power sector	Generation & storage	Dispatch, markets, and transmission	Distribution	Consumption
Stakeholders	Fossil fuel producers, importers, or distributors	Electricity generation companies	Power exchanges, transmission companies, system operator	Distribution and retail companies	Retail customers and large consumers
CPI regulation point	The sale or import of fossil fuels to electricity generators	Emissions of fossil fuel generators	Carbon content of generators' bids or In-puts in the dispatch	Carbon content of electricity purchased for distribution	Carbon content of electricity consumed
Examples	Colombia carbon tax	South Africa carbon tax, China national ETS, Kazakhstan ETS	South Korea ETS	Electricity importers in the California Cap-and-Trade Program	China ETS regional pilots

4 These include regulated retail tariffs for end consumers to protect against natural monopoly abuse or to ensure social tariffs for low-income households; obligations of medium-term contracting of part of the demand for large customers or distributors, with prices that do not reflect short-term market variations; curtailment of least-cost intermittent generators when the system is not flexible enough or reciprocally mandates the purchase of a minimum share of renewables; regulation of dispatch that gives priority to security over least cost (for instance, to save water in reservoirs in hydro-dominated systems in anticipation of droughts); wholesale tariff caps on generators to protect distributors when fuel prices are too high and are not allowed to be passed through in tariffs (as seen in China); minimum off-taker obligations with guaranteed prices to attract independent power producer (IPP) investors or to prevent state-owned generation assets, etc.

FIGURE ES3

Overview Matrix - Simplified assessment of CPIs options in three power sector models: fully liberalized market, single-buyer model and vertically integrated monopoly



BOX ES1

How to read the overview matrix of CPI assessment in three different power sector models

The overview matrix visually summarizes the four main impacts expected from a CPI along the value chain, depending on where it is applied, and for three typical power sector models: fully unbundled and liberalized, single buyer, or vertically integrated monopolistic state-owned enterprise. It distinguishes between an ETS and a carbon tax. Readers can focus on the specific row relevant to their power sector model.

For each power sector model, and for each of the five possible regulation points along the value chain, labeled from A to E, two small colored matrices are displayed, one for an ETS and one for a carbon tax. Each small colored matrix has

→ **Four petals corresponding to the first four intermediate outcomes (clockwise):** generation investment (Gen Inv), dispatch (Disp), wholesale purchase (Whol Purch), and consumption (Cons)
- Green means that the CPI influences the decision toward low carbon
- Yellow means that the CPI influence is limited
- Red means the CPI influence on a decision toward low carbon is negligible
- Dotted patterns introduce gradations for the sake of relative comparison: dotted green means less influence than solid green, etc.

→ **One underlying bar for fiscal revenue generation and collection** (Revenue Collection), corresponding to the fifth intermediate outcome
- Green means that the entire electricity price increase induced by the CPI is collected by the government and can thus be reallocated as part of the design of the CPI
- Red means only a minimal part of the increase is captured by the government (it mostly increases the infra-marginal rent received by the generators)
- Yellow means that additional revenues are expected to be minimal

→ **One central button for signaling the relative easiness of implementation**
- Green means "technically easy to implement"
- Red means "difficult or impossible to implement"
- Yellow means "neither easy nor very difficult to implement"

MAPPING OUT THE IMPACTS OF CPI OPTIONS ALONG THE VALUE CHAIN

The effectiveness and implementation of an ETS or a carbon tax are influenced by the structure of the sector and existing policies and regulations, which interact with the CPI. These factors result in varying impacts on decision-making processes throughout the value chain. Section 4.5 in Chapter 4 systematically examines these impacts and side effects for both ETS and carbon tax in three typical power structure models. The indicative findings of this analysis are synthetized in the general overview matrix that follows (Figure ES3; see also ES1). While this visual synthesis is mostly indicative and should be used carefully, taking into account specific national circumstances, it clearly tends toward more green in the "fully liberalized" row and more red in the "vertically integrated SOE (state-owned enterprise)" row. There is generally more influence (greener) on the intermediate outcome petal corresponding to the regulation point where the CPI is applied, and less for the ones observed upstream or downstream of that point (except for the vertically integrated SOE where three potential regulation points are merged).

Revenue collection is better (green) if the regulation point is downstream of the dispatch.

Lessons and recommendations

The role and impact of a CPI can vary significantly based on the national energy mix, the development priorities guiding the sector policies, and current sector structure shaped by past and ongoing reforms. The regulation point along the value chain where the CPI is applied also influences these outcomes.

The main findings of the analysis conducted in this report can be organized into a series of lessons and recommendations to help achieve the expected outcomes, in particular the ones related to (i) shifting toward a lower-carbon generation mix at the generation stage, (ii) prioritizing the dispatch of power generation plants with lower carbon emissions, (iii) shifting toward less carbon-intensive wholesale purchases of electricity, and (iv) shifting toward less carbon-intensive consumption patterns.

These lessons and recommendations, detailed in Chapter 5, are summarized in Figure ES4.

FIGURE ES4

Main lessons and recommendations

I. The role of CPIs in the decarbonization of the power sector in LICs and MICs

Lesson 1:
Challenges faced by power sectors in low- and middle-income countries differ significantly from those in high-income countries. Policy landscapes for deploying CPIs are therefore different, influencing their role and design.

Recommendation 1:
The specific challenges of LICs and MICs need to be identified and acknowledged early to ensure that CPI role and design can take these into account, as a way of minimizing the risk of adding hurdles and maximizing opportunities to jointly address these challenges while mitigating emissions.

Lesson 2:
Governments have a wide variety of policy instruments and reforms at their disposal to drive decarbonization of their current and future power sector. The role of carbon pricing needs to be defined within this broader policy mix, taking into account overlapping policies.

Recommendation 2:
A CPI-based policy should not be designed in isolation but rather as part of a broader sector decarbonization policy package, supported by a thorough analysis of potential complementarities and/or redundancies with other power sector decarbonization policy instruments.

II. Different CPIs for different power sector structures

Lesson 3:
The power sector is a complex, highly regulated value chain, offering a variety of potential regulation points and design options for CPIs, delivering different impacts on the decisions of the agents along the chain to decarbonize the sector.

Recommendation 3:
When considering adopting a CPI for the power sector, governments should consider different potential regulation points and choose based on the assessment of which stage of the value chain the CPI can most effectively move the sector toward a lower carbon intensity, considering the country's specific circumstances.

Lesson 4:
The structure of power sectors will have a potentially strong and distinct incidence on the effectiveness of different types of CPIs.

Recommendation 4:
When choosing the type of CPI, the structure and the size of the power sector are critical. In the case of a power sectors of limited size or dominated by an oligopoly, an ETS can only be considered if the sectoral scope is extended beyond the power sector to ensure that the number of participants is large enough to deliver the expected benefit of trading. In systems run mostly by a vertically integrated SOE, a carbon price should be accompanied by strong regulatory oversight to ensure that it is reflected effectively in the merit order dispatch.

III. Designing CPIs to ensure effectiveness, minimize undesired impacts, and maximize co-benefits

Lesson 5:
For a CPI applied at a determined point of the value chain to have an impact on the emissions of the sector, it must provide a signal that is strong and predictable enough to influence the decision processes at that point and possibly beyond.

Recommendation 5:
Designing and calibrating the level of CPIs to achieve real reductions must be based on a solid diagnosis of the switching values that can change the outcome of the decisions made at the regulation point and beyond. Driving investments toward low-carbon technology requires decision makers to have an ability to anticipate the evolution of the carbon price over the medium term.

Lesson 6:
Carbon pricing may interact with other policies in the power sector and thus be designed accordingly to prevent reducing its effectiveness or generating negative consequences.

Recommendation 6:
When designing a CPI, it is necessary to investigate and simulate potential interactions with other existing regulations that influence the formation of electricity prices in order to guarantee that the CPI will actually contribute to lowering emissions. It is equally important to embed in it features that address context-specific undesirable effects or inefficiencies and help reconcile the prevailing development objectives with the new decarbonization goal, testing and adjusting as needed.

IV. Political economy challenges and learning curve

Lesson 7:
In systems that are constrained by a lack of generation capacity, a carbon price may lead to higher electricity costs without achieving emission reductions.

Recommendation 7:
In capacity-constrained systems, decarbonization efforts should focus on energy efficiency and future system development, in particular investment in renewable generation and transmission. When the power sector is centrally planned, a shadow carbon price can be introduced into least-cost optimization-based planning and/or caps based on top-down emission reduction targets can be used to constrain the models.

Lesson 8:
A carbon price can be politically challenging to implement, but strategies exist to overcome political hurdles. The design of the recycling of the carbon revenue is an essential part of carbon pricing.

Recommendation 8:
The generation and the recycling of carbon revenues should be part of the design from the early stages. Regular consultations with stakeholders at design, assessment, and successive adjustment stages are critical for correctly anticipating their response, facilitating access to alternatives, building political acceptance, and agreeing on measures to address undesired impacts and deliver development co-benefits.

Three main questions to guide the choice and the design of CPIs for the power sector in LICs and MICs

As this report indicates, optimal design of CPIs for LICs and MICs is still evolving. The diversity of contexts in which CPIs would be applied in these countries, along with limited experience in implementing an ETS or a carbon tax in their power sectors, complicates the creation of prescriptive guidelines for selecting and designing a CPI to support decarbonizing the electricity services crucial for social and economic development. While some regulation points and design options have already been tested, others remain underexplored despite showing promise for addressing the specific needs and circumstances of these countries.

Despite these unknowns, the report offers preliminary and simple guidance to help countries navigate the decision-making process around designing the carbon pricing instrument suitable for decarbonizing their power sector and addressing global GHG emissions. This guidance is framed around three broad questions, encouraging policy makers and practitioners in each LIC and MIC country to reflect on their unique circumstances and develop tailored responses to these questions.

Question 1:

When introduced in the power sector, would the carbon pricing instrument need to cover other sectors as well?

The answer to this question has significant consequences, influencing the range of potential regulation points and determining where emission reductions occur and who bears the costs.

If other sectors (besides the power sector) are included, then upstream (on fuels used in thermal plants) and downstream (on consumers) regulation points are natural candidates for a unified CPI that covers both the power sector and other sectors. Conversely, if only the power sector is considered, applying a CPI upstream only on fuels consumed by the power sector offers no advantage over applying it at the generation stage. Additionally, applying a CPI only to electricity consumption, without covering other forms of energy consumed, could create perverse incentive to shift from electricity to more carbon-intensive fuels. Thus, in the latter case, "internal" points such as generation, dispatch, and distribution stages might be the preferred choices.

In the case of an ETS, if an ETS covers multiple sectors, power entities in the ETS could buy allowances from other sectors with lower GHG abatement costs or sell allowances if emission reductions are cheaper within the power sector. This flexibility could lead to a different distribution of actual emissions reductions, financial flows (in investment and in payments), and decommissioning of emitting facilities compared to an ETS applied solely to the power sector with a similar emissions target.

Question 2:

Considering the circumstances of the country's power sector (such as energy mix, challenges, power sector structure), who are the stakeholders along the value chain that can respond most effectively to a carbon pricing instrument?

If the energy mix is diversified with various technologies, an ETS or a carbon tax applied at the generation stage can lead to significant emissions reductions, by influencing investment decisions, improving plant efficiency, or altering the merit order.

However, in a hydro-dominated system reliant on flexible thermal during the dry season, a CPI at the generation stage may only achieve modest efficiency gains and increase the cost of electricity without changing the merit order.[5]

Similarly, in a coal-dominated system experiencing load-shedding, a CPI at the generation stage might not lead to substantial quantity responses, but could encourage the purchase of offsets if allowed. Downstream responses may be limited by compensation mechanisms or rate regulations aimed at preventing politically unacceptable price increases, especially when the quality of service is poor.

Nonetheless, in such configurations, stakeholders at the distribution or consumption stages might have options to respond, especially in coal-dominated systems, such as signing bilateral contracts with renewable energy independent power producers, which can be crucial for project financing, or investing in energy efficiency, storage, or demand management. Addressing this question helps identify the most effective regulation points along the value chain for implementing an effective CPI.

5 It might have a longer-term impact on investment on pumped or battery storage, but only to the extent that the proper capacity mechanism allows.

Question 3:

What side effects can result from the interaction of an ETS or a carbon tax applied at a given stage of the value chain with the existing sector regulations and other policy instruments? How can these interactions be addressed to ensure consistency with other policies?

Investigating this question is crucial as it allows policy makers to anticipate potential conflicts with other policies aimed at addressing specific challenges faced by LICs and MICs, such as ensuring affordable access to electricity for low-income users. The significance of these side effects can vary greatly depending on the specific circumstances of the country. For example, in a coal-dominated system with a CPI at the generation stage, the resulting electricity price increase would primarily generate revenue for the government, which could be used for compensatory measures. In contrast, in a hydro-dominated system, it would mostly boost the revenue of the hydropower plants.[6]

Side effects may also arise from interactions with other policy instruments, such as feed-in tariffs, renewable energy portfolios, green certificates, programs to decommission old polluting plants, energy efficiency certificates, and demand response mechanisms. If not properly considered, these interactions can diminish the CPI's effectiveness, such as by driving allowance prices close to zero in an ETS.

The answer to this question is essential for deciding what kind of CPI to implement, as well as its design and calibration (i.e., the level of carbon tax, the ambition of the caps, etc.). It also informs how to allocate carbon revenues and design the appropriate recycling mechanisms to align new decarbonization goals with existing policies addressing other development challenges. Elements to address this question are present in different parts of the report, in particular in the fifth section, on how to design a CPI to ensure effectiveness, minimize undesired impacts, and maximize co-benefits.

6 In a merit order–based dispatch, all generators usually receive the clearing price defined by the cost of the marginal plant. When adding a carbon tax, the clearing price is increased when the marginal plan is a flexible thermal plant, which is frequently the case. In a coal-dominated system, the increase of the revenue received by the coal plant corresponds roughly to the carbon tax, which is also paid by the coal plant thus collected by the government. In a hydro-dominated system, the increase of the revenue received by the hydropower plants resulting from the increase of the clearing price is not collected by the government because hydropower is zero carbon and thus does not pay any carbon tax. For a more detailed discussion, see "Impact on the inframarginal rent received by the dispatched generators in the spot market" in Section 3.3.2 and Figure 6.1, "Infra-marginal rent and revenue collection from carbon tax in the case of hydro-dominated and coal-dominated systems."

1. Introduction

1.1 Impetus for this report

There is an urgent need for action. Demand for electricity in low- and middle-income countries (LICs and MICs) is rapidly growing. If they are to meet the challenge of serving this demand and providing the electricity needed for socioeconomic development, they must increase power generation.[7] If this is to occur without making it impossible for the world to meet its objective codified in the Paris Agreement on Climate Change, countries must rely on low-carbon power.

Electricity is the lynchpin of meeting the Paris Agreement. The Paris Agreement is aimed at limiting the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. In 2023, at the 28th Conference of the Parties (COP28), the world agreed to transition away from fossil fuels, the main driver of climate change. Moreover, 130 countries endorsed a global pledge on renewables and energy efficiency, which set targets to triple installed global capacity of renewable electricity and double the rate of energy efficiency improvements by 2030 compared to 2023.[8] Electricity generation is the largest source of energy-related greenhouse gas (GHG) emissions worldwide (IEA, 2021e). The global power sector's strong dependence on fossil fuels has made it the single largest source of CO_2 emissions, contributing 42% of global emissions (IEA, 2023g). As well, most projected low-carbon development pathways rely on electricity as the major source of power. Several cost-competitive technologies—including hydropower, wind, solar photovalic (PV), nuclear power, electricity storage, and smart grids—now offer alternatives to fossil fuel generation. As a result, low-carbon development pathways tend to include both the rapid decarbonization of electricity supply and mass electrification of energy services, a step that would increase electricity demand even further (Fay et al., 2015).[9]

LICs and MICs play an increasing role in emissions. Historically, high-income countries (HICs) produced most energy-related GHG emissions, but the landscape is rapidly changing. Following a model set by several HICs, LICs and MICs have built significant fossil fuel generation capacity to meet growing electricity demand, which has increased the absolute emissions of the power sector (World Bank, 2022e). While some LICs and MICs rely primarily on hydropower and therefore their power sectors make minimal contributions to GHGs, others are on the list of the world's biggest emitters in absolute terms.

A growing number of developing countries have announced commitments to carbon neutrality by mid-century. These countries are considering a range of policies to decarbonize their power sectors. Their aim is to promote the uptake of low-carbon electricity, increase energy efficiency, and phase down fossil fuels. To achieve these goals, reform to existing policy instruments as well as new instruments, including standards, quotas, pricing, fiscal and subsidy instruments, as well as financing mechanisms and public programs to support energy efficiency, technological innovation, and compensation for early retirement of carbon intensive assets may be necessary.[10]

7 Low- and middle-income countries (LICs and MICs) are defined by the World Bank as countries that have gross national income per capita below USD 13,845 per year (in Fiscal Year 24) (Hamadeh, Van Rompaey, & Metreau, 2023).

8 Renewable energy goal is to "triple the world's installed renewable energy generation capacity to at least 11,000 GW by 2030." Energy efficiency goal is to "double the global average annual rate of energy efficiency improvements from around 2% to over 4% every year until 2030" (COP28, 2023).

9 According to Fay et al. (2015), low-carbon development pathways require action on four pillars of a zero-carbon strategy: (i) decarbonization of electricity, (ii) massive electrification and a switch to cleaner fuels, (iii) improved efficiency and reduced waste in all sectors, and (iv) improved carbon sinks such as plants and soils.

10 A more detailed indicative list of the range of possible decarbonization policy instruments can be found in the theory of change (Figure 1.1).

The number of LICs and MICs embracing carbon pricing instruments (CPIs) is also growing. Part of a wider package of policies supporting a transition to a low-carbon electricity system, CPIs are in varying stages of being considered, designed, or implemented in these countries. CPIs such as carbon taxes and emissions trading systems (ETSs) are intended to create an economic disincentive to GHG-emitting activities, in particular production and use of fossil fuel–based energy, making lower-carbon options more competitive than fossil fuel technologies (see the theory of change in Section 1.2). To date most CPIs have been implemented in HICs, which tend to have different types and severity of challenges in adopting CPIs as well as having power systems that are structurally different from those in LICs and MICs.[11] There is limited global experience and research examining the functioning and effectiveness of carbon pricing in LICs and MICs.

This report offers needed information for policy makers, practitioners, and related stakeholders. It draws on the range of work related to carbon pricing in the power sector undertaken through the World Bank Partnership for Market Readiness (PMR) and Partnership for Market Implementation (PMI) programs, a previous report,[12] existing literature, expert interviews, and case studies. Box 1.1 describes the PMR and PMI work. This report was written primarily for energy policy makers, practitioners, and related stakeholders in LICs and MICs. For this audience the report identifies lessons emerging from burgeoning experiences in low- to medium-income countries about the role a CPI can play in the electric power sector. At the same time, the report is relevant to policy makers working on wider climate and socioeconomic policies. Policy makers and practitioners should use this report to identify factors to consider when designing and implementing CPIs, particularly in relation to the objectives they aim to achieve by adopting a carbon tax or ETS, the specific decarbonization challenges they face, and structure of their domestic power sector.

11 For example, some challenges to low-emissions electric power sector development in LICs and MICs include continuous growth in electricity demand and insufficient supply, lack of affordable financing, constraints in transmission and distribution, lack of cost-reflective tariffs, and historical cost-effectiveness of fossil fuel-based power generation. In many LICs and MICs, these challenges have contributed to a strong legacy of fossil fuel-based generation assets and thus a fossil fuel-dominant power mix.

12 "Reconciling Carbon Pricing and Energy Policies in Developing Countries – Integrating Policies for a Clean Energy Transition." PMR report, The World Bank, de Gouvello, C., Finon, F., Guigon, P., 226 p.

BOX 1.1

Partnership for Market Readiness and Partnership for Market Implementation[12]

Convened by the World Bank, the PMR supported emerging economies and developing countries with their readiness to assess and design CPIs to facilitate the reduction of emissions from 2011 to 2021. The PMR provided funding and technical assistance to 23 countries. For example, work in China focused on the inclusion of the electricity sector of the national ETS. PMR work in Chile and South Africa focused on the design of a carbon tax. Argentina and Thailand country programs included work to support RE uptake through certificate schemes, while Türkiye piloted a monitoring, reporting, and verification (MRV) system in the electricity sector through PMR.

The PMI, launched at COP25 Madrid, is the successor program of the PMR and aims to assist countries mainly to implement carbon pricing instruments aligned with their development priorities. The PMI participant countries are presently Bangladesh, Botswana, Chile, China, Colombia, Guinea, Indonesia, Kazakhstan, Malaysia, Mexico, Montenegro, Pakistan, Panama, Senegal, Türkiye, Ukraine, and Viet Nam (PMR, 2021). Currently, the PMI implementation support is provided for ETS implementation in Colombia, Mexico, and Türkiye. The program is helping in expansion of the ETS and just transition actions in Indonesia; implementation and sophistication of the CPI mix and articulation of just transition with carbon pricing instruments in Chile; strengthening and expansion of the ETS in Kazakhstan; broadening and deepening of the ETS in China; and implementation of a pilot crediting program in Viet Nam.

This report is structured as follows. This introductory chapter describes the scope of the study, which is framed around a theory of change, literature gaps that the report aims to address, and the methodology used. The rest of **Chapter 1** presents the scope and methodology of the report. **Chapter 2** provides an outline of the key features, priorities, and trends of power sectors in LICs and MICs and policy instruments that can be used for low-emissions electric power sector development. Next, **Chapter 3** introduces CPIs as one category among several policy instruments that governments can mobilize to regulate GHG emissions. It explores the design of CPIs and their regulation point and potential roles in the power sector in LICs and MICs, building on the work done or underway in PMI member countries to which this report intends to contribute. An assessment of the potential impacts of pricing carbon in different power sector contexts follows in **Chapter 4**, focusing on a shift toward lower-carbon supply mixes, influencing dispatch in favor of lower carbon plants, a shift toward less carbon-intensive wholesale electricity purchase, a shift in consumption patterns, and an intake of new government revenues. (All of these elements are mapped in the theory of change.) The report concludes, in **Chapter 5**, with a set of lessons learned and recommendations that LICs and MICs considering or designing carbon prices can use to make their CPIs more successful.

13 Partnership for Market Implementation website: https://pmiclimate.org/

1.2 Scope of report and theory of change

Carbon pricing lowers emissions by affecting the incentives of power sector agents. These agents are responsible for a series of investment and consumption decisions made along the value chain of the power sector that determine GHG emissions of the power sector. In the absence of carbon pricing, these agents respond to a range of incentives that result from the market and fiscal regulations that apply at each of these stages of the value chain.

There are two types of carbon prices, direct and indirect. Indirect carbon pricing instruments, such as fuel excise taxes, are not usually implemented to achieve climate outcomes and the incentives to reduce GHG emissions they create are not directly proportional to the relative emissions associated with the activities impacted by these policies (World Bank, 2024b, p. 52; see also World Bank, 2023f; World Bank, 2022g). Direct carbon pricing instruments apply a price incentive proportional to the GHG emissions generated by a given product or activity. These include carbon taxes, ETSs, shadow carbon prices, and carbon crediting mechanisms. Shadow prices are applied to power system planning and dispatch without directly adding cost to the sector.[14] Relatedly, carbon crediting mechanisms can provide measurable and verifiable emission reductions from certified projects, for example by providing additional income to low-carbon electricity generators for their role in reducing GHG emissions that would have been emitted in their absence. Carbon taxes and ETSs, which are the most common forms of direct CPIs implemented in the world today, are the focus of this report.

This report offers insights about the potential impact of carbon taxes and ETS in LICs and MICs. Specifically, it examines the impacts of carbon taxes and ETSs along different parts of the power sector value chain in LICs and MICs and factors that policy makers should consider when designing such instruments. The complexity of power sector value chains, markets, and regulatory environments can generate confounding incentives, rules, and constraints that condition behaviors and investment decisions of stakeholders. These factors can make it difficult to determine the impact of an existing CPI or to forecast the impact of a future CPI. To address this need, this study disentangles the various factors, offering important considerations for LICs and MICs when adopting and designing a carbon tax or an ETS.

The theory of change suggests how CPIs can drive GHG reduction. The theory of change constructed for this study is shown in Figure 1.1. The research reported here tests this theory of change across multiple LICs and MICs, thereby illuminating the role of carbon pricing in the wider transition to a more sustainable world.

1.2.1 Energy policy objectives for power sectors in low- and middle-income countries

CPIs are implemented in the context of other, vital objectives. LICs and MICs pursue development priorities and objectives in their power sectors as well as decarbonization. Decarbonizing the power sector in LICs and MICs therefore requires integrating other objectives and thus designing policy regulations and instruments, including CPIs, that can maximize synergies while mitigating potential conflicts (de Gouvello, Finon, & Guigon, 2020). The theory of change lists such objectives in the left-hand box. They are described in more detail in the following paragraphs.

14 For example, governments can incorporate an estimate of the social cost of carbon into least-cost supply models that inform planning decisions. A shadow carbon price does not introduce a direct carbon cost to the sector; however, the effect may be that an option is chosen that is more costly in the absence of the carbon price. Companies can also apply a social cost of carbon to internal decisions, called internal carbon pricing.

FIGURE 1.1

Theory of change on the role of carbon pricing in the power sector in low- and middle-income countries

Energy policies objectives for LICs and MICs

- **Universal access:** ensure universal access to efficient and clean energy services (SDG7)
- **Affordability and competitiveness:** ensure that energy is affordable for low/middle income households and supports competitiveness of industry
- **Energy security:** ensure that energy supply is reliable (including resilience to climate change), matches the demand with anticipation and mitigates exposure to dependency and crisis
- **Local environment and health protection:** mitigate negative externalities of energy supply and consumption on local environment and health (via air pollution)
- **Climate change mitigation:** reduce contribution to increase of GHG concentrations in the atmosphere

Key policy instruments to address corresponding challenges with implications for decarbonization

Command & control instruments: includes energy efficiency standards, emissions standards, mandates and targets, power plant decommissioning programs, etc. 1

Carbon Pricing:

- Fossil fuel subsidy reforms to reduce "negative" carbon price
- Indirect carbon price via fuel taxes (e.g. fuel excise duty)
- Carbon crediting mechanisms
- Direct carbon pricing (carbon tax or similar, emissions trading system) 2
- Shadow price or forecast direct carbon price in power sector system planning & operations

Other pricing instruments: includes PPAs, Bilateral contracts, Feed in Tariffs, Auctions, trading mechanism for wholesale markets, price ceilings, bands and floors, tariff design including ToU, compensation for Demand Response, other beyond the meter resources, etc.

Other fiscal instruments: includes taxes, subsidies, levies, and feebates

Other quantity instruments: includes Power Generation Rights, Energy Savings & Green Certificates, Renewable Energy Portfolio Standards

Targeted financing instruments: financing mechanisms to develop the energy generation facilities and infrastructure, green funds and guarantee funds whenever relevant, etc.

Public programs to support just transition: include public funded R&D programs and pilots, and other enabling components (i.e., capacity building, MRV,..) as well as schemes to protect workers vulnerable to job losses and support for transitioning out of fossil fuel for regions which local economy is highly dependent on the production and local use of such resources.

Intermediate outcomes from effective carbon pricing in power

Response to carbon price incentive

- Shift toward lower-carbon generation mixes through decisions on investments and retirements of power sector assets, and improved energy efficiency and fuel adjustments in existing power plants 3
- Shift of dispatch towards lower-emissions power generation sources by changing merit order and accompanying flexibility resources 4
- Shift toward less carbon intensive wholesale electricity purchases by ditributors, retailers and/or large customers
- Shift towards less carbon intensive electricity consumption patterns by changing time of consumption, improving efficiency or behind the meter renewables 5

New government revenue

New revenue from tax or auctions of emissions allowances used for environmental and social objectives, facilitate response to carbon price signal and/or reduce reliance on other (less efficient) revenue sources 6

Development outcomes from effective power decarbonization

- Global public good of avoided or reduced GHG emissions
- Delivery of affordable and clean energy services
- Health benefits from less air pollution
- Fiscal revenue optimization
- Low-carbon power support decarbonizing economy through electrification of transport, buildings, industry
- Potential energy security and balance of trade benefits (if reduced reliance on imported fuel) 7
- Technology innovation 8
- Macroeconomic benefits

Critical assumptions:

1. Complementary actions selected are pursued in an appropriate sequence or in parallel to form a virtuous cycle that increases political appetite for enhanced ambition over time (World Bank, 2023c).
2. Interactions of carbon pricing with other policies are well managed, and the carbon price is strong and predictable enough to influence decision-making.
3. Carbon price is factored into the decisions around investments in new generation and retirement of existing power plants (explicit assumption for government agencies).
4. Electricity system is designed so that a direct carbon price is fully reflected in the "price offer" or "on-grid" tariff of a generator in the dispatch mechanism. Dispatch mechanism operates based on merit order.
5. Carbon cost is passed through to retail prices. The elasticity of demand determines the responsiveness of consumers to price signals.
6. Carbon pricing provides revenues to the government, which can be used to reduce more inefficient taxes.
7. Energy security can be improved by relying more on domestic sources of energy.
8. Technological innovation, such as the adoption of new storage technologies, is required to operate a future net-zero electricity system with high shares of variable renewable energy sources.

First, most LICs and MICs have not yet achieved universal and affordable access to electricity. The Sustainable Development Goals (SDGs) reflect this objective in that SDG #7 calls for "universal access to affordable, reliable, sustainable, and modern energy services" and SDG #1: eliminate poverty; SDG #4: quality education; SDG #8: decent work and economic growth; SDG #9: industry, innovation, and infrastructure; and SDG #11: sustainable cities and communities all rely on an expansion of the electric power sector (IEA, IRENA, UNSD, World Bank, WHO, 2022). LICs and MICs need to continue to invest in expanding the grid or providing off-grid solutions to serve populations and activities located in peri-urban and rural areas. For the power sector to provide a platform for economic and social inclusion, it must provide universal access to electricity that is affordable to all population tiers (Foster & Anshul, 2020). In Sub-Saharan Africa, about 74% of the population[15] could not afford an extended bundle of energy services (IEA, 2022b), the level required for a refrigerator,[16] which can make new investments into the power sector difficult to finance and operate sustainably.

Second, many LICs and MICs struggle with security of supply. That is, electricity generation is not consistently adequate to cover system demand or delivered at the voltage and frequency (typically 50 or 60 hertz [Hz]) that will prevent damage to electrical equipment. Security of supply has three major components:

- **Energy security:** Countries must secure a long-term supply of primary energy. Those that do not may experience higher prices and volatility and may even have to ration electricity as a result. Some countries rely heavily on imported fuels, which represents a threat to security even if the suppliers are political allies (Glachant, Joskow, & Pollitt, 2021, pp. 66-67).
- **Generation adequacy:** Sufficient firm generation capacity must be installed to ensure peak demand can be met to sustain economic growth; blackouts, even planned and rolling ones, represent a threat to growth and well-being (Glachant, Joskow, & Pollitt, 2021, p. 67).[17]
- **System reliability:** The system operator must be able to act in real time to balance the system and ensure frequency stability in cases of a sudden increase or decrease in demand or a sudden loss of generation. Deviating from the acceptable frequency levels will automatically trigger an "uncontrolled blackout or system collapse" (Glachant, Joskow, & Pollitt, 2021, pp. 67-68).

Natural and geopolitical shocks are imperiling energy security, generation adequacy, and system reliability. Examples of these disruptions are:

- natural threats such as storms, floods, droughts, etc.;
- technological threats such as unpredicted equipment and infrastructure failures;
- human-caused threats such as accidents, but also terrorism, conflict, and cyberattacks; and
- disruptions to clean energy supply chains; for example, of critical minerals.

Building electricity systems' resilience to these risks is key to ensuring energy security and reliable services. Power sector resilience can be defined by "the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to and recover rapidly from disruptions to the power sector through adaptable and holistic planning and technical solutions" (National Renewable Energy Laboratory, 2019).

15 An essential bundle of energy services includes four lightbulbs operating for four hours per day, a television for two hours per day, and a fan for three hours per day.

16 An extended bundle includes four lightbulbs operating for four hours per day, a fan for six hours per day, a radio or television for four hours per day, and a refrigerator.

17 It is known whether there is sufficient capacity to meet demand, and rolling blackouts can therefore be planned ahead, with which end users will be affected agreed ex ante. Countries usually set an acceptable average number of hours of rolling blackouts (see Chapter 3 of Glachant, Joskow, & Pollitt, 2021).

Financial viability is a crucial foundation for such resilience. Yet failures of markets and governments can put such financial viability out of reach. Underlying these challenges, LICs' and MICs' power sectors frequently face failures of markets and governments. Political influence in tariff setting combined with inefficiencies in delivery and revenue collection has, in some cases, meant that power sector utilities did not recover their costs, which undermined the financial viability of LICs' and MICs' power systems (Kapika & Eberhard, 2013). Thus power sector agents had difficulty recovering their investment and operating costs, which means they may not be able to continue to operate and maintain their assets or ensure that any new assets they need are attractive to investors. To achieve financial viability of the sector, regulated wholesale and retail tariffs must be set such that tariffs are cost reflective, but this is not the case in some LICs and MICs (Trimble, Masami, Arroyo, & Mohammadzadeh, 2016). This challenge is often exacerbated by high costs of capital in LICs and MICs, which can be between two and three times higher in emerging and developing economies than in advanced economies (IEA, 2023). Certain utilities, as a result, run large deficits that limit their own balance sheets and creditworthiness as well as their service and security of supply. (Trimble, Masami, Arroyo, & Mohammadzadeh, 2016; Kapika & Eberhard, 2013). They can also discourage new investments due to the risk that the asset will not receive the required return on investment over its operational life and can also increase the risk-adjusted rate of return required by investors. A lack of credible off-takers and counterparties for power purchase agreements (PPAs) have weakened the investment climate for new infrastructure in many LICs and MICs (Eberhard, Gratwick, Morella, & Antmann, 2016).

Mitigating climate change while protecting the local environment and public health, principally by reducing air pollution and GHG emissions from fossil fuel generation, represents an additional challenge. In general, the global power sector has a strong dependence on fossil fuels and thus has become the single largest source of CO_2 emissions, contributing 42% of global emissions (IEA, 2023). Historically, most energy-related GHG emissions have been produced in high-income nations, but the landscape is rapidly changing. Following a model set by several high-income countries, significant fossil fuel generation capacity has been built in LICs and MICs to meet growing electricity demand, which has increased the absolute emissions of the power sector (World Bank, 2022a). While some LICs and MICs contribute little to GHGs, in some cases because they rely primarily on hydropower generation, rapidly growing LICs and MICs have now joined the list of the world's biggest emitters in absolute terms.

While instruments designed to support decarbonization of the power sector are the focus of this report, the sector also has other non-GHG-related environmental impacts that contribute to overall environmental sustainability, and that may also be subject to national policies or political priorities. Beyond carbon emissions, the burning of fossil fuels also releases non-GHG pollutants such as NO_x, SO_2, $PM_{2.5}$, and PM_{10}. These pollutants can cause damage to human health (a particular issue in rapidly urbanizing LICs and MICs) and harm to the environment and ecosystems. Non-fossil fuel generation technologies have their own challenges. For example, the building and operation of hydropower plants can have impacts on the ecosystem and biodiversity around the hydropower plant, including fish and other species living and depending on the water source. Meanwhile, nuclear power plants must store the radioactive residue to protect humans and wildlife from radioactive exposure and damage.

1.2.2 The need for new policy instruments to achieve the new decarbonization goals in the power sector

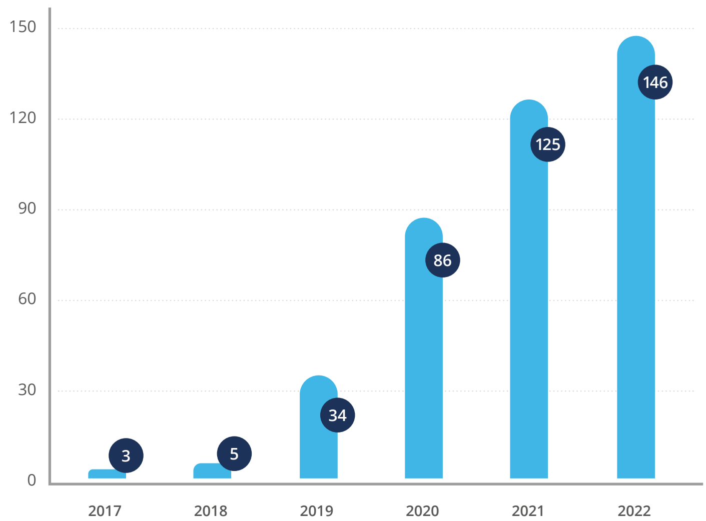
Most governments of LICs and MICs have now acknowledged the need to move toward carbon neutrality. Most governments endorsed the global pledge to triple installed global capacity of renewable electricity by 2030. As illustrated in Figure 1.2, between mid-2019 and 2022, the number of countries that had announced some type of commitment to carbon neutrality by 2070 increased from five to over 140, and the portion of the global economy covered by net zero targets has expanded almost sixfold to 91% (Net Zero Tracker, 2023). These new commitments translate into adding decarbonization as a new policy objective besides the former ones that have driven the energy policies in LICs and MICs to date.

Many governments are taking action in line with their commitments. Most have also developed long-term mitigation strategies and submitted Nationally Determined Contributions to the United Nations Framework Convention on Climate Change with political commitments to deploy RE. They are incorporating these commitments and targets into power sector plans and the underlying policies to extend finance and procure low-carbon generation capacity, mandate energy efficiency improvements, etc. Some governments, in particular in fossil fuel–producing countries, are also implementing "just transition" measures that aim to protect businesses and workers vulnerable to job losses caused by the green energy transition.

Carbon pricing policies can make a valuable contribution to a broad package of green energy policies. Section 2.3 describes this broader package in more detail, and other components are acknowledged in various places in this report. CPIs are no silver bullet. The theory of change lists, in the second box from the left, common policies that affect the emissions of the power sector, situating carbon pricing within a broader package of policy instruments that can be implemented by LICs and MICs to transition to a low-carbon electricity system. The mix of policies governments implement should be tailored to domestic circumstances, priorities, and needs.

FIGURE 1.2

Number of countries that have announced commitments to net-zero / carbon neutrality



Source: *Data sourced from Net Zero Tracker (2023). Note: Sum of the countries for which the announced targets are defined as climate neutral(ity), climate positive, GHG neutral(ity), net zero, zero carbon, zero emissions, carbon negative. Status dates that were blank have been counted in 2022.*

Increasing the cost of electricity generated from fossil fuels is designed to impact the value chain of the power sector. Putting a price on GHG emissions in the power sector through a carbon tax or ETS increases the marginal cost of generating electricity from fossil fuels and/or the cost of using it. The hypothesized impact of this change is illustrated in the center of the theory of change in light blue. In theory, the increased cost both acts as an incentive for energy conservation and low-carbon consumption and makes zero- and lower-carbon technologies more profitable to invest in and operate than fossil fuel technologies. This report focuses on the decision processes that impact emissions along the value chain of the power sector and hypothesizes that a CPI may have four intermediate outcomes directly affecting specific stages of the value chain:

- **A shift toward lower-carbon generation mixes** because it creates price signals that increase investment in lower-carbon generation capacity, retirement of carbon-intensive power plants, and investment in energy efficiency or fuel switching[18] within existing power plants. This outcome is mostly a medium/long-term impact on future emissions.

- **A shift of dispatch toward lower-emissions power generation sources** by increasing the marginal cost of carbon-intensive generation, making it less competitive and shifting the merit order used to ensure that the lowest-cost power plants to meet demand are also less carbon intensive. This outcome has a short-term impact on current emissions and can also influence longer-term investment and retirement decisions.

- **A shift toward less carbon-intensive wholesale electricity purchased by distributers, retailers, and in certain cases by large final customers,** by signing medium- to long-term PPAs and/or signing bilateral contracts directly between wholesale purchasers and electricity producers. This outcome can lead to a short- to long-term impact by increasing market shares of renewable energy and removing some low-carbon capacities from markets and reducing availabilities of fossil fuel generation.

- **A shift toward less carbon-intensive consumption patterns,** in terms of either the quantity or the timing of electricity consumed, in response to price signals. This outcome can lead to both a short-term impact on current emissions by shifting to less carbon-intensive generation hours as well as a longer-term impact by influencing consumers' investment decisions in energy efficiency or behind-the-meter distributed renewable energy and storage.

While not directly affecting the decision processes that impact emissions, a fifth intermediate outcome is also influential enough to be a subject of this report:

- **An intake of new government revenues,** through either carbon tax yields or the proceeds of emission allowance auctions. The outcome in terms of decarbonization of the power sector depends on how these new carbon revenues are recycled in the economy. Such revenues can be used to generate complementary incentives or to enable change to short-term behaviors or long-term investment.

The rationale behind each of these outcomes is discussed in detail in Section 3.

Whether these outcomes are realized in practice will depend on a range of factors. These include market design and regulation of the power sector and the design of the CPI itself. The point of regulation along the value chain and the degree to which costs are passed through that value chain are important. The power sector value chain involves a wide range of stakeholders who are already exposed to a variety of incentives,

18 Such as using biomass at coal generators.

including existing regulatory mandates or restrictions. Moreover, LICs' and MICs' power sectors vary considerably in terms of regulation, structure, private sector participation, and degree of competition (Foster & Anshul, 2020). How a CPI is designed and its interaction with the existing market incentives and regulatory structures in a jurisdiction will have a direct influence on its impact. Section 4 assesses the potential impacts of pricing carbon in different power sector contexts.

1.2.3 Development outcomes from effective power decarbonization

Hypothesized development outcomes of a transition to a low-carbon electricity system are both positive and negative. These outcomes are outlined in the furthest right-hand box of the theory of change. On the one hand, the avoided GHG emissions will contribute to mitigating climate change, the effects of which are disproportionately felt in LICs and MICs. As well, a lower-carbon electricity supply will generate less air pollution, leading to significant health benefits (Hamilton et al., 2021). If the transition leads to an increased reliance on domestic RE resources, rather than imported fuels, it may have energy security and macroeconomic benefits (IRENA, 2016). Furthermore, the increased revenue intake from carbon taxes and ETS auctions could improve optimization of government revenues. On the other hand, pursuing the decarbonization of the power sector may also make the achievement of other development objectives more difficult. Electricity could become more expensive, hindering affordability. Renewable energy is intermittent while fossil-fuel based energy is dispatchable, and low-carbon systems may involve reducing the use of domestic fossil fuels resources and associated economic activities, negatively affecting energy security. Whether these positive and negative development outcomes emerge will be highly context specific and will depend on the ability to design policy instruments, in particular CPIs, that can accommodate policy objectives that are not climate related (de Gouvello, Finon, & Guigon, 2020).

CPIs must be designed to maximize positive outcomes. Given the wide range of confounding factors, it can be difficult to isolate the causal role that a CPI will have in these broader development outcomes. To support this exercise, the theory of change lists a series of assumptions to be fulfilled for the expected intermediate outcomes of carbon pricing to be realized at the bottom. In shedding light on the theory of change and its assumptions, this report provides insights into the enabling conditions required for countries to achieve their desired outcomes from carbon pricing.

1.3 Methodology

This report uses a two-part methodology. Key literature pertaining to different contexts of PMI countries was reviewed, and case studies of select countries across different income levels and contexts were conducted. The case studies are based on a desk review of literature and consultation with various power sector and carbon pricing experts in governments, regulatory bodies and utilities. Details for each of these approaches and how they have informed this report are outlined in the following sections. The overarching goal is to answer the central question, designed to test the hypothesis provided in the theory of change: What role can direct CPIs, specifically carbon taxes and ETSs, play in supporting decarbonization along the different parts of the power sector value chain in LICs and MICs?

1.3.1 Literature review

The documents reviewed were selected based on their relevance to three key topics: pricing issues in the power sector, low-emissions development in the power sector, and carbon pricing in general and as relevant to power sector in both planning and dispatch. Annex A includes a short summary

BOX 1.2

Gaps in the literature

There are gaps in the literature regarding carbon pricing in the power sector in LICs and MICs. The initial literature review analysis suggests that additional research is needed on how carbon pricing specifically can fit into the wider power sector policy landscape in LICs and MICs and how it will impact the wider energy policy objectives of these countries, including security and reliability of supply, affordability, access, and resilience in addition to decarbonization. There is also limited research on carbon pricing's potential role and its impact on different stages of the value chain in the context of "regulated" or hybrid power sector structures. Literature is limited around how tariff setting can be reformed in LICs and MICs to allow for the carbon pricing signal to pass through to consumers without negatively impacting on wider power sector development objectives (e.g., affordability) and how carbon pricing can help shift the investment landscape in LICs and MICs. The role of carbon pricing in incentivizing demand-side efficiency or shifts in the timing of consumption is also not well explored in the literature. Beyond carbon pricing in LICs and MICs, discussions around the broader energy transition in the context of regulated markets is also still quite limited.

and description of the main sources. Based on the literature review undertaken, gaps in the literature were identified with respect to carbon pricing in the power sector in LICs and MICs, presented in Box 1.2.

This report aims to shed light on these gaps with particular emphasis on four topics.

- The mechanisms through which carbon pricing shifts incentives along the value chain in the context of different power sector structures.
- The key preconditions for carbon pricing to have the desired effect in the power sector and how this aligns with the current power sector contexts in LICs and MICs.
- Potential trade-offs with wider power sector objectives, associated policies, and power sector characteristics in LICs and MICs that can constrain the key role literature indicates CPIs can play in driving cost-effective decarbonization.
- How carbon pricing can be designed to fit within a package of instruments that together can contribute to energy sector development objectives (per the theory of change), with trade-offs managed through complementary measures.

1.3.2 Case studies

The four main case studies, China, Colombia, Kazakhstan, and South Africa, capture a range of lessons learned from carbon pricing implementation in the power sector in LICs and MICs. These countries cover a broad range of power sector characteristics common in other LICs and MICs (e.g., state-owned monopoly power utility, high coal reliance, and issues with affordability and security). Two of the countries have carbon taxes and two have ETSs and Colombia has plans to adopt an ETS. (See Table 1.1 for the range of characteristics represented.) These differences allow us to scrutinize the elements that make a CPI successful or not in delivering the five targeted intermediate outcomes in LICs and MICs as well as the interrelation between CPIs and other development goals and other decarbonization policy instruments.

TABLE 1.1

Characteristics of selected case studies

Jurisdiction	Carbon pricing instrument	Elements for which lessons learned from case study are available
China	Implemented ETS with intensity-based caps and technology-specific benchmarks	• Hybrid market model that is still undergoing active reform. • Power sector dominated by coal that is highly linked with national industrial and economic activity. • Power sector capacity overbuilding. • ETS based on intensity caps and technology- specific benchmarks for the power sector.
Colombia	Implemented carbon tax/ planned ETS	• Power sector already dominated by a high share of renewable hydropower (74% in 2021), with smaller shares of gas (15%) and coal (5%). However, the reliance on hydro shifts in drought years, when fossil fuel energy generation increases. • Reflecting pressure from associated industries, coal and natural gas are exempt from the carbon tax (only until 2025 for coal). • Temporary presidential oversight of tariff setting, following a sustained period of increasing tariff prices and inflation. • Considering implementing a dual instrument carbon price with the introduction of the ETS.
Kazakhstan	Implemented ETS	• Coal and gas dominated electricity system. • History of high fossil fuel subsidization. • Wholesale electricity has mostly (90%) been traded through bilateral contracts, which circumvents dispatch decisions based on price signals. A single-buyer model was introduced in 2023. • History of low tariffs in the power sector, which are not cost reflective. • Regulated tariffs that do not allow for carbon cost pass-through in previous phases of the ETS.
South Africa	Implemented carbon tax	• The adoption of a carbon tax in a context of high stakeholder opposition. • Lack of sufficient generation capacity. • High reliance on coal, favored by corporations and associated powerful interest groups. • History of subsidized energy. • Impact of an indebted state-owned monopoly power utility, which is set to be unbundled. • High concerns of the distributional impacts of the carbon tax, with high share of the population living under the line of poverty.

The methodology for the four in-depth case studies (China, Colombia, Kazakhstan, South Africa) included literature and document review as well as interviews. Interviews with local power sector and carbon pricing experts were conducted using semi-structured questionnaires, with questions designed to shed light on the different power sector structures and challenges in the focal countries and interrogate the impact that carbon pricing has had or is expected to have along the power sector value chain. The project team also interviewed World Bank experts and government and industry practitioners in each country. A full description of the methods appears in Annex B.

