Digest of the HANDBOOK ON Electricity Markets

International Edition

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with generous support from the authors of the *Handbook on Electricity Markets*.

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FOREWORD

The record-breaking temperatures seen in the summer of 2022 have shown the impact of global warming. Whether in Europe or China, no one can escape it.

Decarbonisation is the only way forward: future electricity generation will have to come to a large extent from renewable energy with the remaining share coming from other low-carbon sources. The tremendous growth of renewable electricity capacity is fundamentally changing global electricity systems and presents power grids with enormous challenges. In the past decade, China has emerged as a global renewable energy champion, ranking first for both investment in and production of renewable energy. In 2021, renewable power plants made up more than 1 000 GW of China's 2 200 GW installed power capacity, in a mix of solar, wind and hydropower. With the new round of power market reforms in 2015, the coal-fired power tariff reform in October 2021 and the announcement in January 2022 that a national unified power market system is to be established, momentum is building for the creation of an electricity market in China.

China's power market designers and policy makers are now grappling with the problem of how to integrate intermittent renewable energy effectively under China's socio-technical system. It is a good moment to find out about the experiences of other power markets throughout the world that have confronted similar issues. What market measures have helped to minimise power curtailment, blackouts, and stranded assets?

The publication of the *Handbook on Electricity Markets* in November 2021 could not have come at a better moment. Edited by Jean-Michel Glachant, Director of the Florence School of Regulation, Paul L. Joskow, Massachusetts Institute of Technology, and Michael G. Pollitt, University of Cambridge, it includes contributions from the most brilliant thinkers and experts in the field of electricity markets.

The EU-China Energy Cooperation Platform has commissioned an EU-funded Digest of the Handbook so that its key points are available to busy decision-makers. Jean-Michel Glachant and Nicolò Rossetto of the Florence School of Regulation have condensed its contents, in consultation with its numerous expert contributors. An edition of the Digest is available for distribution in China, alongside an international edition in both Chinese and English. The China edition includes an extra chapter, 'Takeaways from the Handbook on Electricity Markets in China,' by Michael G. Pollitt.

In commissioning the Digest, ECECP hopes to ensure that the wealth of information in the handbook can reach the widest possible readership, and so share findings that could help to ease the global transition to a carbon-free economy.

Dr Flora Kan

Team Leader of the EU-China Energy Cooperation Platform

CONTENTS

Glossary

Term	Description
ACER	Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
bbl	barrel
BBSCEDLMP	bid-based-security-constrained-economic-dispatch-with-locational-marginal-prices
BEV	battery electric vehicle
CAISO	California Independent System Operator
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CEGB	Central Electricity Generating Board
CfD	contract for difference
CPS	Carbon Price Support
CSG	China Southern Grid
DG	distributed generation
EMDE	emerging markets and developing economies
EMR	Electricity Market Reform
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESI	electricity supply industry
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EV	electric vehicle
FCAS	Frequency Control Ancillary Service
FERC	Federal Energy Regulatory Commission
FiT	feed-in tariff
FTR	financial transmission right
GB	Great Britain
Hz	Hertz
ICEV	internal combustion engine vehicle
IDF	integrated distribution framework
IEA	International Energy Agency
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
LDV	light-duty vehicle

Term	Description
LMP	locational marginal pricing
LMPM	local market power mitigation
LNG	liquefied natural gas
M&A	mergers and acquisitions
MCP	market-clearing price
MIT	Massachusetts Institute of Technology
MW	megawatt
MWh	megawatt-hour
NDRC	China’s National Development and Reform Commission
NEA	National Energy Administration
NEM	National Electricity Market
NETA	New Electricity Trading Arrangements
O&M	operation and maintenance
OECD	Organisation for Economic Cooperation and Development
OFTO	Offshore Transmission Owner
ORDC	operating reserve demand curve
PHEV	plug-in hybrid electric vehicles
PJM	Pennsylvania-New Jersey-Maryland
PPA	power purchase agreement
PUCT	Public Utility Commission of Texas
PV	photovoltaics
RES	renewable energy supply
RPS	renewable portfolio standards
RTO	regional transmission organization
SASAC	State-owned Asset Supervision and Administration Commission
SEM	Single Electricity Market
SGCC	State Grid Company of China
SPC	State Power Corporation
T&D	transmission and distribution
TSO	transmission system operator
VoLL	value of lost load
VRE	variable renewable energy
WACC	weighted average cost of capital