Additional smaller case studies complement the four in-depth case studies. These were conducted to provide broader insights into different jurisdictions' experiences with carbon pricing. They were based on reviews of secondary literature and served to inform and validate the theory of change (see Table 1.2).

TABLE 1.2

Rationale for smaller case studies

Jurisdiction	Carbon pricing instrument	Elements studied
State of California	Implemented ETS	• A CPI applied to both generators and importers of electricity. • A mechanism for mitigating the impact of carbon pricing on households, especially low-income households. • A method to improve the political acceptance of increasing household electricity bills while still preserving the carbon price.
Chile	Implemented Carbon tax	• The implementation of an ETS alongside a carbon tax as a means to improve the policy effectiveness.
European Union	Implemented ETS	• Interface between carbon market and power market. • The evolution of free allocation to auctioning of emission allowance allocations for the power sector. • The impact that the EU ETS has had on the power sector across member states.
Republic of Korea	Implemented ETS	• The introduction of environmental dispatch to prioritize low-carbon generation. • The observed limited impact of environmental dispatch due to the low cost of carbon seen by carbon-intensive generators.

2.

Electric power and decarbonization in LICs and MICs

The overall purpose of the power sector in any country is supplying reliable electricity at a fair price to consumers to run electrical appliances and machinery. It thus consists of complex infrastructure that actually delivers the electricity: consumers and multiple organizations, each with different sets of interests, policies, markets, and institutional arrangements. The characteristics of these different elements, and their relationships with one another, strongly influence how different kinds of policy instruments including carbon prices can (or cannot) be implemented in the power sector and the impact that they have. Carbon pricing, if appropriately designed, can alter the price signal of electricity through the power sector value chain. Price signals can determine the incentives and cash flows between agents in the sector, and thus influence investment, dispatch, and consumption decisions.

This section introduces the specifics of LICs' and MICs' power sectors and the policy instruments that can be used to decarbonize them.

It begins by setting out the core elements of the power sector value chain and its main stakeholders as well as the highly heterogenous power sector structures that have emerged in LICs and MICs. It then presents the high-level challenges and objectives of power sectors in LICs and MICs. It then delves into the specific objective of decarbonizing the power sector and the specific policies and instruments that are being or could be deployed to achieve that objective, including carbon pricing instruments. Finally, it proposes a synthetical vision of the potential influence of the CPIs in the power sector in LICs and MICs, including an infographic that articulates that influence with the different elements introduced in this chapter.

2.1 Power sector characteristics, value chain, and stakeholders

This section sets out how the power sector can be structured differently using examples from different countries. It will outline the common and diverse characteristics in LICs' and MICs' power sectors to provide context for the type of existing incentives and drivers currently at play. These characteristics strongly influence the effectiveness of carbon pricing in the power sector. For example, if a carbon price is placed at the generation stage, the power sector structure and regulation will determine to what extent the carbon price is passed through in the value chain to end consumers. As discussed in Section 4.3.1, there are many examples where price signals do not pass through as expected based on regulatory interventions and other rigidities. This section will provide context for subsequent discussion on how and where carbon price signals can be applied such that they will flow through the power sector value chain.

2.1.1 The power sector value chain and stakeholders

The power sector value chain is traditionally depicted in a linear fashion. The upstream fuels sector (coal, gas, uranium, etc.) or free inputs (wind, sun, water, etc.) enable electricity generation. Power plants generate electricity. At bulk levels this energy is stepped up in voltage and transferred to the high-voltage transmission grid. The electricity is then transformed down to distribution voltages in substations, where it enters the distribution grid and flows to households and businesses as part of downstream delivery to end consumers. Maintaining the continuous and reliable operation of this system is the responsibility of system and network operators and requires balancing of generation, demand, and power flows to ensure grid parameters such as frequency remain stable.

Technology change has meant that the value chains of a growing number of electricity systems are no longer linear and sequential. Rather, power sector value chains are better characterized as networks of connections with increasing distributed generation, "beyond the meter" resources, and bi-directional flow patterns on transmission and distribution networks (Crofton, Wanless, & Wetzel, 2015). This change of paradigm, illustrated in Figure 2.1, relies largely on digitalization of monitoring and processes and is more advanced in HICs and upper middle-income countries and still at early stage in lower-middle-income countries (LMICs) and LICs.

FIGURE 2.1

Paradigm change in the power sector

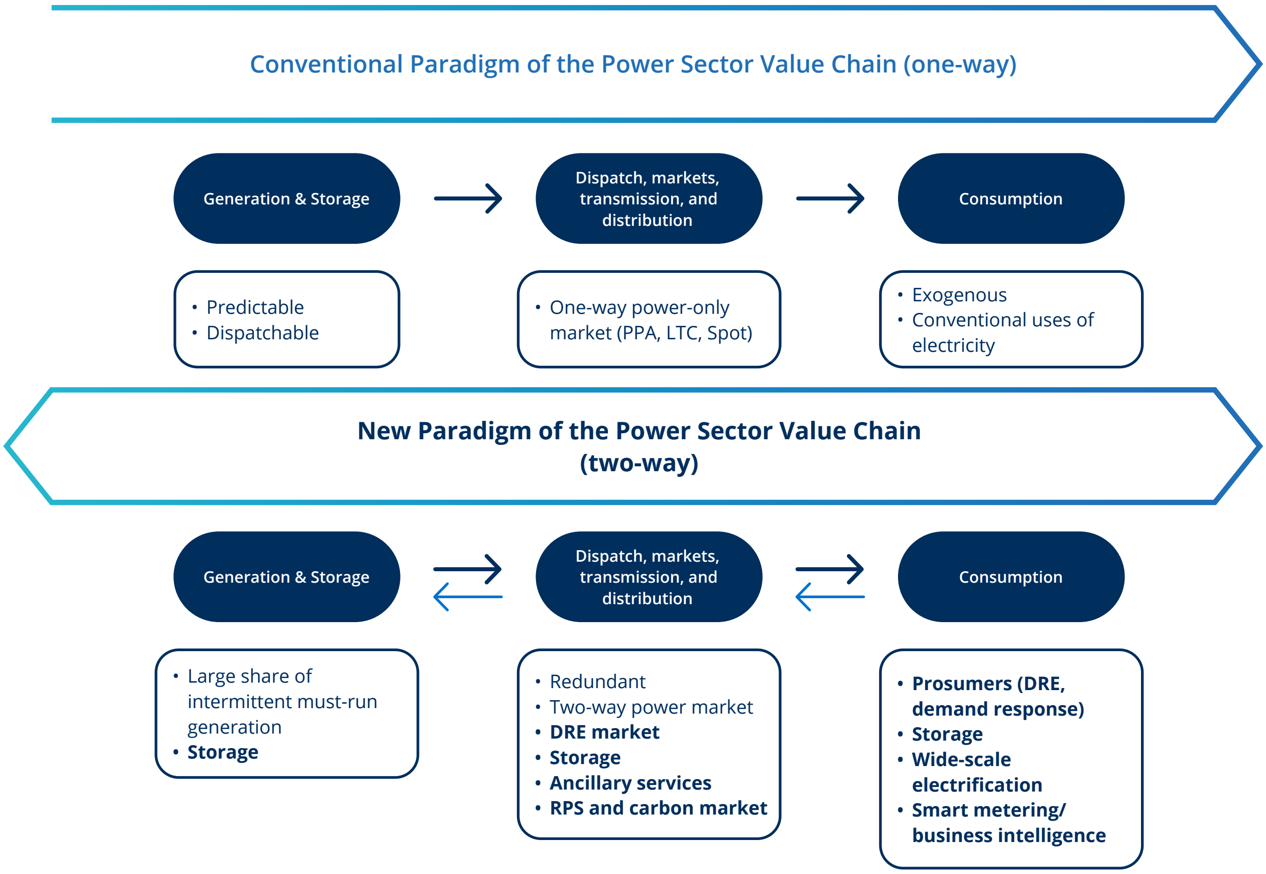
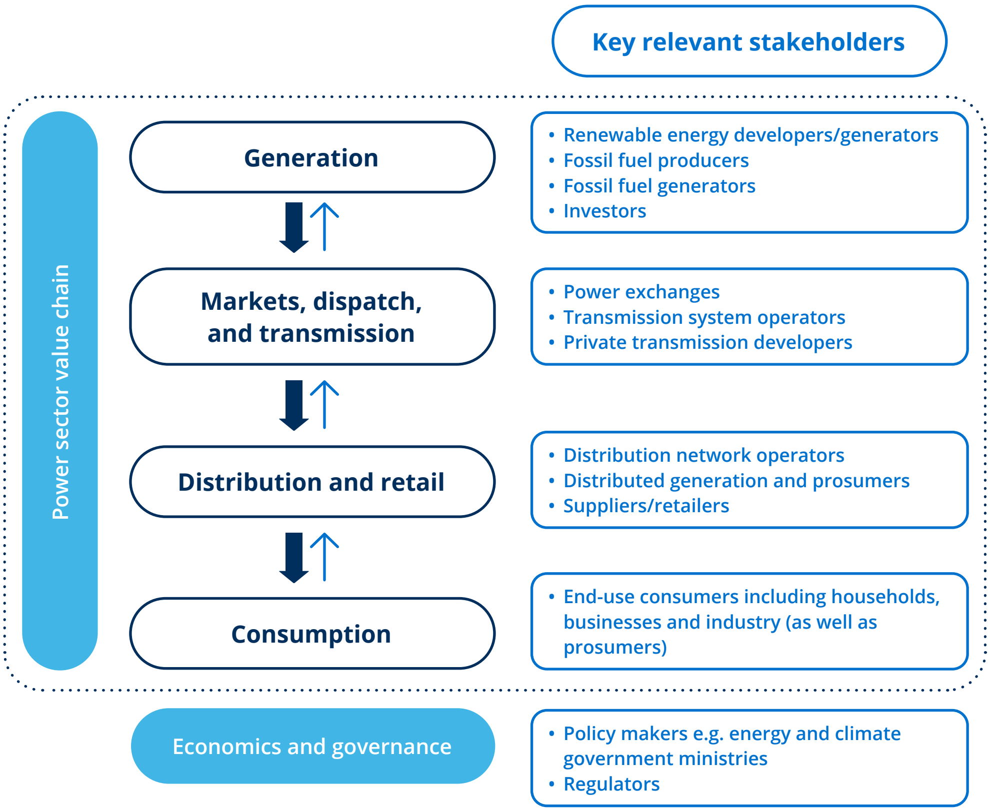


Figure 2.2 provides a simplistic categorization of the value chain and the different stakeholders involved in each category. These stakeholders have their own preexisting "web of incentives" depending on a country's laws and regulations, taxation, and market design. Carbon pricing may have implications for each of these stakeholder types. Abbreviations:
PPA = power purchase agreements;
LTC = long-term contracts;
DRE = distributed renewable energy;
RPS = renewable energy portfolio standards.

Today there is large heterogeneity between countries' power sector structures—the regulatory frameworks, markets, and institutions that govern how the different players in the power sector interact. As presented in the next subsection, a large state-owned utility could own and operate through the whole value chain to deliver electricity to consumers, or the value chain could be covered by a number of different agents that specialize and/or compete to deliver these services. The type of power sector structure can determine how efficiently the sector operates and how specific policy objectives are implemented.

FIGURE 2.2

Simplified electric power sector value chain and stakeholders



2.1.2 Power sector structures

Historical developments produced the current heterogeneity in power structures. After the Second World War, most countries had vertically integrated state-owned public utilities. In the 1980s and the 1990s, many countries liberalized and unbundled the power sector to encourage private sector participation, introducing competition wherever possible to increase efficiency, reduce state subsidies, and attract the private capital needed for the development of their systems. The objective of these reforms was to steer the power sector away from bureaucratic processes with political influence and toward cost-competitive and profit-motivated firms that would have the incentives to innovate based on customer needs, as well as to overcome the limited capacity of the public sector to finance investment.

Structural reforms to the power sector typically consisted of four approaches. These were as follows (Foster & Anshul, 2020):

→ Horizontal and vertical unbundling of state-owned utilities (separation of generation, transmission, and distribution and introducing multiple players in the generation and distribution segments).

→ Private sector participation and in some cases, privatization of state-owned utilities (private firms operating as profit maximizers and cost minimizers).

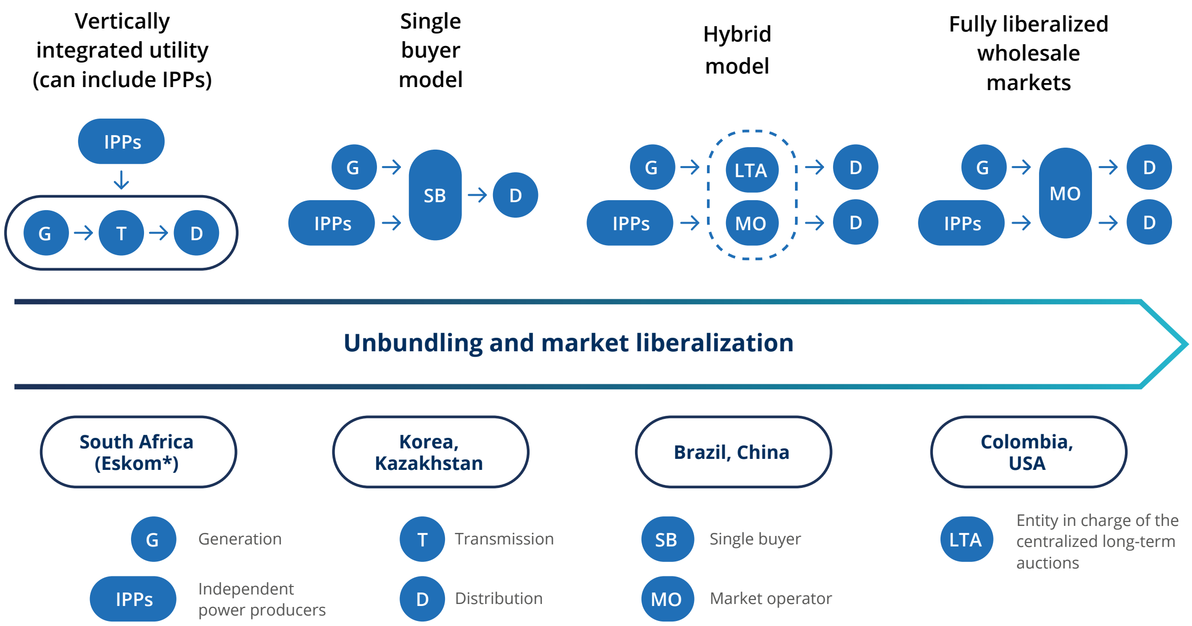
→ An autonomous regulator of a jurisdiction's power sector, independent from political interventions (regulation of service quality and tariffs).

- Liberalized and competitive wholesale and retail power markets (to stimulate efficient competition between generators on the generation side and distributors and retailers on the commercialization side).

The degree to which these reforms were adopted varied significantly across both high-income countries and LICs and MICs. In developing countries, privatization and liberalizations were not as successful as in Organisation for Economic Co-operation and Development (OECD) countries, in part because risk could not always be mitigated enough to attract adequate private investors. In the 2000s, in several developing countries newly implemented market regimes were formed again to create safer and more stable regulatory environments through long-term contracts between new and existing producers and retailers, sometimes awarded through auction-based mechanisms aligned with central planning. Other countries paused the reform and maintained a substantial public sector involvement, for instance through a single-buyer model, alongside private independent power producers (IPPs) (Roques & Finon, 2017). As a result, based on the degree of successive power sector reforms undertaken, countries have ended up with a variety of different power sector structures. As is shown in Figure 2.2 and Figure 2.3, power sector structures can be represented based on their vertical and horizontal integration/unbundling and the level of public or private ownership of the sector. The vertical dimension relates to dividing the different segments of the value chain (generation, transmission, and distribution) into different institutions with different ownerships. The horizontal dimension relates to the degree of competition within a segment—from monopoly power to perfect competition.

FIGURE 2.3

Degrees of market liberalization and unbundling of power sector



• Eskom is in the process of unbundling

Evidence shows there are diverse approaches to achieving desired sector outcomes. Some countries have achieved positive outcomes through implementing the 1990s reform model in full, while other countries have improved their power sector's performance with a combination of a competent state-owned utility and private-sector participation (Foster & Anshul, 2020). The subsections that follow describe a vertically integrated utility, the single-buyer model, and fully liberalized wholesale markets. Hybrid models, which combine elements of the other three, are also briefly introduced.

Vertically integrated utility:

A vertically integrated utility owns and operates the power generation, transmission, and distribution segments as a monopoly and is usually state owned. As its placement at the very left of the spectrum in Figure 2.3 indicates, this is the structure with the least amount of unbundling and market liberalization. This structure provides the utility with more flexibility than any other in how to manage its costs and ultimately the electricity price it charges customersr. However, there is no competition in any of the three segments. A variation of this model is a vertically integrated utility with IPPs. Here, IPPs provide the investment into new generation capacity and sell this to the incumbent utility. IPPs can thus offer privately financed generation assets when a public utility is cash constrained. South Africa's power sector provides an example of this variation (see Box 2.1).

BOX 2.1

South Africa's vertically integrated utility, Eskom

South Africa currently has a state-owned vertically integrated utility, Eskom, which owns and operates the generation, transmission, and distribution segments of the power sector. Eskom's coal power plants produce 80% of electricity generation in South Africa. Independent power producers can build new generation capacity and sign PPAs to sell their electricity to Eskom. Municipalities own 40% of electricity distribution.

The National Energy Regulatory of South Africa (Nersa) regulates the sector and it approves the end-user tariffs. However, the tariffs it approves are overall not cost reflective (not covering all costs of the utility), such that Eskom struggles to recover the full costs of its operation. Consequently, Eskom's coal power plants have been poorly maintained and the electricity system regularly struggles with an inadequate capacity margin such that load shedding and rolling blackouts are common (Hanto et al., 2022).

The Scheduling and Dispatch Rules of the South African Grid Code dictate dispatch procedures. This code stipulates that the system operator should "Schedule and Dispatch generation and demand-side resources to least cost whilst maintaining the prescribed system security" (Nersa, 2015, p. 10). Moreover, because of severe supply constraints, Eskom dispatches all available generators in periods of load shedding.

The government of South Africa has plans to unbundle Eskom, and the transmission segment has already been legally separated into the National Transmission Company of South Africa, a subsidiary of Eskom Holdings. In August 2023, the government gave the go-ahead to unbundle distribution, while the remaining Eskom is expected to only operate in the generation segment of the value chain.

Power sectors dominated by a vertically integrated utility face a number of acute challenges that can limit capacity to invest in new energy projects. Where a vertically integrated utility owns most or all of a jurisdiction's generation capacity, there is no need for a market to trade wholesale electricity. As such, there can be a lack of clear price signals and price formation along the value chain segments of the utility. For example, generators are not directly competing against each other, which can result in higher prices. The vertically integrated utility determines dispatch according to either its own internal guidelines or instructions from the government. The utility sets retail prices, and in many cases a regulator that is independent of the utility or the government approves them, which can distort price signals and make regulatory oversight challenging. To add to this, some literature suggests that state-owned utilities do not have the drive for cost cutting that more competitive markets will incentivize (Foster & Anshul, 2020). If a vertically integrated utility is unable to sustain itself without support from the government, which is the case in several LICs and MICs, they will also have limited capacity to invest in new energy projects.

Without strong regulatory oversight, the utility can in theory operate the electricity system in a way that benefits itself and/or the government. In this case it may be unlikely to invest and innovate in the most efficient and least-cost technologies that will benefit the consumers. The state-owned utility, owning both the generation assets and the transmission lines, could also restrict the access of new IPPs wanting to enter the generation segment by not allowing them to connect to the transmission grid. It can also influence government decisions on subsidies, tariff levels, and investments to benefit itself or special interest groups, rather than the broader population. Governments can also be disincentivized to adopt policies that would result in increases in electricity supply costs, such as carbon pricing, if its state-owned utility is already unable to recover its costs in tariffs and relies on the government for financial support.

Strong regulatory oversight can overcome many of the challenges of vertical integration. An independent regulator is crucial to avoid political influences impacting the market. In 2015, 70% of developing countries had an electricity regulator (Foster & Anshul, 2020). These regulators typically approve the retail price of electricity. But the degree to which the regulation works in practice varies. In several LICs and MICs that have vertically integrated sectors, regulatory oversight has not been adequate.

Single-buyer model:

Under the single-buyer model, the state has majority ownership of the transmission and distribution segments but not the generation assets. There are several generation companies that are usually privately owned, and the transmission and distribution segments are still bundled but separated from generation. Under this model, the generation sector is financially independent and therefore impacted by commodity prices such as gas and coal prices. Kazakhstan provides an example of this model (see Box 2.2). New generation capacity can come from IPPs. The utility's transmission system operator typically becomes the single buyer of electricity from the generation companies and any existing IPPs. Allowing for multiple wholesale *sellers* of electricity is a pre-condition for the functioning of the single-buyer model, but, in the absence of multiple buyers of electricity, there is no competition in the distribution/retail segment. A variation of this model, the modified single buyer, introduces some competition into this segment because IPPs can sell a portion of their electricity directly to certain customers.

The purchasing process is vulnerable to problems. The single buyer purchases electricity competitively based on pre-determined criteria, typically security of supply and least cost. This can be done by auction or by creating a cost-based pool with information on the system's marginal cost published by the single buyer. Auctions can ensure generators are dispatched according to the

BOX 2.2

Kazakhstan's transition to a single-buyer model

Kazakhstan's power sector operated as a wholesale market model with bilateral contracts until 2023. As part of its former power sector reform starting in 1996, Kazakhstan introduced a wholesale market with pool market rules and a merit-order dispatch system based on half-hourly pricing (USAID, 1996). In this centralized market, the Kazakhstan Electricity and Power Market Operator ran online auctions for day-ahead and intra-day trades for generators and energy supply organizations (ESOs). There is also a real-time balancing market and market for system and ancillary services and centralized dispatch managed by the National Dispatch Centre of the System Operator.

Despite the existence of the wholesale spot market, 90% of electricity was typically traded through bilateral agreements between generators and ESOs. These contracts allowed for certainty on price and quantity for both the generator and the consumer, rather than relying on volatile market prices. However, this circumvented the dispatch system based on auctioning and hourly pricing. Thus, generators entered long-term bilateral contracts based on pre-agreed prices rather than market-based hourly auction pricing.

In July 2023, Kazakhstan adopted a single-buyer model. Existing bilateral contracts were terminated, and a priority order was created for purchases by the single buyer. The single buyer first purchases from must-run renewables with PPAs and from generators that operate under inter-governmental agreements. It then purchases from CHP plants. Next, generators with investment agreements for new capacity or refurbishment are prioritized. The remaining power needed can be purchased in the day-ahead spot market based on auctioning. Finally, the single buyer engages in international trades with neighboring countries to address any surpluses or shortages among the interconnected countries.

merit order, subject to security of supply. However, in this model, additional non-financial criteria can also be used to inform purchasing decisions, i.e, fossil fuel industry groups can lobby or otherwise influence the state to purchase their generation over more sustainable options. Ultimately, it is the government's responsibility to ensure that generation companies are paid the amount agreed upon in the PPA, even if the revenue from tariffs is insufficient to recover the costs of supply or demand falls short of forecasts, which buffers customers and electricity distributors from paying the full costs of electricity supply. It also becomes the government's responsibility to enforce payment collection from electricity distributors, which may be difficult from a political standpoint (Lovei, 2000).

Wholesale market model:

The wholesale market model can offer a fully competitive sector. In the wholesale market model, generators compete to sell their electricity generation to eligible large purchasers, including industrial customers and different distribution and retail companies, which purchase electricity on behalf of end consumers. Thus generators are subject to market forces such as commodity prices, and multiple buyers create fully competitive electricity markets. An effective competition requires simultaneous multiple independent sellers and multiple independent buyers. Colombia's power sector provides an example of a fully liberalized wholesale market (see Box 2.3 and Figure 2.3).

BOX 2.3

Colombia’s wholesale market model

Colombia’s electricity sector has been unbundled and liberalized since 1995. Since then, electricity has been traded through long-term bilateral contracts (for eligible large or industrial customers) or through the wholesale spot market. Revenues for generators are primarily secured by entering long-term bilateral contracts rather than trading in the spot market (Mastropietro, Rodilla, Rangel, & Batlle, 2020). Distribution companies buy electricity for their end customers through contracts with generators or in the wholesale market. There is competition between retailers for large electricity customers, but households must use the retailer associated with their local distributor (McRae & Wolak, 2020).

A wholesale market can include myriad transaction modalities. A power sector that enables private sector participation through the establishment of a competitive market, an autonomous regulator, and unbundling of a state-owned utility is expected to de-politicize decision-making on investments[19] while strengthening the regulatory environment and the role of price signals, as well as improving accountability in the market.

Prices can be formed in long-term forward contracts in the futures market, in the spot market (day-ahead and intra-day auctions), and in the real-time (balancing) market. Long-term forward contracts are bilateral contracts, such as PPAs, between generators and distributors/retailers/large customers. Future contracts are standardized financial products sold on a futures exchange. Futures contracts are between buyers and sellers of electricity and can also include traders and financial intermediaries. Buyers or sellers of electricity put down an initial margin requirement[20] to enter the contract. They then pay or receive a fixed price for the purchase or sale of electricity once the electricity is delivered at the future date agreed in the contract. In the spot market, generators and retailers typically submit hourly or half-hourly bids and offers for the electricity they want to buy or sell in the auction markets. When forward and futures markets are involved, market participants can enter contracts that set a price today for future delivery. This provides a hedge against their exposure to future electricity spot prices while ensuring generators have certainty about their sales and retailers have certainty about meeting their customers’ demand in the future. Futures contracts provide liquidity to market participants and allow hedging against wholesale price volatility in the spot market. If there is a sufficient number of generators in the market and sufficient capacity margin in the system, spot price should be competitive.

Under certain conditions, wholesale prices can be capped. With sufficient numbers of buyers and sellers of electricity, the wholesale market model can reduce market power and information biases of agents that operate across the vertical segment. In theory, competition will lead to downward pressures on prices and incentivize innovation and efficiency. However, if there is a limited number of players in the market, a regulator sometimes introduces a wholesale price cap, which prevents

19 This assumes there is sufficient private investment interest and availability in the country’s power sector, otherwise government support such as FiTs and CfDs may be needed.

20 The margin requirement is set by the futures exchange and is typically a fraction of the value of the contract.

generators from increasing their "offers" to uncompetitive levels in times of market distress, for example, where market power opportunities can arise.

Wholesale markets are open to innovations that promote renewable energy. The regulator can establish a **guarantee of origin** or **renewable energy certificate market.** These are certifications for a specific quantity of low-carbon electricity. Through these markets, consumers can pay for a guaranteed amount of low-carbon electricity to cover their demand. In this way customers can provide financial incentive for generators to supply and grow their low-carbon generation capacity.

In addition to the wholesale market, a capacity reserve mechanism may be introduced. In this case firm and flexible generators receive payment per year from the mechanism (i.e., per megawatt [MW]/year) to be available on demand for a limited time when a non-dispatchable resource suddenly becomes unavailable (i.e., due to lack of wind or sun). In addition to addressing the intermittency introduced by renewables, this can provide a revenue stream for generators with low load factors. Capacity auctions can be used to procure this needed capacity, typically a few years in advance, to ensure existing plants are available to operate and new flexible plants have incentives to enter the market. The auctions can be technology specific to incentivize certain technologies, such

BOX 2.4

China's hybrid electricity market model[20]

China's power sector structure is complex and represents a dynamic hybridization of elements from multiple models, ranging from vertically integrated state-owned enterprises (SOEs) to IPPs, centralized competitive auctions, and pilot spot markets.

Most power generation projects are undertaken by a few large SOEs and a wide range of smaller IPP firms, subject to authorization from local governments and total capacity at province level determined by the National Energy Authority (NEA).

Dispatch decisions are coordinated by public grid companies, which are undertaken by provincial, regional, and national dispatch centers. Power producers sell electricity in a dual-track system through (i) market-based mechanisms and (ii) the government, which imposes on-grid tariffs and through plans for each power plant in which there are pre-determined numbers of hours of generation per year.

Previously, China's wholesale pricing system was mostly based on a system of central benchmark on-grid tariffs. Since 2015, bilateral trading and centralized auctions have created a shift toward market-based price discovery. Market-based mechanisms are primarily medium- and long-term contracts, which can be bilaterally negotiated or operated (National Development and Reform Commission [NDRC] & NEA). Until October 2021, these markets had price caps set slightly above the benchmark, which prevented the pass-through of increase into tariffs. In October 2021, NDRC loosened the price cap to 20% above the benchmark level and removed the price limit on energy-intensive industries (NDRC, 2021).

China is currently piloting short-term markets such as day-ahead spot markets. In 2023, the State Council issued a policy signal to accelerate the development of the spot market (State Council, 2023), but progress to date has been limited.

21 For more detail see Annex B.1, China Case Study.

as low-carbon flexible generation capacity (carbon capture, utilization, and storage mechanisms [CCUS], hydrogen, battery storage, pumped hydro storage, etc.).

Hybrid market model:

The hybrid market model has elements of the vertically integrated, single-buyer, and wholesale models. Such models have emerged in many countries, including in LICs and MICs. Box 2.4 provides the example of China's hybrid market model.

2.1.3 Dispatch procedures

System operators determine the final dispatch of generators so that supply and demand on the network continually remain balanced and stable in real time. In the spot market, the system operator can determine dispatch in a centralized dispatch system (common in the US) or market agents can determine dispatch through trades on power exchanges or bilateral contracts in a decentralized self-dispatch system (common in Europe). In a decentralized market, generators owning a portfolio of assets are free to select the combination of plants that will ensure they meet their contractual commitments in the market. In this case, the system operator becomes the "residual system balancer" and takes action in the balancing market to ensure real-time balance between demand and supply. The system operator is also responsible for procuring services such as ancillary services and capacity reserves.

Three dispatch methods exist.

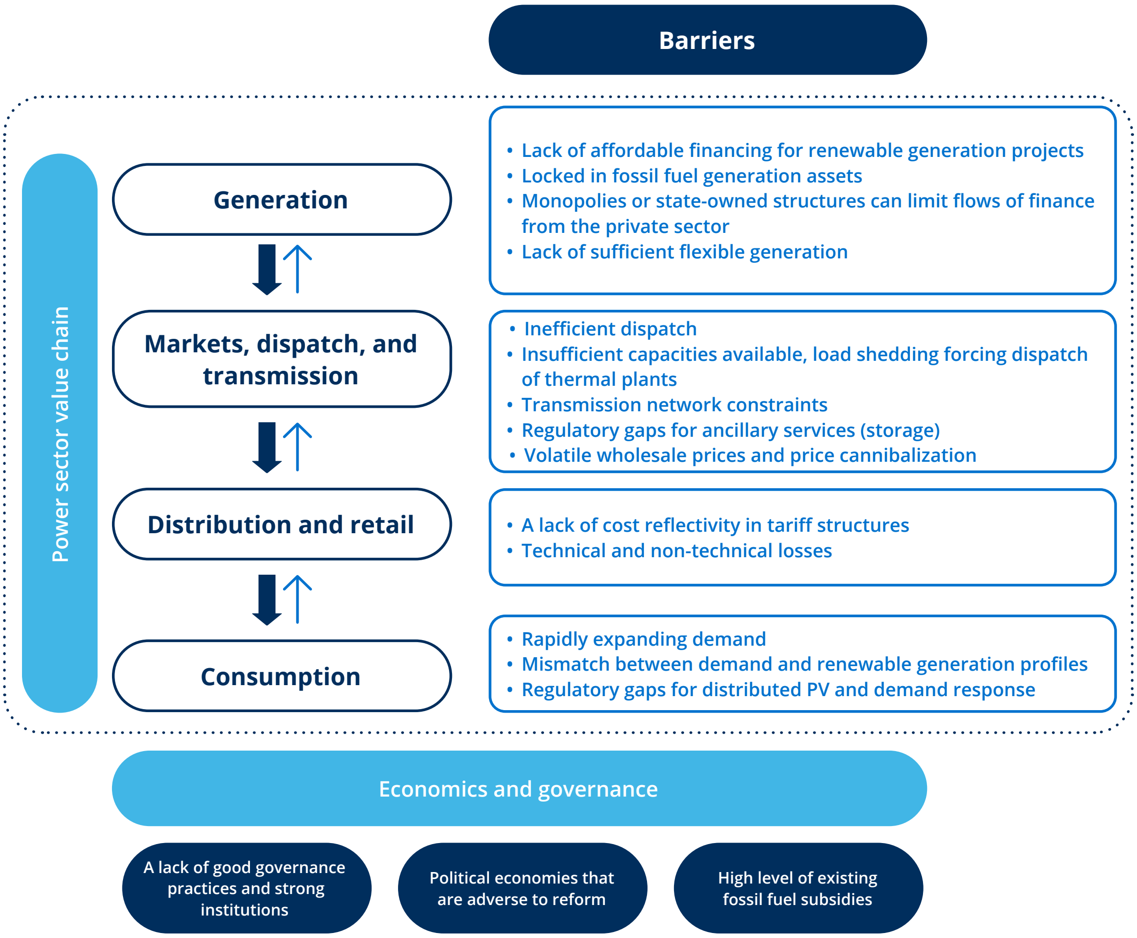
- **In merit order dispatch,** the most common dispatch method, generators are given priority based on their short-run marginal costs of generation.
- **In administrative dispatch,** planning agencies determine dispatch in a regulated electricity production system based on predefined technical, economic, or political factors. This method has been used in China.
- **Environmental dispatch** follows an administrative dispatch approach, but incorporates the ETS allowance cost, such that generators' carbon emissions are factored into the dispatch decisions (see Section 4.2 for further details). This method was introduced in Korea in 2022 (see Box 3.4 in Section 3.2.2)

2.2 Key challenges in LICs' and MICs' power sector decarbonization

LICs' and MICs' specific challenges must be considered when formulating solutions, such as carbon pricing, to address decarbonization in their power sectors. Some challenges are particularly acute in LICs and MICs, where demand may be expanding rapidly, while others, such as network constraints, affect HICs equally. As Rottgers and Anderson (2018) detail in Figure 2.4 and as shown in the following subsections, these challenges can be categorized by where they exist in the power sector value chain: generation and storage, dispatch, distribution, and consumption. An overarching goal of addressing these challenges in decarbonization policy is to ensure that decarbonization solutions do not compromise the ability of LICs and MICs to achieve the policy priorities assigned to their power sector, including universal access, affordability, security of supply, and maintaining financial viability.

FIGURE 2.4

Schematic overview of key issues in LICs' and MICs' power sector structures for decarbonization



2.2.1 Challenges regarding generation and storage

2.2.2.1 Lack of affordable financing for low-carbon generation projects, insufficient installed capacities

Affordable financing is lacking. Substantial investment is required in scaling up the share of low-carbon generation in the energy mix of LICs and MICs. Renewable power plants tend to have higher up-front capital costs than thermal power plants but benefit from lower operating costs (IEA, 2023). Therefore, the availability and affordability of financing is central to their economic attractiveness and the ability of LICs and MICs to make capital investment in low-carbon electricity infrastructure. However, as mentioned in Section 1.2.1, the cost of capital can be between two and three times higher in emerging and developing economies than in advanced economies (IEA, 2023), such that it can cost over 30% more to decarbonize the power systems in these countries (World Bank, 2023). This lack of affordable financing, combined with other issues like poor maintenance, governance problems, and demand growth, has led to insufficient installed generation and transmission capacities in several LICs and MICs, which considerably limit the options for system operators to balance the system.

International organizations such as the World Bank can implement programs to encourage the investment required. Decarbonization will require substantial investment from private financiers (World Bank, 2023, p. 5). To attract the large and international investors they need, LICs and MICs need to be able to provide a pipeline of large, predictable, and bankable projects to secure affordable costs of capital, which requires strong institutions and long-term planning so that investors can be guaranteed enough investment opportunities to cover their transaction costs (IEA, 2023). Climate financing and grants must be scaled up (IEA, IRENA, UNSD, World Bank, WHO, 2022, p. 4). Guarantees and other mechanisms can be implemented to reduce key investment risks in LICs and MICs including those associated with foreign exchange rates and long-term off-take agreements (IEA, 2023).

2.2.1.2 Locked-in fossil fuel generation assets

Fossil-based generation is locked in in many LICs and MICs. Generation assets are long-term investments and new thermal plants can lock in a certain carbon trajectory for decades to come. Many countries have a strong legacy of fossil fuel–based generation and/or have made significant investments in thermal power plants in recent years. Phasing them out can make them stranded assets, imposing a financial loss on investors. For example, over USD 1 trillion of coal power plant investments are yet to be recovered worldwide, not least because the average coal power plant in China and Indonesia was built only thirteen years ago (IEA, 2022a, p. 15). Moreover, once polluting infrastructure is built, retrofits or energy efficiency upgrades can often be costly or technically impossible to implement before the end of the plant's productive life cycle. These technical and financial realities can create a hard lock-in of emission-intensive development pathways in countries where investors have portfolios with a large concentration in fossil fuel assets. Less tangibly, the institutions, technical knowledge, vested interests, and political lobbies surrounding incumbent industries can create a soft lock-in of the status quo (Granoff, Hogarth, & Miller, 2016).

Just Transition programs offer solutions. These programs can help reduce the "risk and impact of stranded assets" and work to find a politically feasible decarbonization pathway (World Bank, 2023, p. 5). The World Bank is implementing a Just Transition project in South Africa, providing finance to support the decommissioning and repurposing of the Komati coal-fired power plant using renewable batteries. The plant repurposing will enhance energy security with renewable resources as well as supporting workers through a transition plan and community-driven projects (World Bank, 2022).

2.2.1.3 Lack of sufficient flexible generation

A critical challenge in the sustainable energy transition will be ensuring that electricity systems have sufficient flexible generation to balance the grid. Power systems must maintain a certain system frequency (typically 50 Hz or 60 Hz), and gaps between supply and demand can cause frequency instability, demand-shedding activities, and blackouts in the grid. In contrast to variable renewables, dispatchable technologies can adjust their output to always ensure demand equals supply. They can thus play a role in solving constraints in the transmission network (see Section 2.2.2.2). Examples of existing technologies include combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), storage/reservoir hydropower, pumped storage hydro, coal, and (to some extent) nuclear power. The range of dispatchable technologies that a country can adopt cost-effectively depends partly on the country's resource base. Some LICs and MICs have hydropower resources that can provide these services, which are already low carbon. Other countries must rely primarily on gas and coal power to provide energy and system balance and stability to the grid. Fuel switching from coal to gas generation can reduce emissions from firm and flexible generators. A country's ability to take this approach depends on its gas endowments, infrastructure, and potential to import gas from other countries.

As the share of intermittent renewables increases, flexible generators will be required to do more ramping to ensure energy balance and frequency stability. Turbine-spinning generators that depend on coal, gas, or nuclear power also provide valuable inertia to the system, preventing large instantaneous frequency changes in the network. To ensure energy balance in response to large capacities of intermittent generation could require installing additional capacity at low penetration rates to ensure sufficient generation capacity on wind-still and cloudy days. Financing these assets is more challenging, due to the expected low operating hours and thus high break-even prices needed. A capacity reserve mechanism can be introduced to incentivize investments in such flexible generation. An alternative option is to invest in interconnector capacity between countries or markets to leverage the variation in renewable generation and demand patterns across countries.

2.2.2 Challenges regarding dispatch, markets, and transmission

2.2.2.1 Inefficient dispatch

Inefficient dispatch can inhibit a country's ability to cost-effectively meet demand and undermine the incentives created by carbon pricing to transition to a low-carbon electricity system. Inefficient dispatch occurs when generators are not dispatched in an order that minimizes whole systems costs. It can occur for several reasons, including transmission constraints and contractual constraints. Renewable energy-based generation typically can only be built where the corresponding renewable resource is available and if its location on the network does not have the capacity to transport the full generation capacity of the renewables to demand centers, curtailment will then be required at times. To address this problem, more expensive flexible generators located closer to load centers must be dispatched. Contractual constraints arise in administrative dispatch systems, as generators are sometimes dispatched to ensure they receive a minimum number of operating hours stipulated in their contract, as opposed to only when their costs are below or equal to the market price. Vertically integrated utilities lack the transparency of other structures, which can exacerbate risk of inefficient dispatch, for example if the systems operator prefers to optimize financial results for the company rather than obtain the lowest cost for users.

The financial implications of inefficient dispatch decisions can be substantial. Previous studies show that Bangladesh could have saved USD 1.65 billion in 2014 and Pakistan could have saved over USD 1 billion in 2018–2019 through efficient dispatch, reducing unnecessary reliance on expensive power plants (Nikolakakis, Chattopadhyay, & Bazilian, 2017; Schreider, Schmitt, & Reithe, 2020).

2.2.2.2 Network constraints and regulatory gaps for storage

Power systems can face several technical network issues that serve as barriers to the connection of new renewable generation to the grid. Transmission and distribution grids have been built to transport electricity from centralized power plants to homes and businesses around a country or between countries. However, the introduction of new RE connections to the grid can put an increased strain on existing LICs' and MICs' transmission and distribution systems, especially when renewable projects are concentrated in areas far from the existing centralized plants and from where demand is located. As more variable RE comes online alongside the reduction of fossil fuel generation, new challenges around maintaining balance on the grid arise and issues around frequency regulation and ramping can emerge. The absence of regulation for authorizing and compensating ancillary services (in particular for battery storage) combined with transmission constraints frequently leads to the curtailment of a substantial share of the production from intermittent renewable energy sources that the grid cannot absorb.

Network challenges can be particularly acute in LICs and MICs. Network constraints typically call for costly grid reinforcements, which LICs and MICs typically find more difficult to fund than HICs do. LICs and MICs often suffer from more technical and non-technical losses due to a lack of regular maintenance and inefficient management (Babayomi, Dahoro, & Zhang, 2022). According to the IEA, in 2022, the average technical losses as a percentage of output were 5–7% in HICs but 19% in India and 15% in Africa and Latin America (IEA, 2023).

Mitigation strategies can be implemented. Constraints can be mitigated by modernizing the grid, by building new transmission lines, and by establishing an enabling regulatory framework for storage and other ancillary services that can increase the flexibility of the grid. Congestion pricing can also generate the needed cost signal to incentivize the building of transmission infrastructure where it is the most needed. Such new infrastructure can allow lower-carbon generation technologies to connect and deliver clean power.

2.2.2.3 Volatile wholesale prices and price cannibalization

In liberalized power sectors with a spot market, renewables can suffer from "price cannibalization." An increasing share of intermittent renewables can lead to a phenomenon called price cannibalization, where renewables receive a lower generation-weighted price than the average price if they trade in the spot market. This can occur in countries, so far most of them HICs, that have achieved significant shares of intermittent renewables. There typically are periods with an oversupply of renewables, which will push down the wholesale price of electricity in the spot market. Typically, these are periods with high wind speeds and/or solar radiation and low demand. If renewables trade in the spot market in these circumstances, they are likely to receive their lowest price when they generate the most. Conversely, when there is low generation from solar and wind farms, fossil fuel generators typically make up the shortfall by ramping up. As fossil fuel generator costs are impacted by the fuel cost (and other costs such as a carbon price), the highest prices will typically be seen during periods of high fossil fuel generation and when the market is tight. This effect causes the wholesale spot prices to be volatile depending on the share of renewable generation in the network. Further, it can mean that the *generation-weighted* price an intermittent renewable plant receives does not cover the average cost of the asset over its useful life, even if the *non-weighted average* price observed in the market would supposedly be sufficient to cover its costs. To eliminate this risk, renewable projects can couple with energy storage or sign PPAs that guarantee a sufficient price across the useful life of the asset and reduce or remove the impact of volatile wholesale prices on its investment case.

2.2.3 Challenges regarding distribution and retail

2.2.3.1 A lack of cost reflectivity in tariff structures, technical and non-technical losses

In many LICs and MICs, retail tariffs are regulated and set at levels that do not reflect the full economic costs of electricity services provided. The rationale for doing this can be to ensure affordable electricity is available to low-income households or to protect the competitiveness of electricity-intensive industries. At the same time, retail tariffs are already relatively high in some LICs and MICs, and making them cost reflective would constitute a particular strain on consumers (Trimble, Masami, Arroyo, & Mohammadzadeh, 2016). Thus, there are political pressures to maintain controls, even though cost-reflective tariffs might ultimately benefit the power sector as a whole from more financially sustainable utilities (Lee & Usman, 2018, p. 17). High levels of technical and non-technical losses[22] and inefficiencies in utility management and operations incurring costs in LICs and MICs can mean that cost reflectivity is particularly challenging to achieve (Lee & Usman, 2018, p. 17).

Tariffs that are not cost reflective hinder a transition to a low-carbon electricity system for two reasons. First, a lack of cost reflectivity in retail tariffs causes many utilities in LICs and MICs to run at a loss, reducing their financial creditworthiness and credibility as counterparties to long-term PPAs. This can undermine the confidence of investors and financiers in the financial viability of new renewable generation projects (Rudnick & Velasquez, 2018, p. 5). Second, such tariffs blunt the price signal to consumers and thus make them unlikely to optimize their consumption or invest in energy efficiency.

2.2.4 Challenges regarding consumption

2.2.4.1 Mismatch between demand and RE generation profiles, regulatory gaps for distributed resources

The demand profile of electricity systems frequently does not align with the instantaneous output of renewable energy sources. For example, wind and solar generators only generate electricity at high load factors on windy and sunny days, respectively. Hydropower generation varies by season and between years depending on hydrology. In contrast, dispatchable generators like thermal plants (see Section 2.2.1.3) can ramp up to meet peak periods of demand, for example during mornings and early evenings. This mismatch becomes a greater challenge as more RE is added to the grid, for several reasons:

- **Renewable energy generators are typically concentrated in certain geographical areas to benefit from favorable weather conditions.** The weather conditions are exogenous to the system and require flexible generators to balance demand with supply.
- **A lack of responsive and flexible low-carbon generation capacity.** such flexibility can only be provided by specific sources of low-carbon generation like hydropower, gas generator with carbon capture and storage (CCS), concentrated solar, hydrogen-to-power, and battery storage, most of which are not yet available in LICs and MICs.
- **Lack of capacity for demand-side management** that has the potential to shift the timing of electricity consumption to when supply is greatest. Frequently, the marginal plants dispatched at peak periods are fossil fuel–based (i.e., gas, fuel oil, diesel). Demand-side management is instrumental to reducing the

22 Non-technical losses include inability to bill and collect payment from part of the consumers for a series of reasons, which includes incapacity to provide legal connections and meters to new customers, inaccuracies in the customer database and billing system, inability to replace broken meters, illegal connections, meter tampering and corruption, etc.

need for these plants. This involves shifting demand to align with when electricity is least costly to generate, for example through properly designed time-of-use (ToU) tariffs that vary throughout the day or demand response programs.[23] However, demand-side management relies on having certain infrastructures in place first, such as sophisticated smart grids and smart electricity meters. South Africa has ambitions to increase ToU tariffs in the future, but to date only HICs have implemented such measures (Department of Minerals Resources and Energy, 2022). In addition, for grids that have reached high levels of variable renewable energy to reduce emissions, demand-side management will be critical to reducing the need for fossil fuel generators to ramp up to meet the demand when variable renewable energy suddenly drops.

- **When auto-generation from renewables exceeds local demand, the generation is lost** unless the excess can be absorbed through energy storage such as batteries.

In many LICs and MICs, regulatory gaps regarding distributed resources, mainly demand response, and net metering/export of excess of auto-generation to the grid and battery storage limit the capacity of customers to adapt their behaviors and invest in technical solutions, which can help maximize the use of renewable energy sources.