CHAPTER 1. Introduction to the Handbook on Electricity Market

Jean-Michel Glachant, Paul L. Joskow and Michael G. Pollitt

The electric power industries in all countries have changed enormously over the roughly 140-year history of central station generation/transmission/distribution systems supplying electricity to the public. The evolution has reflected technological change on both the supply and demand sides, exploitation of economies of scale, environmental and other policy constraints, organizational and regulatory innovation, interest group politics and ideology.[1] This handbook focuses on the latest set of institutional changes to electric power sectors around the world that are generally captured by the phrases restructuring, competition, decarbonization and regulatory reform.

The contemporary restructuring of the electric power industry has involved: (1) the separation or unbundling of the previously (typically) vertically integrated — through common ownership or regulated long-term contracts — generation, transmission, distribution and retail supply segments of the industry; (2) the deconcentration of and free entry into the generation segment; (3) the reorganization of the transmission/system operations segment; and (4) the separation of the physical distribution (delivery) segment from the financial arrangements for retail supply of energy. These restructuring initiatives have been designed to enable competition between generators to supply energy, ancillary services and capacity in wholesale markets and to open retail supply to competition. Regulatory reform has been focused on actions to facilitate the efficient evolution of competition, to improve the performance of the remaining regulated monopoly segments of the industry and, most recently, to integrate efficiently intermittent wind and solar generation along with electricity storage, as electric power systems respond to constraints on greenhouse gas emissions.

Government policies and regulation have been particularly important in directing the design of wholesale markets, defining the obligations and behaviour of transmission owners and system operators, improving the performance of regulatory mechanisms that specify how transmission and distribution system owners and system operators are compensated, and guarding against anti-competitive behaviour in the newly competitive wholesale markets and retail supply segments. Policies designed to decarbonize the electricity sector by replacing fossil-fuel generation with zero-carbon resources, primarily adding intermittent wind and solar generation along with storage, have created a new set of issues for system operation, wholesale market design, retail rate design, the investment framework for wind, solar and storage, reliability and other considerations. Electric power systems built around dispatchable, primarily thermal generation with capacity constraints are now evolving to manage systems

1. For good histories of early developments in electricity supply, demand, organization and regulation for several countries, see Caron and Cardot (1991), Hughes (1983) and Klein (2008).

with intermittent wind and solar generation at scale, energy storage and high levels of spot market price volatility as zero marginal operating cost intermittent resources penetrate these systems. Deep decarbonization is transforming electric power systems from capacity-constrained systems to energy-constrained systems. This transition requires aggressive carbon emissions constraints with network reliability criteria.

Different countries, and even states and provinces within countries, have approached this basic restructuring programme in different ways. The first major initiative occurred in England and Wales starting in 1989.[2] Restructuring and competition initiatives in the US, Canada, Australia, the EU and other countries proceeded in the late 1990s and early 2000s. In most cases, early reforms have been followed with additional design and regulatory changes in response to problems that emerged during the reform process, lessons learned, new environmental policies, especially policies to respond to climate change, and the evolution of generation supply and storage technologies compatible with these environmental goals (wind, solar, storage, system operations and computing capabilities, energy efficiency and demand response). While the basic architecture of restructuring is similar across countries, states and provinces, there are significant differences in the details. And there are some countries and regions that have not restructured at all and continue to rely on traditional arrangements (e.g., large parts of the US and Canada).

This handbook brings together a wealth of expertise to look at both the current legacy state of power markets around the world (in Part I) and how those power markets can and should adapt to new low and zero-carbon generation technologies, energy storage and the policy priorities that are driving their adoption (in Part II). In the rest of this introduction, we briefly summarize some of the key issues covered in the 21 chapters that follow this one.

Part I Taking Stock: The Legacy

Chapter 2 by Richard Schmalensee discusses the strengths and weaknesses of the traditional institutional arrangements, outlined above, as they emerged following the First World War. The chapter also identifies some of the challenges to wholesale and retail markets and retail pricing associated with deep decarbonization of electricity supply and the associated reliance on intermittent wind and solar generation and energy storage as dispatchable fossil-fuel generation is replaced.

The handbook then turns to wholesale and retail market design, strengths and weaknesses of different approaches, and adaptations over time in several different countries and regions. There are many similarities between these market models, but also some important differences. The market models have all evolved in response to lessons learned from experience and to changes in public policies. While Part I of the handbook does not cover the market models adopted in all countries and regions, the range of wholesale and retail market design differences and adaptations to

2. Chile, which unbundled generation, transmission and distribution in 1982, is sometimes identified as the first system to adopt these reforms. However, while Chile restructured and unbundled generation, transmission and distribution, its system remained highly regulated with relatively little real competition. The Electricity Act of 1982 has been amended three times (1999, 2004 and 2005) after major electricity shortages.

imperfections and public policy changes capture most of the variations that we see around the world.

Chapter 3 by Paul Joskow and Thomas-Olivier Léautier presents the basic theory of optimal investment and pricing at the bulk power or wholesale level for systems comprised primarily of dispatchable fossil-fuelled and nuclear thermal generating capacity. This theory can be traced back to the work of Marcel Boiteux, Ralph Turvey and others in the 1950s and 1960s. That work focused on optimal investment and optimal pricing for a centrally planned monopoly with dispatchable thermal generation at what we would now call the wholesale level.[3] However, this basic theory formed the basis for the initial design of competitive wholesale markets, essentially assuming a duality between optimal investment and pricing in a centrally planned system with price formation and investment in competitive wholesale markets. Whether and how this basic theory and its application to wholesale market design must be revised to account for deep decarbonization of the electricity sector with high levels of intermittent wind and solar generation and storage is the focus of Part II of this handbook.

Chapter 4 by Frank Wolak discusses the key design features of successful wholesale electricity markets in general. These include: (1) matching the wholesale market design and resulting generator dispatch and congestion management to the physical attributes of electric power systems; (2) market and regulatory mechanisms to govern the incentives for entry and exit of generators consistent with achieving long-term generation resource adequacy criteria; (3) horizontal market power concerns and mitigation mechanisms; and (4) mechanisms to integrate demand response into wholesale markets. The chapter also discusses issues that arise in small markets and developing country contexts. It concludes with a brief discussion of market design issues associated with the integration of grid-scale and distributed renewables, mainly wind and solar.

Chapter 5 by Stephen Littlechild discusses the development of competitive retail supply markets. The unbundling of physical delivery services (distribution) from the contractual arrangements defining how independent intermediaries can compete to arrange for and are compensated for the electricity consumed by retail customers is truly an innovation that departs from the historical responsibilities of local distribution companies both to deliver electricity and arrange for its supply (and be paid for them in return). Retail competition has been especially valuable for larger customers with interval meters, demand management capabilities and some onsite generation. Competitive electricity retail suppliers can offer contracts that give these customers better price signals and can integrate retail consumption and load management decisions with wholesale markets. Retail competition for residential and small commercial customers has been more controversial, though this may change as smart meters, real-time pricing, smart grid enhancements and individual customer utilization settlements protocols (rather than load profiles) are more widely deployed. The chapter starts by discussing early thinking about restructuring and competition during the 1980s. It goes on to analyse the creation of retail markets around the world during the 1990s and early 2000s. The concerns about and interventions in retail supply

3. Optimal scheduling and the derivation of shadow prices for water stored behind dams in hydroelectric stations were developed in parallel.

markets during the 2010s are presented next. Finally, Littlechild questions whether the concerns are justified and asks what might happen in the future.