2.2.4.2 Rapidly expanding electricity demand

Different from HICs, many LICs and MICs have burgeoning urban populations and growing economies that are driving rapid growth in electricity demand. Demand for electricity in LICs and MICs has grown by 6–7% per year since the 1990s (Foster & Anshul, 2020). Emerging markets and developing economies are projected to constitute 75% of the global electricity demand increase through 2050 (IEA, 2021). Rapid growth in demand presents LICs and MICs with both opportunities and challenges for transitioning to a low-carbon electricity system. As they constantly need to add new generation capacity, LICs and MICs have opportunities to cost-effectively adopt new low-carbon generation technologies and have less need than countries with stagnant demand to retrofit or retire existing infrastructure (Granoff, Hogarth, & Miller, 2016). However, rapid growth in demand necessitates considerable investment in new generation capacity just to absorb the demand increment, with no room to displace existing capacities. Thus, existing fossil fuel–based plants might still need to be dispatched to meet the existing demand, such that emissions do not drop even if new added generation is low carbon. In many LICs and MICs, investment in new capacity has failed to keep up, in part for lack of cost recovery, which as described earlier, has led to severe constraints in capacity, transmission, and distribution. This has undermined the aim to ensure affordable and reliable electricity to all customers (SDG #7). For some LICs and MICs, such as South Africa, chronic loadshedding has ensued, inhibiting economic growth. In addition, a shortage in supply relative to demand creates market pressure and increases the risk of electricity becoming unaffordable, which is a particular concern for LICs and MICs. When the quality of service worsens, the customers become increasingly averse to tariff increase, generating a negative cycle.

23 It is however important to note that ToU tariffs and demand response programs only reduce emissions if properly designed, the reason being that "peak period," defined as the costliest, does not necessarily coincide with "carbon peak period." For instance, in a coal-dominated system where gas plants are marginal during the peak period, moving demand out of the peak can increase the emissions. The value of carbon should be considered in the formula used to establish the price signal for ToU or the compensation for demand response programs.

2.2.5 Challenges regarding economics and governance

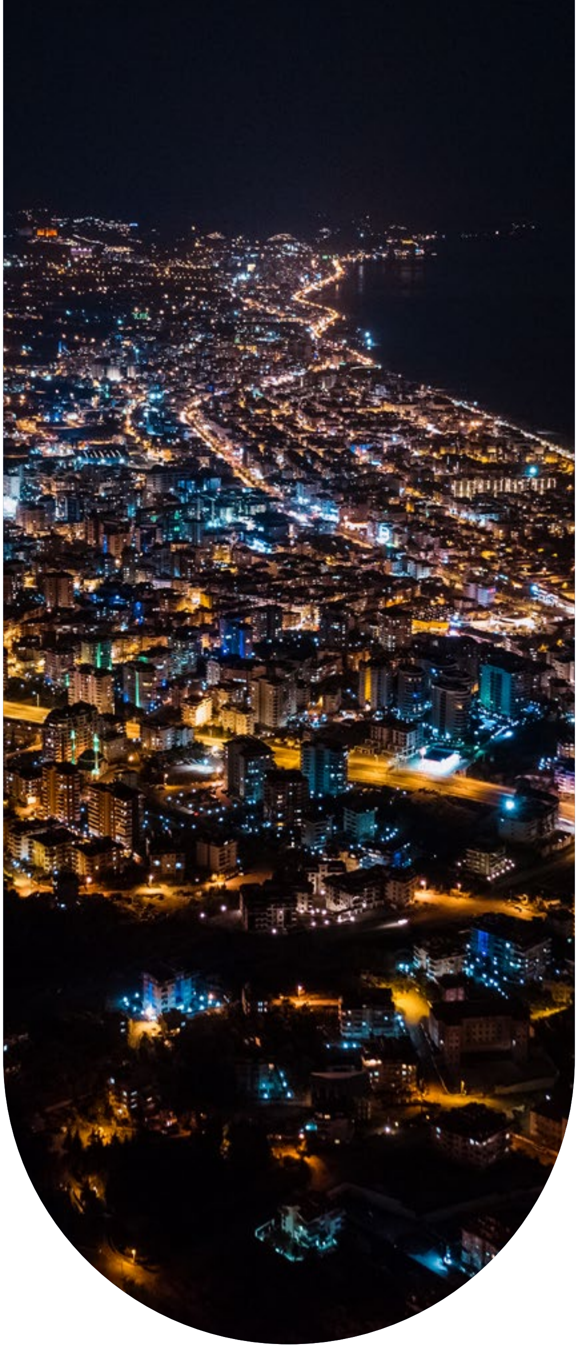
2.2.5.1 A lack of good governance practices and strong capacity within institutions

Strong governance and institutions will be fundamental to the transition to low-carbon energy systems, which is lacking in many electricity sectors in LICs and MICs. In the Global Electricity Regulatory Index, LICs and MICs received an overall regulatory governance score of 64% (with 100% being the top score) in 2021 (Rana, Ngulube, & Foster, 2022). Several LICs' and MICs' power sectors lack strong institutions, independent regulation, and good governance practices, which are defined by accountability, transparency, capacity, and public participation (Dixit, Dubash, Maurer, & Nakhooda, 2007, p. 7). Good governance practices and strong institutions are required to develop the long-term strategies, plans, and legislation that are needed to provide clear signals around planning and regulation, and thus, an investment environment with more certainty and reduced risks (World Bank, 2023, pp. 4-5; Rudnick & Velasquez, 2018, p. 9). As a result, private financers are disincentivized from building energy infrastructure in countries without these elements, especially when it comes to investment in RE, which is more capital intensive than conventional thermal power. Thus there is a need to establish robust governance frameworks and independent regulators. (Rana, Ngulube, & Foster, 2022).

2.2.5.2 Political economies that are averse to reform

Governments of LICs and MICs may be averse to implementing new policies for the power sector if they are expected to cause distributional conflict. Such conflict arises if people see proposed policies as negatively affecting them, or if the policy causes job losses and increasing living costs (Hallegatte et al., 2024). Decarbonization has winners and losers and interest groups may use their influence in government to undermine decarbonization policies to protect those likely to incur costs (Hanto et al., 2022, pp. 165-166). For example, carbon-intensive industries like coal mining face concentrated impacts. This is of particular concern in coal-dependent countries. As the most coal-dependent country in the G20 (World Bank, 2022d), South Africa depended on coal mining for 2.3% of its gross domestic product and 88% of its electricity generation in 2019. A shift toward renewables is expected to increase jobs in decentralized areas but reduce jobs in central areas of the coal sector (Hanto et al., 2022, pp. 164-165). However, when there is uncertainty around the equitable distribution of benefits from transitioning to renewables, there is greater fear and resistance. Therefore, implementing reforms may not be feasible in many LICs and MICs without measures to ensure that the transition is just (Hallegatte, et al., 2024).

In addition, there are strong interest groups that can use their influence in government to undermine decarbonization policies (Hanto et al., 2022, pp. 165-166). This happened during South Africa's Renewable Energy Independent Power Procurement Program which was undermined by influential actors with vested interests in the coal industry and ideological oppositions to private sector involvement in the energy sector. Those actors included the state monopoly power company Eskom and industry trade unions (Hallegatte et al., 2024).



2.2.5.3 High level of existing electricity subsidies

Many LICs and MICs have a high number and volume of electricity subsidies, which pose a range of challenges. Such subsidies are powerful in Kazakhstan, South Africa, and Indonesia. Electricity subsidies are a government policy aimed to ensure electricity remains at affordable levels particularly for low-income households and industries exposed to international competition, an acute challenge for LICs and MICs. They also lower the effectiveness of carbon prices, representing a form of negative carbon pricing. They impose a fiscal burden on the sector, further constraining its ability to invest in clean energy (IMF, 2022). In addition, in many cases studied, electricity subsidies disproportionately benefit wealthier households, as these typically consume more electricity than poor households and in some countries poor households have no access to electricity at all (Arze del Granado et al., 2012; Mayer et al., 2015). Electricity subsidies have also been attributed to slower economic growth (Devarajan et al., 2014) and limiting the uptake of renewable energy (Bridl et al., 2014). Nonetheless, the removal of subsidies can be a politically challenging process as consumers may see it as a direct challenge to the sector's responsibility in maintaining universal access and affordability.

2.3 Policy instruments for decarbonizing power sector

A broad range of policies can support decarbonization in the power sector. Research and international experience indicate that these policies include financial support, pricing instruments, regulation, mandates, standards and certifications. This chapter summarizes key policy instruments, including forms of carbon pricing, that can be used to drive decarbonization in the power sector. **In general, these policy instruments depend on one of three pathways** (IEA, 2020): fostering the development of low-carbon generation, promoting more efficient use of electricity, or incentivizing a reduction in operating hours or a phase out of carbon-intensive generation. A sample of policy instruments in each category are presented in Table 2.1, Table 2.2, and Table 2.3. The next section addresses direct carbon pricing, via carbon taxes and emissions trading systems, the focus of this report, in more detail,

The three pathways are intrinsically connected. Policies designed to support low-carbon electricity can affect the competitiveness of fossil fuel generation, and policies designed to curb fossil fuel generation can bolster the investment case for low-carbon generation. In high-carbon electricity systems, policies that increase the cost of fossil fuel generation can incentivize more efficient consumption if those costs are passed on to consumers. Moreover, more efficient consumption can reduce the overall demand for electricity, such that existing low- or zero-carbon technologies can meet a larger share of demand.

Nevertheless, it is useful to consider the three objectives independently. Increasing renewable generation capacity will not necessarily lead to a reduction in fossil fuel generation, particularly where there is high growth in electricity demand, where the regulation in place favors dispatchable resources, or where the political economy favors the incumbent generators, all of which can readily occur as in LICs and MICs. The majority of existing power sector–related commitments to decarbonizing the power sector focus on adding renewable capacity or output, and in many countries, the policy instruments implemented have aimed primarily at achieving that objective. Fewer commitments have been made to phase out or cap emissions from fossil fuel generation. A 2020 analysis by the International Renewable Energy Agency (IRENA) showed that out of 196 countries, 178 had a mismatch between RE targets in their NDCs and the policies and measures featured in their national laws and strategies (IRENA, 2022c).

It is also important to recognize that power sector stakeholders respond to the whole set of incentives along the value chain, including the ones generated by preexisting instruments. Achieving the decarbonization of power sectors in LICs and MICs could therefore require a substantial adjustment of these preexisting policy frameworks and instruments to align them with the new decarbonization objectives, or at least prevent conflict between them. New instruments might also be needed to provide additional incentives to induce the required investments and behavior changes. These can include a variety of instruments, far beyond direct or indirect carbon pricing, but they must be carefully designed to ensure the resulting set of incentives in the value chain are efficient in moving toward carbon neutrality while still complying with development priorities.

TABLE 2.1

Policy instruments that can foster the development of low-carbon electricity (pathway 1)

Policy instrument	Description
Market or sector reform	Structural changes to the power sector can be used to incentivize the growth of participants and capacity in the low-carbon generation sector. These reforms can include (a) the de-verticalization/opening up of industry segments to allow for increased participation of renewable IPPs in the generation segment and (b) reform of the system operator and dispatch protocol to prioritize low carbon generation in the merit order. More limited reforms aim to correct inadequate incentives that can favor or generate lock-in effects on carbonintensive generation.
Public research and development	Public funds can be invested in the research and/or demonstration of new technologies that are not currently commercially viable such as large-scale electrolyzers. This support can accelerate "first- and nth-of-a-kind" technologies that will be crucial to fully decarbonize the grid, including nascent low-carbon flexibility technologies such as electrolyzers, hydrogen-to-power, small modular reactors, and short- and long-duration electricity storage.
Carbon credit scheme	If a low-carbon energy project meets the eligibility requirements of an international or domestic carbon offset program, it can earn credits for the avoidance of other generation emissions to support the financial viability of the project.
Tax incentives	Tax incentives provide financial benefits to low-carbon generation investors. Examples include the removal of value-added tax from products used to build plants, corporate tax benefits for the investment company, and accelerated depreciation plant equipment.
Feed-in tariffs	Feed-in tariffs allow RE generators to earn their revenues from a fixed rate per unit of energy that is typically set above the current market rates and is thus usually subsidized. The government or energy regulator sets the feed-in tariff, which provides certainty in project revenue for project developers. They can also be used to incentivize investment in distributed generation by domestic or commercial customers by enabling them to sell excess electricity to the grid.
Feed-in premiums	Feed-in premium is an alternative to the feed-in tariffs and provides a fixed premium (top-up) above the market price. The feed-in premium allows renewable generators to respond to price signals in the market while receiving a premium that attracts investments in new renewable capacity.
Renewable energy auctions	Renewable energy auctions are competitive processes that project developers participate in to secure long-term power purchase agreements with utilities or system operators for selling the electricity from new power plants. Auctions incentivize the building of cost-efficient projects, resulting in the development of low-cost and low-carbon electricity generation while providing certainty in project revenue for project developers. Auctions can be used to develop projects that achieve new generation that aligns with the government's desired or planned future energy mix.

Policy instrument	Description
Contracts for difference	A contract for difference is an agreement between the government and low-carbon project developers on a price that the developer will earn for the energy it sells into the wholesale market regardless of market volatility. It is a market mechanism where a strike price is determined, and the generator will have to pay back any earnings above the strike price but will receive a top-up for revenues below the strike price. The instrument provides certainty on project revenue for project developers.
Targeted financing instruments	Providing financing mechanisms for building new low-carbon energy generation and required ancillary services infrastructure, such as green equity funds, increases the competitiveness and reduces the risk associated with these projects.
Renewable energy certificates (green certificates) and renewable energy portfolio standards	Renewable energy certificates (RECs) are certificates that guarantee that the corresponding amount of electricity was generated by renewable sources. One REC typically represents the certification of 1 megawatt hour (MWh) of renewable electricity. Introducing an REC scheme can provide an additional source of income for renewable generators, which receive the proceeds for selling RECs in addition to the wholesale price. RECs can be sold on a number of platforms, including online exchanges and over-the-counter markets. Under a mechanism called renewable energy portfolio standards (RPS), governments can mandate utilities to purchase a minimum percentage of their electricity supply from renewable sources as verified by RECs. Payments for RECs provide a pathway for utility companies or consumers to financially support RE developers as it provides additional revenue from their generation.
Demand response instruments	Distribution and retail companies can offer customers services that incentivize them to reduce their demand at carbon peak periods such as interruptible service contracts and demand flexibility services. This may include installation of smart meters/energy management systems, which allow customers to see their demand profiles to help inform their participation in options to reduce peak demand. In active demand side management the electricity supplier pays consumers to lower their electricity consumption during a particular period. Passive demand side management involves ToU tariffs: hourly pricing that incentivizes consumers to reduce consumption during peak use hours.
Carbon tax	This instrument is a tax levied that is proportionate to the quantity of emissions produced by a power producer. A carbon tax changes the relative prices of carbon-intensive and low-carbon generators and can incentivize the planning and development of low-carbon electricity.
Emissions trading system	In an ETS, the allowance price changes the relative prices of carbon-intensive and low-carbon generators and can incentivize the planning and development of low-carbon electricity.
Shadow carbon price in planning	A shadow carbon price is an assumed carbon price that can be applied in planning and dispatch decisions without adding an actual payable carbon cost to an agent (i.e., a generation company). For instance, introducing a shadow carbon price in planning can lead to the prioritization of new low-carbon electricity generators that previously were not competitive with new, cheaper fossil-fuel power plants. A shadow carbon price in planning can also influence the expansion of the transmission grid to better facilitate the connection of new low-carbon generation plants.

TABLE 2.2

Policy instruments that can promote more efficient use of electricity (pathway 2)

Policy instrument	Description
Minimum energy efficiency mandates	These set a minimum level of energy efficiency that must be achieved for that sector/product. Businesses, industries, and building owners must be audited and obtain certification to prove compliance. Mandates have been effective in phasing out inefficient equipment from the market and improving the efficiency of energy consumption in industrial operations. However, mandates are only effective if there are viable pathways to achieve the minimum standard, such as energy efficiency technology development and energy efficiency certificate trading.
Energy efficiency certificate (white certificates)	An energy efficiency certificate certifies that a 1 MWh reduction in energy consumption compared to a baseline has occurred through an energy efficiency activity. Energy efficiency certificates are similar to RECs but they indicate energy reduction rather than emission reduction. Reducing energy demand, however, can reduce reliance on fossil fuel–based generation.
Emissions trading system	In emissions trading systems, a central authority allocates or sells a set number of allowances that permit industries to release a specific quantity of GHG emissions, creating a cap on the amount that market participants are allowed to emit in a specified period. The ETS compliance obligation is commonly based on direct emissions (Scope 1), for which electricity generators pay the cost of purchasing allowances and can pass them on to consumers. This incentivizes consumers to use electricity more efficiently or to purchase it from low- or zero-carbon energy producers. In a small number of systems, covered entities are also liable for their Scope 2 emissions, which are the indirect emissions induced by the consumption of electricity.
Carbon tax	Emissions taken into account for the purpose of carbon taxation can also be calculated using a Scope 2 approach. This creates an incentive for industrial consumers either to reduce their electricity consumption or to purchase it from low- or zero-carbon energy producers.
Carbon-based time-of-use tariffs	A modulation of regulated tariff. While conventional time-of-use tariffs increase at peak demand periods, carbon-based time-of-use tariffs increase at times of day when the carbon content of the electricity consumed is higher. The two types of tariffs can be combined if the conventional form is already in place to reconcile economic and environmental efficiency. Such tariffs are not carbon taxes because they only modulate the tariff (a higher tariff during carbon-intensive periods is compensated by a lower tariff during a lower carbon-intensive period).

TABLE 2.3

Policy instruments that can incentivize the phase out of carbon-intensive generation (pathway 3)

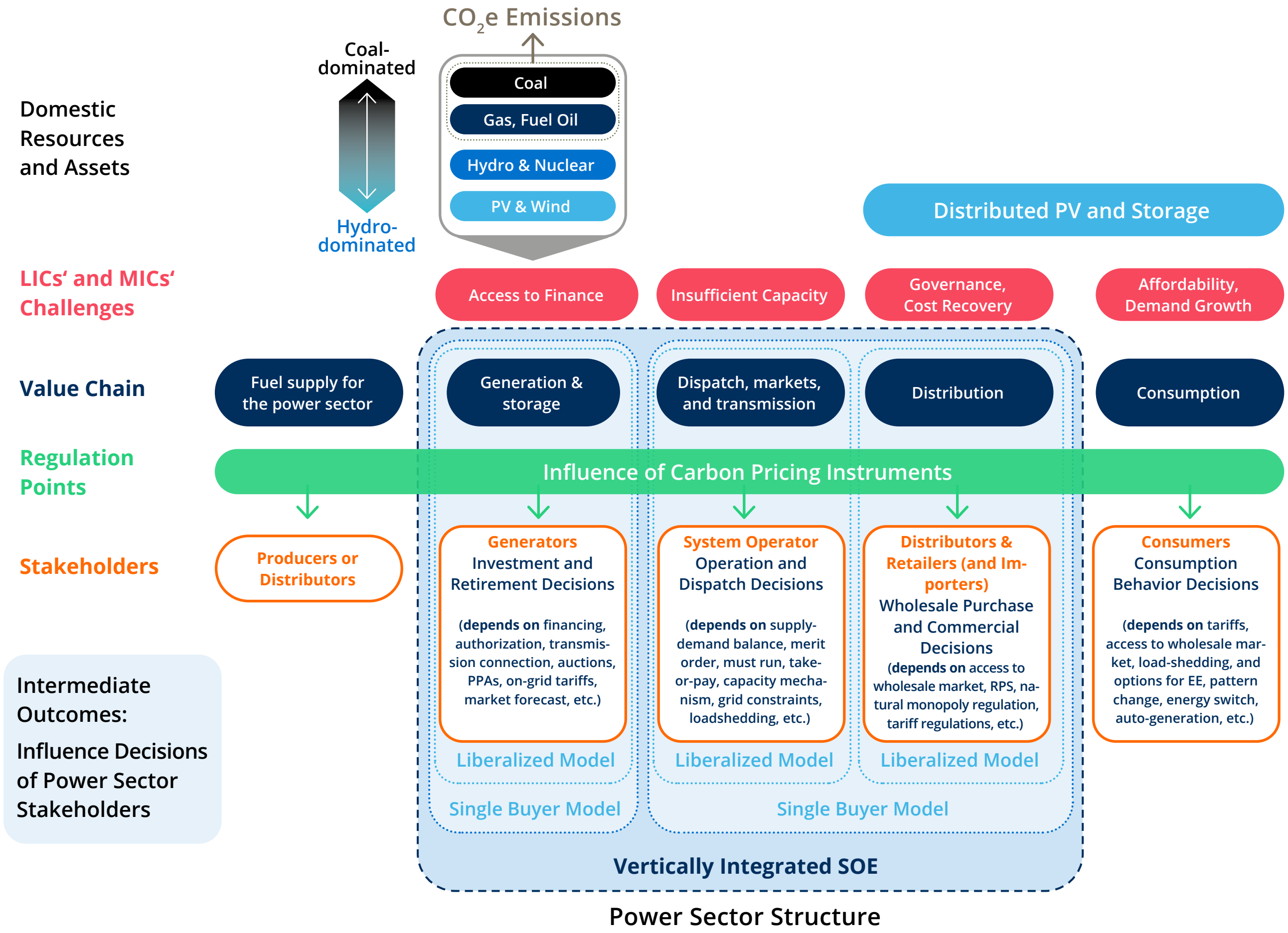
Policy instrument	Description
Reforms to fossil fuel subsidies	Many governments use subsidy measures to artificially lower the price of coal, oil, or natural gas production and/or consumption in their country. Fossil fuel subsidies can function as a "negative" carbon price. Reforms to reduce or phase out these subsidies will reduce the negative carbon price and increase the cost of fossil fuels, which disincentivizes carbon-intensive energy generation while reducing the financial burden of these subsidies on governments.
Carbon tax	This instrument is a tax levied that is proportionate to the quantity of emissions produced by a power producer. Thus, carbon-intensive power generators will incur greater costs from tax obligations and thus lose competitiveness, leading to lower production and lower emissions.
Emissions trading system	In an ETS, a central authority either allocates or sells a set number of allowances that allow fossil fuel–based generators to release a specific quantity of GHG emissions based on an absolute cap, or an intensity-based cap based on output (i.e., MWh of electricity) defines the amount that market participants are allowed to emit in a specified period. Companies that are unable to meet the emissions reduction required to stay below their emissions allocation are allowed to purchase emission allowances from other emitters with excess allowances or offsets if they are available. The market price of allowance determines the carbon price. In a market-based power system (spot, forward), bids must reflect the cost of the allowances, which causes a change in the merit order that reduces the dispatch of more carbon-intensive generation plants and thus reduces emissions.
Shadow carbon price in dispatch	When an independent system operator manages the dispatch of the generation capacities according to the merit order, it can be mandated to include a shadow carbon price in its calculations, leading to a change in the merit order that reduces the dispatch of more carbon-intensive generation plants and thus reduces emissions.
Decommissioning program	This is a government program that mandates the retirement of carbon-intensive generation facilities. This may be enabled by the introduction of stricter emissions standards or a carbon tax and may require pairing with stranded assets compensation mechanisms.
Stranded assets compensation mechanisms	These mechanisms aim to financially incentivize asset managers of carbon-intensive generation to retire their plants and can include accelerated depreciation and reverse auctions to optimize the allocation of public resources for plant early retirements.
Public programs to support a just transition	These are schemes to protect and support people who work in carbon-intensive industries that are vulnerable to job loss or live in regions that are highly dependent on the use or production of fossil fuels for their local economy to facilitate the transition to a less carbon-dependent economy.

2.4 An infographic visualizing the introduction of a CPI in the power sector in LICs and MICs

Many pieces come together to determine how the emissions of a country's power sector are generated. This chapter introduced these pieces, which determine how investment and behavior decisions made in the power sectors of LICs and MICs determine their greenhouse gas emissions. Many stakeholders along the multiple stages of the value chain and country-specific circumstances play a role. The latter include the challenges that these countries are facing to ensure that their power sectors serve their development priorities, the way the sector is structured due to their history of institutional reforms and regulatory evolutions, and, of course, access to natural energy resources, which varies widely. Introducing carbon pricing in the power sector is about shaping and inserting one or several additional pieces into the puzzle assembled here. Doing it effectively means anticipating how carbon pricing might affect other pieces to eventually achieve the desirable outcome. The infographic below proposes a synthesized visualization of how these different pieces can be articulated together and where, in that representation, a carbon pricing instrument can be introduced to influence the chain of decisions to help move the sector toward a decarbonization pathway.

FIGURE 2.5

Infographic synthesizing the introduction of CPIs in the power sector in LICs and MICs



3. Roles of carbon pricing in the power sector

Having positioned the new challenge of decarbonization among the other challenges faced specifically by power sectors in LICs and MICs, alongside the variety of potential policy instruments that can be mobilized to overcome that challenge, it addresses the design elements of carbon taxes and ETS, the different points along the power sector value chain at which they can be applied, and their potential role(s) in contributing to power sector decarbonization.

3.1 Key elements of CPI design in the power sector

A wide range of policies create an economic disincentive to emit GHGs and can thus be considered as carbon pricing. As mentioned in Section 1.2, these policies can be widely varied. The four main types of carbon pricing are

- Direct carbon pricing — A monetary cost, proportional to a ton of carbon dioxide equivalent (CO_2e), conveyed through an ETS or a carbon tax and reflected in the price of product or services (Agnolucci, 2023)
- Indirect carbon pricing — Policies that impose a cost on carbon-containing energy sources, although the cost is not necessarily fully aligned with the carbon content. These influence the relative prices of products and services and contribute to the net price signal (Agnolucci, 2023). Examples include tax reliefs or the application or removal of subsidies (de Gouvello, Finon, & Guigon, 2020).
- Shadow carbon pricing — Planners use an assumed carbon price related to emissions in their decisions regarding the type of generation to build or retire, or by system operators in the establishment of the dispatch merit order (World Bank, 2022).
- Implicit carbon pricing — A carbon price is calculated from companies' mitigation activities or cost of complying with regulations.

Further details on taxonomy of carbon pricing instruments can be found in PMR and PMI literature, as well as the State and Trends of Carbon Pricing series developed by the World Bank.

Direct carbon pricing includes carbon tax and emissions trading systems. This report focuses on these instruments, which work by creating a cost per unit of emissions. Their structure is as follows:

- Carbon tax—A fee is levied on emissions of the covered entities that is proportionate to the quantity of emissions produced by an activity (World Bank, 2022). For example, coal power plants will pay more carbon taxes than gas power plants per unit of electricity due to its higher carbon content. The carbon price is the tax rate set by the government.
- Emissions trading system—A central authority allocates or sells allowances that allow polluters to release a specific quantity of GHG emissions, creating an incentive for market participants to limit their emissions in a specified period. Market participants can trade these allowances between themselves on secondary markets. The market price of allowance determines carbon price.

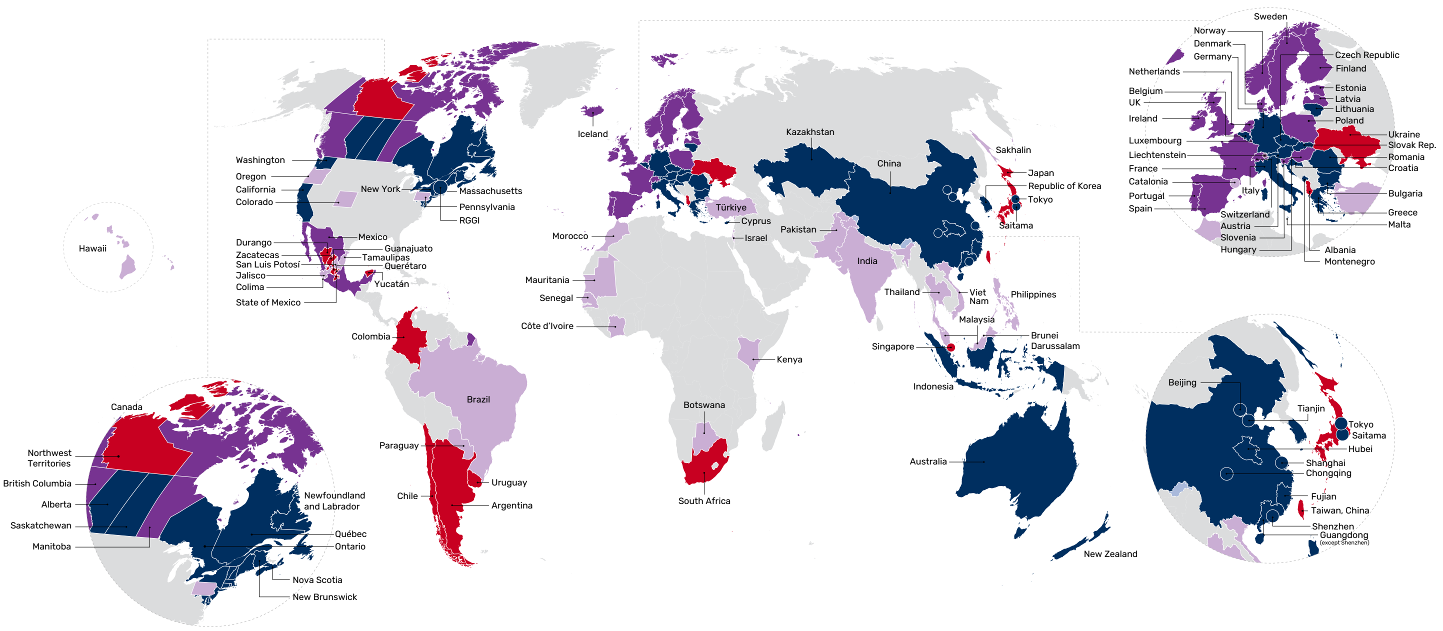
This carbon price signal creates an economic incentive for emitters to reduce emissions and invest in lower-carbon alternatives. Emitters compare the carbon cost with the cost of undertaking emission abatement activities. Carbon pricing can also create an incentive for consumers to reduce consumption of high-emission goods and services if the price signal is passed through the supply chain to consumers.

→ **Social cost of carbon and carbon credits are beyond the scope of this report.** These are other manners of pricing carbon that can be incorporated into support mechanisms for renewable energy. The social cost of carbon is a monetized estimate of the carbon price needed to reflect the damages to society caused by an additional ton of CO_2e emitted into the atmosphere Carbon credits are based on the quantity of emissions a power plant theoretically avoids by producing renewable electricity that displaces fossil fuel–generated electricity. The credits can then be sold as offsets through voluntary carbon markets or, where permissible, to buyers that can use them to comply with their emission reduction obligations, for example in an ETS.

Figure 3.1 shows the various countries that have implemented, are scheduled to implement, or are considering implementing a direct CPI. Most of these examples will have a carbon price imposed on the power sector. The latest insights on carbon pricing can be found in the State and Trends of Carbon Pricing 2023 (World Bank, 2023f).

FIGURE 3.1

Map of carbon taxes and emissions trading schemes implemented or scheduled for implementation around the world



- ETS and carbon tax implemented
- ETS implemented
- Carbon tax implemented
- ETS or carbon tax under consideration or under development

Instruments “under development” are where a government is actively working towards the implementation of a carbon pricing instrument and this has been formally confirmed by official government sources. This includes, for example, where a mandate has been established, but regulated entities do not yet face compliance obligations. If a government has announced its intention to work toward the implementation of a carbon pricing instrument and official government sources formally confirm that intention, the instrument is “under consideration.” For those countries with multiple instruments that have both “under development” or “under consideration” and “implemented” instruments, the map will show the status of the latter. The status of instruments in subnational jurisdictions is also reflected in the map.

Source: World Bank. 2024. State and Trends of Carbon Pricing 2024. State and Trends of Carbon Pricing. Washington, DC: World Bank

Some key features of the power sector are particularly well suited to direct carbon pricing. It is a large-emitting sector with several available low-carbon technologies that can be implemented cost-effectively. The administration of carbon pricing can also be more straightforward in the power sector than in other sectors, as most jurisdictions have sufficient data availability to enable accurate measurement of emissions and MRV. However, other market distortions outside of electricity markets, including tax interactions and carbon leakage, can have implications for the cost-effectiveness of different CPI designs.

There are multiple aspects of a CPI design to consider. It is critical that a CPI is progressively developed, adjusted, road-tested, and strengthened from the outset. This will determine whether it is phased in successfully and provide a predictable and increasing price signal that will drive economic and sustainable emissions reductions. It will also harden the instrument to political challenge. It can be difficult to strengthen designed elements of a CPI once regulated parties become accustomed to the original design. Several guidebooks have been developed through the World Bank's PMR program that provide advice on the design and implementation of a carbon tax and ETS. This section discusses several of the critical design elements that are specific to the power sector.

3.1.1 Design elements relevant to both a carbon tax and an ETS when applied to the power sector

Definition of emissions to which a CPI would apply

A carbon tax or an ETS could apply to different scopes of emissions, depending on the application of the instrument in the power sector value chain. Most CPIs will apply to Scope 1 emissions, relevant where the CPI is applied at the generation stage. Scope 1 emissions are emissions that occur directly from sources owned or controlled by an organization (GHG Protocol, 2019). Within the power sector these will be mostly associated with the burning of fuels to produce energy. Scope 2 emissions are those that result from the purchase of generated energy, including the purchase of grid electricity (GHG Protocol, 2019). Scope 2 emissions will be covered by a CPI in the power sector if it is applied at the distribution or consumption stage in the value chain.

All power sector CPIs target CO_2 emissions associated with the combustion of fossil fuels. Methane (CH_4) should also be included since leaks can occur in gas-fired power plants. A power sector CPI can also cover sulfur hexafluoride (SF_6) emissions. While less prevalent than CO_2, SF_6 is much more potent and it is released by leaks from electrical equipment, in particular switchgear and transformers.[24] The CPI would have to apply at the transmission or distribution stage of the value chain, as SF_6 is used in such processes.[25]

Scope

National power mixes and reliability of fuel sources are crucial for determining the scope of a CPI within the power sector. Expanding the scope of an ETS to cover more fuel (and generation) types increases the possibility for lower cost abatement and increases general certainty of emissions reductions across a jurisdiction (World Bank, 2021b). For instance, starting in 2026 Colombia's carbon tax will apply to coal used in the power sector at a progressively increasing rate, but the use of natural gas in electricity production will remain exempt (see Annex B.2, Colombia Case Study). Decisions around scope should be carefully considered alongside jurisdictional objectives, which for many LICs and MICs include economic development, energy security, and access.

24 SF_6 has a global warming potential of 22,800 times higher than CO_2. Hence, 1 kg of SF_6 is equivalent to 22.8 tCO_2e. Source: Pollutant information - NAEI, UK (beis.gov.uk)

25 Both CH_4 and SF_6 would need to be measured as CO_2 equivalent. The design of an ETS and its consideration of biomass emissions is also of relevance, since the generation of biomass-fired electricity can be regarded as renewable, dispatchable energy.

The threshold of application also affects CPI scope. Within ETSs, an exclusionary limit is typically applied, relevant to the size or capacity of an installation, often excluding small emitters. The EU, UK, Montenegro, and Switzerland apply the threshold for inclusion at power sector entities with capacity of over 20 megawatts (thermal rated input) (ICAP, 2018). Thresholds may also be placed on the level of emissions per year rather than capacity. Kazakhstan's ETS threshold includes power sector facilities with emissions over 20,000 tCO_2 per year (ICAP, 2023a). Smaller, state-level ETSs in Quebec and Washington State limit inclusion to power sector entities with emissions over 25,000 tCO_2e per year (ICAP, 2023c).

Whether a CPI applies beyond the power sector has major consequences in terms of distribution of impacts. Indeed, the physical distribution of emissions reductions might differ substantially, even if the level of ambition initially defined for the power sector is the same, if the scope includes other sectors. The outcomes regarding the changes in investment in generation, in dispatch, in wholesale purchases, and in consumption patterns might also differ. For instance, if an ETS covers multiple sectors, the power sector might be able to purchase allowances from other sectors if the GHG abatement costs of these sectors are lower, rather than implementing abatement measures within the power sector itself.[26] The consequences would be different in terms of financial flow (in investment and in payments) and decommissioning of emitting facilities than where an ETS with a comparable proportional emissions target applies only to the power sector.

Scope can change over time within the power sector and with respect to applying to other sectors. Many CPIs undergo phases of implementation over several years, typically experiencing gradual expansion.

3.1.2 Design elements of a carbon tax when applied to the power sector

Tax rate

The coverage and rate of a carbon tax defines its impact. These elements determine the amount of emissions abatement targeted, revenue generated, and effect on the economy (World Bank, 2017). There are multiple methods of determining the carbon tax rate and its evolution through time to align with policy objectives. These objectives might include aligning the rate with the social cost of carbon (see Section 2.2.1), raising revenue, or reaching a target for emissions mitigation. Further, industry-specific benchmarks can be applied in which the tax only applies to emissions above a specific threshold. Most jurisdictions have started with relatively lower carbon tax rates so as to allow time for industries to invest in mitigation technologies and adapt to carbon tax rules (World Bank, 2017). Nevertheless, the timeline set for the increase of the carbon tax rate could be highly relevant when it comes to incentivizing investment in nascent low-carbon technologies that, although not profitable at the current tax rate, would be profitable in the future, with higher tax rates.

Tax exemptions

Exemptions are the most commonly used measure to reduce tax contributions from covered entities. They are relatively easy to implement administratively, and can be targeted (for example, to reduce burden on industries exposed to carbon-intensive trade). Three major forms of exemptions exist. A fixed or benchmark exemption for a facility can function as a tax analog to free allocation of emission allowances, with the similar effect of neutralizing the price pass-through of the carbon tax. A percentage exemption serves to reduce the effective carbon price, muting all incentives. Conditional exemptions from a carbon tax can be used as incentives for investment in low-carbon

26 Or, reciprocally sell to others if reducing emissions is cheaper in the power sector.

industries by rewarding larger improvements with tax breaks, or they can be linked to entities that reduce their emissions (for example through agreements with the government). All forms of exemptions will reduce the amount of potential revenues a carbon tax could provide (World Bank, 2017). Limiting exemptions will encourage closer alignment with a polluter pays principle.

BOX 3.1

South Africa carbon tax rates and exemptions

Tax rates

South Africa's carbon tax had an initial price of ZAR120 per tCO_2e for 2019. Until 2022, the rate increased annually by the amount of consumer price inflation plus 2%. In 2023, it was ZAR159 per ton, with the rate trajectory to increase more steeply from 2023 onward (PWC, 2022). In the 2022 budget, the government proposed the following carbon tax rates:

- From January 2023 to December 2029, the rate will increase by a minimum of USD 1.00 annually or by the inflation rate, making the tax at least USD 20/tCO_2e by 2026.
- From January 2030, the carbon tax rate will be at least USD 30/tCO_2e.
- From January 2050, the carbon tax rate will be at least USD 120/tCO_2e.

Tax exemptions

There are tax exemptions currently in place until the end of the first phase in December 2025. They include a mixture of incentive-reducing and incentive-enhancing features. There is a basic tax-free allowance of 60% for all activities, a 10% process and fugitive emissions allowance, and a maximum 10% allowance for trade-exposed sectors. Supporting behaviors are encouraged with a performance allowance of up to 5% for companies that reduce the emissions intensity of their activities and a 5% carbon budget allowance for complying with the reporting requirements, and companies can use carbon offsets to reduce their tax liability for up to a maximum 10% allowance. In the 2022 budget, it was announced that the basic tax-free allowance will gradually phase out beginning January 1, 2026, after stakeholder consultations.

Fossil fuel electricity generators can offset the carbon tax by subtracting the RE premium (National Treasury, 2021) and the electricity levy:

- The renewable energy premium is a premium paid for purchasing RE under the Renewable Energy Independent Power Producer tariff. It is limited to Eskom and other electricity generators that also purchase electricity (National Treasury, 2021).
- The electricity levy (also known as the environmental levy) is placed on fossil fuel generators at 3.5 cents per kWh (SARS, 2012).

Implications for energy generators

The carbon tax in its present form is designed to avoid double taxation of fossil fuel generators. The offset for the electricity levy is set at a higher rate (3.77 versus 3.5 cents per kWh) due to the tax being placed on net generation (generation minus electricity required to power the plant) rather than gross generation.

The carbon tax is set to increase each year, while the electricity levy is constant in nominal terms. This could mean that the carbon tax increases without an offset by the electricity levy. However, because the RE premium payments are so significant, observers still expect that the combination of the electricity levy and the RE premium will zero out the carbon tax altogether. The combined RE premium and electricity levy cannot offset more than the total value of the carbon tax, which ensures there is no effective negative carbon tax.

3.1.3 Design elements of an ETS when applied to the power sector

Emissions target

In an ETS, the government typically sets a cap on the overall emissions allowed from the sectors that the mechanism covers. Key concerns are cost uncertainty and price volatility. To achieve emission reductions over time, the cap can be gradually decreased each year. Governments typically project the cap into the future to provide information to the sector on the level of emission reductions to be achieved. In order to provide some predictability to the constrained entities, the cap trajectory must be defined over a long time horizon, especially for the power sector where the investments are sometimes decided more than a decade in advance. A linear reduction factor can communicate the level of emission reductions each year.[27] Governments can also apply a carbon leakage assistance rate, which can provide assistance to sectors at risk of carbon leakage in the form of free allowances.[28]

In the traditional cap-and-trade system, the target is set as an absolute cap. In this case the cap is then divided into a number of emission allowances, where each allowance represents 1 tCO_2e emitted. In an intensity target, there is a set limit on emissions per unit of output, for example CO_2e emitted per unit of product (steel, cement, electricity, etc.) (World Bank, 2021b). Also called a rate-based or output-based system, or a tradable performance standard, the intensity cap allows the pool of emission allowances to grow in line with output, which means absolute emissions levels may rise. Because an intensity cap has the benefit of adjusting the cap according to economic growth and macroeconomic shocks to an economy, this approach is often used when future levels of demand are particularly uncertain. However, an absolute cap can also guard against uncertainty in future levels of demand by having a cap adjustment mechanism or using banking and borrowing that allow firms to save allowances during economic downturns and use them during periods of economic growth.

Intensity-based caps—when implemented with freely allocated benchmarks—can also be thought of as combining a price on carbon emissions with a subsidy to generation, based on the benchmark. The subsidy component applies at the margin, reflecting that additional output increases the number of allowances a facility will receive (Goulder, 2022).[29] The carbon price determines the incentive to improve efficiency of existing generation facilities, while the net emissions payments influence the incentive to switch to lower-carbon sources and to conserve electricity. When larger subsidies are provided to more carbon-intensive sources, the incentive for source switching is muted. When renewable sources are excluded from generous benchmarks—as with performance standards applied only to emitting sources—regulators will not improve the competitiveness of clean sources. In such cases, complementary policies are necessary to level the playing field for renewables and to ensure proper price signals are passed through to consumers (Fischer, Qu, & Goulder, 2024).

There is a risk that covered entities will not follow the rules to surrender allowances according to their emissions. In this case, the emissions targets set by the ETS each year will not be achieved. Penalties for covered entities that don't surrender enough allowances are thus an essential design feature, ensuring that covered entities comply

27 The linear reduction factor, currently employed in the EU ETS, is one of several options that can be used to decrease the cap. Alternatively, it can be argued that the more emissions are reduced, the harder it is to reduce them further, hence introducing the argument for a progressive slowdown of the decrease of the emissions cap.

28 For a more detailed introduction to ETS, the reader can also refer to Partnership for Market Readiness (PMR) and International Carbon Action Partnership (ICAP). 2016. Emissions Trading in Practice: A Handbook on Design and Implementation. World Bank, Washington, DC. License: Creative Commons Attribution CC BY 3.0 IGO.

29 See also Fischer, Rebating Environmental Policy Revenues: Output-Based Allocations and Tradable Performance Standards, 2001; Fischer, 2003; Fischer, Mao, & Shawhan, 2018.

with the system rules and are encouraged to partake in emissions trading as a less costly compliance mechanism. They only perform this function, however, if they exceed the average price of allowances and are high enough to exceed the cost of actions to reduce emissions to meet compliance obligations, such as investing in new technologies to allow fuel switching within the power plant. The EU ETS penalty for non-compliance is EUR 100 €2012 per tCO_2e (equivalent to ~120 €2024) emitted without an equivalent surrendered allowance (European Commission, 2023a). Furthermore, entities are also required to surrender permits equivalent to the amount not initially surrendered at the compliance date that follows penalty. Thus the cost to emitters is the sum of the penalty and the purchase (surrender) of the missing allowances. This level of incentive has been highly successful.

Allocation of emission allowances

The government can choose either to allocate the allowances to polluting entities for free or to sell allowances through auctions as part of a *primary market* for allowances, which generates income for the government. Auctioning can play an important role in ensuring liquidity and price transparency in the market, since prices are not usually revealed with bilateral trades. Full auctioning is rarely used in the early stages of an ETS, as governments tend to prefer to ease in the carbon cost burden and reduce risk of carbon leakage.

Governments can also distribute emission allowances for free. Free allocation is typically achieved through grandparenting (often referred to as grandfathering in other literature) or benchmarking. In the former, allocation of allowances is made based on the entities' historical emissions. The latter is more complex. Benchmarking allocation of allowances is based on benchmarks of emissions per unit of output. Benchmarks for output-based allocation are based on reference values, published by the government, for the emission intensity targets for covered entities. Entities are then allocated allowances in proportion to their output (i.e., amount of product) for a compliance period. As a result, a price signal is created for greater production. Benchmarks have been based, for example, on (i) historical emissions per output in different sectors (product based), with some reduction factor; (ii) performance standards for given production processes (technology based); or (iii) emission levels per unit of production using the best available technology or best performers. This approach is more data- and resource-intensive than grandparenting, requiring production data and attribution of emissions in multiproduct facilities (affecting in particular industries like chemicals or petroleum refining).

Benchmarking can be universal or differentiated. Universal benchmarks are the same for all utilities producing the same product. Differentiated benchmarks differ according to, for example, production technology. Such choices are highly linked to political and economic objectives. Higher benchmark differentiation may alleviate industry concerns and the dispersion of impacts, but it increases administrative burden and significantly reduces the environmental effectiveness of the CPI. Having one benchmark per product (under the principle known as "one product, one benchmark"), if the methodology does not vary based on the fuel type or technology used, ensures consistent abatement incentives and enhances the competitiveness of relatively clean technologies. By contrast, multiple benchmarks can protect technologies from competing against each other. In this case only emission reductions within a technology type (efficiency improvements) are incentivized, and reductions from source shifting are not. In the power sector, under carbon pricing with different benchmarks for different technologies, there can be an incentive to adopt more efficient plants of a given technology, but less incentive to adopt an alternative cleaner technology with a lower benchmark. Box 3.2 describes China's use of intensity-based caps and benchmarks that differ between electricity generation technologies.

BOX 3.2

China's use of intensity-based caps and technology-specific benchmarks in its ETS[30]

The China National ETS does not place absolute caps on power plants' emissions. Rather, the allowances allocated to coal and gas power plants are based on production output and administratively determined carbon-intensity benchmark (MEE, 2021).

The benchmarks are technology specific: the more carbon-intensive technologies are allocated higher carbon-intensity benchmarks. As detailed in the table in this box, coal is allocated higher rates than gas and less efficient coal-based technologies are allocated higher benchmarks than more efficient ones.

All regulated plants receive the corresponding volume of allowances for free. All plants must surrender allowances corresponding to their actual emissions at the end of the compliance period. Plants performing better than their carbon-intensity benchmark receive more allowances than they need and can sell excess to those performing above their benchmark. Only coal power plants performing worse than their benchmark need to purchase allowances.

Table: Technology-based intensity benchmarks for allowance allocation in China ETS, 2022 level

Technology category	Technology criteria	Carbon intensity benchmark (gCO_2/kWh)
Unconventional coal-fired units	Circulating fluidized bed	930
Conventional coal-fired units at and below 300 MW	High-pressure Subcritical ≤ 300 MW Supercritical ≤ 300 MW	873
Conventional coal-fired units above 300 MW	Subcritical > 300 MW Supercritical > 300 MW Ultra-supercritical coal with CCUS	818
Gas-fired units	Gas Gas with CCUS	390

Source: (MEE, 2023b)

The intensity-based cap is compatible with growing demand. The carbon price component generates an incentive for improving the efficiency of the coal plants; however, the differentiated benchmarks do not encourage fuel switching to lower or zero-carbon power sources since more emissions-intensive technologies receive larger output-based allocations, meaning shifting to less carbon-intensive fuel would result in fewer allowances. In addition, small coal plants performing better than their high benchmarks are incentivized to generate more, since they can then sell the excess allowances they receive to larger, less carbon-intensive coal plants performing worse than their lower benchmark. Furthermore, since the performance standards apply only to fossil fuel sources, RE generators do not receive any permits, so their cost competitiveness does not improve relative to the emitting sources. As a result, additional policies are needed to encourage the deployment of RE.