The handbook then moves on to in-depth discussions of the details of wholesale market designs in specific countries or sub-regions of countries, their strengths and weaknesses, and their evolution in response to weaknesses and changes in public policies. Chapter 6 by David Newbery discusses the market model initially adopted in England and Wales and how it has changed over time. The chapter provides background information on the pre-restructuring (post First World War) electricity sector in England and Wales and the motivations for privatization and restructuring for competition. The chapter then turns to a discussion of the post-restructuring ownership structure of generation, the design of the new wholesale market and the horizontal market power problems that emerged. Dissatisfaction with the performance of the initial industry structure and market design led to deconcentration of generation ownership and major changes in wholesale market design, transforming the initial market into an energy-only market without capacity payments, the so-called New Electricity Trading Arrangements (NETA). We then learn why and how capacity markets and government-mandated procurement of carbon-free resources pursuant to long-term purchased power agreements were reintroduced to support resource adequacy goals and, more importantly, decarbonization goals. The chapter concludes with thoughts on the integration of carbon-free generation resources and potential future reforms.

Chapter 7 by William Hogan discusses the market model adopted by PJM Interconnection in the US. PJM covers all or portions of 13 US states located east of the Mississippi River. PJM is a regional transmission organization (RTO), though in the US context it makes sense to use RTO and ISO (independent system operator) interchangeably. PJM manages wholesale energy, ancillary services and capacity markets for most of the investor-owned utilities, generators and transmission owners in this region. Unlike in most European countries, the day-ahead markets are fully integrated with day-of-markets and real-time operations. These markets are also fully integrated with the management of transmission constraints by relying on a security-constrained bid-based economic dispatch auction market design for energy and ancillary services dispatch and prices. This mechanism yields locational (nodal) prices that vary from location to location when transmission constraints are binding. The chapter starts with a history of PJM (originally just New Jersey and Pennsylvania), going back to its roots in the 1920s as a centrally-dispatched power pool, to the reforms during the 1990s and the ultimate creation of the basic wholesale market framework that defines PJM today. The chapter goes on to discuss many of the details of the PJM market model, whose basic version has largely been adopted by the other ISOs/RTOs in the US. Interestingly, PJM includes states that have fully restructured to rely on competitive wholesale and retail competition as well as states that continue to rely on vertically integrated monopolies.

Chapter 8 by Ross Baldick, Shmuel Oren, Eric Schubert and Kenneth Anderson discusses the market model in the Electric Reliability Council of Texas (ERCOT), which covers most of Texas. The chapter places the restructuring programme in ERCOT in a fascinating historical, political and ideological context. Unlike PJM, ERCOT is a single-state ISO. Nor is ERCOT subject to Federal Energy Regulatory Commission (FERC) jurisdiction but rather to the jurisdiction of the Public Utility Commission of Texas (PUCT). As a result, state policies, ISO policies and market design features can be harmonized more easily than in multi-state ISOs, where each state is a stakeholder and federal and state policies, especially regarding efforts to decarbonize the electricity sector, often differ. ERCOT model also reflects a deep commitment to competition in the electricity sector by Texas policymakers. The chapter reviews the restructuring process in ERCOT, the goals for wholesale and retail markets, the evolution of the design of both and brings us up to date on current issues. Today, ERCOT wholesale markets have many similarities to the other ISO/RTO markets in the US. However, there is an important difference regarding how ERCOT handles resource adequacy. Unlike the other ISO/RTO markets, ERCOT does not have a capacity market or use a centralized market to allocate capacity obligations.[4] It does not establish forward capacity reserve requirements. Rather, ERCOT is an 'energy-only' market, though this simple phrase can be misleading. ERCOT model recognizes that for an electricity market to achieve an efficient long-run equilibrium and to achieve associated resource adequacy goals, energy prices must be allowed to rise to very high levels to reflect the value of lost load as capacity constraints begin to bind and the market must ration scarce capacity. To do that, ERCOT introduced an administratively determined operating reserve demand curve (ORDC) and associated protocols to manage generating capacity scarcity with a price mechanism. The ORDC is in turn based on assumptions about the value of lost load, loss of load probabilities and other variables. In ERCOT, energy prices can rise to 9000 $/MWh, the presumptive value of lost load. On the contrary, the other ISOs define capacity needs and use a capacity market to allocate responsibilities for paying for the needed generating capacity or demand response. These markets have price caps in response to concerns about market power in energy and ancillary services supply markets. The price caps are in the range of 1000–2500 $/MWh. The chapter describes nicely how these market design features evolved and how they work today. Texas also has abundant wind and solar resources and wind generation 'in particular' grew early and rapidly. The chapter illuminates how ERCOT has managed the influx of intermittent generation, as well as a pragmatic application of central planning combined with competitive tenders to choose and select transmission projects to relieve congestion between the major wind generation region and load regions.