30 See Annex B.1, China Case Study for a more detailed presentation.

Grandparenting is a form of lump-sum transfer of emission rents that does not alter abatement decisions. To the extent that producers can pass on the embodied carbon costs into product prices, grandparenting can lead to windfall profits (Sijm, Neuhoff, & Chen, 2006). By contrast, benchmarking in practice creates an output subsidy that limits the pass-through of embodied carbon costs to consumers. It thus mutes incentives for emissions reduction through reduced consumption of goods that are emissions intensive. However, the structure of the power sector—such as monopolistic supply or average cost rate regulation—can influence how these allocation mechanisms eventually impact decisions of stakeholders. Newer ETSs are relying to a greater extent on benchmarking for trade-exposed industries that have a harder time passing along costs. Over time, ETSs tend to transition toward greater auctioning and less reliance on free allocation.[31]

Primary versus secondary market for allowances

Trading is done via the secondary market. To be compliant with an ETS, polluting entities must surrender enough allowances to account for their emissions within a set period. The government can sell allowances through auctions as part of a *primary market* for allowances. If an entity has been allocated or has purchased more allowances than it needs, it can sell surplus allowances on the *secondary market*, which functions as a market for trading existing allowances between market agents.[32] If an entity has not purchased enough allowances in the primary market it can seek them in the secondary market. Hence, ETSs have a cap-and-trade format.

Demand and supply interactions set the market price. In the primary market, the supply of allowances is the number of allowances a government allocates or auctions to the market in each compliance period.[33] Over time, demand must equal supply for the market to clear. The quantity of allowances demanded at a given allowance price depends on the various marginal abatement costs of polluting entities. If an entity's marginal abatement cost is lower than the allowance price, the entity will find it cheaper to undertake the abatement activity than to purchase allowances. Conversely, if an entity's marginal abatement cost is higher than the allowance price, the entity will prefer to purchase allowances. Thus, the relative costs of the allowance price and the individual marginal abatement costs determine the total demand for allowances in both the primary and secondary markets.

Some jurisdictions permit the banking of permits. This enables entities to store their excess permits in their accounts for future use, and such permits are therefore not available for trading. Consequently, the banking of permits can limit the supply of permits in the secondary market. Designing an ETS to show increasing stringency on the ability to bank allowances can influence the price of allowances upward, by showing predictability in the reducing availability (and therefore higher future prices) of allowances.

31 Some jurisdictions also allow non-emitting companies to purchase permits at auctions and resell them in the secondary market. This process is primarily undertaken by financial investors.

32 Some jurisdictions also allow non-emitting companies to purchase permits at auctions and resell them in the secondary market. This process is primarily undertaken by financial investors.

33 This can be lower than the cap since it does not include free allocations. The latter are not included in the market since they are delivered directly to concerned emitters. Consequently, they enter the system without being linked to the market price, and, once allocated, they can be traded on the secondary market.

Government control drives success. The emission cap will be achieved because the government sets the supply of allowances, and demand must equal supply over time. The allowances will be traded at prices that clear the market. Hence, the cap on emissions given by an ETS can ensure national policies or emissions targets are achieved.

3.1.4 Use of dual carbon pricing mechanisms in the power sector

Some jurisdictions have both a carbon tax and an ETS. In a dual carbon pricing system that applies to the same sectors, entities covered by an ETS and a carbon tax would face double pricing of their emissions without remedial measures. This may be the intended design of the two policies, to boost the overall carbon price signal and encourage further emissions reductions. However, entities can be exempted from payments under one instrument to limit negative financial impact and maintain confidence for growth. The UK has a dual pricing system, while Chile (see Box 3.3) and Colombia both have carbon taxes and are in the process of designing ETSs.

Dual carbon pricing has some challenges. It creates regulatory complexity and potential higher transaction costs in the former of higher MRV costs, internal time spent, and capital expenditure (Coria, 2015). Policy makers should recognize the complexity of potentially dealing with both instruments and understanding any exemptions created to ensure particular emissions are not double priced.

The UK adopted a dual system that covered the power sector. The Carbon Price Support mechanism and the UK ETS both apply to electricity generation. Carbon Price Support is a tax that reflects the carbon content of the fuel, which is used as a proxy for emissions. Different rates are provided for different fuel types on a GBP per kWh basis. In combination with the ETS the tax creates a carbon price floor, ensuring a carbon price high enough to encourage coal to gas fuel switching in the power sector, where the ETS allowance was not high enough to do so (House of Commons Library, 2018). In the six years after implementation of the Carbon Price Support the amount of energy generated using coal in the UK fell from a monthly average of 13 terawatt hours in 2013 to 0.97 terawatt hours in 2019 (University College London, 2019). Gas and energy import from France and the Netherlands replaced the output. The impact on electricity bills shows the carbon cost was passed through to consumers: the wholesale price of British electricity increased by GBP 7 per MWh in the first five years, equivalent to an average increase of GBP 26 to consumers' annual electricity bill in 2018 (University College London, 2019).

3.2 Regulation points of CPI in the power sector

Both carbon taxes and ETSs are typically applied at the point of electricity generation. Through this method, the source of emissions—fuel burning for generation—is directly targeted and the burden of application and administration of the carbon price is reduced, as the number of generators is relatively few compared to the number of energy consumers. Placing the CPI regulation at this stage of the value chain is also practical in terms of the ease of measuring power plant emissions, by applying an emissions factor to the type and amount of fuel used to generate electricity. This is an important consideration for LICs and MICs, where distribution and retail companies face difficulties with transmission losses and metering. The result is that emissions cannot be accurately measured further down the value chain.

However, the regulation point within the power sector varies along the value chain. As outlined in Figure 3.2, a carbon tax or ETS can apply at the generation, dispatch, distribution, or consumption stage. It may also apply upstream

BOX 3.3

Development of carbon pricing in Chile

In 2014, Chile became the first country in Latin America to introduce a carbon tax. It applied to carbon emissions, local pollutants, and, based on fuel efficiency and emissions, new passenger cars (Law 20.780 of 2014) (Mesa Puyo & Zhunussova, 2023). This tax was implemented in 2017, and since then it has generated revenue but only produced modest reduction in CO_2 emissions. Recent efforts to have a greater impact include a carbon offsetting mechanism and planning an emissions trading system.

The carbon tax is a component of the tax on stationary sources, which has produced significant revenue. It consists of a levy of USD 5 per ton of carbon emissions from stationary sources that have a thermal capacity of 50 MW or higher. Together with the other component of the tax, and a local pollution charge (Mesa Puyo & Zhunussova, 2023), the tax raised $191 million from fifty-eight taxpayers in its first year. The power sector accounted for 53% of the revenue. Five years later, in 2021, it raised $186 million from fifty-six taxpayers, and the power sector contributed 45.8% of the revenue (Mesa Puyo & Zhunussova, 2023).

The law establishing the carbon tax includes a provision specific to the power sector that unfortunately benefits fossil fuel–based power generation when the total generation cost is greater than the marginal spot price—that is, when the variable cost considered for the economic dispatch plus the carbon tax exceeds the wholesale electricity price. Then utility companies must cover the difference proportionally to the amount of electricity each of them purchases from the system. This benefits fossil fuel-based power generation by relieving high-emitter power plants from paying the carbon tax and affecting RE generators and therefore lowering the incentive to invest in cleaner sources (Díaz, Muñoz, & Moreno, 2018; Mesa Puyo & Zhunussova, 2023). The tax has resulted in a modest 1.1% reduction in national CO_2 emissions (Pizarro, 2021). In October 2021 Chile's Long-Term Climate Strategy indicated that the country will set an increasing trajectory of the carbon price between 2020 and 2025 (ICAP, 2023c). Proposals have been made to improve the scope and mitigation impact of the tax. These include switching from a thermal capacity threshold to an emission-based one, set at 25,000 tCO_2/year for all emitting sources. They also include the implementation of a mandatory GHG reporting scheme on fixed sources and the inclusion of the option to use offsets as a substitute for paying the carbon tax. Furthermore, a fiscal reform implemented in 2020 broadened the number of entities that are subject to the tax and established a complementary domestic offsetting system. In April 2023, the National Energy Commission altered the mechanism employed by electricity generators for the calculation and payment of the carbon tax and improved the conditions of non-emitting plants. This is because the latter paid a total of CLP 3,083 million in compensations in 2022; however, if the changes listed here were implemented, the annual payments would be reduced to CLP 13.5 million, i.e., a 99.6% decrease (ICAP, 2023; Mesa Puyo & Zhunussova, 2023).

Under the Tax Modernization Law, a carbon offset mechanism has been applicable since February 23, 2023. The mechanism allows emission reduction projects developed in Chile to offset carbon emissions under three criteria: (i) the emission reductions must be additional to any environmental or sectoral regulations applicable to the taxpayer, (ii) the Ministry of Environment must be able to measure and verify the reduction in emissions, and (iii) the period of operation of the emission reduction projects should cover the time that the taxpayer is liable to the green tax (Mesa Puyo & Zhunussova, 2023).

The Framework Law for Climate Change was approved in June 2022, introducing emission standards and tradable carbon credits. Entities affected by the system can comply with the standards through carbon credits from carbon reduction or absorption projects developed in Chile and the framework calls on the Ministry of Environment to create a public registry of approved projects (Mesa Puyo & Zhunussova, 2023). It also calls on the ministry to set a maximum amount of greenhouse gas that a source/entity can emit per year, establishing the basis for an ETS, which the Chilean government's 2022-2026 Energy Agenda, published in August 2022, states will be developed for the energy sector in pilot form (ICAP, 2023c).

The Chilean government is currently debating a broad tax reform in Congress, which includes a higher carbon tax (Mesa Puyo & Zhunussova, 2023). An IMF assessment (Mesa Puyo & Zhunussova, 2023) as well as scholarly research (Mardones & Flores, 2017; Mardones & Ortega, 2023; Madeira, 2022) argue that the USD 5/ttCO_2e rate is low by international standards and would need to be increased in order to achieve the climate goals that Chile has set, such as carbon neutrality by 2050 (Framework Law on Climate Change). Studies show that the implementation of the proposed ETS could allow Chile to achieve its 2050 net zero pledge, by increasing the tax rate, replacing the taxation system with an ETS, or through the implementation of a hybrid system. In the latter the ETS could address emissions from the industry and building sectors (Arriet, Flores, Matamala, & Feijoo, 2022; Benavides, Díaz, O'Ryan, Gwinner, & Sierra, 2021; ICAP, 2023c; Mesa Puyo & Zhunussova, 2023).

The specific model to be adopted that will govern how the carbon tax, carbon offsets, and ETS will interact is still being determined.

of the power sector value chain, by way of applying the carbon price to fuels used in power generation. The regulation point of the CPI determines the agents the CPI will directly interact with, and therefore the challenges and incentives for decarbonization. A synthesis of the possible regulation points along the power sector is shown in Figure 3.2.

3.2.1 Upstream fuel distributors

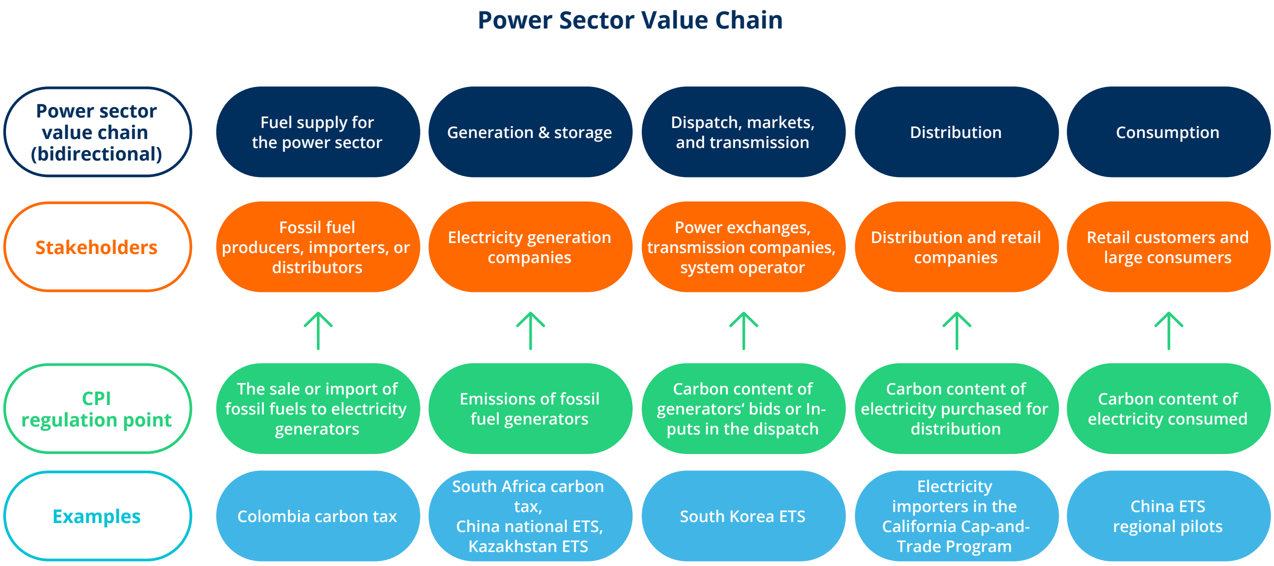
A carbon tax or ETS can be placed upstream of electricity generators, on fuels. In such cases the companies involved in the distribution or sale of fossil fuel must surrender allowances or pay a carbon tax according to the carbon content of the fuels they sell in a determined jurisdiction. The fossil fuel distribution companies then pass on the cost of the fuel to the purchaser. As a result, the carbon price is integrated into the fuel price when the power generation companies purchase them. If all fuel purchased is used to generate electricity, the impact along the power sector value chain would theoretically be the same as if the price were applied at the point of generation. However, policies that alter the price of fuels (for example other fuel taxes or subsidies, which are common in many LICs and MICs) can alter the carbon price signal when it is applied at this stage of the value chain. Subsidies could reduce the carbon price signal in the exchange of fuel, thereby reducing its influence on decisions around dispatch, fuel switching, and investments and retirements of power plants. They can also reduce the incentive to implement CCUS technology if the power generator is not exempted from paying the tax for the fuel corresponding to the captured emissions.

Colombia and Washington State placed their CPIs upstream of the power generation stage. In Colombia, all fuel buyers within the fuel distribution value chain pay the carbon tax at the point of sale or import, but the sellers or importers collect the tax at the first exchange and pay it to the national authority.[34] When current exemptions on coal for the power sector are lifted, this tax will

34 Following the implementation of ETS2, this system will also apply in the EU. More specifically, compliance rules will apply to suppliers, required to surrender permits for the emissions of fossil fuels sold to final consumers in the road transport and building sectors. "ETS2" has not been introduced yet.

FIGURE 3.2

Regulation points along the power sector value chain



be payable by relevant power generators at the time of purchase, as well as other purchasers. In a similar method, Washington State's cap-and-trade program requires fuel distributors to obtain emissions allowances for the fuel refined and used in the region.

3.2.2 Generation stage

A CPI can be applied at the generation stage. Power generation companies must then surrender emission allowances or pay a carbon tax proportional to their emissions.[35] Emissions are priced when fuel is combusted in the power plant and emitted at point source into the atmosphere. The cost of purchasing allowances or paying a carbon tax becomes an additional operational cost to the generation companies. Hence, the price signals are changed such that those generators with higher emissions (fossil fuel plants) become more expensive to operate. The carbon price has no or minimal effect on lower-emitting plants, giving them a comparative advantage. The South African carbon tax and the China and Kazakhstan ETSs all apply a CPI to the generation stage of the value chain. The California Cap-and-Trade system is an example of a CPI applied at the point of generation for electricity produced within the state as well as to companies that import electricity from outside the state. Section 3.2.4 describes how the California CPI applies to imported electricity in further detail.

Applying a carbon price at the point of generation typically filters through the value chain. If competition is sufficient, generators will typically sell their electricity at close to their marginal cost. Not passing on the cost of a carbon tax would mean a generator does not cover its unit operating costs, which is not rational market behavior.[36] Thus generation companies internalize the carbon cost into their selling price as they do with other variable costs.

35 If emissions are captured at the point source of emissions through CCS then there is no need to redeem allowances or pay a carbon tax. Under CCU (without storage), for e-fuels for instance, the carbon utilized in a product would still ultimately be emitted into the atmosphere and would lead to an obligation to surrender associated allowances, as is the case in the EU ETS. Both options are however dependent on the design of the ETS.

36 Unless there are other costs such as start-up and ramping costs that make a generator deviate from pricing its offers covering its marginal costs. In centralized dispatch models, such as that of the US, start-up and ramping costs are paid to a generator. This is done via power plant-specific uplift payments, which are added to the market price of electricity.

The cost of emission allowances to be passed through would usually use the secondary market as a reference. Generators have an economic incentive to pass on a price equal to the market value of allowances trading in the secondary market. If they do not generate electricity, they can sell their allowance at the market price. So long as the profit from the sale exceeds the profit of generating, they will have no incentivize to generate. Hence, generators price in the value of an ETS allowance on the market the day they generate or sell the electricity rather than the price at which they purchased the allowance (Frondel, Schmidt, & Vance, 2012). Distribution companies and retailers tend to pass on to consumers the carbon cost they paid when they purchased electricity on the spot market. In a liberalized retail market, it would not be economically rational for retail companies to sell electricity to their customers below the purchase price they paid in the wholesale market. In some countries, setting the price that low could be considered as anti-competitive behavior by the regulator.

Inhibiting the pass-through of carbon costs downstream can boost effects, however. As discussed in Section 4.3.1, such policies can include regulated retail tariffs that do not reflect the added costs of generation or, in certain cases, explicitly prohibit carbon cost pass-through. Such limitations put pressure on generators' finances, considerably increasing the effect of carbon prices upstream to disincentivize generation from fossil fuels. They may even discourage generators from generating in case the carbon price would make them run deficits. However, it also reduces the incentive for consumers to reduce electricity consumption or invest in energy efficiency measures.

3.2.3 Dispatch/transmission stage

A CPI can be placed at the dispatch stage to change the merit order. The system operator adds the full carbon price to the cost of generators when establishing the merit order. This action ensures the carbon price is passed through in full to the distribution and retail companies. However, the generators do not necessarily feel the carbon cost, in particular if generators receive free allowances or payment for the volume that the dispatch order would require them to purchase. In such a configuration, the regulation point of the CPI can be considered hybrid, since while it is the mandate of the system operator to implement it in the dispatch, payments and compensations might be applied at the generation stage, thus inducing effect both upstream (generation) and downstream (due to pass-through to distribution and retail companies). South Korea provides an example of an ETS applied at the dispatch stage. The new country's "environmental dispatch" system was established in 2022. This is described in Box 3.4.

BOX 3.4

Environmental dispatch system used in South Korea

Electricity generation in South Korea derives mainly from coal, at around 40% of generation, followed in descending order by gas and nuclear generation. Renewable generation makes a further small contribution to the generation mix but is expected to increase to 21.6% by 2030 (IEA, 2023).

South Korea's ETS (K-ETS) was launched in 2015, covering around 74% of national emissions by targeting the power sector, as well as industrial, buildings, waste, transport, and domestic aviation. The K-ETS allowance prices have varied between phases, starting at KRW 9,910 (USD 7.51) in 2015, reaching the peak of KRW 40,800 in 2019 (~USD 30), and falling again to the lowest value in 2022, at KRW 7,350 (USD 5.41)

(ICAP, 2023c). However, the general trend in allowance prices shows a steady rise since ETS implementation, and ETS design aspects in the current third phase are expected to strengthen the carbon price signal further (Kuneman, Acworth, & Bernstein, 2021).

Despite this progress, the ETS and power sector were structured in a way that ensured that power production profits remained stable and unaffected by the ETS, which created little incentive to reform or decarbonize supply or alter dispatch practices. Further issues included a relatively low allowance price, lack of carbon cost pass-through to end users, and high levels of free allocation (Asian Development Bank, n.d.).

The first issue was that wholesale electricity prices in the South Korean power sector did not reflect the emission allowance price (Kuneman, Acworth, & Bernstein, 2021).

Wholesale electricity prices were mainly determined in cost-based competitive markets through the system marginal price and the capacity payment, which did not reflect K-ETS allowance costs. The earnings for supplying electricity were based on a monthly rate determined by the regulator that would cover the cost of the generation with a markup. Power producers were also refunded for ETS allowance costs they incurred monthly through a mechanism external to electricity cost formation. This compensation mechanism acted as an effective government subsidy and was introduced to limit potential financial losses of power producers and prevent price increases for consumers (Kuneman, Acworth, & Bernstein, 2021). When it was combined with the 100% levels of free allocation, there was little carbon price signal felt throughout the sector, and effectively no carbon costs felt by the generators.

The economic dispatch model used to determine the dispatch order was based on technology benchmarks and corresponding operational costs set by the regulator, which also did not factor in allowances costs.

In 2022, South Korea introduced environmental dispatch into their electricity sector so that the Cost Evaluation Committee could reflect net allowance costs in the system marginal price, which determines the wholesale electricity prices paid to the generators. This dispatch method incorporates the cost of purchasing additional carbon emissions allowances (over the level of freely allocated allowances) into the marginal cost of carbon-intensive generation in the wholesale price (set by the regulator) with the aim of making carbon-intensive generation less competitive in the merit order. Under this environmental dispatch arrangement, the carbon cost and fuel cost determine the dispatch order, in order to facilitate fuel switching (Asian Development Bank, n.d.). Through this mechanism, coal-fired power generation would have the highest carbon cost and become disadvantaged in electricity dispatch decisions compared to gas-fired power generation. Thus coal power plants are pushed to the margin and used less often in favor of lower-carbon options. However, the carbon cost signal is not yet high enough to drive substantial fuel switching. In addition, because of the net cost compensation mechanism, the current system is expected to have a very limited role in guiding investment toward low-carbon alternatives or early decommissioning of the still relatively young coal power plant fleet (Park et al., 2023).

Though the impact of reform has been minimal, it is expected that in the future, as benchmarking reaches stricter targets and more of the sector's allowances are auctioned, the impact will become more material (Ernst, William, Tobias, & Anatole, 2021).

In theory a CPI can also be placed at the transmission stage. This would consist of internalizing the value of carbon in congestion pricing in situations where the lack of transmission capacity prevents the connection of RE plants and forces the local dispatch of fossil fuel generation plants. Such a carbon-based congestion pricing option,[37] which no country has used so far, would generate the incentive to build the additional transmission infrastructure where it is most needed to reduce emissions.

3.2.4 Distribution stage

A CPI can be applied at the distribution stage, making distribution and/or retail companies pay a carbon price proportional to the carbon content of the electricity that they purchase. This method requires a robust monitoring system to oversee the supply structure of retail companies and ensure that the correct CO_2 emission factor is charged for the electricity consumed. Distribution and retail companies will be incentivized to pass on the cost to their electricity consumers, which will pay higher tariffs in response to the carbon price. If there is sufficient competition between retail companies, they may compete to sign bilateral contracts with renewable and low-carbon generators to offer their customers attractive tariffs. This can increase the demand for renewable PPAs. However, where regulators approve regulated tariffs, a regulator can prevent distribution and retail companies from raising their tariffs to cover the cost of the carbon price.

The California Cap-and-Trade program has a distribution stage component. Regulation occurs at the point of generation and the point of electricity import. California is highly dependent on imported electricity, and many of the companies that import electricity are distribution utilities.[38] Importers are required to surrender allowances equivalent to a specified carbon content if the electricity was purchased from a known out-of-state generator or a default emissions factor if there is no traceable contract path to a generator (Von Wald, Cullenward, Mastrandrea, & Weyant, 2021). Under this system, importers have a strong incentive to source their electricity from lower-carbon suppliers, potentially by signing bilateral supply agreements with zero- and low-carbon generators. Utilities ended their contracts with coal generators in other states at the outset of the program to reduce their exposure to the California CPI (Cullenward, 2014).

3.2.5 Consumption stage

A CPI can be applied at the consumption stage, integrated into the consumer's electricity bill. The price is based on the consumption-weighted emission factor of the grid. A CPI applied at the consumption stage can take the form of an electricity tax, based on the amount of embedded carbon, or it can be incorporated into an ETS through the coverage of indirect emissions where a consumer's Scope 2 emissions (i.e., those that result from the purchase of electricity consumption; see Section 3.1.1) generate a compliance requirement. Consumers can respond to such a CPI in multiple ways, ranging from shifting the period of their consumption based on when electricity is most carbon intensive, signing bilateral contracts with renewable energy IPPs,[39] purchasing renewable energy certificates or offsets, implementing energy efficiency measures, becoming RE auto-producers, or even becoming

37 While not based on carbon-related congestion pricing, the principle of generating additional carbon revenue streams for transmission investment enabling emissions reductions has already been enacted via the Clean Development Mechanism of the Kyoto Protocol, which enables the certification of tradable emissions reductions certificates. (See https://cdm.unfccc.int/methodologies/index.html)

38 While some of the electricity importers are distribution utilities, not all of them fit neatly within this category: (1) importers could be owners of the out-of-state generation asset from which the electricity is derived; and (2) importers do not necessarily hold direct relationships with ratepayers.

39 Still, this raises the question of how such contracts will affect the calculation of the emission factor, especially if the consumer and the renewable electricity generator are not located in the same region.

prosumers (i.e., by installing solar rooftops). Unfortunately, in some LICs and MICs distribution companies do not have the proper metering and billing systems to monitor consumers' Scope 2 emissions, and, moreover, in some areas meter tampering and illegal connections are prevalent.

China used consumption stage ETSs in pilot provinces. Before the establishment of the national ETS in 2021, China conducted regional ETS pilots that included indirect emissions from electricity consumption in the quotas of the regulated industry facilities, covering both locally generated and imported electricity (IEA, 2020d). Since dispatch and retail prices for electricity were highly regulated, preventing the ability to pass through carbon costs in case it would have been applied at the generation stage, applying the carbon price to indirect emissions was an alternative to motivate larger consumers to alter their consumption patterns (IEA, 2020d). While including imported electricity reduced the risk of carbon leakage, it carried the risk of double counting emissions. China addressed this risk by using the regional grid average emission factors for indirect electricity emissions (IEA, 2020d).[40]

3.3 The potential role of carbon pricing in the power sector

The report considers that hypothesize that carbon pricing has five intermediate outcomes. These are based on the theory of change illustrated in Figure 1.1 and some depend on where the CPI is placed in the value chain:

- **A shift toward lower-carbon generation mixes** by creating price signals to invest in lower-carbon generation capacity and retire carbon-intensive power plants.
- **Prioritized dispatch of lower-emissions power generation sources** by changing the marginal cost of carbon-intensive generation and hence the merit order of different generation assets.
- **A shift toward less carbon-intensive wholesale electricity purchased by final consumers.**
- **A shift in consumption patterns in emission-intensive electricity systems**, in terms of either the quantity or the timing of electricity consumed, in response to the price signals.
- **An intake of new government revenues**, through either carbon tax yields or the proceeds of emission allowance auctions, which can be earmarked for social or environmental objectives.

The first three of these relate to the decisions economic agents make along the value chain. The first two depend on a CPI being placed at generation or the dispatch stage of the value chain. A CPI placed at the distribution or consumption stage could indirectly change investments and dispatch through consumers responding to a change in price signals.[41] The fourth intermediate outcome, related to change in consumption patterns, can occur regardless of where the CPI is placed along the value chain, as long as it is passed through the value chain to retail tariffs. The fifth intermediate outcome relates to the revenues, which can go toward decarbonizing the sector at different points in the value chain or toward more general government expenditures (compensating regressivity, balancing fiscal reform, etc.).

40 It should be noted that this system can weaken the impact of the price signal, since the use of the average carbon content prevents the companies with the lowest emissions from being favored compared to those with the highest emissions.

41 A carbon price applied at the point of distribution or consumption could theoretically also have a direct impact on decisions further up the value chain if market structures allowed consumers to participate directly in wholesale markets or if consumption practices shifted sufficiently (for example, in time of use) to affect wholesale market prices.

The structure of the power sector drives the impact of carbon pricing. In countries that have efficient and sophisticated markets for electricity trading, merit order dispatch, a variety of generation options available in excess most of the time, and mechanisms for passing through the carbon costs to consumers, carbon pricing can send signals throughout the power sector value chain and indeed the wider economy. However, carbon pricing is likely to function differently in jurisdictions with different power sector structures, particularly those with high degrees of government control (World Bank, 2019a).

The remainder of this section provides more detail about the five outcomes. The subsections that follow explore how these outcomes are expected to materialize in countries that have efficient markets for electricity trading, merit order dispatch, mechanisms for passing through the carbon costs to consumers, and/or adequate transmission capacity and dispatchable generation capacity. They also explain some technicalities related to the dispatch process and how carbon pricing can impact the so-called infra-marginal rent that generators can earn, leading to some rent transfer along the value chain from customers to generators. Chapter 4 builds on the theory and insights presented in this chapter to explain the challenges to implementing carbon pricing to achieve these outcomes in different power sector contexts, including in LICs and MICs.

3.3.1 A shift toward lower-carbon generation mixes

A carbon price can induce a shift to lower-carbon generation mixes by changing incentives in three ways. These include disincentivizing investment in new carbon intensive assets, incentivizing the early retirement of existing carbon-intensive assets, and incentivizing investment in renewable generation. This section explores each of these mechanisms in more detail. Research has verified that countries with weak or no carbon pricing tend to attract more international public financing for coal-fired power plants than renewable projects (Edianto, Trencher, & Matsubae, 2022).

Disincentive to invest in new carbon-intensive generation assets

Carbon pricing targets net present value (NPV). Investors typically forecast NPV, based on anticipated revenues and costs, when they assess whether to invest in a new generation project. The higher the NPV, the more profitable an asset is expected to be over its useful life. Carbon pricing can lower the NPV of high-carbon assets in two ways:

- By increasing the overall costs of a high-carbon power plant over the lifetime of the asset by adding tax and/or ETS allowance liabilities.
- By reducing the utilization rate of the asset, thus lowering expected revenue over time (Section 3.3.2 provides further information on how dispatch and utilization rates are determined).

The NPV is discounted using the generation company's weighted average cost of capital (WACC). If a CPI creates uncertainty regarding how many operating hours a generator will run for, this may increase the risk to investors. This can increase the cost of capital requirement by investors such that generators affected by a CPI become less attractive investments.

The CPI can decrease operating hours. Generators have an incentive to generate electricity if the price they receive is above or equal to their respective marginal cost.[42] Generators thus submit to the system operator their offer prices (in liberalized markets) or costs (in regulated markets) of generating a given amount of electricity. The system operator compiles all the offers/costs on a cost curve, with the lowest to highest bids/costs in ascending order. This forms the merit order curve, which shows how much electricity generators are willing to generate at a given price. This in turn determines operating hours, either through centralized dispatch through a system operator or by generators notifying the system operator of their own trades through PPAs or power exchanges, known as self-dispatch.

The type of CPI can have an important influence on how these impacts play out. Carbon taxes provide greater certainty on price. ETSs provide certainty on cumulative emissions reductions within the system, in that the cumulative number of allowances is limited. Adding price floors and price ceilings to ETSs provides some price certainty. The carbon tax is set by the government and typically projected into the future. For example, South Africa's carbon tax has been projected for each year until 2030. This provides some certainty regarding the cost of carbon in the medium term as long as the South African government does not change the projected rates.

TABLE 3.1

Comparison of ETS to carbon tax on emissions and prices

	ETS	Carbon tax
Certainty on cumulative emissions reductions	Yes (insofar as the government maintains the announced policy).	No.
Certainty on price	No, but the introduction of ETS allowance price floors and ceilings can provide certainty on the ETS allowance price range.	Yes, but possible political changes can lead to changes in the announced level of the tax.
Impact on investors	An allowance price below its long-term expectation is financially beneficial to fossil fuel generators, while a higher-than-expected allowance price can reduce expected revenues. The impact on dispatch and operating hours is also uncertain if trading in the wholesale market. The risk of higher-than-expected allowance prices can increase the WACC.	Investors can forecast impact on carbon tax but will not know the complete impact on dispatch and operating hours if trading in the wholesale market.

42 Some generators like coal power plants will also consider start-up costs when deciding to operate.

An ETS does not provide a stable carbon price signal. Since it was established in 2005, it has varied greatly and been impacted by macroeconomic shocks and other decarbonization policies that have shifted the price away from its expectations. After the global financial crisis, the allowance price decreased substantially from its forecast, and although this was beneficial to fossil fuel generators, it may have lowered the WACC for fossil fuel generation companies. The uncertainty regarding the future allowance price feeds into uncertainty about the future marginal cost of polluting generators, and this added risk can impact the risk-adjusted rate of return investors expect from the asset. If there is a higher downside risk to profits due to potentially higher than expected emission allowance prices, investors will demand a higher return on their investment. Therefore, the weighted average cost of capital will increase, and the net present value of the asset will decrease. If the government has not introduced a price floor and ceiling, a market participant can hedge the risk of allowance price volatility using risk-mitigation mechanisms. The overall impact on the net present value of the asset may also depend on the cost of such a financial instrument.

ETSs may nonetheless deliver the intended outcome more reliably than carbon taxes. Despite the greater uncertainty of the actual carbon price, an ETS provides more policy certainty than a carbon tax. The uncertainty around emissions reductions from a carbon tax raises the policy risk of locking in the wrong emissions reduction trajectory for a jurisdiction, while an ETS directly limits emissions. Box 3.5 provides insights into how generation companies purchase ETS allowances in the European Union.

Retirement of fossil fuel generators

Predictable carbon prices may create an incentive to expedite retirement of the most harmful power plants. Thermal generation may retire early and the most carbon intensive forms of thermal generation (e.g., brown coal) may retire prior to cleaner forms (e.g., natural gas). If a coal power plant receives fewer operating hours in the dispatch due to a carbon price that favors lower-carbon technologies (see Section 3.2.2), its revenues will be lower, and it could struggle to recoup its fixed costs, which will need to be honored despite a reduction in operating hours. If a carbon price is introduced to a generator on a PPA, and there is no clause for price adjustments for a carbon price, the plant can become uneconomical to operate. If this scenario persists, the power plant can be shut down indefinitely. Carbon prices can thus accelerate the retirement of high-carbon generation assets, and early retirements of coal plants in countries across Europe, in particular in Portugal and Spain, have demonstrated this impact (EDP, 2020).

However, under certain circumstances with insufficient capacities, undesirable effects can happen. In many countries fossil fuel generators are still needed to ensure system security and adequate supply margins and are thus valuable to the system. In liberalized wholesale markets, if a fossil fuel generator receives fewer operating hours due to a carbon price's impact on the merit order, firm and flexible power plants can mitigate some of the revenue reductions by increasing their offers during periods when the reserve margin is low. This can contribute to extreme wholesale prices during these hours.

Governments can introduce capacity markets to prevent such outcomes. Such markets can help ensure a sufficient number of flexible generators are available during market stress and reduce their need to recoup all of their costs over a few operating hours in the wholesale market. A fixed annual payment to a generator for being available during periods with low reserve margins can compensate a generator for its fixed costs and support financial return. Both Kazakhstan and Colombia have introduced capacity markets to support investments in generation capacity.

BOX 3.5

EU ETS allowance trading

In the EU ETS, there is no more free allocation of emission allowances for the power sector. Generation companies can purchase EU allowances (EUAs) at any time, from either the primary market (auction mechanism setup in each member state, selling allowances on a regular basis) or the secondary market (between market participants) to cover their emissions in accordance with the EU ETS rules. At the end of the compliance period (every year), they must surrender the number of allowances matching their emissions.

Instead of purchasing the EUAs they will eventually need to redeem on the EU ETS secondary spot market, generation companies in the EU frequently buy so-called "futures contracts" that hedge the price of EUAs in the future. These contracts function much the same as futures contracts for other inputs, such as fuels, that companies buy to hedge against future prices changes.

Financial intermediaries sell futures contracts on futures exchanges (such as the Intercontinental Exchange). Generation companies typically buy futures contracts for EUAs up to three years ahead of delivery.

Because an EUA is a perfectly storable commodity and there is no cost for storage, the futures price is linked to the EU ETS spot market price. Financial intermediaries can sell a futures contract today, purchase the contracted amount of EUAs in the primary auctions or the secondary market at any time at the price of the day, and store it until the delivery date of the futures contract. Upon entering the contract, the financial intermediary will charge a cost of carry (also known as the margin), which includes the financing costs (i.e., interest rate payments) of the futures instrument. It then sells the agreed volume of EUAs to the buyer in the future at the price on the day when the contract was initially signed. Hence, generation companies effectively purchase EUAs on credit, with the interest payment included in the cost of carry. This means that the total futures contract price is slightly higher than the prevailing spot market price for EUAs, but the generation company will have price certainty without needing to frontload all the cost of buying EUAs as it would if purchasing these on the market.

Not all jurisdictions with an ETS have an established market that includes futures contracts and corresponding financial intermediaries, but both are critical to the functioning of the EU ETS in the power sector. Without the ability to purchase futures contracts, a generation company may instead have to purchase all the allowances it needs in upcoming years today to ensure it has certainty on the EUA price. This cost would be a significant drain on the cash reserves of generation companies. By instead purchasing futures, generation companies cover their future EUA needs, but only pay the initial margin today, which is a fraction of the total price of the instrument. Financial intermediaries provide liquidity to the market, as well as carrying the risk linked to price variation and thus reducing the exposure of generation companies to variations in the market.

The price that generators pay for EUAs in the EU ETS is not necessarily the same as the carbon price that their bids on the power market reflect. Indeed, to ensure that the carbon price signal of the day affects all generators bidding on that day equally and thus effectively influences the merit order dispatch on that day, the EU ETS requires that the generators include the allowance spot market price of the day in their power bids, acting thus as price takers in the carbon markets for that purpose.

Capacity markets can extend reliance on carbon-intensive generation. By providing a lifeline to highly polluting power plants these markets can negate the incentive to retire them created by a carbon price. Usually, a carbon price does not directly increase the price a fossil fuel generator bids into capacity auctions,[43] but it could have an indirect effect. If the carbon price decreases the operating hours in the dispatch and the generator does not recover the lost revenue through extremely high pricing during low reserve margin periods, it can try and recover the lost revenue in the capacity market. Hence, a carbon price can have the indirect effect of increased costs in the capacity market above what would be needed without a carbon price.

In the long term, high prices in the capacity markets will likely lead to lower emissions. The higher prices charged by polluting assets in the capacity market will create an incentive to invest in low-carbon flexible generation capacity, which can also participate in these markets. As low-carbon flexible technologies exploit learning benefits and economies of scale over time, they are likely to become more cost competitive with high-carbon assets. Governments can accelerate the deployment of low-carbon flexible technologies through technology-specific auctions, as described in Section 2.1.2.

Incentive to investment in plant efficiency improvements, fuel switching, emission abatement technologies, and renewable energy

A carbon price can support investment in energy efficiency in power plants. Beyond creating disincentives to invest in new emission-intensive generation, a predictable carbon price can also create incentives for highly polluting power plants to reduce their carbon costs by investing in energy efficiency improvement measures, and thus have a lower effective emission factor. This is for instance the main expected outcome of a CPI based on technology-specific carbon intensity benchmarks, like the China national ETS (see Box 3.2). It can also incentivize fuel switching in existing facilities, such as adapting coal power plants to use biomass to reduce their carbon price liability. Alternatively, a CPI can incentivize installing emerging emission abatement technologies like CCS. Box 3.6 provides an example of how the EU ETS interacts with incentives for investing in CCS.

Direct carbon prices alone do not make renewable energy technologies more profitable. However, carbon prices can indirectly incentivize investment in renewable generation by increasing the marginal cost of fossil fuel generators, making them less competitive as an investment case

43 Such a direct effect is however not impossible: it can be featured in the design of the capacity market mechanism, as is currently the case in the PJM capacity market regulation, which states that capacity market sellers may include emission allowance costs (including those associated with the Regional Greenhouse Gas Initiative) as part of the resources' net avoidable cost rate calculation (https://www.pjm.com/directory/merged-tariffs/oatt.pdf, Section 6.8(d-1) of Attachment DD).

BOX 3.6

Incentivizing CCS in the EU ETS

Since 2013, the EU ETS has allowed for CCS technologies to be used to capture emissions from fossil fuel entities to reduce their compliance obligation. The EU ETS regulates emissions at source, such that fossil fuel emitters can reduce their compliance obligations by installing CCS technologies, and thus surrender fewer emission allowances. However, emissions can only be subtracted if the carbon is stored at a site permitted under the EU CCS Directive. Also, CO_2 must be transported through pipelines to be counted as emission reductions. The EU has developed detailed regulations for how CCS applications interact with the EU ETS. However, 10 years after the introduction of the ETS, there were no facilities that had stored carbon to reduce their compliance obligation.

As the EU allowance price reached euros 100 per ton in February 2023, the EU ETS is reaching prices that can make the installation of CCS financially viable. If the cost of installing CCS technology over its lifetime becomes lower than the projected carbon cost of an installation over a similar time frame, then CCS can be financially attractive to the investors owning the installation.

However, CCS technologies involve substantial up-front investment in return for long-term savings under a carbon tax or ETS or revenue through the sale of emission reductions or allowances. Fluctuations in the price of emission allowances could undermine the investment case. Carbon contracts for difference (CCfD) offer a potential solution to provide stable carbon revenue to companies looking to invest in CCS installations. A CCfD is a contract between two parties—typically a government and an investor—that allows the investor to hedge against market fluctuations in the price of emission allowances. If the final trade price is higher than the "strike price" listed in the CCfD, then the investor will pay the government the difference. If the opposite is true, then the investor will benefit from the difference. Governments are increasingly exploring CCfDs as a mechanism to strengthen the commercial case for investments in early-stage emission reduction technologies and materials like CCS and unlocking financing by providing greater price certainty.

against zero- or low-carbon technologies like wind and solar. If renewable technologies sell their power in the wholesale market with marginal pricing, they can benefit from an increase in the market clearing price if the marginal generator is a fossil fuel generator that pays the carbon price. The higher market clearing price increases the inframarginal rent (the difference between the market price and a market participants' marginal cost of production) that renewable generators receive. This can make the investment case for low-carbon generation stronger.

Many renewable generators do not sell electricity via the spot market but rather via bilateral PPAs. Spot market prices tend to be too volatile for securing financing for high up-front capital costs and low operating costs like RE. Thus, renewable developers tend to sign long-term, fixed price PPAs instead as these can provide long-term certainty about prices and offtake. The improved competitiveness induced by a CPI applied at the generation or distribution stage of the value chain can incentivize distribution companies or large consumers to sign long-term PPAs with renewable generators. This price certainty can be critical to the investment case for renewable technologies. However, a fixed offtake price as part of a PPA will prevent a renewable generator from benefiting from the higher clearing price in the wholesale market induced by a CPI.[44]

3.3.2 Influencing dispatch and wholesale purchases in favor of lower-carbon plants

A CPI can change the merit order of generators, in particular switch natural gas and coal. In the short run, a CPI can affect dispatch decisions through the merit order effect. Figure 3.3 shows a simplified illustrative example of a merit order curve. On the left, the demand curve intersects the natural gas "offer" without a CPI. Imposing a carbon price on fossil fuels impacts the marginal cost of different technologies. When a carbon price is applied, as in the figure to the right, the marginal costs of natural gas and coal increase, and coal becomes more expensive than natural gas due to its higher carbon emission factor. Thus, coal and natural gas switch in the merit order, and now coal, the most carbon-intensive form of generation, can become the most expensive technology (depending on the relative prices of coal, oil, and natural gas). The equilibrium price increases, total electricity generation is reduced, and natural gas can generate at full output, whereas coal generates at reduced output, as the marginal generator. Consequently, total emissions are reduced from fuel switching.

The change does not impact RE, which continues to be at the bottom of the merit order curve. Wind and solar are on the left side of the curve, for two reasons. First, different from coal and gas, the marginal cost of generating a unit of electricity using these low-carbon technologies is essentially zero—solar and wind are "free" inputs into the production process. Second, these technologies also have a cost of curtailment such that renwable generators will want to deliver all the electricity they produce at any positive electricity price. Therefore, zero marginal cost technologies are at the bottom of the merit order and since they are not impacted by the carbon price, they remain so after applying it.

Eventually, carbon pricing can align merit order according to both cost and carbon intensity. With a robust carbon price, the marginal cost of coal power, which is generally the most carbon-intensive form of generation, can become the most expensive technology (depending on the relative prices of coal, oil, and natural gas). If demand is sufficiently met by technologies lower on the merit order, the coal generator will not receive a buyer for its high-cost offer and will not generate in the hours where the electricity price is below its marginal cost. The outcome is that lower carbon-intensive technologies become more competitive and get prioritized in the merit order over higher carbon-intensive technologies and emissions are reduced.

Impact on the inframarginal rent received by the dispatched generators in the spot market

A carbon price increases the wholesale price in markets with marginal pricing, and therefore the infra-marginal rent, when the marginal generator is a fossil fuel generator. Figure 3.3 shows the merit order of generators in a hypothetical power system. The marginal generator sets the price in a wholesale market with pay-as-clear pricing. All generators that have lower marginal cost than the marginal generator receive an inframarginal rent. Prior to the carbon tax, this includes renewables, nuclear, and coal. Once the carbon price is applied, brown coal becomes the marginal generator and no longer

44 Power purchase agreements (PPA) are bilateral contracts for trading electricity between a generator and a supplier/retailer/consumer. As PPAs are signed between two agents, there can be a lack of transparency around their content and terms. The price of a PPA is usually fixed per MWh, except for adjustments for inflation, exchange rates, and fuel prices. As the price is fixed, a generator's revenues are determined by the number of operating hours and level of output it has been assigned in the PPA. If the price and number of operating hours are set out in a PPA, the investor has more certainty regarding the amount of revenue it will receive during the lifetime of the asset. PPAs are in many cases preferred for assets with large upfront capital costs and low operating costs, as they provide certainty on revenues, on which the investment case is based to recoup the high capital costs during the lifetime of the asset.

receives inframarginal rent. Instead, in the example shown, gas generators start receiving inframarginal rent. The carbon price reduces the inframarginal rent of black coal. The renewables and nuclear receive a higher wholesale price for their generation, and thus the introduction of the CPI induces an increased rent transfer from customers to those renewable generators, even if they are consuming zero carbon electricity. If a gas plant was the marginal plant before the CPI and it begins receiving an inframarginal rent because of the CPI, that inframarginal rent also represents a new transfer from consumers to the gas plant owner. Taxing these additional inframarginal rents may correct such rent transfer.[45]

Depending on the merit order curve and national circumstances, a CPI can increase inframarginal rent for some carbon-intensive plants. Fossil fuel plants can use different fuels (e.g., gas, coal), they can use different types of fuel (e.g., brown coal, black coal), and they can have different levels of fuel efficiency, which influence the marginal cost of a generator. If there are coal generators with different marginal costs being dispatched at the same time, and the coal power plant with the highest marginal cost sets the price (marginal generator), the more efficient and lower marginal cost coal plants will receive an inframarginal rent. After applying a CPI, the rent transfer does not change for coal power plants with the same emission factor as the increase in the carbon cost perfectly offsets the increase in the wholesale price. Lower-polluting coal power plants will increase their rent while higher-polluting assets than the marginal generator will have a decrease in their rent.

There is an extreme case of rent transfer from consumers to *all* generators. This occurs when the marginal generator is a fossil fuel generator and when ETS allowances are allocated for free. This is because fossil fuel generators include the opportunity cost of the ETS allowance price in their costs/bids (they could opt to sell these allowances on the carbon market instead), thus increasing the clearing price, without however having to pay for the allowances. Even the marginal generator gains the rent. This situation occurred during the pilot phase of the EU ETS, but it was resolved once allowances were auctioned in the following phases.[46] There are ways to prevent this outcome, for instance by collecting and redistributing part of that additional infra-marginal rent through separate channels that do not erase the carbon price signal (e.g., corporate windfall tax, profits levy).

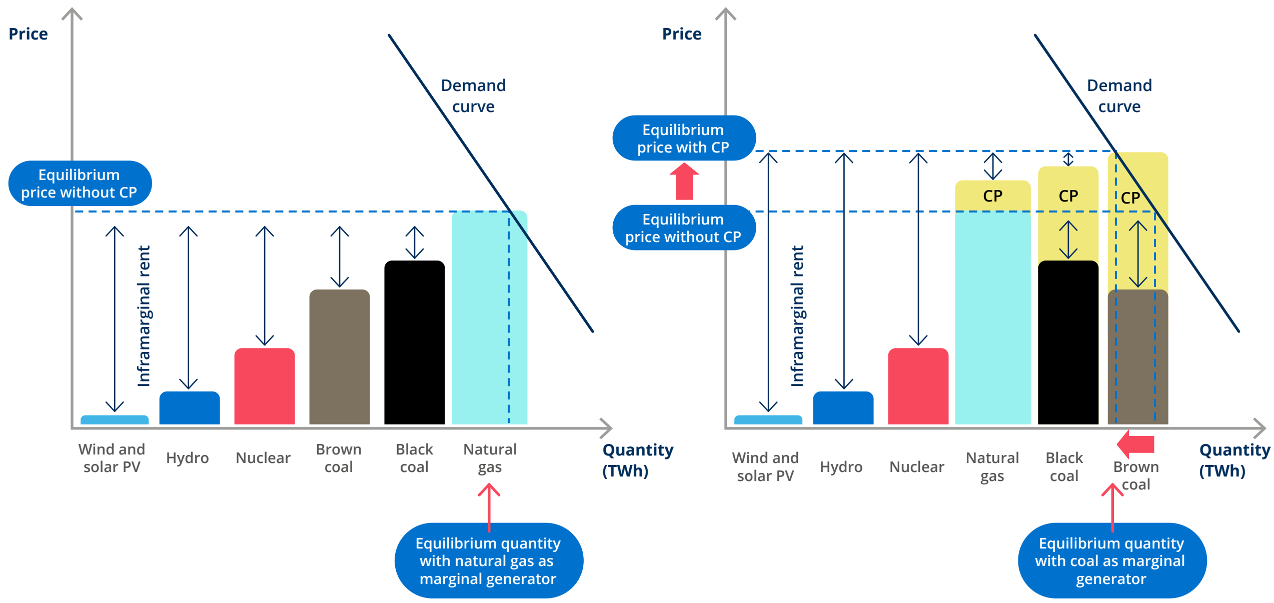
A shadow carbon price could induce a similar change of the merit order without adding a direct carbon cost. This option, which does not add any carbon cost to the current variable costs, would reduce the elevation of the rent and therefore the rent transfer. It can be a solution when the number of participants in an ETS would be too small to establish a functional carbon market or in case of a vertically integrated utility with internal dispatch. The application of the shadow carbon price in the dispatch would require independent oversight or be included in the mandate of the system operator.

45 This happened notably during the winter of 2022 when several European countries such as France and Greece taxed power companies' windfall profits.

46 There is abundant economic literature on the carbon pass-through after the EU ETS pilot phase implementation. Sijm J. , 2005, and Sijm, Neuhoff, & Chen, 2006 report that a significant percentage of the market value of free allowances is passed through to the wholesale electricity price on the German market, and substantially increases the profits of some companies. IPA Energy Consulting, 2005 and Fezzi & Bunn, 2010 find a similar cost pass-through in the UK and other EU countries.

FIGURE 3.3

Illustration of change in merit order with addition of carbon prices (CPs)



Carbon taxes and ETSs have differing impacts on dispatch. Carbon taxes provide more foresight and stability in the ranking of generators in the merit order. The merit order will still change over time depending on the relative input prices of coal, gas, hydro reservoir levels, etc., but not to the same degree as with an ETS. With an ETS, carbon prices change over time as the market trading determines new allowance prices, and it is not often clear what the allowance price (or future contracts) will be in a few months' time, thus adding the volatility of the carbon market to the volatility of the energy commodities. The fact that coal and gas power plants have different emissions intensities means changes in the allowance price can change the merit order during shorter periods of time.

Various factors cause uncertainty in the allowance price under an ETS, including RE variability. For example, RE generation is an endogenous factor in the demand for fossil fuels in power markets that can impact the allowance price in a system. For example, a year with high wind speeds and solar radiation can reduce the residual demand for coal- and gas-fired power plants, reducing demand for allowances. Similarly, the seasonal variations in hydrology impact the economic value of hydro plants. The market can flexibly adjust to these market outcomes over time and provide the most dynamic price signals for investing in and dispatching the appropriate generation technology.

In addition, in an ETS, there can be a time lag between when an entity purchases an allowance and when it prices the allowance into electricity prices, leading to multiple carbon prices. An entity can purchase plenty of allowances when allowances are relatively cheap during a compliance period (i.e., one year) but can still generate electricity from fossil fuel plants when the daily allowance price is the highest. It thus would not need to pay or to reflect the carbon price at its higher range, despite generating during the period when the carbon price is higher. The EU ETS has overcome this problem through requiring generators to include the allowance price of the day they generate as the carbon price that affects dispatch. As generators are price takers in the carbon markets at the moment they issue their bid on the power market, the carbon market directly and daily influences merit order dispatch in the EU countries. Box 3.7 describes the EU example of achieving decarbonization objectives with a policy package that includes the EU ETS.

Influencing the carbon intensity of the energy mix purchased by distributors

A CPI placed at the generation or distribution stage can improve the market for renewables PPAs. Retail or distribution companies that compete to sell electricity to customers will seek the most cost-competitive PPAs. If the carbon price increases the cost of fossil fuel generator PPAs without impacting renewables PPAs, this will incentivize distribution and retail companies to sign PPAs with renewable generation companies. This again will increase the demand for long-term renewable PPAs, which can lead to a more attractive market for long-term renewable PPAs. Renewable generation companies will be incentivized to commission new renewable projects to meet the demand for competitively priced renewable electricity. When placed at the distribution stage, the CPI offers an alternative to renewable portfolio standards that require suppliers to purchase a set amount of RE.

A CPI at the distribution stage can also indirectly impact dispatch. If a CPI placed at the distribution stage changes the retail tariffs, this can impact the demand for electricity. As explained in Section 3.3.3, the CPI will increase the price of a (cost reflective) flat tariff, which can incentivize reduced demand. As the marginal generator is commonly a fossil fuel generator, this will decrease the demand for this generator and consequently reduce emissions. If a CPI impacts ToU tariffs, shifts in consumption patterns away from periods with high fossil fuel generation can also reduce emissions. However, the merit order would not be changed and, for instance, coal might still be dispatched before gas.

3.3.3 A shift in consumption patterns

Carbon pricing in countries with carbon-intensive electricity generation is likely to lead to higher consumer prices. The expectation is that the cost is passed through the value chain to end consumers, either through competitive wholesale and retail markets or through regulated retail tariffs that are adjusted in response to the higher generation costs. For example, carbon costs are factored into retail tariffs in the UK, where the regulator determines a price cap on the

BOX 3.7

EU progress on decarbonizing the EU power sector

The share of renewables in gross electricity generation increased from 15% in 2005 to 44% in 2023 for the EU-27 member states (Ember, 2024). This was driven by the broad use of non-market-based schemes (such as feed-in-tariffs [FiTs], feed-in-premiums [FiPs], CfDs, etc.). Some evidence suggests that the renewable support measures contributed to a lower price of emission allowances, dampening the incentive to reduce emissions. Nevertheless, EU power sector emissions have dropped 46% below their peak in 2007 (Ember, 2024). While there is no observed counterfactual where the EU ETS was not implemented over the same period, statistical methods indicate that the EU ETS contributed to 7.5% of the emissions reductions during the period 2008 to 2016, despite low allowance prices (Bayer, 2020).

retail tariff, and where the UK ETS and carbon price tax (see Section 3.1.4) is passed through to the wholesale cost component that retail companies are allowed to recover.

Higher electricity prices caused by carbon pricing can make the consumers adjust their consumption and reduce their carbon footprint. If demand is elastic, consumers may reduce their electricity consumption through more diligently turning off appliances not in use or changing to more efficient appliances. Higher prices can also lead to households and businesses opting for investments in energy efficiency (heat or pressure recovery) and self-generation (solar rooftops) that reduce their electricity consumption from the grid or turn consumers into net electricity producers (ICAP, 2018).

Brazil provides an illustrative example of higher tariffs when availability of hydroelectricity is low. It has introduced a tariff flag system that adds an extra charge per kWh to consumers' bills when there is low availability of hydropower (for example in a dry year) and fossil fuel generators, which have a higher cost of generation, are supplying more of the power. The flag is green when hydropower is plentiful, yellow when it is less so, which carries a moderate charge, and red when conditions are most severe, which has two levels of charge (Stroski, 2019). Although the objective of the policy is to cover the higher cost of fossil fuel generation, it also bills fossil fuel generators.

Exposure to the higher cost of fossil fuel generation from a CPI can differ by the consumer. Large industrial consumers may be able to access the wholesale market directly and therefore be exposed to the hourly wholesale price. They will then have an incentive to adjust their consumption to the varying wholesale price, including variations due to carbon pricing. If a large consumer signs a PPA with a generator, then the carbon price may be passed through depending on the contract clauses and whether it is a fossil fuel generator. Large consumers would usually have many options to respond to the price signal reflecting the carbon price, including changing consumption patterns, investing in energy efficiency, signing bilateral PPAs with RE producers, developing self-generation, etc. Household and smaller businesses may only have access to regulated tariffs and, depending on the structure of the tariff and willingness of regulators to approve higher tariffs, may not be directly exposed to the cost of a CPI. If they are, they might also have options to respond to the variations due to the carbon price, although facing more constraints, including access to alternative suppliers and to financing. Box 3.8 explains how consumption patterns in the EU have been observed to change in response to fluctuating retail tariffs.

BOX 3.8

Changing consumption patterns in response to fluctuating retail tariffs

There is some evidence that consumers in the EU respond to electricity price signals from the region's ETS. Norway is part of the EU ETS but has negligible fossil fuel generators. However, it is connected to Sweden, Finland, Denmark, Germany, Netherlands, and the UK through interconnectors, such that the wholesale prices in Europe influence the Norwegian market. A study found that households with hourly pricing reduced their electricity demand by 2.92% in response to high prices communicated (Hofmann & Lindberg, 2024).

CPIs can change consumption patterns regardless of where they are placed in the value chain. In unbundled and liberalized power sectors, retailers or distribution companies buy electricity on the wholesale market or through PPAs with generators, and then sell the electricity on to end consumers. If a CPI is placed at the generation or dispatch stage of the value chain, the carbon price will be included in the wholesale price that retail or distribution companies pay, which they will pass on in their retail tariffs. If a CPI is placed at the distribution/retail stage of the value chain, distribution and retail companies will pay the carbon price on the carbon content of the electricity they purchase and will be expected to pass through the carbon price in their retail tariffs to cover their costs. Where a CPI is placed at the consumption of electricity, a separate carbon cost can be included in addition to the retail tariff charged by the retail or distribution company. However, this requires a smart meter to differentiate between hourly time periods according to the carbon intensity of the supply mix.

There is a whole host of ways in which retail tariffs can be designed. Retailers or distribution companies *supposedly* want to offer cost-reflective tariffs that cover their cost of electricity purchases, their operational and capital costs, as well as a rate of return on their investments. Hence, cost reflective tariffs will include the pass-through cost of a CPI. Where regulation does not specify a given tariff structure, retailers and distribution companies can typically choose how they design their tariffs. Options include:

- **Cost-reflective flat tariffs:** These will cover all relevant costs including the expected carbon price component. Higher tariffs, from (the pass-through of) a carbon price can incentivize reduced consumption of electricity. However, flat tariffs by default do not reflect the carbon intensity of the grid at a particular time of day, but rather are averaged over a longer period of time. Higher retail tariffs will increase the price signal and incentive investment in energy-efficient machinery, appliances, and behaviors. Tariffs can also reflect seasonal changes to costs, by having a different tariff for months with higher expected costs.

- **Cost-reflective time-of-use tariffs:** ToU tariffs have different electricity prices depending on demand at a particular time of the day. Typically, these consist of lower nighttime rates and rates and schedules are usually fixed for a period of months. Thus they are typically based on an estimate of the average carbon cost during day or night for the period, rather than the actual carbon content on a particular day or night. Although overall emissions are higher during peak periods with high fossil fuel content, it is possible that the emissions per kWh are lower when power comes from gas peaking plants, while off-peak generation relies proportionally more on higher emission-intensive coal generation. However, in countries with significant solar photovoltaic (PV) generation, ToU tariffs can create an incentive to consume electricity during the day when the solar PV generates the most, reflecting the change in the cost of the electricity generated.

- **Variable tariffs:** These are based on the hourly spot price in the wholesale market. In this case, the consumer will pay a low rate during hours with low wholesale prices, and higher prices during hours with high wholesale prices. The carbon price is fully passed through in the wholesale market, which again is fully passed through to the end consumer through the spot price tariff for a particular hour. The consumer now has an incentive to reduce their consumption during periods of high wholesale prices, which are typically when there is a high demand for electricity, or a high generation share of fossil fuel generators. This is known as passive demand-side management. The consumer shifts their consumption without any direct financial incentives other than the cost savings gained from shifting their consumption away from high price hours and toward hours where the price is lower due to an abundance of zero marginal cost low-carbon generation. The main way they do this is by adjusting equipment to run at the time with the lowest electricity price, such as heating, boiler, and washing machines, which can be set on timers or using smart meter functionalities. This will reduce the demand for the marginal generator, which is fossil fueled generation in many LICs and MICs.

Tariffs that reflect the carbon price can be implemented without a wholesale market. For countries such as South Africa and South Korea that do not have a wholesale market in place, the utility can set electricity prices based on pre-defined rules and methodology. This is typically done in countries where unbundling has not occurred, and a vertically integrated utility generates electricity and supplies it to customers. The impact of a carbon tax or allowance price on the regulated tariff will depend on the methodology and changes to the methodology may be needed to ensure the final tariffs reflect a carbon price. In South Africa, Nersa has stated in its Electricity Regulation Act (2006) that "tariffs and revenues must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return" (Eskom, 2021).

3.3.4 An intake of new government revenues

Both CPIs and ETSs can raise government revenue. In addition to providing a price signal along the value chain, a CPI can raise government revenues, which can be recycled toward decarbonization objectives at different points of the value chain or spent on general government expenditure (e.g., compensating for regressivity or balancing fiscal reform). For carbon taxes, revenue is only raised for sectors and entities that do not have carbon tax exemptions. In the case of an ETS, revenue is raised only if the government sells emission allowances, which is generally done through an auction, rather than giving them away for free. If allowances are allocated for free or there are exemptions to certain sectors, the government forgoes revenue from the scheme. Carbon pricing is rarely applied to the power sector alone. Therefore, any revenue the CPI generates in the power sector is only a contribution to the overall CPI revenue generation.

Some jurisdictions designate how such revenue will be spent. Strictly speaking, tax earmarking (ring fencing a tax for a specific purpose) is not economically efficient, because the revenue from a particular tax generally does not match the necessary expenditure for the designated purpose in volume, time, or consistency. However, earmarking can have advantages. It can make taxation more politically palatable and add transparency and accountability in public budgets, which strengthens the fiscal social contract between the government and citizens. Governments often commit to a revenue package that utilizes the revenues of carbon taxes and auctions of emission allowances for investments that stimulate the creation of green jobs and green industries, reduce the burden of the carbon tax on low-income consumers or electricity-intensive sectors, or shift the tax burden away from other forms of tax as a way to bolster public support. However, the extent to which a jurisdiction can do this depends on its legal system. In California, for example, the distribution of the climate credit (generated from private distribution utilities selling their allowances in the state's ETS) is overseen by the California Public Utilities Commission, the state's regulator of privately owned utilities companies, whereas revenue from the state's cap-and-trade program that is directed to the greenhouse gas fund must be spent in accordance with legislature requirements.

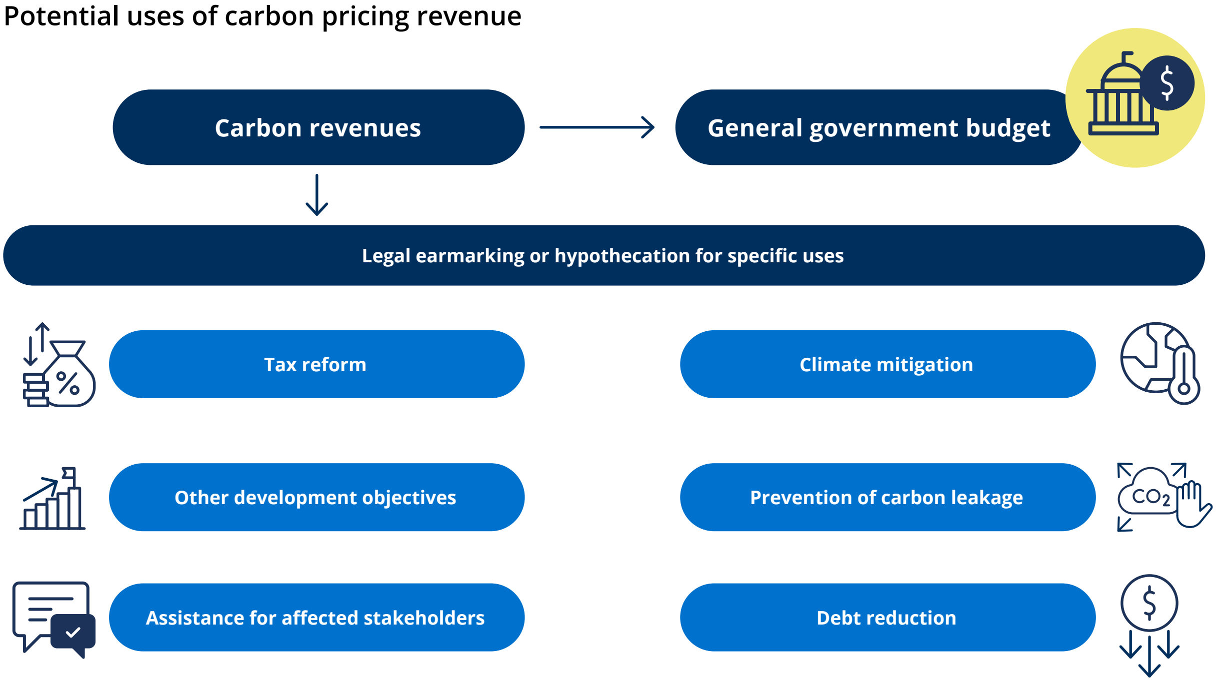
Revenue gathered from CPIs can be dispersed in varying ways. It can be placed into dedicated funds, used to support tax rebates, to support tax shifting, or to support decarbonization measures. Funds are expected to have more beneficial impacts on energy policy aims than the other two options, and many jurisdictions have established special-purpose funds to direct CPI revenue spending (ADB, 2022; World Bank, 2019). Targeted funds make clear what recycled revenue will be used for, showing transparency over government income. In relation to the power sector, revenues from a CPI could be used to reconcile carbon pricing with other energy policy priorities, such as supporting the objectives of affordability and competitiveness, for example through revenue checks for low-income households and reduction in corporate tax for companies that are export-facing (de Gouvello, Finon, & Guigon, 2020). This can be important for gaining public and industry acceptance for a carbon price. Revenue can also be used to support the transition to RE sources, for example by financing the cost of feed-in tariffs or feed-in premiums, providing incentives to increase renewable energy generation, therefore indirectly reducing carbon emissions by causing generation shifts (Kurakawa, 2020).

Revenues from a CPI can be used to compensate the sector for the cost implications of a CPI. For example, a revenue neutral scheme can return the revenues in the form of a lump-sum payment. Lump-sum payments are an efficient and non-distortionary means to allocate money to agents. Such payments will not undermine the agents' financial incentive to reduce emissions. A revenue-neutral CPI can help lessen the impact on businesses and consumers. Given the reliance of industry and services on electricity and fuels, this can ensure the CPI does not undermine the health of the economy.

Many countries spend revenue on climate-related activities. Figure 3.5 shows how carbon pricing revenues were spent during the year 2022-2023 for a number of different countries. The chart shows countries ordered by revenue raised in a descending clockwise order for both carbon tax and ETS separately, as shown by the arrow (volume of revenue decreases). Overall, the largest amount of revenue went to earmarked activities (58%) with general budget the second most common (32%).

FIGURE 3.4

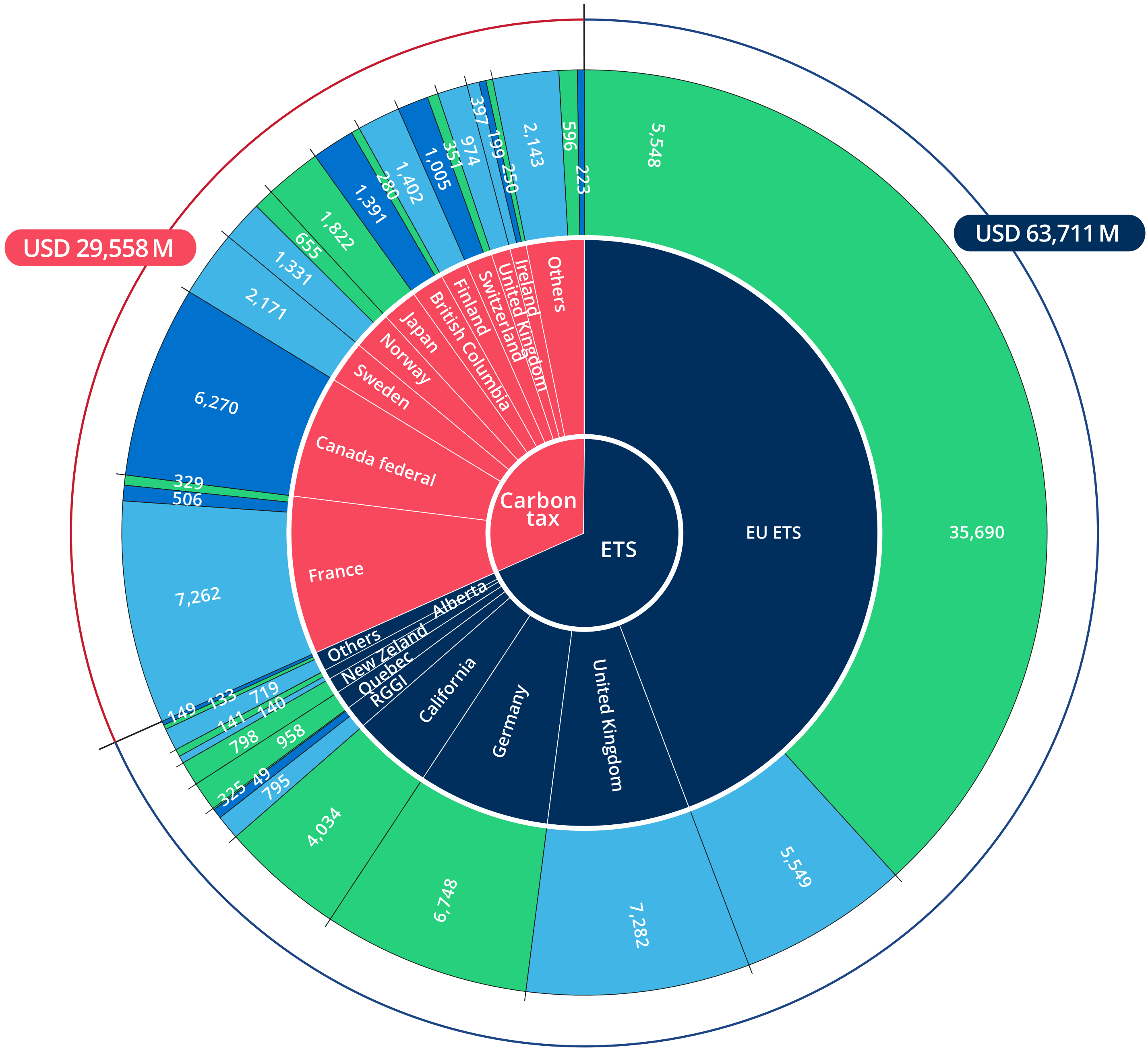
Potential uses of carbon pricing revenue



Source: World Bank, 2019, p. 23.

FIGURE 3.5

Carbon revenues by revenue use and jurisdiction, 2022–2023



Source: I4CE-Institute for Climate Economics with data from World Bank, government officials, and public information, November 2023

Revenues can be used to combat regressive effects. A CPI that leads to higher energy prices will directly influence net income and spending, regressively impacting lower-income households that spend a higher proportion of their income on energy use (World Bank, 2019b). Tax or ETS allowance revenues may be distributed to correct this effect. For example, measures to mitigate regressive distributional impacts can include energy subsidies for households, reductions on applicable carbon taxes for business, or investment in energy efficiency for households.

CPI revenues can also be used to reduce government reliance on other revenue streams. A carbon tax or ETS is generally considered more efficient than some other forms of taxation, because it is designed to correct the negative externalities caused by GHG emissions. The revenues from a carbon tax can be used to reduce inefficient taxes, to achieve a more efficient taxation policy. However, if a CPI is successful in achieving its primary aim of reducing GHG emissions, the revenues that it will generate will gradually decrease over time.

Revenue can be channeled to social and environmental objectives. Several existing carbon taxes and ETSs illustrate how. Box 3.9 describes how revenue from the EU ETS is earmarked for energy and climate change objectives. Similarly, under the Regional Greenhouse Gas Initiative in the northeastern United States, allowance auctions generate billions of dollars in new government revenue (RGGI, 2019).[47] The participating states invested 58% of this revenue in energy efficiency programs that have reduced demand for power, wholesale electricity prices, and consumers' electricity bills. Other examples of how the states used the auction proceeds include investments in community-based or private-sector installation of renewable energy or advanced power generation systems, credits to reduce consumers' electricity bills, funding for education or job training, or administering the RGGI or state government operations more generally (Hibbard, Tierney, Darling, & Cullinan, n.d.).

CPI revenue can be used to address political challenges. Examples in Box 3.9 demonstrate how the recycling of revenue from the EU ETS helped address stakeholders' concerns about the impact of carbon pricing on electricity tariffs and competitiveness, which can be instrumental in alleviating some the political hurdles to implementation. This function is described further in Section 4.4.

47 RGGI states generated $3.2 billion in allowance auction proceeds in its first ten years, according to "The Regional Greenhouse Gas Initiative: 10 Years in Review."

BOX 3.9

Use of revenues from the EU ETS

The EU has used auctions as the default method of allocating allowances since 2013. Between 2012 and 2020, an estimated EUR 57 billion was raised in EU ETS auctions. In 2019, total revenue exceeded EUR 14 billion. The ETS Directive states that at least 50% of auction revenue should be used for energy and climate-related purposes. Between 2013 and 2019, 78% of auction revenue was spent on energy and climate-related projects (European Commission, 2023b).

NER 300 Program:
The NER 300 Program, set up during the third phase (2013–2020), involved selling 300 million emission allowances from the New Entrants' Reserve. The funds were issued in two rounds of auction calls. The first award took place in 2012, awarding EUR 1.1 billion to twenty RE projects. The second award took place in 2014 and awarded EUR 1 billion to eighteen RE projects and one CCS project. Since 2014, no new proposals have been planned. Instead, future calls will be disbursed through the Innovation Fund.

The Innovation Fund:
The Innovation Fund is the EU's funding program for the deployment of net zero technologies. It provides support through grants, financial instruments, and project development assistance. It is funded from the proceeds from auctioning a set number of allowances. In 2023, the total number of allowances that fund the Innovation Fund increased from 450 million to 530 million. Based on a projected carbon price of EUR 75 per ton, the fund would have EUR 40 billion to invest during the period 2020–2030.

The fund focuses on projects that develop innovative low-carbon technologies, innovative RE generation, carbon capture utilization and/or storage, energy storage, and net zero mobility and buildings. Following the revised EU ETS Directive, different competitive bidding mechanisms can be used to support projects under the Innovation Fund. This includes (i) fixed-premium contracts, (ii) contracts for difference, and (iii) carbon contracts for difference. A new support mechanism called "competitive bidding" was introduced in 2023, which allocates projects based on auctioning. The first allocation will be through a fixed-premium pilot auction to incentivize production of renewable fuels of non-biological origin (RFNBO) hydrogen. A pilot auction was planned for November 2023 with a budget of 800 million.

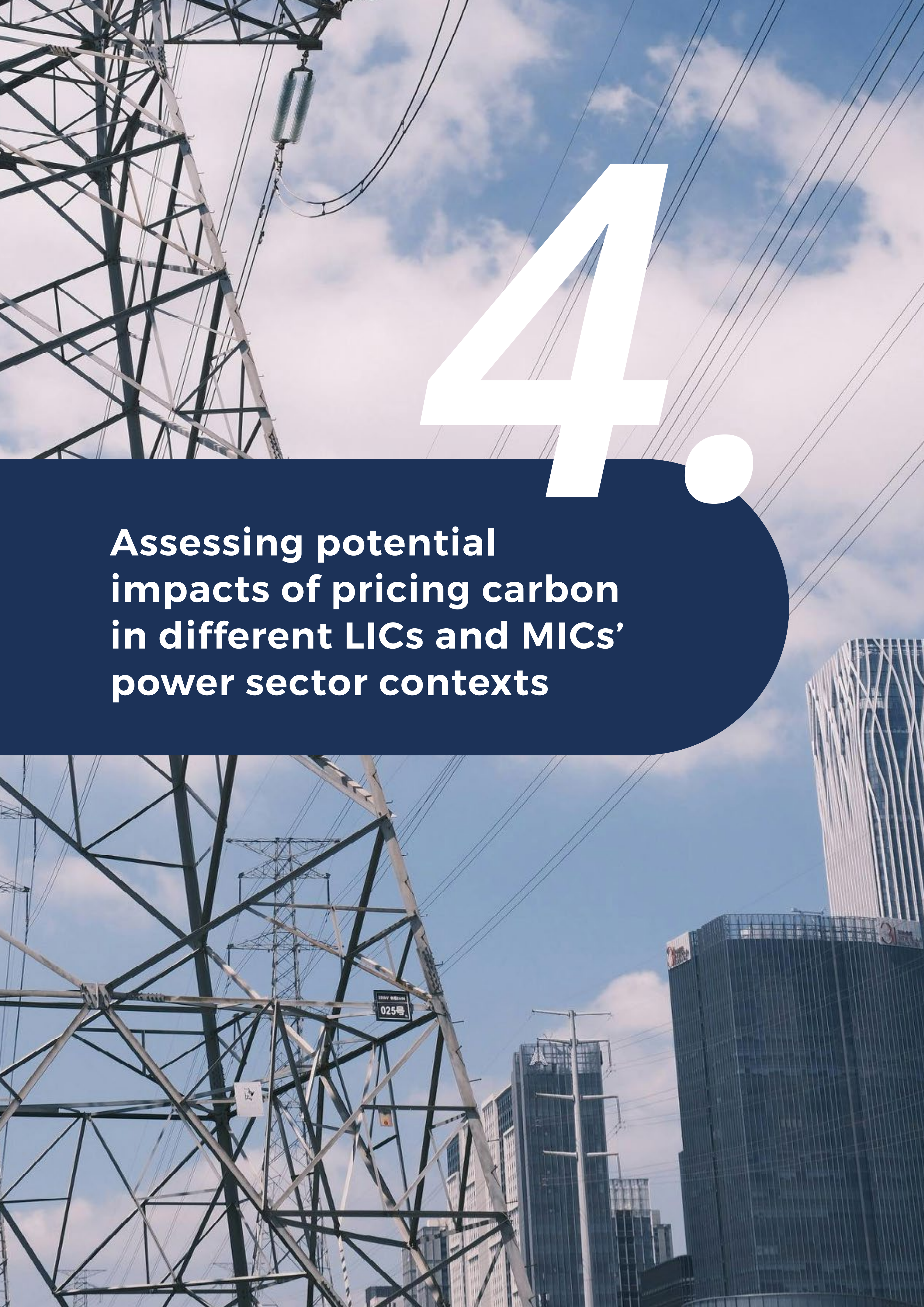
The Modernization Fund:
The Modernization Fund is a funding program dedicated to supporting the transition of ten low-income EU member states to climate neutrality. These countries are Bulgaria, Croatia, Czechia, Estonia, Hungary, Latvia, Lithuania, Poland, Romania, and Slovakia. The fund will support these countries with investments in renewable energy, energy efficiency, energy storage, energy networks, and a just transition in carbon-intensive regions.

The proceeds from 2% of the total allowances from 2021 to 2030 will go toward the Modernization Fund, an estimated EUR 20 billion across the period (assuming EUR 75/ton). Five beneficiary member states have opted to transfer additional allowances to the fund. This is expected to add around EUR 28 billion to the fund, such that its total size across the period 2021–2030 is expected to be EUR 48 billion.

To obtain financing for an investment from the Modernization Fund, member states submit proposals to the European Commission, the fund's investment committee, and the European Investment Bank. The bank confirms if the proposed investment is a priority investment, according to the EU ETS Directive. Non-priority investments can be granted based on technical and financial due diligence assessments. The commission then makes a disbursement decision.

The REPowerEU Plan

In the context of the war in Ukraine, in May 2022 the European Commission proposed a plan to decrease its dependency on Russian gas imports. Rapid reforms to the energy system were proposed. New financing had to be secured to invest in different areas of the energy system. It was decided to partly finance those new projects by dedicating additional revenues from auctions of emission allowances to what was dubbed the REPowerEU Plan. The target was to generate EUR 20 billion for REPowerEU funding—EUR 8 billion from member states' auctioning and EUR 12 billion from the resources of the Innovation Fund (European Commission, n.d.). Meeting this target (in euros rather than in EUA) will require adapting the additional sales according to the evolution of the price in the EU ETS: if the EU ETS price decreases, the volume of additional sales must be increased. This creates a risk of a bearish impact on the price since the supply of emission allowances is enlarged. A vicious cycle could arise, which could have counterproductive effects on the funding of REPowerEU, as the price signal that the EU ETS provides contributes toward the decarbonization of the European energy system.



4. Assessing potential impacts of pricing carbon in different LICs and MICs' power sector contexts

The previous chapter explored how CPIs could work in the power sector from a theoretical perspective and based on how they have worked so far, mostly in advanced economies. LICs and MICs have different policy priorities that translate into different challenges for their power sectors, in particular when it comes to implementing their new commitment to decarbonize their economies.

This section explores how a CPI has or is likely to function differently in jurisdictions with different power sector structures, particularly in LICs and MICs, where to date, carbon pricing has been applied to only a limited extent. This chapter is organized in accordance with the intermediate outcomes expected from the introduction of CPI as presented in the Introduction chapter (Section 1.2.3) and in the theory of change (Figure 1.1).

Tools provided in the appendix consolidate the insights of this chapter. The appendix to this chapter provides a series of three matrices, which are tools built upon the findings of this analysis to help track the impacts of the CPIs and eventually assess the different CPI options for each of three typical structure models for the power sector: (i) models, a fully unbundled and liberalized market; (ii) a single-buyer model, and (iii) a vertically integrated public monopoly. The first three matrices each propose in a systematic way the multiple chains of influence of an ETS and a carbon tax along the value chain of the sector as well as the conditions in which they result in effective emissions reductions depending on the power sector's structure. The fourth matrix is a qualitative and visual synthesis of the three detailed matrices.

4.1 The potential for a shift toward lower-carbon generation mixes

Carbon pricing can lower the carbon intensity of the generation mix but conditions apply. As explained in Section 3.3.1, a predictable carbon price can send an investment signal encouraging a shift in the generation mix toward lower- or zero-carbon power plants. To impact investment and retirement decisions, a CPI must be placed at the fuel supply, generation, dispatch, or distribution stage of the value chain. The generation and dispatch stages will impact the operating hours and revenues a generator receives, while a carbon price at the distribution stage may incentivize distribution companies to sign PPAs with renewable generators directly to reduce their exposure to a carbon price. However, in some power sector contexts, there are hurdles that can prevent carbon pricing from achieving the expected outcome of impacting investment and retirement decisions of generation capacity. These are discussed in the following subsections.

4.1.1 Insufficiently high carbon price to shift investment decisions

Some countries have set the carbon price signal too low. For a carbon price to affect investments and retirement decisions, it must be high enough to increase the cost of carbon-intensive generation such that it is competitive compared to lower-carbon alternatives. LICs and MICs that have adopted a carbon price have often included design elements that negated any potential impact on power sector investment or retirement decisions to protect industry, households, and businesses from rising electricity costs. Colombia and South Africa have both included exemptions from the carbon tax in the power sector, which has meant that price signals provided are negligible or nonexistent. In China and Kazakhstan, the method used to allocate emission allowances has resulted in a different carbon price being applied to natural gas and coal-fired generation, reducing the incentive to phase out coal (see Box 4.1). All these countries are intending to reform how the carbon price is set in the power sector in the future.

The carbon price must be stable to affect long-term plans. To have an impact on investment decisions, a CPI must have a predictable price trajectory to enable companies to factor the carbon price into long-term business plans. This requires stability of the political design and provisions that can provide some certainty on the evolution of the price. As most LICs and MICs are still in the early stage of implementing CPIs, frequently opting for a pilot phase for testing features, including caps, allowance allocation methods, level of carbon tax and exemptions, as well as the possibility to use offsets, the predictability of the carbon price signal has generally been limited so far.

BOX 4.1

The impact of Kazakhstan's ETS on investment and retirement decisions

Kazakhstan has implemented an emissions trading system that currently uses a benchmark approach in which emission allowances are only traded in the secondary market between ETS market participants. Unfortunately, the design of the benchmark system means the price signal is currently too low to encourage a shift in investment decisions toward low-carbon sources.

Kazakhstan introduced an emissions trading system in 2013, and it is now in its fifth phase. It has covered the power sector since Phase 1 and used grandfathering as the free allocation method in Phases 1 and 2. Benchmarking was introduced in Phase 3, which applies different emission benchmarks to different generation technologies based on their fuel use. Since Phase 4, only a benchmark approach has been used to allocate allowances. In Phase 5 (2022–2025), the free allocation is based on the average output during 2017–2019, multiplied by the technology benchmark, and adjusted down by 1.5% for each year during the phase.

Kazakhstan's ETS, as currently structured, provides limited incentive to shift investments and retirements in a transition to lower carbon generation. The benchmarks are set at a high level, resulting in an oversupply of allowances, which has caused the price of emission allowances to remain low, at roughly KZT 563 (~USD 1.22 per tCO_2e). The principle of "one product, one benchmark" is also currently not being applied in the power sector. Instead, a different benchmark is applied to coal and gas power, meaning that coal generators receive more emission allowances than gas generators. With these two benchmarks, there is only an incentive to reduce the emissions on the margin, and not to shift to lower-carbon forms of generation, such as from coal to gas. In Phase 3, the coal benchmark in Kazakhstan was 0.985 tCO_2/MWh and the natural gas benchmark was 0.621 tCO_2/MWh, compared to a coal benchmark of 0.75 tCO_2/MWh and a natural gas benchmark of 0.365 tCO_2/MWh in Germany (Howie & Atakhanova, 2022). These different benchmarks could create an incentive for future investments in more efficient (ultra-super critical) coal plants rather than gas generation capacity. Giving all power generators the same benchmark (under the one product, one benchmark principle) could strengthen incentives to transition away from emissions-intensive generation. If a single benchmark were applied to the electricity sector, the carbon price might incentivize the most emission-intensive technology to be retired before less-polluting technologies.

The price of emission allowances is expected to increase going forward as the reduction factors reduce the allowances each year. The benchmark emission factors are also expected to be reduced in the future. However, there is little indication that government or private actors have begun factoring these price increases into tariffs, power purchase agreements, or plans. The planned energy balance up to 2035 gives no indication that carbon pricing was factored into the cost curves in the energy balance modeling exercise. Instead, the NDC emission reduction targets were used as an underlying assumption. This forecast energy balance is re-approved each year, so it will incorporate new policies and developments in subsequent revisions. The PMI Kazakhstan program currently includes plans to strengthen the auction design, benchmarking, and MRV of the ETS to cover additional sectors and to focus on just transition and stakeholder engagements (PMIF, 2023).

4.1.2 Security of supply challenges

Alternative options for lower-carbon dispatchable generation may not be available in the short term and/or transmission constraints may inhibit the addition of alternative options. If there are limited low-carbon dispatchable generators in the system, fossil fuel generators will be called upon to ensure energy and system balance. In these cases, a carbon price will add costs to the system without achieving a shift to a lower-carbon electricity mix.

Moreover, to enable a shift from coal to natural gas generation capacity, a gas network needs to be in proximity to the gas generation plant. In Kazakhstan, a limited gas network hinders its opportunities to invest in gas plants across the country (see Box 4.2).

Limiting pass-through can create negative incentives, including energy security issues. Some LICs and MICs have a wholesale price cap in place or restrictions on generators' ability to pass on carbon costs along the value chain. In this context, fossil fuel generators will have to pay the carbon price without passing the cost on to distributors or consumers. Countries with wholesale price caps that are set too low often find there are issues with reliability and adequate capacity margins in the grid. Similar to situations of fuel price peaks, a too-high carbon price without the possibility to pass it through might generate an incentive for carbon-intensive plants to try to escape from dispatch, for instance by entering "on-maintenance" mode to limit financial losses, thus possibly undermining energy security.

There might be unexpected effects on capacity mechanisms. Some dispatchable generators, such as peaking plants, rely on the high wholesale prices in a limited number of hours each year to recoup their capital expenditure. As mentioned in Section 3.3.1, higher-capacity payments can incentivize a shift to low-carbon flexible technologies in the longer run. However, for countries that have adopted capacity auctions, if the auctions do not differentiate between technologies, there is a risk that the higher carbon assets will be awarded payments, which can lock in existing high-carbon assets for longer periods while crowding out new or higher up-front capital cost low-carbon flexible technologies from the market.

BOX 4.2

Issues with incentivizing lower-emission generation in Kazakhstan

Kazakhstan has both coal and gas resources. However, its gas network is only built out in certain areas, and this hinders investments into new gas generation assets where the gas network does not exist. Fuel switching from coal to gas cannot take place without the required gas infrastructure to supply gas power stations. This limits a carbon price's ability to incentivize fuel switching and can lock in carbon from existing or new coal power plants for years to come.

Kazakhstan also has wide variations in temperature between summer and winter. In the winter, the temperature can fall to -40°C, and part of the population relies on reliable heat from combined heat and power plants for survival. The intermittency of solar PV and wind will require significant dispatchable generation on standby to cover shortfalls in intermittent renewable generation during the winter.

4.1.3 The influence of power sector structure on investment and retirement decisions

Different power sector structures can impact how carbon pricing interacts with investment decisions in generation. Power sector structure impacts how electricity is traded and between what parties. When a carbon price is levied at the generation stage of the value chain, generation companies may have different incentives based on the power sector structure in place in a jurisdiction. Vertically integrated utilities can determine investments in the generation fleet based on government mandates or its own incentives and internal plans. If vertically integrated utilities know they can pass on the cost of electricity to consumers, they may invest in a generation fleet that serves their special interests rather than minimize total costs subject to security of supply. Continuing emphasis of vertically integrated SOEs on fossil fuel electricity, especially on coal, may reflect the desire of governments to maintain the value of sunk cost in investment leading to carbon lock-in (World Bank, 2023).

While a carbon price can change the relative operating costs of generators, a locked-in fossil fuel generation fleet will limit opportunities to deviate from existing generation schedules. If the vertically integrated utility has invested in sufficient generation capacity, it will not be incentivized to invest in new lower-carbon technologies at the expense of lower utilization of its existing fleet. In the absence of new investment, generators with higher marginal costs will continue to operate. As the utility can pass on the costs to the consumers, its financial return may benefit from this practice.

Where a utility contracts with IPPs, carbon pricing's ability to incentivize new investments in renewables may be overshadowed by a risk of insolvency for the utility. An indebted utility may struggle to honor its contracts and therefore create uncertainty about offtake from IPPs.

Competition is crucial if a CPI is to drive investment in renewables. A single-buyer model allows multiple sellers of generation, effectively introducing competition that will ensure new generation capacity is cost competitive. Investors will likely take a projected carbon price into account when considering investment in different technologies. The standard single-buyer model also means there are no bilateral contracts, which ensures the transmission system operator has complete control over dispatch (subject to its contracts with generation companies). Similarly, a wholesale market stimulates competition between generators, where investors will make the investment case based on the most cost-competitive technologies. A wholesale market allows for carbon pricing to shift new investment decisions toward low-carbon assets. However, long-term carbon price projections must be strong enough to reduce investors' risk. A volatile ETS allowance price may reduce investors' confidence in the predictability of the long-term carbon price signal.

Discussion about whether an existing wholesale market can incentivize low-carbon generation capacity at the scale and pace needed to reach global decarbonization goals is ongoing (Chattopadhyay & Suski, 2022, p. 26). Most renewable projects in LICs, MICs, and HICs are currently developed under support schemes that do not rely on carbon pricing (such as FiTs, CfD, guaranteed prices, etc.). In these cases, because it introduces low-carbon capacities based on out-of-the-market measures, an ETS applied at the generation stage could be negatively impacted, as the resulting reduction in market share for carbon-intensive generation could lead to a decrease in the price of emissions allowances. Consequently, even if investments in low-carbon technologies are implemented, the bearish impact on the carbon price could prevent the phase-out of the most emitting power plants. Governments must consider the interaction of different policy measures when designing renewable support measures and CPIs to avoid such outcomes. One way is to update the ETS cap trajectory over years to ensure the cap is set at a level that creates a robust carbon price signal.

Where relevant, long-term projections of carbon prices must be factored into central planning decisions to induce a shift to a lower-carbon generation mix in the long term. In many LICs and MICs, energy ministries, rather than markets, drive the decision of whether to add new capacity and what type, or when to retire existing power plants. Thus costs, which CPIs seek to manipulate, may not drive these decisions. Indeed, governments often optimize for factors such as the security of supply or the social impacts. These factors may negate the effect of the carbon price on investments and retirements. Optimization criteria for capital expenditure investments is in place, but there is a broader problem of trusting decisions to central actors, which creates the potential risk of gaming. Even if generally, capacity decisions are informed by least-cost modeling, there are challenges.

A forecasted carbon price could be factored into the cost of fossil fuel generation in this least-cost model, which would have the effect of favoring investments in lower-carbon over high-carbon forms of generation. However, least-cost models do not always factor in carbon prices. As well, governments may not provide a long-term projection of the carbon price, which can limit the ability of a central planner to correctly optimize the generation fleet for the thirty to forty years of operation that are typically the scale of investments in generation capacity. The projection of a reduced ETS cap each year also may not create a robust carbon price if complementary policies such as renewable auctions reduce emissions equivalent to the cap reduction factor. The design of an ETS, including design elements such as banking, can adjust the supply of allowances to achieve a robust ETS allowance price.

Sometimes the least-cost modeling is conducted with economy- or sector-wide emission caps or RE commitments as constraints, based for example on NDC commitments. Least-cost optimization can thus be used to optimize future generation fleet based on the constraints of a carbon tax, an emission cap, or a percentage reduction in emissions. However, many LICs and MICs have limited capabilities to undertake sophisticated optimization based on these criteria. Applying a shadow carbon price to the power sector, a hypothetical cost to carbon emissions, is a simpler way to alter the modeling output of integrated resource plans. The shadow price has the same effect on the model as a real carbon price but does not add actual costs to the electricity system.

4.2 The potential influence on dispatch and wholesale purchases in favor of lower-carbon plants in LICs and MICs

Influencing dispatch is an important mechanism by which a carbon price can affect greenhouse gas emissions in the short term. As explained in Section 3.3.2, the dispatch procedure determines the order in which generators are utilized to meet electricity demand. For a CPI to impact dispatch it must be placed at the generation or dispatch stage of the value chain. When a carbon price is applied to fossil fuel generators, it increases the short-run variable cost of fossil fuel power plants, such that carbon-intensive generators can become less favorable in the merit order. In contrast, lower-carbon generators that originally had higher costs than some fossil fuel generators may have relatively lower costs after a carbon price is applied to fossil fuel generators. As a result, fossil fuel generators' operating hours may be reduced, reducing their profitability and emissions (IEA, 2020). A CPI placed at the generation or distribution stage can also have an influence on the electricity traded through long-term PPAs as it will incentive purchasers to sign lower-carbon PPAs to minimize the carbon price they pay (either directly or in the PPA price). As with shifts in the generation mix, there are several factors that can inhibit carbon pricing from effectively favoring low-carbon technologies in dispatch and wholesale purchases. These are discussed in the following sections.

4.2.1 Capacity, energy, or grid constraints

Sufficient generation capacity is crucial. Sufficient generation capacity must be available, beyond the minimum needed to serve the demand, for system operators, distributors, and/or large consumers to select between high- and low-carbon options and sufficient transmission capacity must be available to enable low-carbon options. Several LICs and MICs are severely capacity constrained, meaning that generation capacity that is available will tend to be dispatched regardless of the price. There are different levels of capacity constraints, ranging from chronically constrained to constrained only during peak periods. Ideally, additional capacity is available at all times, but carbon pricing can have its intended effect on dispatch during off-peak hours even for a system that experiences capacity constraints during peak periods. However, as mentioned in Section 4.1.1, this would require that the carbon price is sufficiently high to dispatch lower-carbon before higher-carbon generation, i.e., gas generators before coal. Box 4.3 discusses the challenges that South Africa has faced with security of supply. Another issue LICs and MICs commonly face is a lack of transmission infrastructure to get renewable electricity to market, which forces system operators to curtail renewables and prevents distributors and large consumers from signing PPAs with them.

BOX 4.3

Security of supply in South Africa

The power system in South Africa has suffered from ongoing power cuts and rolling blackouts in the last few decades. In 2022, power cuts occurred on more than 200 days with outages of six to eight hours a day for most households (Enerdata, 2023b). The problems can be attributed to a lack of sufficient generation capacity and a low energy availability factor of existing plants. In 2023, there were periods when Eskom's coal power plants had an overall capacity factor of only 45% (Daily Investor, 2023).

The main driver of these supply problems has been Eskom's financial struggles. The utility has experienced cost and schedule overruns at new coal plants, tariffs that do not reflect actual production costs, and mismanagement such that it is deeply in debt (Hanto et al., 2022). This financial situation hampers Eskom's ability to maintain its generation assets. As maintenance works get postponed, a coal power plant can experience more unplanned outages, which reduces its availability factor and adds to the supply constraint problem. Eskom's financial constraints also limit its ability to invest in new generation plants. For example, Eskom has been granted permission to build a 3-gigawatt (GW) combined cycle gas turbine power plant in Richards Bay using liquefied natural gas. However, because the National Treasury has given Eskom debt relief, Eskom is not allowed to borrow any more money, and thus it cannot finance the construction of the plant. The capacity constraints facing South Africa will persist until more plants are built, and all power plants will be dispatched to meet peak and even part of off-peak demand when they are available, regardless of the cost of carbon.

Energy constraint is also a problem. Countries can become energy constrained when the inputs into certain generation technologies are limited. For example, countries that rely heavily on hydropower in their electricity mix can become energy constrained during droughts. Colombia provides an example (see Box 4.4).

For the carbon price to drive a shift from coal to gas generation, access to gas must first be secured. It must be naturally endowed with the required resources or able to import the fuel from other countries. Gas infrastructure must also be in place to transport gas from its storage sites to the gas generator locations. Without these conditions,

BOX 4.4

The impact of Colombia's carbon tax on dispatch decisions

Colombia first introduced a carbon tax as part of structural tax reforms in 2016. In the current design, the tax applies to the carbon content of liquid and gaseous fuels. It does not apply to coal or gas when used for electricity generation. Therefore, the tax has not applied to the power sector and thus has likely not impacted dispatch decisions in the past. However, following tax reforms in 2022, the carbon tax will gradually be applied to coal generation, starting at 0% in 2024, increasing by 25% intervals until the full rate applies in 2028. Gas used for electricity generation will remain exempt from the tax.

Colombia uses a merit order dispatch system, where centrally dispatched generators compete for the right to generate. The market is cleared ex post, such that dispatch and wholesale prices are determined based on the actual bids and offers at the time of dispatch, together with the activation of ancillary services.

Colombia's power mix is highly seasonal, with hydropower providing baseload power and grid balancing services in the wet season and coal and gas providing it in the dry season. The value of hydropower in the spot market is complex and depends on the amount of water in the reservoirs, expected rainfall and weather conditions, as well as prices of other generators and expected demand. This value determines whether a hydro generator will be the marginal generator, or whether coal or gas will be the marginal generator in the spot market. In wet seasons, hydro generators tend to drive the wholesale price of electricity, as they set their prices marginally lower than coal in an effort to be dispatched. In dry seasons, gas generators tend to drive the wholesale price as hydropower capacity is greatly reduced and more expensive gas power is utilized.

When the carbon tax does apply to coal power generation in Colombia, it may incentivize a shift to gas generation. This will only occur if the carbon tax is high enough to counteract the large price difference between the cheaper coal- and more expensive gas-generated power. This price difference fluctuates over time, but a small carbon tax is unlikely to overcome it. The effect may change in the future as the carbon tax increases and the electricity mix changes to include a higher proportion of renewable capacity.

Colombia's transmission constraints create an additional barrier to the carbon tax influencing dispatch decisions. Even with the added tax, transmission constraints may result in wind and solar being "constrained off" and a coal or gas generator being "constrained on" to make up the shortfall of electricity from renewables that are constrained due to grid congestion near renewable installations. This leads to additional costs to consumers, as generators are dispatched out of merit, and thus no longer at least cost.

a carbon price cannot change generation from coal to natural gas. Countries may also be constrained in their natural endowment of coal, which dictates the type and quality a country is likely to use if it has domestic coal reserves and a coal power plant fleet. A carbon price may not incentivize a shift toward coal types with lower carbon intensity if this is not available at a competitive price to the existing coal type.

In situations where capacity, energy, or grid constraints inhibit the dispatch or purchase of lower-carbon alternatives, thermal plants will continue to be utilized, even if the carbon price applied increases their operating costs.

4.2.2 The influence of power sector structure on how carbon pricing affects dispatch decisions

Vertically integrated state-owned utilities bring specific challenges for a CPI to be effective. Several LICs' and MICs' power sectors are dominated by such utilities. Conflicts of interest can arise as a result, as the transmission system operator is owned by the same utility as the generation plants that could be disadvantaged by the carbon price. A vertically integrated utility may not be incentivized to follow a merit order dispatch protocol with discipline if it can pass on the full costs to consumers. As it has private insights into the running costs of different generators, it could in theory dispatch generators without including consideration of the carbon price. If it can pass on the cost of the carbon price to consumers through its retail tariffs, it may dispatch generators according to what maximizes the recovery of costs for its plants, rather than minimizing costs. If the source of renewable electricity is IPPs, the utility may be incentivized to run its own coal power plants rather than purchasing cheaper electricity from an IPP. In these cases, there is a risk that a carbon tax will not lead to a shift in dispatch practices toward lower-carbon options, but rather to higher overall system costs that the consumer or taxpayer will ultimately pay.

There are strategies to overcome these challenges. A government can strengthen its governance and frameworks to ensure dispatch protocol is followed and the carbon price is having its intended effect. One way to accomplish this is to ring-fence each generator, requiring the utility to account for the carbon tax or ETS obligation for each generator separately.

An alternative is to implement a shadow carbon price. A government could implement a shadow carbon price in the dispatch to ensure the dispatch favors lower-carbon generators. A shadow carbon price can change the merit order in dispatch, thus delivering the same emissions reduction but with no direct cost attached to it. There will be an implicit cost, which is the difference in costs of generating electricity based on a different mix of power plants and dispatch operations. A shadow carbon price will not convey a price signal through the value chain[48] and is thus specific to the point in the value chain for which it is applied, that is, the dispatch. Using it to drive the dispatch requires a specific mandate assigned to the system operator, which must be supported by an appropriate regulation, including reporting and monitoring requirements. There is also a risk of a compounding effect if some parts of the value chain are covered by a real carbon price while another part is covered by a shadow carbon price, which requires simulation and coordination. In vertically integrated utilities, there may be a concern regarding how to observe that the shadow carbon price is being applied, for instance in the dispatch procedure. As generation companies will not be directly liable for paying for the carbon price and may not know the relative costs of all other generators, they may not know if the shadow carbon price is applied selectively to benefit the utility's own carbon-intensive generators.

48 Except in terms of additional costs that may be incurred by shifting toward lower-carbon options that are potentially more costly in the absence of a carbon price.

The single-buyer model brings different challenges. In contrast to the vertically integrated model, it ensures all generation companies are treated according to the same rules. If it does not allow bilateral contracting, the single-buyer model ensures all generation assets are dispatched according to the system operators' instructions. However, there is a potential risk to IPPs' revenue expectations if IPPs are not able to anticipate their generation schedule. To protect against low utilization rates, an IPP may require a take-or-pay contract that guarantees the system operator will pay for a number of hours (whether it dispatches those hours to the generator or not) (Chattopadhyay & Suski, 2022). The system operator may prefer to use all generators it pays for rather than pay for additional low-carbon generation when available and to also compensate higher-carbon generators for a set number of hours despite a lower running schedule.

Application of a carbon price can also affect existing PPA contracts. Contracts can be revised to allow the generator to pass through the carbon cost, or exemptions can be made. However, experience in LICs and MICs suggests that significant portions of power plant capacity are dedicated to bilateral PPAs and renegotiating the terms of these can present significant challenges. To reduce the use of take-or-pay agreements, a capacity payment can be introduced into PPAs that can ensure firm and flexible generators can continue operating at low utilization rates.

The same principle goes for wholesale markets. If centralized dispatch is deployed, the system operator can ensure generators are dispatched in merit order, but if self-dispatch is in use, bilateral contracts may interfere with the merit order dispatch. However, market reform toward a wholesale market model has been limited in LICs and MICs.

4.2.3 Failures at the dispatch point

Inefficient dispatch threatens the goals of carbon pricing. LICs and MICs often suffer from inefficiencies in dispatch due to several constraints, which cause networks to rely unnecessarily on expensive generation. As Section 2.2.2.1 describes, inefficient dispatch can result when generators sign long-term power purchase agreements that require a minimum level of generation and receive capacity payments regardless of their output. Inefficiencies can also result from a poorly designed or followed dispatch protocol, transmission constraints, or a lack of technical capacity among grid operators. It is difficult to determine the effect of a carbon price in a power sector that suffers from inefficient dispatch, and there is a risk that it will simply add additional costs to supply without shifting dispatch toward lower-carbon forms of generation.

Low carbon prices also undermine influence at the dispatch point. Economic dispatch (based on merit order) would by default prioritize the most cost-efficient generators in the system. When coal is much less expensive than gas, a low carbon price will not be sufficient to outweigh that gap. In this scenario, dispatch is not being influenced as intended, coal remains the "cheapest" dispatch option, and it could be prioritized over lower-carbon options. In such a case, carbon pricing will add a cost without changing the carbon intensity of the electricity consumed.

Exemptions for power generators have similar effects. Such exemptions are typically issued to secure national energy supplies and limit potential impacts of the carbon price on economic growth. Exempting certain fossil fuel generators from paying a carbon price signal can give them an advantage in the dispatch compared to other fossil fuel types. If such exemptions are applied to higher-carbon generators, such as coal power plants, dispatch will not be influenced in favor of the lower-carbon options, and the carbon price will be intentionally distorted. To overcome such issues around influence of economic dispatch, environmental dispatch could be introduced to favor lower-emitting generators, even if they are not the most economically optimal option.

4.2.4 The influence of power sector structure and regulation on how carbon pricing affects wholesale purchase decisions

Buyers of electricity on wholesale markets must be free to shift their sources for a CPI to be effective. The power sector structure also determines whether a CPI can influence the carbon content of electricity purchased through long-term PPAs. For this outcome to be realized, buyers of electricity on wholesale markets must be free to decide from which generators they source their electricity. South Africa recently granted permission for the City of Cape Town to purchase electricity directly from IPPs. In Colombia, retailers sign long-term PPAs with generators, and 10% of energy electricity retailers procure through PPAs must be with renewable generators. However, many LICs and MICs have vertically integrated systems or single-buyer models that do not allow bilateral PPAs between distribution companies or large consumers and IPPs. Thus buyers of electricity on wholesale markets are not free to decide from which generators they source their electricity and cannot shift their purchases to renewable generators to take advantage of their lower generation and carbon costs. Hence, these wholesale purchasers do not have the possibility to influence their Scope 2 emissions. There also may be other barriers such as credit worthiness that can limit a distribution company's ability to sign long-term PPAs with generators when the regulation allows it in some contexts.

Other difficulties in shifting purchase decisions can arise. Many of these mirror those associated with shifting dispatch decisions, including generation and transmission constraints and the need for lower-carbon alternatives to exist. Some are specific to the purchase point. Suitable policies and market arrangements for wheeling—the transportation of electricity through the electrical grid from seller to buyer—and other ancillary services must be established to enable the basic functioning and balancing of the grid during bilateral trading.

The degree to which distribution companies can pass through their carbon cost determines its effect. Distribution companies that are unable pass through their carbon costs to consumers will have a stronger incentive to source electricity from renewable generators than those that can easily pass on their costs through the value chain. Competition between multiple retailers, if enabled by the local power sector model, can make this difficult; the degree to which a company will choose to increase retail tariffs based on a carbon price will be driven by the competitiveness of the retail market and the risk that consumers will shift to another supplier or opt instead for self-generation. Section 4.3.3 discusses this issue further. In some countries a central regulator sets retail tariffs, while others regulate and constrain how distribution companies set them. If the regulator differentiates between controllable and uncontrollable costs, electricity purchases could be considered uncontrollable costs that must be passed through in full, while the network costs would be considered controllable costs. Most systems permit pass-through of taxes, including carbon taxes, which are considered fixed costs, but the extent to which the cost of emission allowances in an ETS, which are considered variable costs, can be passed through varies by jurisdiction.

Wholesale purchasers can also respond to a CPI by purchasing RECs or offsets. In addition, when subject to an ETS or a carbon tax, distribution companies can, depending on the national legislation, purchase RECs or offsets as described in Section 2.3. Introducing an REC or an offset scheme can offer alternatives to distribution companies to lower the carbon content of the electricity they sell to their customers. In doing so, they may alleviate the tax rate or decrease the electricity's carbon content below the set benchmark that would authorize the company to sell allowances instead of buying them. If no national REC mechanism is set, distribution companies might be able purchase international RECs instead to achieve their targets.

4.3 Potential shift in consumption patterns in LICs and MICs

Consumers can potentially respond to a CPI in many ways. In countries with carbon-intensive electricity generation, a carbon price will increase the overall cost of generation. If the added cost leads to higher retail tariffs, it could create an incentive for households and businesses to reduce their consumption of electricity, to consume it more efficiently, to shift consumption to times in the day when the carbon content of electricity generation is lower, and to invest in energy-efficient technology and/or into behind-the-meter RE like solar rooftops with or without battery. When large industrial companies are allowed to access the wholesale market, they also will have the incentive to sign bilateral contracts with RE producers.

Shifts in consumption can occur regardless of where the CPI is placed in the value chain, but there are barriers and risks. The goal of creating such shifts is to create impact upstream, such that fossil fuel generation plants are dispatched less frequently and thus potentially undermining the viability or attractiveness of such plants as future investments. However, the structure of the sector might prevent the pass-through of the carbon price signal down to the consumer. Moreover, consumption is the point in the value chain where some of the most potential adverse effects can be observed, particularly in terms of affordability and competitiveness. The following subsections describe some common challenges of shifting consumption patterns in the context of LICs' and MICs' power sectors.

4.3.1 Insufficient pass-through of carbon costs to retail tariffs

Some regulations interfere with pass-through. The governments of many LICs and MICs (including Kazakhstan) have explicitly prohibited generators from passing through carbon costs to protect households and businesses from increasing electricity tariffs. In some cases, tariffs are cross-subsidized by large industrial or commercial tariffs and thus have no impact on the consumption patterns of households. As discussed in Section 2.2.3.1, in several LICs and MICs, regulators have kept retail tariffs below levels of cost reflectivity, such that electricity tariffs implicitly are subsidized by the utility (and eventually the government, as in South Africa).

Subsidized tariffs complicate the picture. Adding a carbon price to subsidized tariffs may provide a signal to consume electricity more efficiently, albeit not as strong a signal as without a subsidy. Keeping tariffs low can meet the government's objective of ensuring electricity is affordable to consumers, or avoid negative impacts on competitiveness. However, a controlled tariff may not be sufficient to change consumption patterns enough to meet emissions reductions goals. Where the carbon intensity of electricity grids is high, subsidized tariffs can function as an indirect negative carbon price, which incentivizes increased consumption of

BOX 4.5

Socioeconomic barriers to tariff increases in South Africa

Eksom makes annual requests to the National Energy Regulator of South Africa to boost retail tariffs, and disputes over Nersa approving less than Eskom requests often go to the courts. In 2023, Eskom requested an increase of 32% to help cover its debt burden; Nersa approved 18.7%, citing the needs of consumers and concerns about "the short, medium and even longer term" economic well-being of the country (EWN, 2023b).

Some level of cross-subsidization is also taking place. The inclining block tariffs were increased less than average, resulting in subsidies to residential customers at the expense of municipal, commercial, and industrial customers (Eskom, 2021).

The South African government said ahead of the 2023 tariff announcement it could not interfere in a statutory process of raising electricity tariffs, despite noting that "South Africans were not even getting the electricity they paid for" (EWN, 2023a). However, South Africa is currently looking to reform its power sector, with the unbundling of Eskom into separate legal entities.

electricity. Some jurisdictions have therefore reduced tariff subsidies prior to adopting carbon pricing. As explained in Section 4.4, governments can use revenue recycling from a carbon price to ensure that low-income households and export-facing businesses are protected from increased electricity prices attributed to a CPI rather than controlling tariffs. As Box 4.5 discusses, however, it is difficult to ignore socioeconomic considerations when setting tariffs. Many LICs and MICs have been cautious about such changes because of political concerns, as described in Section 5.4.

Imposing a carbon price directly on large industrial consumers subverts the problems of pass-through. As outlined in Section 3.2, a large industrial consumer of electricity can be included in an ETS and thus required to surrender allowances for the carbon content of the electricity it consumes. It may therefore decide to invest in energy efficiency activities that reduce its overall electricity demand, invest in auto-generation (e.g., solar rooftops on industrial facilities and industrial parks), or sign bilateral contracts with RE IPPs. As seen in Colombia and South Africa, the willingness of large consumers to sign long-term PPAs with renewable generators, even when a carbon price is not applied to them directly, is crucial to show bankability of the projects, and to the expansion of low-carbon options in the energy mix. This influence on consumers can therefore be a key factor in potential future displacement of thermal generator options.

A consumption tax on electricity can also induce a reduction in emissions in carbon intensive systems. A consumption tax on electricity, while not proportional to the carbon content of electricity, can incentive reduced consumption and investments in auto-generation and thus reduce emissions in carbon intensive power systems. It does not tend to affect investment in RE generators, however. South Korea's consumption tax on retail tariffs provides an example (see Box 4.6).

BOX 4.6

South Korea's inclusion of carbon costs in retail tariffs

South Korea has a wholesale electricity market, but KEPCO, a state-owned company, maintains a monopoly over the country's distribution and retail sectors. KEPCO has historically prioritized electricity price stability for customers over cost reflectivity. As a result, changes to generation costs, such as a carbon price, do not affect customer electricity bills. For example, in 2022, KEPCO absorbed much of the price volatility of gas and coal power, resulting in a USD 18 billion loss (Heinemann, Frizis, & Heilmann, 2022). Hence, there has not been an incentive for demand-side shifts.

In 2021 Korea introduced a climate and environmental charge, which effectively serves as a consumption tax, that appears separately on electricity bills in addition to the main retail tariff. This addition consists of charges to contribute to the cost of the ETS, the Renewable Portfolio Standard (previously included in the main tariff), and surcharges associated with coal reduction policies. It is debited to consumers on a volumetric basis (Ernst, William, Tobias, & Anatole, 2021).

The introduction of this additional climate rate sets a mechanism for cost recovery that will become increasingly relevant as wholesale electricity prices reflect higher shares of allowance costs in the future. To be successful, the climate rate, or retail tariffs more broadly, will need to be kept at pace with rising costs under the ETS (Ernst, William, Tobias, & Anatole, 2021).

Outside of electricity tariffs, large industrial electricity customers are exposed to the carbon price of the ETS due to the indirect emissions of the electricity they consume, although this effect is limited, as it only applies if they exceed their free allowance allocation (Asian Development Bank, 2018).

4.3.2 Time-of-use tariffs and smart metering

Currently, ToU tariffs are rare in LICs and MICs and tend to reward use of carbon-intensive fuel. As explained in Section 3.3.3, ToU tariffs create an incentive for consumers to shift consumption toward times during which generation is the cheapest, thus potentially when renewable electricity generation is greatest and emissions lower. However, this requires several conditions not common in LICs and MICs. ToU tariffs require smart meters, which have been uncommon in LICs and MICs. Likewise, making use of such meters requires that the utility have the capacity to be commercially efficient; that is, that it have a regularly updated customer database and be able to quickly replace defective meters, detect fraud and regularize illegal connections, and bill and collect payment efficiently. Those LICs and MICs that have implemented ToU tariffs have set them so that they reflect the variation of the generation cost, not the variation in carbon content. Since coal generation is generally cheaper than gas generation, making ToU tariffs carbon friendly will require a change in this methodology.[49] Box 4.7 describes the time-of-use pricing in South Africa. As is common in LICs and MICs that have ToU tariffs, it is only implemented for large customers and it has met a number of challenges.

49 Typically, when gas power is more expensive than coal power is used at peak time, ToU can create an incentive to shift out of peak when coal is used.

BOX 4.7

Time-of-use tariffs in South Africa

Eskom offers time-of-use and seasonal tariffs to larger customers and municipalities. This includes the MegaFlex tariff for large customers, which differentiates tariffs based on time of day and season. The time-of-day component is divided into peak, standard, and off-peak rates. The seasonal component is divided into high-demand season (June through August) and low-demand season (September through May). The peak time energy charge is in one instance over six times higher than the off-peak charge, creating a strong incentive for customers to which the tariff applies to consume electricity outside of peak times (6–9 a.m., 5–7 p.m.).

Because South Africa's system generally has a low share of renewables, Eskom's time-of-use pricing is mostly based on changes to demand during the day in an already constrained system. Incentivizing consumers to not consume electricity during the periods with highest demand leads to less consumption during the hours when the costliest fossil fuel generators produce to meet demand, which include gas generators. Thus the marginal shift in demand caused by the ToU can move generation from gas during peak hours to coal during off-peak hours, and the ToU is more likely to increase emissions than reduce them.

As South Africa adds more renewable capacity to the system, ToU tariffs will increasingly reflect changes in the cost of supply throughout the day. Wholesale spot prices are typically depressed during midday/noon periods of high solar generation, as fossil fuel dispatch generators ramp down to balance the amount of solar PV during midday.

Once a higher carbon tax is imposed on fossil generators in South Africa, together with an increase in solar power, the time-of-use tariffs could be updated to create further incentives for consumers to shift their consumption patterns away from times of peak demand and toward periods when the carbon intensity of electricity generation is lowest.

4.3.3 Auto-generation and the risk of grid defection

Higher electricity tariffs caused by a carbon price can increase the incentive to defect from the grid. This can reduce the pressure on electricity systems that struggle to build additional capacities or already suffer from chronic load-shedding and thus the burden load-shedding has on consumers and businesses. Load-shedding is a common cause of grid defection. In these cases, households and businesses that can afford it often opt to "defect" from the grid by investing in back-up diesel generators, renewable auto-generation, and off-grid solutions. For example, consumers can invest in rooftop solar PV with battery storage system, which allows the consumer to become a prosumer.

Auto generation has numerous advantages for the households that can afford it, but it can raise costs for those that cannot. If distribution companies allow for net metering, consumers only pay for their net consumption, which effectively means they are exporting electricity to the grid at the same price as they purchase electricity from the grid. If the grid costs are recovered through energy tariffs (per kWh), consumers that invest in solutions like solar rooftops can reduce their contribution to these grid costs, while still relying on the network to export and import electricity when necessary. Wealthier households are more likely to afford the up-front capital cost of such systems, eventually passing on the network costs through tariffs to poorer households that cannot afford such solutions. In Box 4.8, South Africa provides an example of households and businesses investing in auto-generation and off-grid solutions to protect themselves from load-shedding activities and rising electricity tariffs.

Distribution companies can also support selectively decentralized solar to help alleviate grid constraints. Such systems can be targeted to supply specific areas on the grid that experience low reliability of supply, and the battery can provide ancillary services to the network. This can often be a lower-cost alternative to grid expansion. Improving reliability can also build trust and increase revenue collection (World Bank, 2021d).

BOX 4.8

Auto-generation in South Africa

In South Africa, businesses and private households are increasingly investing in generating their own electricity to reduce their exposure to rolling blackouts. In response to the significant amount of load-shedding taking place in South Africa, Eskom is now implementing a net-billing and feed-in tariff to incentivize investments in commercial and household rooftop solar generators in an attempt to increase the country's generation capacity (Hanto et al., 2022). Although this can reduce the load on the grid during the most constrained hours of the day, the network costs of operating and maintaining the grid can disproportionately fall on lower-income consumers that cannot afford the up-front cost or financing required to install solar PV and storage solutions. When a higher carbon price is added, it may have the unintended consequence of increasing the incentive for grid defection in South Africa.

4.3.4 The distributional effects of carbon pricing's impact on retail tariffs

Carbon pricing can easily exacerbate the affordability challenge. Many LICs and MICs struggle with high poverty levels and ensuring families have enough income to pay for housing, heating, and cooking. In this context, any CPI instrument must reflect a careful assessment of impact, which will depend on CPI design and conditions on the ground (World Bank, 2021b). If a CPI leads to higher electricity costs, households that only marginally can afford to use electricity in their homes will feel the burden most sharply.

There are also distributional impacts on businesses and industry. Small and medium businesses may be more sensitive to electricity price increases than larger businesses, and electricity-intensive industries and export-facing industries that compete on global prices are vulnerable. There is also a risk of "carbon leakage," where businesses move their operations to new jurisdictions to reduce or avoid carbon price liability.

Revenue recycling can reconcile the objectives of decarbonization and affordability of the sector, however. Revenues can be used to subsidize the first set of kWh per month for all households to ensure low-income households can afford basic electricity. The South African government has had a Free Basic Electricity Policy in place since 2003 that provides the first 50 kWh each month to all consumers for free, funded through the government's general budget. Section 4.4 provides additional information about how governments can use revenue from carbon pricing to improve social protection in response to increases in energy prices. For instance, lump-sum transfers or energy checks for low-income households, subsidies for energy efficiency, or reduction in social security and corporate taxes for businesses can offset the impacts of a carbon price on those most vulnerable without erasing the incentive to adjust consumption patterns (de Gouvello, Finon, & Guigon, 2020, p. 90). Box 4.9 describes how climate credits have been used in the US State of California to help protect customers from increased retail tariffs due to carbon pricing.

BOX 4.9

Climate credit in California

The California Climate Credit program is a flat credit applied to the electricity bills of privately owned utilities that has been in place since 2014. This policy aims to mitigate the distributional impacts of carbon pricing in the power sector and reduce adverse impacts on low-income households while preserving the carbon price signal, among other objectives (Public Utilities Commission of the State of California, 2012; Vona, 2023).

To fund the climate credit, electric utilities are allocated free emission allowances based on the carbon compliance costs associated with the electricity they forecast to supply to customers. The California Air Resources Board ensures privately owned distribution utilities (which provide 73% of electricity sold in the state) sell all these allocations on the ETS market. The California Public Utilities Commission ensures the revenue from private distribution utilities selling allocations (less administrative and outreach costs) is used to fund the climate credit for their customers, and that up to 15% of the revenue is used to benefit customers.

Meanwhile, publicly owned utilities and cooperatives can use free allowances for compliance or consign free allowances to auction. Publicly owned utilities and cooperatives can choose how to spend their revenue related to consigning free allowances to auction, provided these entities ensure the revenue is used for ratepayer benefit or to fund GHG reduction projects like renewable energy projects.

The climate credit is distributed as a lump-sum credit to customers of investor-owned utilities through their electricity bills regardless of income, household size, or actual electricity consumption. This credit provides a financial buffer to electricity consumers. However, as a flat credit, it does not change electricity rates, and thus the incentive for households to improve energy efficiency and reduce electricity consumption remains. Higher-income households are typically more exposed to the impacts of carbon pricing because they tend to consume more. At the same time, under the California ETS, electricity generators (some of which are owned by distribution utilities) and electricity importers are still obligated to participate in the ETS and surrender allowances corresponding to their emissions. Thus, their operation costs (and therefore wholesale market prices) are linked to the cost of carbon and the incentive to decarbonize remains (Woo, et al., 2018).

4.4 Potential intake of new government revenues in LICs and MICs

As mentioned in Section 3.3.4, governments can raise revenue by introducing a carbon tax or an ETS with auctioning of allowances. An ETS with free allocations of allowances does not raise revenue for the government. The tax and/or auction revenue is collected by the government and can be used for funding general spending plans or can be earmarked for particular government-funded programs and policies.

Objections need to be addressed up front. The most anticipated objections are affordability and, relatedly, industry competition with businesses with access to cheap carbon-intensive power. A redistributive mechanism such as a lump-sum payment that compensates for the pass-through of the carbon price in tariffs can address affordability concerns. A CPI that funds such a payment can actually make electricity more affordable than it is without the carbon pricing for certain categories of consumers, thus reconciling it with one of the key development priorities for LICs and MICs. A new money flow can be put in action that can then be seen as a virtuous cycle that increases the volume of resources that generate the incentives to decarbonize while reconciling that objective with the preexisting priority to protect low-income consumers, as in the case of the climate credits in California. Ensuring initial buy-in by protecting the most vulnerable households and businesses can provide momentum for increasing the carbon price, which can provide further revenue used to further incentivize behavior change and energy efficiency measures. Intelligently designed support can also be channeled to counter the industrial lobbies and the legitimate fears of losing competitiveness. A recent report from the World Bank shows that thorough surveys indicate that other ways to use the revenues collected need also to be considered to improve the acceptability of a CPI (World Bank, 2024a).

Revenue from a CPI can be a powerful tool for overcoming political objections, but revenue intake in LICs and MICs has often been minimal. Carbon taxes are often set too low to raise significant income, free allocation of ETS allowances is common, and exemptions are often sufficient to undermine revenue generation. To some degree this reflects the fact that the primary objective of carbon pricing was to incentivize the decarbonization of the power sector; raising new government revenues was only a secondary concern, and this was the case in China, Colombia, Kazakhstan, and South Africa. Political gridlock often prevents carbon prices from being set high enough to generate significant revenues, as well. Box 4.10 describes how some of the revenues from the carbon tax in Colombia were used to support sustainability measures. This allocation in part reflected political concerns (Rodriguez, 2023), which were satisfied by showing the purpose of the tax was to change behavior, while simultaneously putting the revenue to good use.

Getting beyond compensation: enabling response and addressing needs. Other barriers to political acceptability include limited options to respond to the carbon price signal. Implementing policies that increase price elasticity by creating and facilitating access to response options increase the acceptability of a CPI as well as its effectiveness (World Bank, 2024c).[50] Governments can increase options for industries by financing green industrial policies and for residential customers by facilitating the financing of up-front costs of behind-the-meter renewables (i.e., solar rooftops, solar water heaters, etc.) and more efficient appliances (for instance through the electricity bill).

50 See in particular Chapter 4, "Policy Design: Managing the Distributional Effect of Climate Policies."

BOX 4.10

Use of carbon tax revenue in Colombia

Colombia's carbon tax was introduced in 2016 with an aim to raise funds for the country's new development agenda. The carbon tax raised COP 629 billion (USD 158 million) in its first year of operation (The Earth Institute, Colombia University, 2019). These funds were earmarked for environmental and development objectives.

To begin with, 70% of revenue was used for the Peace Fund of Colombia, which is linked to the Final Agreement of Peace, while 30% went to environmental measures, including payments for environmental services. Beginning in 2020, the division of revenue changed to a fifty-fifty split between environmental and Peace Fund projects, and beginning in 2023, it approached 80% for environmental projects, which includes supporting NDC measures, while 20% still goes to the Peace Fund (Rodríguez, 2023; World Bank, 2019b).

Surveys conducted about factors influencing public support for energy subsidy reforms also offer insights. These reforms are similar to carbon pricing in terms of impact on prices and redistributing effects. One such study systematically examined citizen attitudes and preferences toward such reforms, using tools from experimental economics and a novel data collection method to survey 37,000 respondents in twelve MICs around the world. It showed that affected people might value compensation through addressing other pressing needs—like addressing deficits in education or health services or improving electricity service quality—as much as, or more than, direct cash transfers. However, such preferences can only be unveiled via participatory and consultation processes, in particular those undertaken to build the legitimacy of the proposed mechanism and to prevent distorted perception, including among the targeted beneficiaries (World Bank, 2023a).

4.5 Matrices to track CPI impacts and assess CPIs in different power sector structures

Chapter 4 thus far has discussed the impact of various factors on the success of CPIs in lowering emissions without compromising other key development goals. It has illustrated the potential impact of a carbon price or ETS on key decision processes along the value chain of the power sector, depending on the sector's structure and the constraints caused by national circumstances. It has explained how each of these types of CPI influences the decision of the decision-makers at the corresponding stages of the value chain, depending on the regulation point to which the instrument is assigned, the existing sector's autonomy due to structure and regulations, and the range of options that are available, including in terms of lower-carbon-content alternatives. The discussion has shown that the influence of the CPI can result not only in modifying the carbon content of the electricity generated, dispatched, purchased, or consumed but also in other, sometimes negative, consequences, such as the increase of the infra-marginal rent of non-displaced generators, including, in certain cases, carbon-intensive ones.

The discussion has addressed upstream and downstream impacts of CPI. It has described the impact downstream of a CPI's place on the value chain if pass-through of the price signal occurs, as well as the factors that drive pass-through. It has described how the CPI can affect decisions upstream by changing the demand curve, both in shape and in volume, and by generating incentives for energy purchasers to contract with new RE IPPs that will then displace fossil fuel incumbents. Chapter 4 has also addressed how structures and regulations of the power sector affect such outcomes.

The remainder of this chapter presents three matrices designed to present the insights of this chapter graphically, as well as one overview matrix that previews and summarizes the other three. The matrices present the multiple chains of influence and the conditions that determine whether CPIs result in effective emissions reductions. Each is based on one of the typical structure models for the power sector: (i) a fully unbundled and liberalized market, (ii) a single-buyer model, and (iii) a vertically integrated public monopoly. Each of the three matrices that follow the overview matrix reflects the impact of an ETS and a carbon tax applied separately at each of the five possible regulation points: (i) the upstream stage of the fuels being burned to generate power; (ii) the power generation stage; (iii) the dispatch stage; (iv) the distribution or retailer stage, also called the wholesale purchase stage; and (v) the consumption stage. Each column of the matrix corresponds to a regulation point. Since the application of a CPI at a regulation point also influences decision processes occurring upstream and downstream that point, the corresponding upstream (versus downstream) influence is described in cells located above (versus below) the cell describing the direct impact at the regulation point.

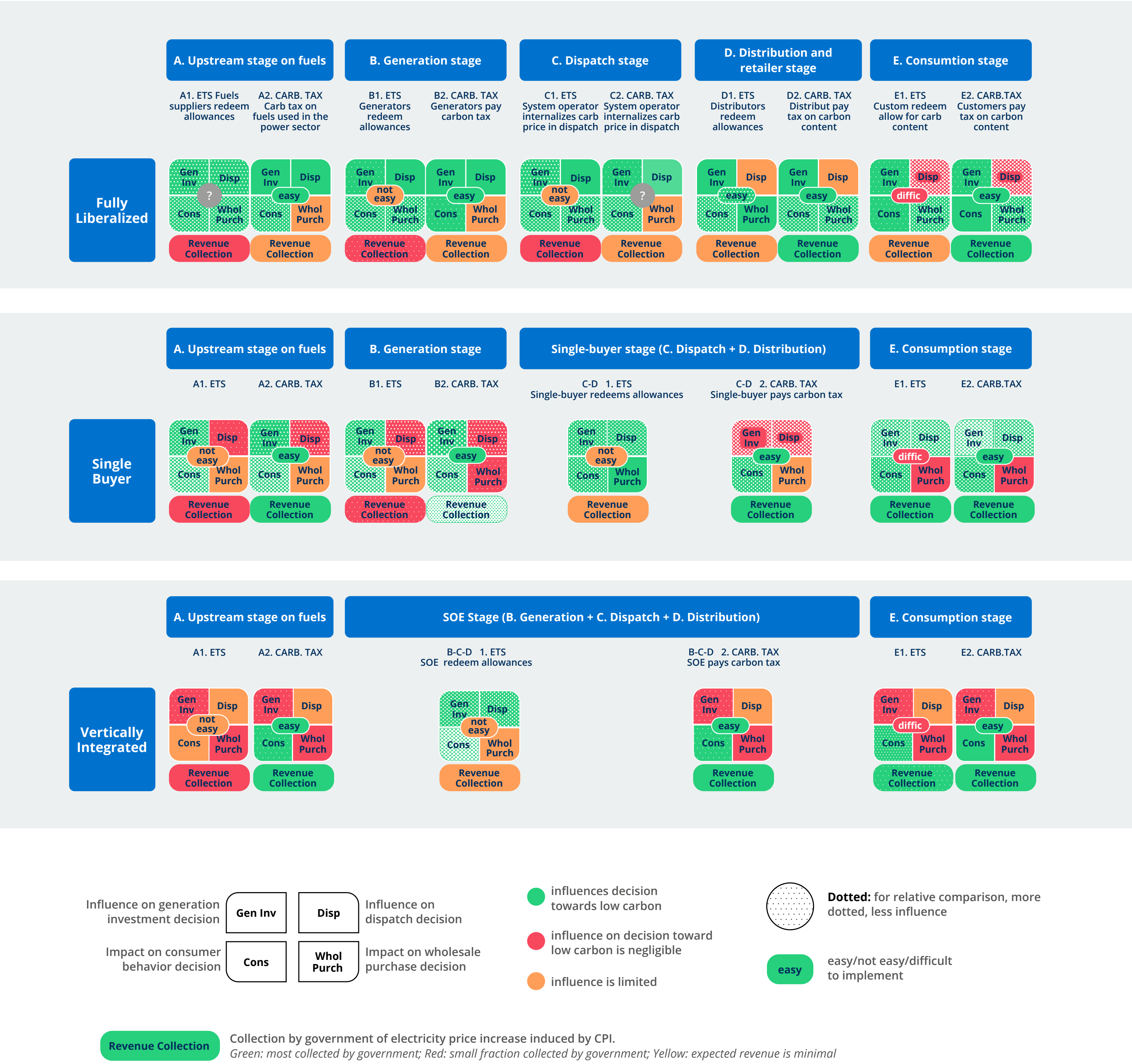
In addition to Chapter 4, the matrices rely on the insights of the Introduction and the first three chapters of the report. They explore how the direct and indirect influences on the decision processes presented in Chapter 4 generate the outcomes presented in the Introduction and the theory of change and analyzed throughout this report. The four desired shifts are related, respectively, to investment, dispatch, distribution, and consumption. These include a shift toward lower-carbon generation capacities, a shift in dispatch toward lower-emissions power generation, a shift toward less carbon-intensive wholesale electricity purchase, and a shift toward less carbon-intensive consumption patterns.

The matrices reflect a balance between complexity and completeness on the one hand and simplicity and accessibility on the other. They are simplified but include a diverse range of influences and conditions, reflecting how they are substantially affected by other national circumstances. For instance, they address the effects of carbon taxes and ETSs on the characteristics of the energy mix (i.e., hydro dominated or coal dominated) and whether a system suffers from capacity constraints that lead to load-shedding. The same structure has been assumed for the three matrices corresponding to the three models, but the differentiation between applying the CPI to the generation, the dispatch, and the distribution stages is not as relevant for a vertically integrated public monopoly as for a fully unbundled and liberalized market. Nonetheless there might be impact on both (i) the way the CPI is designed and regulated and (ii) the internal decision processes within the SOE, which can be important when the design of the CPI evolves in parallel to reform of the sector that includes a partial or total unbundling. In line with such complications, the matrices are not predictions, but are offered to guide the thinking of policy makers and practitioners to inform their own analyses regarding possible CPI options as well as their possible consequences in the context of their particular national circumstances.

Figure 4.1 is a qualitative and visual synthesis of the detailed matrices presented next. It offers a visual overview of the main outcomes of carbon taxes and ETSs, depending on the regulation point selected along the value chain, for each of the three typical power sector structure

FIGURE 4.1

Overview matrix: Simplified assessment of CPIs options in three power sector models: fully liberalized market, single-buyer model, and vertically integrated monopoly



models and differentiating an ETS from a carbon tax. The qualitative results presented in this matrix are only suggestive, rather than predictions; the conditions mentioned in the detailed matrices (such as no load-shedding) apply here. Thus it should not be seen as prescriptive guidance but rather as a guide for exploring and discussing options. For each power sector model, and for each regulation, two small colored matrices are displayed, one for an ETS and one for a carbon tax. Each small colored matrix has

- four petals corresponding to the first four intermediate outcomes: generation investment (Gen Inv), dispatch (Disp), wholesale purchase (Whol Purch), consumption (Cons);
- one underlying bar for fiscal revenue generation and collection (Revenue Collection), corresponding to the fifth intermediate outcome, and
- one central button for signaling the relative easiness of implementation (easy, not easy, difficult).

The figure uses a color system for the first four indicators. The colors indicate that the expected impact is clearly positive (green), limited (yellow), or insignificant (red). Dotted patterns reflect gradations (for the purpose of conveying nuances on how to compare relative to solid colors); for example, dotted green means less positive than solid green and dotted red means less insignificant. The indicators are as follows:

- **"Generation investment"** represents the potential impact of the CPI in changing investment (or retirement) decision in generation, thus the contribution to the first outcome; that is, a shift toward lower-carbon generation capacities: green means either less investment in fossil fuel–based generation or more investment in RE generation.
- **"Dispatch"** represents the potential impact of the CPI on the operation of the system, thus the contribution to the second outcome; that is, a shift in dispatch toward lower-emissions power generation: green means changing merit order in favor of less carbon-intensive plants or by forcing in more renewable PPAs (bilateral contracts between distributors/retailers and RE IPPs).
- **"Wholesale purchase"** represents the potential impact of the CPI on the purchasing decision of the distributors and/or the retailers, thus the contribution to the third outcome; that is, a shift toward less carbon-intensive wholesale electricity purchase: green means generating an incentive to purchase more electricity from renewable energy producers, for instance by signing bilateral contracts, especially if the system is coal dominated, and less from carbon-intensive producers.
- **"Consumption"** represents the potential impact of the CPI on the behavior of the consumers, thus the contribution to the fourth outcome; that is, a shift toward less carbon-intensive consumption patterns: green means the consumer displaces its consumption toward a less carbon-intensive period, or invests in energy efficiency, or signs bilateral contracts with RE suppliers, or invests in behind-the-meter renewable and storage (e.g., solar rooftops).

"Revenue collection" refers to the extent to which the government collects the increase of the electricity price caused by the CPI and thus can direct it to address compensations or complementary mechanisms (for instance financing to enable the response to the carbon price signal): green means the government collects all of the price increase, red means the government collects only a minimal part of the increase (when most of the increase of electricity bills increases the infra-marginal rent received by the generators), and yellow means that revenues are expected to be minimal.

The overview matrices provide a general sense of the impact of different CPIs along the value chain under different contexts. Implementing the insights offered here requires a thorough understanding of specific national circumstances. Nonetheless, the matrices show some general trends. For example, there is more green in the "fully liberalized" row and more red in the "vertically integrated SOE" row. The intermediate outcome petal corresponding to the regulation point where the CPI is applied generally shows more influence (more green) than the points upstream and downstream of that point (the vertically integrated SOE, where the three potential regulation points are merged, is an exception). Revenue collection is better (green) if the regulation point is downstream from the dispatch.

In a number of configurations, a complementary CPI would change the colors. For instance, in the vertically integrated monopoly and single-buyer models, adding a shadow carbon price in the dispatch would make the impact on the dispatch of a CPI applied at the consumption stage green and adding a carbon-based ToU would make the impact on the consumption stage of a CPI applied at the upstream stage green. Likewise, opting for a technology-specific intensity-based ETS would turn "dispatch" to red for an ETS applied at the generation stage.

The alphanumeric numbering in the overview matrix is the same as in the detailed matrices to facilitate access to the information in the detailed matrices that supports the visual synthesis presented in each cell of the overview matrix. This alphanumeric numbering is described in Box 4.11.

BOX 4.11

How to read the three detailed matrices to track and assess the impacts of CPIs applied at different regulation points in the three typical power sector models

The three matrices correspond, respectively, to the three typical sector structures: the fully unbundled and liberalized power sector model, the single-buyer model, and the vertically integrated SOE.

The three matrices have the same structure and aim to track the outcomes of an ETS or a carbon tax depending on the regulation point at which it is applied along the value chain. The five successive stages of the value chain where the ETS or the carbon tax is applied are presented horizontally on successive pages.

The uppercase letters represent the regulation points along the value chain where the CPI is applied, the number 1 represents the ETS, and the number 2 represents the carbon tax, as follows:

- "**A**" refers to the "upstream stage," so A1 and A2 are, respectively, an ETS and a carbon tax **applied on fuels** consumed by the power generation plants.
- "**B**" refers to the "generation stage," so B1 and B2 are, respectively, an ETS and a carbon tax **applied on the GHG emissions directly emitted** by the power generation plants.
- "**C**" refers to the "dispatch stage," so C1 and C2 are, respectively, an ETS and a carbon tax **applied on the induced GHG emissions when establishing the merit order**.
- "**D**" refers to the "distribution stage" (also called the "wholesale purchase stage"), so D1 and D2 are, respectively, an ETS and a carbon tax **applied on the CO_2 content of the wholesale electricity purchased** by the distributors and/or retailers.
- "**E**" refers to the "consumption stage," so E1 and E2 are, respectively, an ETS and a carbon tax **applied on the CO_2 content of the electricity consumed** (Scope 2) by the consumers.

The lowercase letters represent the stages along the value chain where the influence of the CPI is observed. The letter "**b**" represents the generation stage, "**c**" the dispatch stage, "**d**" the distribution stage (also called the wholesale purchase stage), and "**e**" the consumption stage. (There is no "a" because no observations were made upstream to the power sector value chain on the fuel sector.) This point of observation can be different from the stage at which the CPI is applied, reflecting the fact that CPIs can affect stakeholders downstream or upstream from the regulation point. At the same time, when the letter is the same, one uppercase and one lowercase, the cell is describing the direct impact of a CPI at the stage where it is applied. These "direct impact" cells also have thick blue borders.

- To illustrate, cell **B1.b** describes the direct impact expected from an ETS (number 1) applied at the generation stage (uppercase "B") on the investment decision in generation/early retirement of a generation asset (lowercase "b"). Thus B1.b describes the outcome "shift toward lower carbon generation capacities."
- Cell **B1.c** describes the indirect impact expected from an ETS applied at the generation stage on the dispatch ("c"). Thus B1.c describes the outcome "shift toward lower carbon power generation."
- Cell **D2.d** describes the direct impact expected from a carbon tax (2) applied at the consumption stage ("D") on the consumer's decision ("d"). Thus D2.d describes the outcome "shift toward less carbon-intensive consumption patterns."
- Cell **D2.b** describes the indirect impact of a carbon tax applied at the consumption stage on the decision made in terms of investment at the generation stage/early retirement of generation assets ("a"). Thus D2.b describes the outcome "shift toward lower carbon generation capacities."

Much as in the overview matrix, the colors indicate the expected impact, from clearly positive (green), to limited (yellow), to insignificant (red), with gradations reflecting the degree of different outcomes. Lighter colors enable the introduction of some gradations, especially for the sake of relative comparison with darker colors: lighter green means "less positive" than solid green, lighter red means "less insignificant" than solid red. Each cell is divided into two parts. The upper part describes the impact itself and the lower part lists the conditions required to deliver the desirable outcome in terms of emissions reductions. The easiest way to read each matrix is to start with the direct impact cells, which are bordered in thick blue and have the same letter twice (one uppercase, one lowercase).

MATRIX 1 – FULLY LIBERALIZED

FULLY LIBERALIZED A. UPSTREAM STAGE ON FUELS		**FULLY LIBERALIZED** B. GENERATION STAGE	
A1. ETS *More research needed* **Principle:** fuels suppliers redeem allowances **General issues:** Uncertain how upstream caps determination and allowances allocation method might impact cost for power sector	**A2. CARBON TAX** **Principle:** carbon tax applied on fuels used in the power sector **General issues:** - Same as in the generation stage - CPI might discourage CCUS or require exemption for thermal plants with CCUS	**B1. ETS** **Principle:** generators redeem allowances **General condition:** Either a large country or multisectoral ETS **General issues:** - Increases infra-marginal rent of all dispatched generators, if free allowances, opportunity cost pocketed by emitters, minimal collection by government - If caps are based on intensity benchmarks, this creates negative incentives and uncertainty on final emissions	**B2. CARBON TAX** **Principle:** generators pay carbon tax - No country size/sector scope restriction - Can use existing fiscal institutions and processes **General issues:** Increases inframarginal rent of all dispatched generators such that only a fraction is collected by the government through the carbon tax
A1.1. Impact on generation investment / retirement decision: - Same as for carbon tax (A2.1), although impact depends on price on carbon market thus **less predictable**	**A2.1. Impact on generation investment / retirement decision:** - Same as for carbon tax on the generation stage (B2.1), except for CCUS	**B1.1. Impact on generation investment / retirement decision:** - Can (but may not) add cost on thermal and reduce dispatch projections - Can drive early decommissioning of coal - Can discourage new investment in thermal generation, especially coal - Can generate incentive to invest more in RE (although advantage can be difficult to predict)	**B2.1. Impact on generation investment / retirement decision:** - Adds cost on thermal and reduces dispatch projections - Can drive early decommissioning of coal - Can discourage new investment in thermal generation, especially coal - Generate incentive to invest more in RE
Conditions to influence investment/ retirement: *Same as for carbon tax, although less predictable*	***Conditions to influence investment/retirement:*** *- Carbon tax high enough to undermine competitiveness against lower-carbon sources* *- No grid constraints limiting RE (curtailment)* *- Can be limited by capacity mechanism procuring thermal plants* *- No or limited role of long-term take-or-pay or vested contracts preventing decommissioning*	***Conditions to influence investment/retirement:*** *- Limited volume of free allowances* *- Absolute cap (not intensity based) low enough* *- No or limited role of long-term take-or-pay or vested contracts preventing decommissioning* *- Can be limited by capacity mechanism procuring thermal plants* *- No grid constraints limiting RE (curtailment)* *- Secondary markets & hedging improve predictability for decision*	***Conditions to influence investment/retirement:*** *- No carbon tax high enough to undermine competitiveness against lower-carbon sources* *- No grid constraints limiting RE (curtailment)* *- Can be limited by capacity mechanism procuring thermal plants* *- No or limited role of long-term take-or-pay or vested contracts preventing decommissioning*
A1.2. Impact on dispatch decision: Same as for carbon tax, although **less predictable** (A2.2)	**A2.2. Impact on dispatch decision:** - Adds cost on thermal and reduces dispatch projections - Can drive early decommissioning of coal - Can discourage new investment in thermal generation, especially coal - Incentive to invest more in RE	**B1.2. Impact on dispatch decision:** If allowances are 1) not intensity based: - displace carbon intensive generation - increase clearing price 2) based on technologically specific intensity benchmark: - incentive only to improve plant efficiency; can lead to dispatch of more carbon intensive plants performing better than benchmark	**B2.2. Impact on dispatch decision:** - Displace carbon intensive generation - Increase clearing price
Conditions to have an influence on dispatch: *Same as for carbon tax, although less predictable (A2.2)*	***Conditions to have an influence on dispatch:*** *Same as for carbon tax at generation stage (B2.2)*	***Conditions to have an influence on dispatch:*** *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season* *- Availability of diverse carbon intensity options (variety of coal technologies, gas, fuel oil, etc.)* *- No or limited role of take-or-pay, vested contracts*	***Conditions to have an influence on dispatch:*** *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season* *- Shift possible across diverse carbon intensity options (coal, gas, fuel oil, RE, etc.)* *- No or limited role of take-or-pay, vested contracts*
A1.3. Impact on wholesale purchase by distributors/ retailers: Same as for carbon tax, although less predictable (A2.3)	**A2.3. Impact on wholesale purchase by distributors/ retailers:** Same as for carbon tax at generation stage (B2.3)	**B1.3. Impact on wholesale purchase by distributors/ retailers:** - Increase clearing price on wholesale market - Degrade competitiveness of carbon-intensive suppliers for bilateral contracts, thus incentive to opt for bilateral contract with low-carbon suppliers, although these might charge more	**B2.3. Impact on wholesale purchase by distributors/retailers:** - Increase clearing price on wholesale market, **but legislation usually allows pass-through of taxes, thus reducing impact** - Degrade competitiveness of carbon intensive suppliers for bilateral contracts, thus incentive for bilat. with low-carbon suppliers, though might charge more
Conditions to reduce carbon content: *Same as carbon tax, although less predictable (A2.3)*	***Conditions to reduce carbon content:*** *Same as for carbon tax generation stage (B2.3)*	***Conditions to reduce carbon content:*** *- No load shedding forcing "buy all"* *- Availability of low-carbon suppliers* *- Competition at retail level* **(if not, carbon price can be passed through to clients, undermining incentive to purchase low-carbon)** *- Cost of allowances not eligible as reimbursable cost for distributors in regulated tariffs*	***Conditions to reduce carbon content:*** *- No load shedding forcing "buy all"* *- Availability of low-carbon suppliers* *- Competition at retail level (if not, carbon tax can legally be passed through to clients, lessening incentive to purchase low-carbon)*
A1.4. Impact on consumption decision: Same as for carbon tax although less predictable (A2.4)	**A2.4. Impact on consumption decision:** Same as for carbon tax at generation stage (B2.4)	**B1.4. Impact on consumption decision:** - Diluted among other costs and commercial offers of retailers **- Large customers accessing market:** increases clearing price on spot and degrades competitiveness of carbon intensive suppliers for bilateral contracts, thus opt for low-carbon suppliers, although they might charge more **- Smaller regulated customers:** diluted pass-through increases price, thus (limited) incentive to save energy	**B2.4. Impact on consumption decision:** - Passed through as a tax but generally averaged over consumption time **- Large customers accessing market:** increases clearing price on spot and degrades competitiveness of carbon intensive suppliers for bilateral contracts, thus opt for low-carbon suppliers, although might charge more **- Smaller regulated customers:** averaged pass-through increases price, thus (limited) incentive to save energy
Conditions to reduce carbon content: *Same as carbon tax, although less predictable (A2.4)*	***Conditions to reduce carbon content:*** *Same as for carbon tax generation stage (B2.4)*	***Conditions to reduce carbon content:*** *- No load shedding forcing "buy all" for large users* *- Availability of low-carbon suppliers in short to medium term* *- Enabling regulation for RE IPPs wheeling and distributed solar photovoltaic (DPV)* *- Requires smart meters and ability of retailers to differentiate price in time according to carbon content to maximize customers' response*	***Conditions to reduce carbon content:*** *- No load shedding forcing "buy all"* *- Availability of low-carbon suppliers, in short to medium term* *- Enabling regulation for RE IPPs wheeling and DPV* *- Requires smart meters and ability of retailers to differentiate price in time according to carbon content to maximize customers' response*

MATRIX 1 – FULLY LIBERALIZED (continuation)

FULLY LIBERALIZED C. DISPATCH STAGE
More research or experience is needed to continue to inform this table for an ETS or a Carbon Tax applied at Dispatch Stage

FULLY LIBERALIZED D. DISTRIBUTION AND RETAILER STAGE
More research or experience is needed to continue to inform this table for an ETS or a Carbon Tax applied at Distribution / Retailers Stage

C1. ETS	C2. CARBON TAX	1. ETS	2. CARBON TAX
Principle: System operator internalizes carbon price in dispatch Dispatch/system operator is a unique monopolistic entity that neither participates directly in an ETS nor pays the carbon tax. In a CPI applied at this stage, the system operator has a mandate to internalize the carbon price in the merit order based on cost (not bids) to displace more carbon-intensive units and determines emissions generated by plants still being dispatched, thus determining allowances needed or the calculation basis for the carbon tax to be added to the cost of the electricity. An alternative is to apply a shadow carbon price in the merit order without an ETS or a carbon tax.		**Principle: Distributors redeem allowances** - Does not change merit order but generates strong incentive to purchase from RE IPPs - Intensity benchmarks can be used to set caps - No increase of inframarginal rent of generators - Presents similarities/possible overlap with RPS - If allowances are auctioned, part of electricity price increase due to ETS is collected by government (exception might be opportunity rent of RE producers); if free allowances, seller retains market value of allowances **General condition:** Necessarily multisector ETS (too small number of distributors/retailers)	**Principle: Distributors pay tax on carbon content** - Does not change merit order but generates strong incentive to purchase from RE IPPs - No increase of inframarginal rent of generators - No sector size or scope condition - Most increase in electricity price induced by carbon tax is collected by government (exception might be opportunity rent pocketed by RE producers, including in bilateral contracts) **General condition:** Requires enabling regulation for RE IPPs wheeling and DPV and/or competition at retail level to prevent simple pass-through of tax to customers
C1.b / C2.b Impact on generation investment/retirement decision: - Reduce future streams of revenue of most carbon-intensive plants through less dispatch, thus discouraging investment in similar technology - Can thus drive early decommissioning of coal plants being displaced - Can generate incentive to invest more in RE		**D1.b. Impact on generation investment / retirement decision:** - No cost added on thermal plants, but growing share of market captured by RE producers via bilateral contracts - Generate incentive to invest more in RE - Can drive early decommissioning of coal	**D2.b. Impact on generation investment / retirement decision:** - No cost added on thermal plants, but growing share of market captured by RE producers via bilateral contracts - Generate incentive to invest more in RE - Can drive early decommissioning of coal
Conditions to influence investment/retirement: *- If cost of allowances is compensated, impact is lessened*	***Conditions to influence investment/retirement:*** *- Same as carbon tax at generation stage (B2.b)*	***Conditions to influence investment/retirement:*** *- No grid constraints limiting investment in RE* *- Can be limited by capacity mechanism procuring thermal plants*	***Conditions to influence investment/retirement:*** *- No grid constraints limiting investment in RE* *- Can be limited by capacity mechanism procuring thermal plants*
C1.c. Impact on dispatch decision: - Displaces carbon-intensive generation - Increases marginal price by excluding cheaper plants and adding carbon price on thermal still dispatched (except if carbon cost is compensated)	**C2.c. Impact on dispatch decision:** - Displaces carbon-intensive generation - Increases marginal price by excluding cheaper plants and adding carbon price on thermal still dispatched	**D1.c. Impact on dispatch decision:** - No direct impact on dispatch decision process (no impact on merit order process), but more PPAs with RE to be included on the supply side, displacing carbon intensive plants - No increase on clearing price (variable cost of RE is zero) - **Possible addition:** Adding **shadow carbon price in dispatch** could also change merit order and displace more thermal	**D2.c. Impact on dispatch decision:** - No direct impact on dispatch decision process (no impact on merit order process) - More PPAs with RE might be included on the supply side, displacing carbon intensive plants - No increase on clearing price (variable cost of RE is zero) - **Possible addition:** Adding **shadow carbon price in dispatch** could also change merit order and displace more thermal
Conditions to reduce emissions in dispatch: *- Supposes ability of system operator to reflect price of allowances* **Also:** *same additional conditions as for ETS at generation stage (B1.b)*	***Conditions to reduce emissions in dispatch:*** *- Same conditions as for carbon tax at generation stage (B2.b)*	***Conditions to have an influence on dispatch:*** *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season* *- No grid constraints limiting RE (curtailment)*	***Conditions to have an influence on dispatch:*** *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season* *- No grid constraints limiting RE (curtailment)*
C1.d. Impact on wholesale purchase by distributors/ retailers: - Increases marginal cost to be passed through - Incentive to sign bilateral contract with low-carbon suppliers, if authorized, although these might charge more	**C2.d. Impact on wholesale purchase by distributors/ retailers:** - Increases marginal cost to be passed through, but **legislation usually allows pass-through of taxes** - Incentive to sign bilateral contract with low-carbon suppliers, if authorized, though might charge more	**D1.d. Impact on wholesale purchase by distributors/ retailers:** - Generates direct incentive to sign bilateral contracts with RE producers, buy renewable certificates, or buy offsets from other sectors to comply with cap - Caps based on intensity benchmarks can be used to adjust to (growing) demand (no perverse incentive like intensity benchmark at generation)	**D2.d. Impact on wholesale purchase by distributors/retailers:** - Generates direct incentive to sign bilateral contracts with RE producers, buy renewable certificates, or buy offsets from other sectors - Incentive might be limited since legislation allows distributors and retailers to pass through all taxes
Conditions to reduce carbon content: *- Supposes that cost of allowances is not compensated. If compensated, incentive is lessened (only increase is due to change in merit order)* ***Also:*** *same additional conditions as for ETS at generation stage*	***Conditions to reduce carbon content:*** *Same as for carbon tax at generation stage (B2.b)*	***Conditions to reduce carbon content:*** *- No excess of allowances, mostly auctioned* *- No or limited role of long-term vested contracts* *- Willingness to sign long-term bilateral contract with RE generators depends on long-term predictability of ETS and floor price* *- Enough RE generators becoming competitive* *- Competition at retail level (if not, carbon price can be easily passed through to clients, undermining incentive to purchase low-carbon)* ***Also:*** *no load shedding forcing "buy all"*	***Conditions to reduce carbon content:*** *- Critical: competition at retail level and enough RE generators becoming competitive (if not, carbon tax is simply passed through to clients, as authorized by law)* *- Willingness to sign long-term bilateral contracts with RE generators depends on long-term predictability of carbon tax* ***Also:*** *no load shedding forcing "buy all"*
C1.e. Impact on consumption decision: Supposedly similar as for ETS at generation stage, except if cost of allowances is compensated, then lessened	**C2.e. Impact on consumption decision:** Supposedly similar as for carbon tax at generation stage	**D1.e. Impact on consumption decision:** - Degrade competitiveness of carbon-intensive retailers, thus opt for low-carbon suppliers, although might charge more - **Smaller regulated customers:** averaged pass-through increases price, thus (limited) incentive to save energy, adopt DPV	**D2.e. Impact on consumption decision:** - Degrade competitiveness of carbon-intensive retailers, thus opt for low-carbon suppliers, although might charge more - **Smaller regulated customers:** averaged pass-through of tax increases price, thus (limited) incentive to save energy, adopt DPV
Conditions to reduce carbon content: *Same as for generation stage (B2.b)*	***Conditions to reduce carbon content:*** *Same as for generation stage (B2.b)*	***Conditions to reduce carbon content:*** *- Large customers that access market have to be also included in ETS **(see consumption stage)*** *- Requires smart meters and ability of retailers to differentiate price in time according to carbon content to maximize customers response* ***Also:*** *no load shedding forcing "buy all"*	***Conditions to reduce carbon content:*** *- Large customers that access market have to be also exposed to carbon tax **(see consumption stage)*** *- Requires smart meters and ability of retailers to differentiate price in time according to carbon content to maximize customers response* ***Also:*** *no load shedding forcing "buy all"*

MATRIX 1 – FULLY LIBERALIZED (continuation)

FULLY LIBERALIZED E. CONSUMPTION STAGE

E1. ETS	E2. CARBON TAX
Principle: Customers redeem allowances for carbon content - Usually part of a wider multisectoral ETS - Wide range of possible responses - Does not change merit order but generates incentive to purchase from RE IPPs - Potentially applicable in case of load shedding (less impact) - Potentially applicable whatever the energy mix is **General Issues:** - Applicable only on large industrial customers - Large number of regulated entities, thus MRV is challenging - Needs to be coordinated or integrated with RPS and/or tradable energy efficiency (EE) certificates mechanisms	**Principle: Customers pay tax on carbon content** - Wide range of possible responses, but needs accompanying enabling measures, especially for low-income households and small/medium enterprises - Does not change merit order but generates incentive to purchase from RE IPPs - Most increase in electricity price induced by carbon tax is collected by government and can be recycled - No increase of inframarginal rent of generators - No sector size or scope condition **General Issues:** Very large number of regulated entities, thus making MRV more challenging (metering, billing, collection issues)
E1.b. Impact on generation investment/retirement decision: - No cost added on thermal plants, but growing share of market captured by RE producers via bilateral contracts with large customers - Generate incentive to invest more in RE	**E2.b. Impact on reneration investment/retirement decision:** - No cost added on thermal plants, but growing share of market captured by RE producers via bilateral contracts with large customers - Generate incentive to invest more in RE
Conditions to influence investment/retirement: *No grid constraints limiting investment in RE*	***Conditions to influence investment/retirement:*** *No grid constraints limiting investment in RE*
E1.c. Impact on dispatch decision: - **Does not impact merit order**, however: - demand is i) reduced by EE & DPV; ii) increased by electrification of uses that **reduces overall emissions of customers** but increases demand, **thus might compensate effect of i)** - demand is potentially less (or more) impacted than with tax since customers can purchase (or sell) allowances from other sectors. - may displace carbon-intensive generation by increasing bilateral contracts signed with new RE IPPs - **Also: adding shadow carbon price in dispatch** could change merit order and displace more thermal	**E2.c. Impact on dispatch decision:** - **Does not impact merit order**, however: - demand to be served is doubly impacted i) by EE and DPV measures reducing conventional demand on grid and ii) by electrification of final uses that **reduces overall emissions of final customers but increases demand, thus might compensate for the impact of EE and DPV on dispatch** - may displace carbon intensive generation by increasing bilateral contracts signed with new RE IPPs - **Also: adding shadow carbon price in dispatch** could change merit order and displace more thermal
Conditions to have an influence on dispatch: *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season*	***Conditions to have an influence on dispatch:*** *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season*
E1.d. Impact on wholesale purchase by distributors/retailers: - Might generate an incentive for distributors/retailers to differentiate offer and propose new contracts with guaranteed low-carbon supply, and thus for them to secure wholesale purchase from RE producers	**E2.d. Impact on wholesale purchase by distributors/retailers:** - Might generate an incentive for distributors/retailers to differentiate offer and propose new contracts with guaranteed low-carbon supply, and thus for them to secure wholesale purchase from RE producers
Conditions to reduce carbon content: *Availability of low-carbon suppliers in short to medium term*	***Conditions to reduce carbon content:*** *Availability of low-carb suppliers in short to medium term*
E1.e. Impact on consumption decision: - Caps can be based on overall carbon intensity of final product, including scope 2 emissions from electricity; can thus also be applied in situation of load shedding **Large customers accessing market:** generates incentive for signing bilateral contracts with RE suppliers, investing in EE and demand management systems, distributed RE and storage, purchase of offsets, RE or EE certificates, and possibly electrification of uses if it reduces overall emissions **Smaller regulated customers:** not applicable: too complex to extend to small customers, except indirectly via their suppliers (see distribution stage)	**E2.e. Impact on consumption decision:** - Carbon tax is calculated based on carbon content of consumption, ideally differentiated by period of time of the day and seasons. **Large customers accessing market:** generates incentive for signing bilateral contracts with RE suppliers, investing in EE and demand management systems, distributed RE and storage, purchase of offsets, RE or EE certificates, and possibly electrification of uses if reduces overall emissions. **Smaller regulated customers:** generates incentives for more efficient behaviors and appliances, solar rooftops. - can be replaced by a carbon content-based modulation of existing tariffs to ensure overall cost neutrality for consumers
Conditions to reduce carbon content: *- **Applicable only to large industrial customers*** *- Availability of low-carbon suppliers in short to medium term* *- Requires enabling regulation for RE IPPs wheeling and DPV to unlock this type of response* *- Requires accompanying measures to enable response, especially EE/DPV up-front cost financing for small customers* *- Limited short-term reductions if hydro-dominated, except at peak season requiring thermal* *- Needs to be coordinated or integrated with RPS (if applicable to large customers) and/or tradable EE certificates mechanisms to prevent multiple transaction costs and weakening carbon price signal*	***Conditions to reduce carbon content:*** *- Distribution company shall be well managed: MRV and tax collection depends on metering, billing, and payment collection* *- Availability of low-carbon suppliers in short to medium term* *- Requires enabling regulation for RE IPPs wheeling and DPV to unlock this type of response* *- Requires accompanying measures to enable response, especially EE/DPV up-front cost financing for small customers* *- Requires smart meters and ability of retailers to differentiate price in time according to carbon content to maximize customers' response* *- Bad quality of service (load shedding) makes it virtually impossible to add a carbon tax* *- Limited short-term reductions if hydro-dominated, except at peak season requiring thermal*

MATRIX 2 – SINGLE BUYER

SINGLE BUYER A. UPSTREAM STAGE ON FUELS		**SINGLE BUYER** B. GENERATION STAGE	
A1. ETS *More research needed* **Principle:** fuels suppliers redeem allowances **General issues:** Uncertain how upstream caps determination and allowances allocation method might impact cost for power sector	**A2. CARBON TAX** **Principle:** Carbon tax applied on fuels used in the power sector **General issues:** - Same as generation stage - Might discourage CCUS or require exemption for thermal plants with CCUS	**B1. ETS** **Principle:** Generators redeem allowances **General condition:** - Either many IPPs or multisectoral ETS **General issues:** - Requires strong oversight on dispatch by single buyer - Limited share of cost increase due to CPI is collected by government, especially if percentage of free allocation - If caps are based on intensity benchmarks, negative incentives, and uncertainty on final emissions	**B2. CARBON TAX** **Principle:** Generators pay carbon tax - No restriction on sector scope, number of IPPs can be small - Can use existing fiscal institutions and processes - All cost increase due to CPI is collected by government through the carbon tax **General issues:** - Requires strong oversight on dispatch by single buyer - Single-buyer-owned generation might just pass on carbon tax and continue same
1A1.b Impact on generation investment/retirement decision: Same as for carbon tax (A2.b) although impact depends on price on carbon market thus less predictable	**A2.b Impact on generation investment/retirement decision:** Same as for carbon tax on generation stage (B2.b), except for CCUS, which might be penalized	**B1.b Impact on generation investment/ retirement decision:** - Add cost on thermal IPPs and reduce dispatch projections if cost-based merit order - Can discourage nonsolicited new IPPs investment in thermal generation and reduce their competitiveness in public procurement - Can drive early decommissioning of coal IPPs - Improves relative attractiveness of RE invest **(although advantage can be difficult to predict)**	**B2.b. Impact on generation investment/ retirement decision:** - Add cost on thermal IPPs and reduce dispatch projections if cost-based merit order - Can discourage nonsolicited new IPPs investment in thermal generation and reduce their competitiveness in public procurement - Can drive early decommissioning of coal IPPs - Improves relative attractiveness of investing in RE
Conditions to influence investment/ retirement: *Same as for carbon tax although less predictable*	***Conditions to influence investment/ retirement:*** *Same as for carbon tax on generation stage*	***Conditions to influence investment/retirement:*** *- Limited volume of free allowances* *- Cost of allowances included in variable costs* *- Independent oversight to ensure that single-buyer-owned generation is also displaced in merit order* *- Caps low enough to undermine attractiveness against lower-carbon sources* *- No grid constraints limiting RE (curtailment)* *- No or limited role of long-term take-or-pay or vested contracts guaranteeing dispatch hours (potential legal issue on pass-through or not)*	***Conditions to influence investment/retirement:*** *- Carbon tax internalized in public procurement of IPPs* ***- Independent oversight to ensure that single-buyer-owned generation is also displaced in merit order*** *- Carbon tax high enough to undermine attractiveness against lower-carbon sources* *- No grid constraints limiting RE (curtailment)* *- No or limited role of long-term take-or-pay or vested contracts guaranteeing dispatch hours (then, carbon tax is just passed through)*
A1.c. Impact on dispatch decision: Same as for carbon tax (A2.c) although impact depends on price on carbon market and thus is less predictable	**A2.c. Impact on dispatch decision:** Same as for carbon tax on generation stage (B2.c), except for CCUS	**B1.c. Impact on dispatch decision:** - Can reduce dispatch of carbon intensive generation **if dispatch is based on cost-based merit order, while take or pay provisions in PPAs are frequent** - Depends on carbon market price thus unpredictable (especially limited if intensity based)	**B2.c. Impact on dispatch decision:** Reduces dispatch of carbon intensive generation **if dispatch is based on cost-based merit order, while take-or-pay provisions in PPAs are frequent and taxes are legally allowed to be passed through by single buyer**
Conditions to have an influence on dispatch: *Same as ETS at generation stage (B1.c)*	***Conditions to have an influence on dispatch:*** *Same as for carbon tax on generation stage (B2.c)*	***Conditions to have an influence on dispatch:*** *- Dispatch is based on cost-based merit order and no exemption or compensation* *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season* *- Availability of diverse carbon intensity options (coal, gas, fuel oil, etc.)* *- No or limited role of take-or-pay or preference for single-buyer-owned generator*	***Conditions to have an influence on dispatch:*** *- Dispatch is based on cost-based merit order and no exemption or compensation* *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season* *- Availability of diverse carbon intensity options (coal, gas, fuel oil, etc.)* *- No or limited role of take-or-pay or preference for single-buyer-owned generator*
A1.d. Impact on wholesale purchase by distributors/retailers: Same as for ETS on generation stage (B1.d), except that cost of allowances is already embedded in power supply cost and cannot be singled out anymore	**A2.d. Impact on wholesale purchase by distributors/retailers:** Same as for carbon tax on generation stage (B2.d)	**B1.d. Impact on wholesale purchase by distributors/retailers:** - Single buyer is usually also distributor monopoly, which is thus also signatory of new IPPs - Thus, might decide more in favor of less carbon-intensive IPPs in public procurement, although impact of variable carbon price is difficult to predict **Additional influence:** in case cost of allowances is singled out and is not eligible, reimbursable cost to be reflected in regulated tariffs, then generates incentive to renegotiate take-or-pay with thermal	**B2.d. Impact on wholesale purchase by distributors/retailers:** - Single buyer is usually also distribution monopoly, which is thus also signatory of new IPPs - Thus, might decide more in favor of less carbon intensive IPPs in public procurement - However, **carbon tax on supply is usually passed through as all taxes legally are, thus no influence on internal purchase of supply, especially from internal generation plants**
Conditions to reduce carbon content: Same as B2.b	***Conditions to reduce carbon content:*** Same as B2.b	***Conditions to reduce carbon content:*** - Same as B2.b - ***Additional influence:*** cost of allowances is not eligible reimbursable cost in regulated tariffs	***Conditions to reduce carbon content:*** Same as B2.b
A1.e. Impact on consumption decision: - Same as for generation stage **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use tariffs)**	**A2.e. Impact on consumption decision:** - Same as for generation stage **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use tariffs)**	**B1.e. Impact on consumption decision:** - Carbon cost is unpredictable and diluted among other costs - Thus (limited) incentive to save energy or invest in behind the meter DPV **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use tariffs)**	**B2.e. Impact on consumption decision:** - Carbon tax might be passed through as a tax but is generally averaged over consumption time, thus (limited) incentive to save energy or invest in behind the meter DPV **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use tariffs)**
Conditions to reduce carbon content: Same as B2.e	***Conditions to reduce carbon content:*** Same as B2.e	***Conditions to reduce carbon content:*** Same as B2.e	***Conditions to reduce carbon content:*** - No load shedding forcing "buy all" - Enabling regulation for behind the meter DPV ***Additional influence:*** requires smart meters and ability of retailers to differentiate price in time according to carbon content

MATRIX 2 – SINGLE BUYER (continuation)

SINGLE BUYER C. DISPATCH STAGE

More research or experience is needed to continue to inform this table for an ETS or a carbon tax applied at dispatch stage

SINGLE BUYER D. DISTRIBUTION AND RETAILER STAGE

More research or experience is needed to continue to inform this table for an ETS or a Carbon Tax applied at Distribution / Retailers Stage

C1. ETS	C2. CARBON TAX	D1. ETS	D2. CARBON TAX
Principle: System operator internalizes carbon price in dispatch Dispatch/system operator is a unique internal entity within the single buyer that neither participates directly in an ETS nor pays the carbon tax. In CPI applied at this stage, the system operator has a mandate to internalize the carbon price in the merit order to displace the carbon intensive units and determines emissions generated by plants still being dispatched, thus determining allowances needed for IPPs and single-buyer-owned generation plants, or the calculation basis for the carbon tax to be added to the cost of the electricity. An alternative is to apply a shadow carbon price in the merit order without an ETS or a carbon tax. **General issues:** Requires strong independent oversight on the dispatch operated by single buyer, who might favor its own internal generation.		**Principle: Distributor redeems allowances** - Does not add cost on generation but generates strong incentive to purchase from RE IPPs - Intensity benchmarks can be used to set caps - Direct impact of carbon price on electricity price can be (very) limited - Can be completed by price neutral variation of tariffs based on carbon content variation **General condition:** Necessarily multisector ETS since the single buyer is generally also the unique distribution entity (monopoly)	**Principle: Distributors pays tax on carbon content** - Incentive for single buyer/distributer might be (very) limited since legislation usually allows distributor to pass through all taxes into bills; main impact expected is thus at consumer level - Most increase in electricity price induced by carbon tax is collected by government **General condition:** No sector size or scope condition
C1.b Impact on generation investment/retirement decision: Same as carbon tax (C2.b) but less predictable	**C2.b. Impact on eneration investment/retirement decision:** - Reduce revenue of most carbon-intensive plants being less dispatched, thus discourage investment - Can drive early decommissioning of (coal) plants being displaced - Improves revenue of less carbon-intensive plants, thus can generate incentive to invest more in RE	**D1.b. Impact on generation investment/ retirement decision:** - No cost added on thermal plants, but since distributor is also a single buyer who invests in new/ own capacities, generates incentive for single buyer to invest more in RE plants - But **distributor/single buyer can also trade allowances instead with other sectors** - Generates more appetite for public procurement of RE IPPs - can drive early decommissioning of coal plants owned by single buyer	**D2.b. Impact on generation investment/retirement decision:** - No significant impact, direct or indirect, expected on generation investment or retirement decision processes (no incentive to invest or purchase more or less from RE or coal generators since, as all taxes, carbon tax is legally passed through to customers into bills)
Conditions to influence investment/ retirement: *- Dispatch is determined by cost-based merit order* *- Incentive to early decom. lessened if single-buyer-owned deficitary plants are cross-subsidized* *- Or if cost of allowances compensated*	***Conditions to influence investment/ retirement:*** *- Dispatch is determined by cost-based merit order* *- Incentive to early decom. lessened if single buyer owned deficitary plants are cross-subsidized* *- Or if cost of allowances compensated*	***Conditions to influence investment/retirement:*** *- Depends on relative importance and influence of distribution and carbon cost felt by distribution in single-buyer decision to invest in generation* *- no grid constraints limiting investment in RE* *- can be limited by capacity mechanism procuring thermal plants*	***Conditions to influence investment/ retirement:*** *NA*
C1.c. Impact on dispatch decision: - Displaces carbon-intensive generation, **but single-buyer dispatch decision is in part discretionary** - Increases marginal cost by i) excluding cheaper plants; ii) adding carbon price on thermal (except if carbon cost is compensated)	**C2.c. Impact on dispatch decision:** - Can displace carbon-intensive generation, **but single-buyer dispatch decision is in part discretionary** - increases marginal cost by i) excluding cheaper plants; ii) adding carbon price on thermal (except if carbon cost is compensated)	**D1.c. Impact on dispatch decision:** - Since distributor is also single-buyer system operator who operates dispatch, generates an incentive to minimize carbon content of electricity supplied to distribution, except if limited by dispatch regulation, **but distributors can also trade allowances instead**	**D2.c. Impact on dispatch decision:** - No significant impact, direct or indirect, expected on dispatch decision process (no impact on merit order process, no incentive to dispatch less coal or more RE since, as all taxes, carbon tax is legally passed through to customers into bills)
Conditions to reduce emissions at dispatch: *- Same conditions as for ETS/carbon tax at generation stage* ***And:*** *strong oversight on single buyer who might favor own generation*	***Conditions to reduce emissions at dispatch:*** *- Same conditions as for ETS/carbon tax at generation stage* ***And:*** *strong oversight on single-buyer who might favor own generation*	***Conditions to have an influence on dispatch:*** *- Dispatch regulation allows to internalize minimization of carbon cost for distribution* *- No load shedding forcing "dispatch all"* *- not hydro-dominated, dry season with dependency on thermal* *- no grid constraints limiting RE (curtailment)*	***Conditions to have an influence on dispatch:*** *NA*
C1.d. Impact on wholesale purchase by distributors/retailers: Same as ETS at generation stage (B1.d)	**C2.d. Impact on wholesale purchase by distributors/ retailers:** Same as carbon tax at generation stage (B2.d)	**D1.d. Impact on wholesale purchase by distributors/retailers:** - Generates direct incentive to purchase more from RE IPPs: incentive comes from market price of allowances to be purchased if exceeding allocation, **which can thus be largely free** - Generates incentive to minimize curtailment of RE and maximize use of own RE generation - Generates incentives to buy offsets from other sectors to comply with cap	**D2.d. Impact on wholesale purchase by distributors/retailers:** - Incentive might be (very) limited since legislation usually allows distributors to pass through all taxes - Only incentive is willingness to reduce bill increase to customers
Conditions to reduce carbon content: *Same as ETS at generation stage (B1.d) (except condition on public procurement, which is not applied at this stage)*	***Conditions to reduce carbon content:*** *Same as for carbon tax at generation stage (B2.d) (except condition on public procurement, which does not apply at this stage)*	***Conditions to reduce carbon content:*** *- No excess of allowances, at least part of it auctioned to limit opportunistic behavior* *- incentive is stronger if **pass-through is not allowed** (then most allocation is free)* *- Incentive depends on ambition and long-term predictability of overall ETS and floor price* *- No or limited role of long-term vested contracts* *- enough RE generators becoming competitive* ***Also:*** *no load shedding forcing "buy all"*	***Conditions to reduce carbon content:*** Suggestion: obligation to single-buyer/ distributor to engage in demand side programs, financed by carbon tax proceeds, to help consumers to reduce carbon footprint of electricity consumption (demand management, energy efficiency, DPV, etc.)
C1.e. Impact on consumption decision: Increase of cost due to CPI at dispatch is diluted in time and among other costs within cost structure thus (very) limited incentive to save energy/invest in behind meter DPV **Possible addition: carbon-based time of use tariffs**	**C2.e. Impact on consumption decision:** Increase of cost due to CPI at dispatch is diluted in time and among other costs within cost structure thus (very) limited incentive to save energy invest in behind meter DPV **Possible addition: carbon-based time of use tariffs)**	**D1.e. Impact on consumption decision:** (Very) limited, especially if pass-through is not authorized to maximize incentive at distribution level **Possible addition:** differentiation of tariffs across time periods according to carbon content **(carbon-based time of use tariffs)** (can be price neutral), then incentive to save/reduce energy when most carbon intensive, adopt DPV	**D2.e. Impact on consumption decision:** Averaged pass-through of carbon tax increases electricity bills, thus (limited) incentive to save energy, adopt DPV **Possible addition:** differentiation of tariffs across time periods according to carbon content **(carbon-based time of use tariffs)** (can be overall price neutral), then incentive to save/reduce energy when most carbon intensive, adopt DPV
Conditions to reduce carbon content: *Same as for generation stage (B1.e)*	***Conditions to reduce carbon content:*** *Same as for generation stage (B2.e)*	***Conditions to reduce carbon content:*** ***Additional influence:*** *requires smart meters to differentiate price in time according to carbon content (see also condition for consumption stage); requires excellent metering/billing capabilities*	***Conditions to reduce carbon content:*** ***Additional influence:*** *requires smart meters to differentiate price in time according to carbon content (see also condition for consumption stage); requires excellent metering/billing capabilities*

MATRIX 2 – SINGLE BUYER (continuation)

SINGLE BUYER E. CONSUMPTION STAGE

E1. ETS **Principle:** Customers redeem allowances for carbon content - Usually part of a wider multisectoral ETS - Wide range of possible responses - Potentially applicable in case of load shedding (less impact) - Potentially applicable whatever the energy mix is **General Issues:** - Applicable only on large industrial customers - Large number of regulated entities, thus MRV is challenging - Needs to be coordinated or integrated with RPS and/or tradable EE certificates mechanisms	**E2. CARBON TAX** **Principle:** Customers pay tax on carbon content - Wide range of possible responses but needs accompanying enabling measures, especially for low-income households and small/medium enterprises - Most increase in electricity price induced by carbon tax is collected by government and can be recycled - No sector size or scope condition **General Issues:** - Very large number of regulated entities thus MRV more challenging (metering, billing, collection issues)
E1.b. Impact on generation investment/retirement decision: - No cost added on thermal plants, but growing share of market captured by prosumers (principally DPV) - Reduce incentive to invest in centralized generation, especially public procurement by single buyer if wheeling plus bilateral contracting with RE IPPs is enabled (breach in single-buyer monopoly)	**E2.b. Impact on generation investment/retirement decision:** - No cost added on thermal plants, but growing share of market captured by prosumers (principally DPV) - Reduce incentive to invest in centralized generation, especially public procurement by single buyer if wheeling plus bilateral contracting with RE IPPs is enabled (breach in single-buyer monopoly)
Conditions to influence investment/retirement: *Same as for carbon tax (E2.b)*	***Conditions to influence investment/retirement:*** *- No grid constraints limiting investment in RE if wheeling + bilateral contracting with RE IPPs is enabled* *- Influence on retirement: no load shedding*
E1.c. Impact on dispatch decision: Does not impact merit order, however: - demand to be served is doubly impacted: i) by EE and DPV measures reducing demand on grid and ii) by electrification of final uses that reduces overall emissions of final customers but increases demand, but cons. can also trade allowances instead **Also:** adding shadow carbon price in dispatch could also change merit order and displace more thermal	**E2.c. Impact on dispatch decision:** Does not impact merit order, however: - demand to be served is doubly impacted: i) by EE and DPV measures reducing demand on grid and ii) by electrification of final uses that reduces overall emissions of final customers but increases demand **Also:** adding shadow carbon price in dispatch could also change merit order and displace more thermal
Conditions to have an influence on dispatch: *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season*	***Conditions to have an influence on dispatch:*** *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season*
E1.d. Impact on wholesale purchase by distributors/retailers: Same as for carbon tax (E2.d)	**E2.d. Impact on wholesale purchase by distributors/retailers:** No significant upstream impact expected on wholesale purchase decision from single-buyer/distributor, except if wheeling plus bilateral contracting of large customers with RE are enabled: this might generate an incentive for single-buyer/distributor to propose new contracts with guaranteed low-carbon supply, and thus for it to secure more wholesale power from RE
Conditions to reduce carbon content: *Same as for carbon tax (E2.d)*	***Conditions to reduce carbon content:*** *Enable wheeling plus bilateral contracting of large customers with RE (breaching single-buyer monopoly)*
E1.e. Impact on consumption decision: - Caps can be based on overall carbon intensity of final product, including scope 2 emissions from electricity; can thus also be applied in situation of load shedding **Large customers:** generates incentive for investing in EE and demand management systems, distributed RE and storage, purchase of offsets, RE or EE certificates, and also possibly electrification of uses if reduces overall emissions, but can also opt for trading allowances from other sectors instead **Smaller regulated customers: not applicable: too complicated to extend to small customers**, except indirectly via their suppliers (see distribution stage)	**E2.e. Impact on consumption decision:** - Carbon tax is calculated based on carbon content of consumption, ideally differentiated by period of time of the day and seasons. Incentive is strong if coal dominated, weak if hydro-dominated. **Large customers:** generates incentive investing in EE and demand management systems, distributed RE and storage, purchase of offsets, RE or EE certificates, and also possibly electrification of uses if reduces overall emissions. - Response is substantially increased if wheeling plus bilateral contracting with RE IPPs is enabled. **Smaller regulated customers:** generates incentives for more efficient behaviors and appliances, solar rooftops. - Can be replaced by a carbon content-based modulation of existing tariffs to ensure overall cost neutrality for (small) consumers
Conditions to reduce carbon content: *- Applicable only to large industrial customers:* *- Requires enabling regulation for DPV to unlock this type of response* *- Requires accompanying measures to enable response, especially EE/DPV up-front cost financing for small customers* *- Limited short-term reductions if hydro-dominated, except at peak season requiring thermal* *- Needs to be coordinated or integrated with RPS (if applicable to large customers) and/or tradable EE certificates mechanisms if any to prevent multiple transaction costs and weakening carbon price signal*	***Conditions to reduce carbon content:*** *- Distribution company shall be well managed: MRV and tax collection depends on metering, billing, and payment collection* *- Requires enabling regulation DPV to unlock this type of response* *- Requires accompanying measures to enable response, especially EE/DPV up-front costs financing for small customers* *- Requires smart meters and ability of single-buyer/distributor to differentiate price in time according to carbon content to maximize customers response* *- Bad quality of service (load shedding) makes it virtually impossible to add a carbon tax* *- Limited short-term reductions if hydro-dominated, except at peak season requiring thermal*

MATRIX 3 – VERTICALLY INTEGRATED MONOPOLY

VERTICALLY INTEGRATED SOE A. UPSTREAM STAGE ON FUELS		VERTICALLY INTEGRATED SOE B. GENERATION STAGE	
A1. ETS *More research needed* **Principle:** Fuels suppliers redeem allowances **General issues:** Uncertain how upstream caps determination and allowances allocation method might impact cost for power sector	**A2. CARBON TAX** **Principle:** Carbon tax applied on fuels used in the power sector **General issues:** - Same as generation stage - Might discourage CCUS or require exemption for thermal plants with CCUS	**B1. ETS** **Principle:** SOE generation redeem allowances **General condition:** - Necessarily multisectoral ETS **General issues:** - Limited share of cost increase due to CPI is collected by government, especially if percentage of free allocation - Incapacity to increase electricity cost would lead to mostly free allowances (which can still generate impact on investment/retirement) - If pass-through is authorized, then impact mostly at consumption stage only	**B2. CARBON TAX** **Principle:** SOE Generation pay carbon tax - No restriction on sector scope - All cost increase due to CPI is collected by government through the carbon tax **General Issues:** Incapacity to increase electricity cost would block any possibility of carbon tax If pass-through is authorized (as all taxes legally are), then impact mostly at consumption stage only
A1.b. Impact on generation investment/retirement decision: Adds a cost but does not put a cap on emissions from power plants, thus plants will pass through, thus impact is similar to carbon tax, although impact depends on price on carbon market and is thus less predictable	**A2.b. Impact on generation investment/retirement decision:** - No or very limited impact since SOE is legally entitled to pass-through carbon tax (as all taxes) - Thus, same as for carbon tax on generation stage (B2.b), except for CCUS (see above)	**B1.b. Impact on generation investment/ retirement decision:** - Put a cap but can trade, thus: - Added cost on SOE's thermal generation - Can drive early decommissioning of coal IPPs - Improves relative attractiveness of RE investment (although advantage can be difficult to predict) - Incentives are lessened if pass-through is authorized - Generates incentives to buy credits/offsets from other sector	**B2.b. Impact on generation investment/ retirement decision:** - No or very limited impact since SOE is legally entitled to pass-through carbon tax (as all taxes) - Only incentive would be willingness to reduce bill increase to customers - If not allowed to be passed through to customers, will undermine cost recovery, financial viability of SOE, limiting its ability to invest in low-carbon investment (would take years for RE investment to reduce carbon cost)
Conditions to influence investment/retirement: *Same as for carbon tax (A2b) although less predictable*	***Conditions to influence investment/ retirement:*** *Same as for carbon tax on generation stage (B2.b)*	***Conditions to influence investment/retirement:*** *- Incentive substantial only if* ***pass-through is not allowed;*** *incentive comes from market price of allowances that would have to be purchased if exceeding allocation,* ***which can thus be mostly free*** *- Caps low enough to undermine attractiveness of carbon intensive investment against lower carbon)*	***Conditions to influence investment/retirement:*** *NA*
A1.c. Impact on dispatch decision: Same as for carbon tax (A2.c), although impact depends on price on carbon market, thus less predictable	**A2.c. Impact on dispatch decision:** Same as for carbon tax on generation stage (A2.b), except for CCUS	**B1.c. Impact on dispatch decision:** Can displace carbon-intensive generation if dispatch is based on cost-based merit order, although it depends on carbon market price, thus unpredictable (especially limited if intensity based)	**B2.c. Impact on dispatch decision:** - If carbon tax just passed through and not taken into account in dispatch order, then no impact on dispatch - If carbon tax is considered in dispatch order, might displace carbon intensive plant
Conditions to have an influence on dispatch: *Same as for carbon tax (B2.c)*	***Conditions to have an influence on dispatch:*** *Same as for carbon tax on generation stage (B2.c)*	***Conditions to have an influence on dispatch:*** *Same as for carbon tax (B2.c)*	***Conditions to have an influence on dispatch:*** *- Dispatch is based on cost-based merit order and takes into account carbon cost* *- Oversight of SOE to check dispatch takes into account carbon cost while might have other preferences* *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season* *- Availability of diverse carbon intensity options (coal, gas, fuel oil, etc.)*
A1.d. Impact on wholesale purchase by distributors/ retailers: Cost of allowances is already embedded in power supply cost and cannot be singled out anymore, thus impact on internal SOE wholesale price is similar to a carbon tax	**A2.d. Impact on wholesale purchase by distributors/ retailers:** Same as for carbon tax on generation stage (B2.d)	**B1.d. Impact on wholesale purchase by distributors/retailers:** **Limited impact expected at this stage:** - Either passed though into tariffs, - Or, if not allowed to be passed through into tariffs, will undermine capacity to recover cost and thus financial viability of SOE, potentially limiting its ability to invest in low-carbon investment, since RE investment will reduce carbon tax cost years later. Limited options to respond at distribution stage: SF6 and reduction of losses.	**B2.d. Impact on wholesale purchase by distributors/retailers:** - No impact expected at this stage as carbon tax if normally just passed through internally as all taxes - If not allowed to be passed through into tariffs, will undermine capacity to recover cost and thus financial viability of SOE, potentially limiting its ability to invest in low-carbon investment, since it would take years before RE investment can reduce carbon tax cost. Limited options to respond at distribution stage: SF6 and reduction of losses
Conditions to reduce carbon content: *NA*	***Conditions to reduce carbon content:*** *NA*	***Conditions to reduce carbon content:*** *NA*	***Conditions to reduce carbon content:*** *NA*
A1.e. Impact on consumption decision: Same as for generation stage (B1.e) **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use tariffs)**	**A2.e. Impact on consumption decision:** Same as for generation stage (B2.e) **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use Tariffs)**	**B1.e. Impact on consumption decision:** Carbon cost is diluted among other costs thus (limited) incentive to save energy or invest in behind the meter DPV **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use tariffs)**	**B2.e. Impact on consumption decision:** Carbon tax is passed through as a tax but is generally averaged over consumption time, thus (limited) incentive to save energy or invest in behind the meter DPV **Possible addition:** influence can be more important if tariffs are differentiated across time periods according to carbon content **(carbon-based time of use tariffs)**
Conditions to reduce carbon content: *Same as for generation stage (B1.e)*	***Conditions to reduce carbon content:*** *Same as for generation stage (B2.e)*	***Conditions to reduce emissions:*** *Same as for carbon tax (B2.e)*	***Conditions to reduce carbon content:*** *- No load shedding forcing "buy all"* *- Enabling regulation for behind the meter DPV* ***Additional influence:*** *requires smart meters and good metering/billing capacity of the SOE*

MATRIX 3 – VERTICALLY INTEGRATED MONOPOLY (continuation)

VERTICALLY INTEGRATED SOE C. DISPATCH STAGE *More research or experience is needed to continue to inform this table for an ETS or a carbon tax applied at dispatch stage*		**VERTICALLY INTEGRATED SOE** D. DISTRIBUTION AND RETAILER STAGE *More research or experience is needed to continue to inform this table for an ETS or a carbon tax applied at distribution/retailers stage*	
C1. ETS	**C2. CARBON TAX**	**D1. ETS**	**D2. CARBON TAX**
Principle: SOE System operator internalizes carbon price in dispatch Dispatch/system operator is a unique internal entity within the SOE that neither participates directly in an ETS nor pays the carbon tax. In CPI applied at this stage, the system operator, which is also the SOE, has a mandate to internalize the carbon price in the merit order to displace the carbon intensive units and determines emissions generated by plants still being dispatched, thus determining allowances needed for its own generation plants or the calculation basis for the carbon tax to be added to the cost of the electricity. An alternative is to apply a shadow carbon price in the merit order without an ETS or a carbon tax. **General Issues:** Requires strong independent oversight on the dispatch operated by SOE, who might favor other assets operation and management rationale		**Principle: SOE distribution redeems allowances** **General condition:** - Necessarily multisectoral ETS (SOE either unique or small number) **General issues:** - Limited share of cost increase due to CPI is collected by government, especially if percentage of free allocation - Incapacity to increase electricity cost would lead to mostly free allowances (which can still generate impact on investment/retirement) - If pass-through is authorized, then impact mostly at consumption stage only (limited)	**Principle: SOE distribution pays tax on carbon content** - Incentive for SOE might be (very) limited since legislation usually allows distributor to pass through all taxes into bills; main impact expected is thus at consumer level - Incapacity to increase electricity cost (thus to pass through) would block any possibility of carbon tax as would undermine cost recovery and financial viability of SOE - Most increase in electricity price induced by carbon tax is collected by government **General condition:** No sector size or scope condition
C1.b/C2.b. Impact on generation investment/retirement decision: **- Monopolistic SOE might generally be able to pass through carbon cost, thus limiting impact; nonetheless:** - Reduces dispatch and thus potentially internal streams of revenue of the most carbon-intensive plants being less dispatched, thus discourages investment in similar technology - Can thus drive early decommissioning of (coal) plants being displaced - Improves revenue streams of less carbon intensive plants, thus can generate incentive to invest more in RE		**D1.b. Impact on generation investment / retirement decision:** - No cost added on thermal plants, but since SOE distributor is part of the entity who invests on new own capacities, generates incentive for SOE to invest more in RE plants - Can drive early decommissioning of coal plants owned by SOE	**D2.b. Impact on generation investment/ retirement decision:** No significant impact, direct or indirect, expected on generation investment or retirement decision processes (no incentive to invest or purchase more or less from RE or coal generators since, as all taxes, carbon tax is legally passed through to customers into bills)
Conditions to influence investment/retirement: *- Dispatch is determined by cost-based merit order* *- Incentive to early decom. lessened if SOE-owned deficitary plants are internally cross-subsidized* *- Or if cost of allowances compensated*	***Conditions to influence investment/ retirement:*** *- Dispatch is determined by cost-based merit order* *- Incentive to early decom. lessened if single-buyer-owned deficitary plants are internally cross-subsidized* *- Or if cost of allowances compensated*	***Conditions to influence investment/retirement:*** *Depends on relative importance and influence of SOE distribution and carbon cost felt by distribution in SOE decision to invest in generation and/or retire*	***Conditions to influence investment/retirement:*** *NA*
C1.c. Impact on dispatch decision: - Displaces carbon intensive generation - Increases marginal cost by i) excluding cheaper plants and ii) adding carbon price on thermal (except if carbon cost is compensated)	**C2.c. Impact on dispatch decision:** - Displaces carbon intensive generation - Increases marginal cost by i) excluding cheaper plants and ii) adding carbon price on thermal (except if carbon cost is compensated)	**D2.c. Impact on dispatch decision:** No mechanical change expected in merit order but since SOE distributor is part of the entity deciding dispatch, incentive to reduce carbon content of electricity provided to distribution	**D2.c. Impact on dispatch decision:** No significant impact, direct or indirect, expected on dispatch decision process (no impact on merit order process, no incentive to dispatch less coal or more RE since, as all taxes, carbon tax is legally passed through to customers into bills)
Conditions to reduce emissions at dispatch: *- Same conditions than for ETS/ carbon tax at generation (B2.c)*	***Conditions to reduce emissions at dispatch:*** *- Same conditions than for ETS/ carbon tax at generation stage (B2.c)*	***Conditions to have an influence on dispatch:*** *NA*	***Conditions to have an influence on dispatch:*** *NA*
C1.d. Impact on wholesale purchase by distributors/ retailers: Same as impact on wholesale of ETS at generation stage (B1.d)	**C2.d. Impact on wholesale purchase by distributors/ retailers:** Same as impact on wholesale of carbon tax at generation stage (B2.d)	**D1.d. Impact on wholesale purchase by distributors/retailers:** - Incentive might be (very) limited, since limited/no margin of decision on internal purchase - Either passed though into tariffs (no impact), - Or if pass-through into tariffs is not allowed, limited options to respond at distribution stage (SF6 and reduction of losses); beyond that might undermine capacity to recover cost and thus financial viability of SOE	**D2.d. Impact on wholesale purchase by distributors (SOE distribution division):** - Incentive might be (very) limited since, limited/ no margin of decision on internal purchase and legislation usually allows distributors to pass through all taxes - Only incentive is willingness to reduce bill increase to customers - If pass-through into tariffs is not allowed, limited options to respond at distribution stage (SF6 and reduction of losses); beyond that might undermine capacity to recover cost and thus financial viability of SOE
Conditions to reduce carbon content: *NA*	***Conditions to reduce carbon content:*** *NA*	***Conditions to reduce carbon content:*** *NA*	***Conditions to reduce carbon content:*** ***Suggestion:*** *obligation to SOE/distributor to engage in demand-side programs, financed by carbon tax proceeds, to help consumers to reduce carbon footprint of electricity consumption (demand-side management, energy efficiency, DPV, etc.)*
C1.e. Impact on consumption decision: - Increase of cost due to CPI at dispatch is diluted in time and among other costs within SOE cost structure thus (very) limited incentive to save energy/invest in behind meter DPV. **- Possible addition: carbon-based time of use tariffs**	**C2.e. Impact on consumption decision:** - Increase of cost due to CPI at dispatch is diluted in time and among other costs within SOE cost structure thus (very) limited incentive to save energy invest in behind meter DPV. **- Possible addition:** carbon-based time of use tariffs	**D1.e. Impact on consumption decision:** Similar as for carbon tax (D2.e), but less predictable	**D2.e. Impact on consumption decision:** - No incentive if pass-through is not authorized - If pass-through is authorized, it would be averaged over consumption time, thus (limited) incentive to save energy or invest in behind the meter DPV - **Possible addition:** differentiation of tariffs across time periods according to carbon content **(carbon-based time of use tariffs)** (can be price neutral), then incentive to save/reduce energy when most carbon intensive, adopt DPV
Conditions to reduce carbon content: *Same as for generation stage (B1.e)*	***Conditions to reduce carbon content:*** *Same as for generation stage (B2.e)*	***Conditions to reduce carbon content:*** *Same as for carbon tax (D2.e)*	***Conditions to reduce carbon content:*** ***Additional influence:*** *requires smart meters to differentiate price in time according to carbon content (see also condition for consumption stage); requires excellent metering/billing capabilities*

MATRIX 3 – VERTICALLY INTEGRATED MONOPOLY (continuation)

VERTICALLY INTEGRATED SOE E. CONSUMPTION STAGE

E1. ETS	E2. CARBON TAX
Principle: Customers redeem allowances for carbon content - Usually part of a wider multisectoral ETS - Wide range of possible responses - Potentially applicable in case of load shedding (less impact) - Potentially applicable whatever the energy mix is **General issues:** - Applicable only on large industrial customers - Large number of regulated entities, thus MRV is challenging - Needs to be coordinated or integrated with RPS and/or tradable EE certificates mechanisms, if any exist	**Principle: Customers pay tax on carbon content** - Wide range of possible responses but needs accompanying enabling measures, especially for low-income households and small- and medium-sized enterprises - Most increase in electricity price induced by carbon tax is collected by government and can be recycled - No sector size or scope condition **General issues:** - Very large number of regulated entities, thus MRV more challenging (metering, billing, collection issues)
E1.b. Impact on generation investment/retirement decision: Same as for carbon tax (2.1)	**E2.b. Impact on generation investment/retirement decision:** - No cost added on thermal plants, but growing share of market captured by prosumers (principally DPV) - Reduce incentive to invest in centralized generation
Conditions to influence investment/retirement: *Same as for carbon tax (2.1)*	***Conditions to influence investment/retirement:*** *Influence on retirement: no load shedding*
E1.c. Impact on dispatch decision: Does not impact merit order, however: - demand to be served is doubly impacted i) by EE and DPV measures reducing demand on grid and ii) by electrification of final uses that reduces overall emissions of final customers but increases demand, but consumers can also opt for trading allowances from other sectors instead of changing demand **Also:** adding shadow carbon price in dispatch could also change merit order and displace more thermal	**E2.c. Impact on dispatch decision:** Does not impact merit order, however: - demand to be served is doubly impacted i) by EE and DPV measures reducing demand on grid and ii) by electrification of final uses that reduces overall emissions of final customers but increases demand, but consumers can also opt for trading allowances from other sectors instead of changing demand **Also:** adding shadow carbon price in dispatch could also change merit order and displace more thermal
Conditions to have an influence on dispatch: *Same as for carbon tax (2.2)*	***Conditions to have an influence on dispatch:*** *- No load shedding forcing "dispatch all"* *- Not hydro-dominated with dependency on thermal at dry season*
E1.d. Impact on wholesale purchase by distributors/retailers: Same as for carbon tax (2.3)	**E2.d. Impact on wholesale purchase by distributors/ retailers:** No significant upstream impact expected on wholesale purchase decision from SOE distribution
Conditions to reduce carbon content: *Same as for carbon tax (2.3)*	***Conditions to reduce carbon content:*** *NA*
E1.e. Impact on consumption decision: - Caps can be based on overall carbon intensity of final product, including scope 2 emissions from electricity; can thus also be applied in situation of load shedding **Large customers:** generates incentive for investing in EE and demand management systems, distributed RE and storage, purchase of offsets, RE or EE certificates, and possibly electrification of uses if reduces overall emissions; can also opt for trading allowances from other sectors instead. **Smaller regulated customers: not applicable: too complicated** to extend to small customers	**E2.e. Impact on consumption decision:** - Carbon tax is calculated based on carbon content of consumption, ideally differentiated by period of time of the day and seasons. Incentive is strong if coal dominated, weak if hydro-dominated. **Large customers:** generates incentive investing in EE and demand management systems, distributed RE and storage, purchase of offsets, RE or EE certificates, and possibly electrification of uses if reduces overall emissions. **Smaller regulated customers:** generates incentives for more efficient behaviors and appliances, solar rooftops. - can be replaced by a carbon content-based modulation of existing tariffs to ensure overall cost neutrality for (small) consumers
Conditions to reduce carbon content: *- Applicable only to large industrial customers* *- Requires enabling regulation for DPV to unlock this type of response* *- Requires accompanying measures to enable response* *- Limited short-term reductions if hydro-dominated, except at peak season requiring thermal* *- Needs to be coordinated or integrated with RPS (if applicable to large customers) and/ or tradable EE certificates mechanisms, if any, to prevent multiple transaction costs and weakening carbon price signal.*	***Conditions to reduce carbon content:*** *- Distribution company shall be well managed: MRV and tax collection depends on metering, billing, and payment collection* *- Requires enabling regulation DPV to unlock this type of response* *- Requires accompanying measures to enable response, especially EE/DPV up-front costs financing for small customers* *- Requires smart meters and ability of single- buyer/distributor to differentiate price in time according to carbon content to maximize customers' response* *- Bad quality of service (load shedding) makes it virtually impossible to add a carbon tax* *- Limited short-term reductions if hydro-dominated, except at peak season requiring thermal*

5.

Lessons learned and recommendations

The lessons and recommendations of this report fall into four categories. They include the role of carbon pricing within a broader context of decarbonizing a power sector in LICs and MICs; the need for different CPIs for different power sector structures in these countries; the advantages of creatively adapting the design of CPIs to ensure effectiveness, minimize undesired impacts, and maximize co-benefits; and the political economy challenges that governments need to overcome to move along the learning curve.

5.1 The role of CPIs in the broader context of decarbonizing the power sector in LICs and MICs

Power sectors in LICs and MICs vary substantially in many aspects. However, they commonly share a series of acute challenges that differ markedly from those faced by advanced economies in terms of type or degree.

1.

Lesson 1. Challenges faced by power sectors in low- and middle-income countries differ significantly from those in high-income countries. Policy landscapes for deploying CPIs are therefore different, influencing their role and design.

Common challenges faced by LICs' and MICs' electricity systems—rapid growth in electricity demand, low levels of access and affordability, insufficient and insecure supply, high costs of capital, vulnerability against volatility of international energy prices, lack of cost-reflective tariffs, etc.—provide a different set of priorities for public policies and regulations in the power sector compared to advanced economies. These challenges will persist for the near future and overcoming them must be combined with the new decarbonization goals. Policy instruments to pursue these decarbonization goals, including CPIs, must address these challenges by adapting to each country's policy landscape. Thus, while a lot can be learned from international experiences of implementing CPIs in more mature power sectors of low-growth demand advanced economies, LICs' and MICs' context–specific factors will have implications for the role and design of CPIs in these countries.

Recommendation: *LICs' and MICs' specific challenges need to be identified and acknowledged when the prospect of a CPI is introduced to ensure that the policy reflects the need to meet these challenges while mitigating emissions.*

2.

Lesson 2: Governments have a wide variety of policy instruments and reforms at their disposal to drive decarbonization of their current and future power sectors. The role of carbon pricing needs to be defined within this broader policy mix, taking into account the overlapping policies.

Now that most LICs and MICs have committed to achieving carbon neutrality between 2050 and 2070, their governments can consider a wide range of policy reforms and instruments to decarbonize their power sector. As described in Section 2.3, several of these are already being implemented, like early decommissioning programs, renewable portfolio standards, feed-in tariffs for renewables, tax incentives and subsidies for energy efficiency, demand response mechanisms, etc. Governments typically adopt a package of policies (or reforms to existing policies) to foster the development of low-carbon generation, promote more efficient use of electricity, and phase out carbon-intensive generation. CPIs can be an integral component of this policy mix. Their intended role should be clearly defined alongside those other policies, and their interaction with other mechanisms should be anticipated to ensure that, in tandem, they create an effective incentive framework for an orderly transition to a low-carbon electricity system.

Typically, CPIs aim to create a price signal to reduce utilization of existing carbon-intensive generation and shift investment away from new thermal power plants. CPIs can also incentivize more efficient use of electricity, complementing energy efficiency measures such as building codes. Only under specific market conditions can CPIs create a direct price incentive to invest in new renewable generation. In LICs and MICs (and indeed, many HICs), renewables sell the bulk of their electricity through fixed-price PPAs, and therefore they do not benefit from the increase in wholesale electricity prices induced by a CPI.[51] Still, this illustrates the importance of understanding how a CPI would interact with the existing market and regulatory mechanisms.

Ideally, a CPI can complement policy tools that promote uptake of low carbon generation (such as feed-in tariffs) by creating an incentive to simultaneously phase down the most carbon-intensive power plants (e.g., brown coal) ahead of less polluting options (e.g., natural gas). Building on complementarity will ensure consistency, prevent inefficient redundancies, and maximize effectiveness.

Recommendation: *A CPI-based policy should not be designed in isolation but rather as part of a broader power sector decarbonization policy package, supported by a thorough analysis of potential complementarities and/or redundancies with other power sector decarbonization policy instruments.*

51 Although expectations of a price increase on the wholesale market might eventually generate an opportunity for negotiating higher prices in PPAs.

5.2 Different CPIs for different power sector structures

3.

Lesson 3. The power sector is a complex, highly regulated value chain, offering a variety of potential regulation points and design options for CPIs, delivering different impacts on the decisions of the agents along the chain to decarbonize the sector.

Because of its peculiar economic characteristics, including the power grid being a natural monopoly and the stability of the system imposing a central command-and-control of the dispatching of all generators, the power sector is highly regulated all along its value chain. As described in Section 3.2, CPIs can be applied at different regulation points throughout the power sector value chain, including the points of generation, dispatch and market, distribution, and consumption. The potential impact(s) of a CPI will depend on the point along the value chain at which it is applied. That point will determine the agents whose decisions the CPI directly influence. For example, a CPI applied at the point of consumption, for instance with a carbon tax, might effectively influence consumption patterns. It will however have no direct impact on the decisions concerning dispatch or the supply mix, although it will eventually influence these by changing the demand to be served. If the CPI is applied further up the value chain, at the point in which fuel is burned for power generation, it may create a direct signal for investment and dispatch decisions and then, depending on the structure and the regulation of the sector, may be passed through along the value chain up to the consumers. Frequently, in LICs and MICs, a large share of consumers are captive in the sense that they receive their power from a monopolistic distributor. Tariffs are strictly regulated to avoid abuse of this monopoly power, and governments of LICs and MICs often adopt policies that aim to reduce the cost of electricity for end users. Consumption subsidies, lump-sum credits for consumers, price caps, or regulated retail tariffs set below cost recovery can prevent or limit the pass-through of the carbon cost and thus neutralize the incentive for consumers to adjust their consumption patterns or invest in energy efficiency.

How effectively the CPI will influence the decision process at the stage of the value chain it is applied will eventually depend on how the incentive that it generates combines with the other incentives and regulations already influencing the decision-makers at that stage.

Recommendation: *When considering adopting a CPI for the power sector, governments should consider different potential regulation points and choose the stage of the value chain at which the CPI can most effectively move the sector toward a lower carbon intensity, given the country's specific circumstances.*

Lesson 4: The structure of the power sector will have a potentially strong and distinct infuence on the effectiveness of different types of CPIs.

4.

The degree of liberalization of the power sector, especially the extent to which state-owned utilities have been unbundled, the private sector's ability to participate, and the competition introduced within the market vary considerably across LICs and MICs, as detailed in Section 2.1. Given these conditions, the structure of the power sector and the associated regulations at the different stages of the value chain will have direct influence on the impact of the CPI.

In liberalized power sectors with high levels of competition in the wholesale market, it is simplest for a carbon price to achieve its intended impact at the generation and dispatch stages. As generators have to internalize the carbon price into their bids or bilateral contracts, with a sufficient carbon price signal, competitive pressures will make lower-carbon forms of generation outcompete more emission-intensive forms, first, in the short term, through a less carbon-intensive dispatch and then, over a longer term, through displacing investment from more carbon-intensive to lower-carbon power generation.

The effects of a carbon price signal can be skewed in less liberalized power market structures, particularly in oligopolies or in electricity systems dominated by one vertically integrated state-owned utility. For example, if the same utility administers dispatch and owns a substantial portion of the generation mix, it can have an incentive to prioritize dispatch of its own carbon-intensive power plants to maintain their financial viability, regardless of the price, potentially negating the effect of a carbon price. For a CPI to influence vertically integrated utilities, there must be strong and independent regulatory oversight and a transparent dispatch protocol based on merit order.

In addition, when the sector is small or still largely dominated by one or a small number of companies, in particular by a single public utility, the trading part of an ETS will not work if it is limited to the power sector. In such cases the power sector should be part of a larger sectoral scope to ensure minimum liquidity in the carbon market. This is not an issue in the case of a carbon tax. An alternative could be to introduce a shadow carbon price in the dispatch rules that is subject to either independent oversight or a mandate that the system operator must apply it, which would deliver a similar change in the merit order without adding any carbon cost to the system.

A CPI applied at the downstream consumption stage, for instance a carbon tax or a Scope 2 ETS on the industry, is less dependent on the structure of the sector in terms of its primary intent of influencing the consumption pattern to move part of the consumption to periods when generation is less carbon intensive, for instance when more solar electricity is available. However, how the supply system will serve the resulting demand, and thus generate emissions, will still be highly dependent on the existing structure and regulations. For instance, coal might still be dispatched before gas.

***Recommendation:** When choosing the type of CPI, the structure and the size of the power sector are critical. In the case of a power sector of limited size or dominated by an oligopoly, an ETS can only be considered if the sectoral scope is extended beyond the power sector to ensure that the number of participants is large enough to deliver the expected benefit of trading. In systems run mostly by a vertically integrated SOE, a carbon price should be accompanied by strong regulatory oversight to ensure that it is reflected in the merit order dispatch.*

5.3 Designing CPIs to ensure effectiveness, minimize undesired impacts, and maximize co-benefits

5.

Lesson 5: For a CPI applied at a determined point of the value chain to have an impact on the emissions of the sector, it must provide a signal that is strong and predictable enough to influence the decision processes at that point and possibly beyond.

The high degree of regulation of the power sector means that the economic agents making decisions at each stage of the value chain are exposed to specific sets of incentives. To be effective a CPI must be designed and calibrated in a way such that the new overall resulting set of incentives changes the decision outcome. For example,

→ A CPI applied at the power generation level in a merit order–based system dominated by coal must result in a carbon price that is high enough to change the merit order such that there is a switch between coal and gas power plants at the margin.

→ A CPI applied at the electricity distributor level must be ambitious enough to force the regulated entities to significantly increase the share of renewables in their wholesale purchases, but still be calibrated to remain aligned with the pace of the development of renewable energy-based generation. As with applying a CPI at the point of generation, a strong and predictable carbon price at the point of distribution could influence dispatch because purchasers of electricity will factor in the carbon price when they bid into the market.

- A CPI applied at the consumption stage will only work if the consumer can respond to the price signal. The corresponding demand elasticity and the range of acceptable variations must be reasonably anticipated to calibrate the carbon price signal accordingly.

Once applied at a point of the value chain, the carbon price can have an influence beyond that point, on the decisions made on downstream stages. However, the regulations in place can prevent the signal from being conveyed to the consumers, who ultimately determine whether there is a need to dispatch the marginal plant, which is usually thermal. Liberalization of the sector such that the retail commercialization is actually competitive is quite rare in LICs and MICs. In fact, a large share of consumers are captive in the sense that they can only access electricity from a monopolistic distributor. The consumption subsidies, price caps, and regulated retail tariffs set below cost recovery that are in place to prevent the abuse of monopoly power prevent or limit the pass-through of the carbon cost and thus can neutralize the price signal to end consumers, blunting the impact of the CPI.

For a CPI applied further up the value chain to harvest the benefit of more carbon-efficient consumer behaviors, it is essential that some carbon price signal is transmitted to the customers, either by passing through the carbon price (in whole or in part) or by modulating the tariff to reflect the carbon content of electricity at the time it is consumed. Therefore, in markets that have regulated retail tariffs, the formula used to derive those tariffs must adequately factor in the carbon costs associated with generation. If the objective is to shift consumption to times when electricity is less emission-intensive, the varying carbon costs of generation throughout the day must be factored into time-of-use tariffs and smart meters must be in place.

In all cases, a CPI will be more effective if the actors are able to anticipate the future evolution of carbon price based on planned increases to a carbon tax or tightening caps in an ETS. A predictable carbon price will allow actors to build a carbon price into investment decisions based on future marginal abatement costs.

Recommendation: *Designing and calibrating the level of CPIs to achieve real reductions must be based on a solid diagnosis of the switching values that can change the outcome of the decisions made at the regulation point and beyond. Driving investments toward low-carbon technology requires decision-makers to be able to anticipate the evolution of the carbon price over the medium term.*

Lesson 6: Carbon pricing may interact with other policies in the power sector and thus be designed accordingly to prevent reducing its effectiveness or generating negative consequences.

6.

A number of policy instruments and regulations can interact with carbon pricing instruments and, if these interactions are not anticipated and duly addressed, such interactions can turn the introduction of carbon pricing ineffective or even counterproductive, for example by generating undesirable rent transfers from consumers to generators.

For instance, thermal generation that has been procured via long-term PPAs with minimum take-or-pay obligations can reduce dispatch efficiency and constrain the impact of a carbon price on the merit order. Regulatory measures preventing a carbon price from being passed on by generators can induce generators to curtail output when the carbon cost undermines their financial sustainability, which can be problematic in supply-constrained systems.

Other policies, such as energy efficiency policies and renewable energy support policies like RPS, can affect the carbon price in an ETS. By complying with these other policies, the regulated entities might achieve their emissions targets without using their allowances, thus flooding the market and bringing their price close to zero if the cap is not adjusted, wiping out its price signal. A low allowance price can discourage other investments needed to manage the transition toward deep decarbonization, like CCS, long-term storage, hydrogen-to-power, and retrofits and flexibilization of thermal plants still needed to absorb intermittency and loss reductions investment on the grid. It is thus important that there is coordination between the policies, including in the design and the calibration of ancillary mechanisms that are needed to ensure the carbon price signal can provide an incentive to technologies needed in the future. Carbon price floors, hybrid ETS–carbon tax systems, or carbon contracts for difference are examples of mechanisms that can provide investors with the minimum required predictability and stability for a longer-term price signal.

Introducing a carbon price in a merit order–based system elevates the clearing price and therefore increases the infra-marginal rent of all the generators, which continue to be dispatched, including possibly for the carbon-emitting generators that are less carbon-intensive than the new marginal plant. Consumers may eventually pay this additional infra-marginal rent, resulting in a carbon rent transfer from the consumers to the generators that can undermine the objective of protecting low-income customers or the competitiveness of certain industries. There are ways to avoid or mitigate this, for instance by collecting and redistributing part of that additional infra-marginal rent through separate channels (e.g., income tax) that do not erase the carbon price signal.

Certain designs might seem to address one concern but eventually can generate other problematic issues, requiring good anticipation of economic agents' behaviors exposed to a complex web of intertwined incentives. For instance, an ETS based on carbon-intensity benchmarks to calculate the caps in accordance with the generation may be a way to address the considerable uncertainty that would plague an absolute caps-based ETS in power systems facing strong demand growth, by preventing skyrocketing market prices in case the demand is higher than expected and all generators become buyers. However, in practice, the wide range of difference in carbon intensity across gas- and coal-based generation technologies, and even across different coal-power generation technologies, can lead to technology-specific benchmarks, as observed in China. Such a solution can lead to the equivalent of a negative carbon price for carbon-intensive generators performing better than their benchmarks, receiving more allowances that they can sell, thus improving their profitability and eventually encouraging them to generate more. As has been observed in many cases, setting the right policy instrument requires testing, assessing, and adjusting.

The history of the power sector is a history of permanent reform and invention of creative solutions to adapt to new objectives, which frequently combines multiple objectives like economic efficiency and energy security, taking also into account permanent technology innovation, which opens up options for new solutions. The diversity of instruments that have been created in past decades, including the day-ahead spot market, feed-in tariffs, contracts for difference, time-of-use tariffs, RPS, and demand response, illustrates the role of creativity in designing power sector reforms, which are sometimes initially very country specific. Decarbonization is a new policy objective for the power sector that requires a new round of creativity to combine it with the prevailing development objective. While learning from international experience is useful, one of the key lessons is that creativity is at the core of designing CPIs that will fit local circumstances. The California Climate Credit mechanism is a demonstration of how creativity can deliver win-win solutions to both reduce emissions and contribute to protecting consumers, especially low-income consumers, from carbon costs passed down into retail tariff.

Recommendation: *When designing a CPI, it is necessary to investigate and simulate potential interactions with other existing regulations that influence the formation of electricity prices. It is equally important to embed within it features that address context-specific undesirable effects or inefficiencies and help reconcile the prevailing development objectives with the new decarbonization goal, testing and adjusting as needed.*

5.4 Political economy challenges and learning curve

7.

Lesson 7: In systems that are constrained by a lack of generation capacity, a carbon price may lead to higher electricity costs without achieving emission reductions.

In markets that lack adequate low-carbon generation and/or transmission capacity, there is risk that a carbon price could increase system costs without achieving the desired objectives. Systems that are severely capacity constrained will need to dispatch carbon-intensive power plants to balance the system, or even minimize power outages, regardless of the cost. Without adequate generation of energy conservation alternatives, carbon costs are likely to be added as variable costs, possibly passed through the value chain, and result in higher retail tariffs, with no corresponding short-term effect on the supply mix while further suppressing the demand for low-income households and small businesses.

There still might be some limited opportunity to optimize the carbon content during off-peak periods when the system is not constrained or to encourage efficiency gains on the demand side by applying a CPI at the consumption stage, for instance a Scope 2 ETS on large industrial firms.

Still, in capacity-constrained power systems, the political economy might be adverse and decarbonization efforts should focus on the future development of the system rather than on its current operation. Instruments other than an ETS or carbon tax might be considered to accelerate investment in low-carbon generation options, like concessional financing or investment de-risking instruments.

In centrally planned systems where governments decide what kind of plants to build or retire, a shift to a lower-carbon supply mix may be achieved by incorporating a shadow carbon price into least-cost supply models that inform decisions around investments in new capacity and retirements. Alternatively, these models could be constrained based on top-down emission reduction targets, such as those included in many NDCs.[52]

Recommendation: *In capacity-constrained systems, decarbonization efforts should focus on energy efficiency and future system development, in particular investment in renewable generation and transmission. When the power sector is centrally planned, a shadow carbon price can be introduced into least-cost optimization-based planning, and/or caps based on top-down emission reduction targets can be used to constrain the models.*

52 The effectiveness of these approaches will depend on the respective government's level of ambition and the strictness with which the shadow price or target is adhered to. Both approaches may still incur costs from shifting to a lower-carbon (and potentially higher-cost) supply mix.

Lesson 8: A carbon price can be politically challenging to implement, but strategies exist to overcome political hurdles. The design of the recycling of the carbon revenue is an essential part of it.

8.

Carbon pricing in the power sector can be politically difficult to implement given concerns that it will damage the affordability of power and competitiveness of industry, especially in systems that are struggling to invest at the pace required by the demand growth. Several strategies exist to overcome political hurdles, starting with the guidance provided in the recommendations of this chapter.

In addition, the solution to political barriers may require adopting a broader lens that situates carbon pricing within a broader package of policies aimed not only at mitigating climate change, but also at the preexisting challenges related to LICs' and MICs' development priorities. Failing to account for LICs' and MICs' preexisting challenges when adopting or designing a CPI can generate political economic gridlock that prevents the generation of the revenue that might otherwise be used to co-address broader development aims. For political expediency, many LICs and MICs have adopted measures that reduce the price signal from carbon taxes or ETSs, and as a result the revenue intake from their CPIs is negligible. Generating revenue is typically not the primary aim of CPIs, but it can be used to address political objections to introducing them.

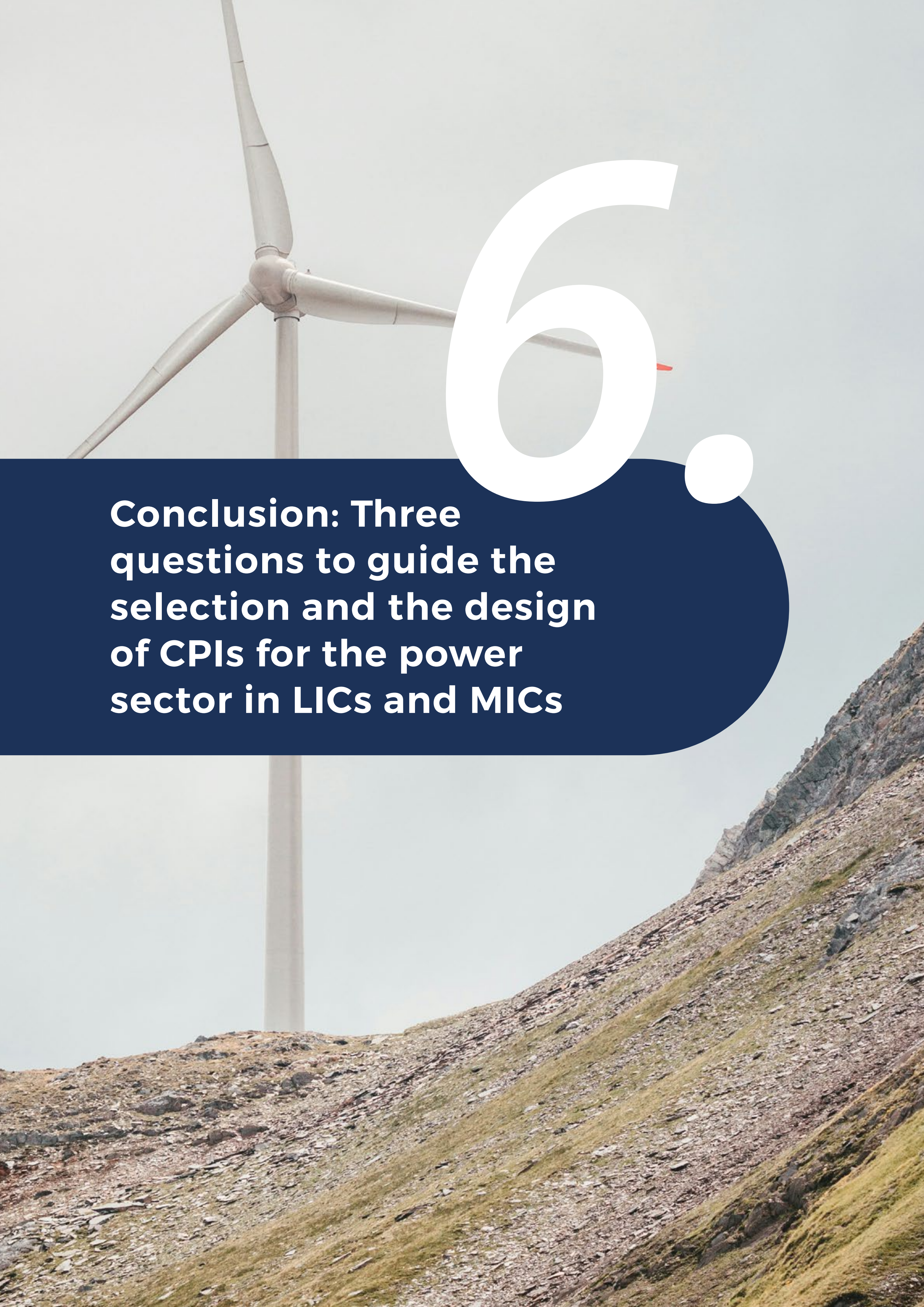
For instance, such revenue can be used to improve affordability. A redistributive mechanism can be designed so that the additional carbon cost would be compensated without erasing the incentive to reduce the emissions. In a new circulatory flow of resources, the carbon price can be passed through, thus inducing changes in behaviors and energy efficiency improvements, while the carbon rent generated can be redirected separately, for instance as a lump-sum flat payment to all customers, regardless of income level, thus neutralizing the redistributive effect. This approach, applied in the flat climate credit mechanism in California, can initiate a virtuous cycle that puts in motion a substantial volume of resources, which generates incentives to decarbonize while reconciling that objective with the preexisting priority to protect low-income consumers. CPI revenue can also be allocated to foster a just transition in regions in which economies depend on fossil fuel-based generation, for instance to fund reverse auction mechanisms to allocate financing to projects proposing early decommissioning and repurposing of coal mining and coal power generation assets.

It also appears that when options to respond to the carbon price signal are limited, acceptability is low. Therefore, besides compensation, revenues collected from CPIs can be used to facilitate access to options to respond, like financing up-front costs of energy efficiency or solar-rooftop investment, and thus improve both the effectiveness of the CPIs and their acceptability.

In view of the diversity of CPI design options and potential interactions with prevailing regulations, consultations with stakeholders and civil society are important not only for anticipating and explaining these interactions but also for designing ancillary features, such as those in which recycling CPI revenues mitigates undesirable effects and delivers co-benefits. Such participatory processes can be essential for building ownership or at least mitigating pushback.

Finally, carbon prices tend to be phased in over time, to build political acceptance and work out administrative complications. Lenient approaches can be adopted in the pilot phase of implementation. A lower level of sectoral regulations or limited jurisdictional pilots can be initially considered rather than higher nationwide legislation levels. In this way, the initial legal framework can be passed such that the capacity of both the new regulatory bodies and the regulated entities can be built. This may be particularly relevant to the deployment of the MRV, the operation of the CPI mechanism, and the enforcement of compliance. Lessons can be learned and initial features revised as needed before stakes are too high. The overall CPI mechanism can thus be progressively developed, adjusted, road tested, and strengthened to then become able to better withstand resistance when ambitions and price signals are progressively raised. A carbon tax can simply be set low initially and increased over time. An ETS can first opt for the simplest allocation rule, grandparenting (based on facilities' historical emissions) and then tighten the caps while progressively increasing the share of allowances allocated through competitive auctions. It appears crucial that actors be able to anticipate the evolution of the price signal so that they can decide on the best options to decarbonize the power mix. This requires that the regulation be predictable and stable over time. This also offers clarity to the governments seeking to anticipate the revenue the CPI may generate.

Recommendation: The generation and the recycling of carbon revenues should be part of the design from its early stages. Regular consultations with stakeholders at design, assessment, and successive adjustment stages are critical for correctly anticipating their response, facilitating access to alternatives, building political acceptance, and agreeing on measures to address undesired impacts and deliver development co-benefits.



6. Conclusion: Three questions to guide the selection and the design of CPIs for the power sector in LICs and MICs

This report provides a framework for implementing carbon taxes and/or ETSs in low- and middle-income countries. These forms of direct carbon pricing can help reduce GHG emissions in what is frequently its largest source, the power sector, by influencing the series of decision processes that ultimately determines how the electricity delivered to consumers is generated and thereby play a crucial role in these countries' achieving their NDC. This report addresses the importance of the structure of the power sector, the choice of the regulation point along the value chain, the other policy instruments affecting stakeholders along the power sector value chain, and how the fiscal revenues that it can generate are used, in determining the impact of carbon tax and ETS on both GHG emissions and other pressing development objectives. Building on the experience of more advanced economies that have already accumulated almost two decades of CPI implementation and on case studies of middle-income countries, it posits the lessons learned so far and the recommendations that can be formulated at this stage.

Optimal design of CPIs for LICs and MICs is clearly a work in progress. This report could draw only on the limited record of carbon pricing policies in LICs and MICs to date. Some design options that may be promising, that are likely to address development challenges and to be well suited to the structure of their power sectors and energy resources endowment, have never been tried in LICs or MICs. There is a strong need for further research and implementation experience to address issues, such as

- the relevance and consequences of adding a carbon cost when, due to losses (technical or otherwise) or energy subsidies, utilities are not recovering the current costs of electricity from consumers;
- the role and relevance of CPIs in situations of load-shedding;
- ways of using carbon revenues apart from compensation to enable a more effective response to the CPI;
- how to calibrate CPIs in LICs and MICs with their exposure to Carbon Border Adjustment Mechanism–like policies;
- the combination of multiple CPIs at different points of the value chain to address signal attenuation and border effects (i.e., imports of electricity) and the potential trade-offs associated with the different possible combinations and associated design features;
- the potential overlaps, complementarities, and integration opportunities with indirect carbon pricing mechanisms designed to support the scaling up of renewable energy (e.g., FiT, FiP, RPS, technology-specific auctions, green certificates) and incentives for improving the energy efficiency on the demand side (standards, demand response, demand-side management, energy efficiency certificates, etc.).

As answers to these questions develop, this report provides early and simple guidance to help LICs and MICs to select and design a carbon pricing instrument for their own national circumstances. This guidance is structured in three successive broad questions designed to prompt the unique reflection each country must undertake to generate its own response to each of these questions.

Question 1:

When introduced in the power sector, would the carbon pricing instrument need to cover other sectors as well?

The response to this question has large consequences. This decision influences the range of regulation points that can be considered, where the actual emissions reductions might eventually take place, and who will bear the cost. A CPI that covers the power sector and other sectors may be able to capitalize on inter-sectoral dynamics to amplify the effect on the power sector, but it can also create harmonization issues. Those that cover other sectors often cover regulation points located upstream (on fuels used in thermal plants) and downstream (on consumers). For those that do not, applying a CPI upstream only on fuels consumed by the power sector does not present any benefit compared to applying it at generation stage. There is also a risk of generating an incentive to shift to more carbon-intensive fuels through sectors other than electricity if they are not covered by the CPI. Thus, if other sectors are to be included within the sectoral scope of the CPI, then the two upstream (on fuels) and downstream (on consumption) regulation points can be considered in addition to the generation, the dispatch, and the distribution stages.

ETSs covering multiple sectors change the market for allowances. In such cases, the power sector might be able to purchase allowances from other sectors, or sell allowances to these, depending on the GHG abatement costs observed in each sector, which can lead to a substantially different distribution of actual emissions reductions, financial flows (in investment and in payments), and decommissioning of emitting facilities.

Referring to earlier chapters can help policy makers address these issues. Section 3.2 on regulation points provides additional information about these choices.

Question 2:

Considering the national circumstances of the power sector (i.e., energy mix, challenges, power sector structure), who are the stakeholders along the value chain that can respond most effectively to a carbon pricing instrument?

The response to this question drives the relevant regulation points along the value chain. The answer may determine one point at which the CPI should be applied. It also may indicate that complementary CPIs at different points of the value chain could be most effective. National circumstances, especially the structure and the regulations of the sector, and to what extent these limit responses along the value chain, should drive these decisions.

For example, the diversification of the energy mix can play a large role in the impact of the CPI at a given point in the value chain. If the available energy mix is diversified, with a range of technologies that allow change in investment, efficiency of plant operation, or merit order by a reasonable carbon price, and take-or-pay or other type of vested contracts do not limit the impact on the dispatch, a CPI at generation or dispatch stage can trigger very substantial emissions reductions. These reductions may materialize both in the short term and by undermining the business model of the most carbon-intensive plants in the long term. However, in a hydro-dominated system that depends on flexible thermal during dry season, generators or system operators in charge of dispatch would not have any alternative to respond to a CPI applied at generation or dispatch stage. Such a CPI would just increase the cost of electricity without changing the merit order.[53] Similarly, in a coal-dominated system suffering from load-shedding, a CPI at the generation or dispatch stage might not generate any substantial response at these stages.[54]

Compensation mechanisms have an impact. The downstream response will be muted if compensation mechanisms are in place to prevent an increase in final prices that would not be politically acceptable when the quality of service is degraded. On the other hand, a CPI applied at the distribution or consumption stage might drive stakeholders at that stage, especially in coal-dominated systems, to invest in energy efficiency, in demand management, in distributed renewables, in storage, or in offsets. They may also sign bilateral contracts with RE IPPs who frequently need such contracts to make their projects bankable.

Complementary CPIs can work in tandem. Depending on the national circumstances, a possible subsidiary answer to this question includes complementary CPIs at different points of the value change. Such circumstances include the structure and the regulations of the sector and to which extent these limit additional induced responses along the value chain. In the case of a CPI applied downstream the value chain of the power sector, a complementary CPI applied upstream might influence more internal decision processes along the value chain and thus promote more emissions reductions from the sector. For instance, in the case of an ETS or a carbon tax applied at the consumption level, an environmental dispatch might provide the change in merit order that the CPI at the consumption level would not. Similarly, an ETS at the consumption level might generate an incentive for signing bilateral contracts with renewable energy generators that the environmental dispatch probably would not.

Referring to earlier chapters can help policy makers address these issues. Section 3.3 on the potential role of carbon pricing in the power sector and Chapter 4, especially Sections 4.1, 4.2, and 4.3, on assessing potential impacts of CPIs, provide analytical insights to inform the response to Question 2. In particular, the three detailed matrices exploring the potential impacts of an ETS or a carbon tax along the five different possible regulation points (upstream, generation, dispatch, distribution, consumption), under three typical power sector structures (vertically integrated SOE, single-buyer, fully liberalized power market) can help the reader infer more in depth options on how the stakeholders embedded in their specific national context could respond to different CPIs applied at different stages of the value chain. These matrices might also help anticipate the adjustments that would be worth considering in the existing CPIs when a country is going through a power sector reform and is moving from one power sector model to another.

53 It might have a longer-term impact on investment on pumped or battery storage, but only to the extent that the proper capacity mechanism allows.

54 It might generate an incentive to buy offsets if these are allowed.

Question 3:

Having selected the most promising CPI regulation points along the value chain, what side effects can result from the interaction of an ETS or a carbon tax applied at this stage with the existing sector regulations and other policy instruments? How can these be addressed to ensure consistency with other policies?

This question is vital to the success of the CPI. Investigating this question will enable policy makers to anticipate potential antagonisms with other policies aimed at dealing with specific challenges faced by LICs and MICs, typically guaranteeing affordable access to electricity to low-income users or facilitating increased access to finance to invest in a response to the carbon price signal. The response to this question is vital to what kind of CPI a jurisdiction should implement and its design and calibration (i.e., the level of carbon tax, the ambition of the caps) as well as how to use the carbon revenues to ensure consistency with other development policy goals.

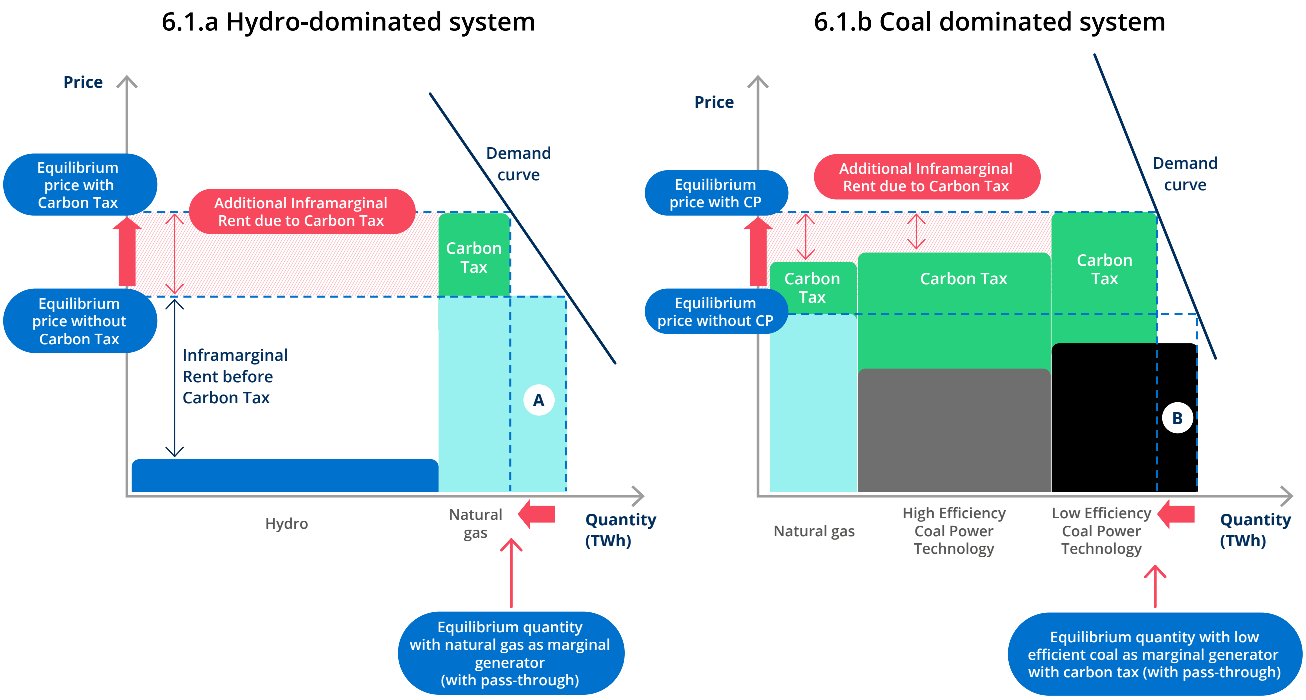
The impact of side effects can vary substantially. The relative importance of these side effects can vary substantially depending on the specific circumstances of the country. For instance, in the case of a coal-dominated system with gas at the margin, with a carbon tax at generation stage, the government would collect most of the price increase of the electricity, which could recycle it for compensation. In a hydro-dominated system where gas is also at the margin, it would mostly increase the infra-marginal rent and thus the revenue of the hydropower plants, with very little revenue collected from the carbon tax by the government (see Figure 6.1).

Side effects can also include interactions with other policy instruments. These also contribute to the decarbonization of the energy sector, like feed-in tariffs, renewable energy portfolios, green certificates, programs to decommission old polluting plants, energy efficiency certificates, demand response mechanisms, etc. If not properly anticipated and designed, the interactions with these other policy instruments can turn the relevance of the CPI almost negligible, for instance by bringing the price of allowances close to zero in the case of an ETS.

Referring to earlier chapters can help policy makers address these issues. Elements to address this question are present in different parts of the report due to its relevance all along the theory of change. Section 3.3.2 on the influence on the infra-marginal rent, Sections 3.3.4 and 4.4 on the recycling of the carbon rent, and Chapter 5 on lessons learned and recommendations (especially Section 5.3 on how to design CPIs to ensure effectiveness, minimize undesired impacts, and maximize co-benefits) provide guidance to build the response.

FIGURE 6.1

Infra-marginal rent and revenue collection from carbon tax in the case of hydro-dominated and coal dominated systems



Note:

- In the simplified illustrative configurations above[55] of a carbon tax applied at generation stage, the government collects only the green areas; the red hatched area represents the increase of the infra-marginal rent paid to the generators that are still dispatched after applying the carbon tax, which is eventually paid by the consumers if there is a pass-through.
- The increase of final price charged to the consumers results in a reduction of the final demand along the demand curve.
- In 6.1.a, emissions reductions result from reduction of gas-based generation due to demand reduction (area A).
- In 6.1.b, emissions reductions result also from change in merit order: gas-based generation which was at the margin before applying the carbon tax has become more competitive than coal and thus moved to the left, while low efficiency coal-based generation has become marginal and is being reduced (area B).

55 For the sake of simplicity of illustrating the potential increase of the infra-marginal rent of incumbent generators, including fossil fuel-based if still dispatched once the CPI is applied, wind and solar power generation has not been considered in these illustrations. Wind and solar plants would also benefit from the increase of the infra-marginal rent induced by the CPI.

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