Chapter 9 by Paul Simshauser discusses the Australian market model. The chapter considers the design features of the National Electricity Market (NEM), retail competition, incentive regulation for transmission and distribution, the regulatory framework and adaptations to the rapid expansion of intermittent renewable energy. Unlike the markets that have been discussed so far, the NEM has no organized day-ahead market, though over-the-counter trades can be arranged day ahead and futures contracts can be bought and sold as well. There are no formal capacity obligations and no capacity market. Accordingly, the NEM is a real-time energy-only market with a high price cap (AU$15000/MWh in 2020). The chapter goes on to discuss the challenges to efficiently integrate intermittent renewable energy supplies and, more generally, to align electricity markets with climate change policies. Recent reforms, their strengths and weaknesses are analysed.

Chapter 10 by Chloé Le Coq and Sebastian Schwenen discusses the Nordic power market that comprises the national markets of the Scandinavian countries. This market also includes trading arrangements with other countries with interconnections

4. California Independent System Operator (CAISO) is another exception since it has relied on a murky resource adequacy requirement protocol that requires load-serving entities to meet resource adequacy criteria specified by the California Public Utilities Commission.

(Germany, the UK, the Netherlands and the Baltic countries). The chapter discusses the evolution and design features of Nord Pool, focusing on trading arrangements between the countries that are part of the Nordic market and the harmonization of differences between national markets. The chapter concludes with discussions of the adaptation of the Nordic market to decarbonization goals and security of supply issues.

Chapter 11 by Fabien Roques discusses the market models adopted in EU countries. There is no single market model that covers all the countries in the EU or, more precisely, the European internal market for electricity. Rather, there are a set of national markets with varying design features that follow EU guidance on certain attributes. The chapter explains that the European model for electricity markets has been shaped by successive laws and policy reforms. These have driven a degree of convergence in the designs of the various national (and regional) markets based on EU competition principles for the electricity sector. Beginning in the 1990s, the focus has been on creating an integrated European market that supports efficient cross-border trade and competition. Unlike the US, where the RTO/ISO markets have 'centralized' day-ahead markets, day-of-markets and integrated congestion management yielding locational price differences, EU markets typically have decentralized day-ahead markets and transmission congestion management. The chapter then emphasizes how policy priorities changed in the 2000s with the emergence of climate change and security of supply concerns. These changing policy priorities have led national markets to adopt their own rules, reversing the coordination trend. European electricity markets have evolved toward hybrid markets with a number of new features, including: (1) support mechanisms for clean technologies; (2) capacity mechanisms to address security of supply concerns; and (3) new planning processes to coordinate generation and grid development.

PART II Adapting to New Technologies and New Policy Priorities

Part II shifts the focus from the current organization of the electricity supply sector to potential future developments. It does this by discussing the promising new technologies that are emerging and indeed scaling up on the supply and demand side (Chapters 12 and 13), the near and further term impacts of renewables and decarbonization on the design of the electricity market and its companies (Chapters 14–17), the potential for electrification of transport and heating (Chapters 18 and 19) and the issues facing the electricity sector beyond the Organisation for Economic Cooperation and Development (OECD) countries (Chapters 20–22).

The electricity system has been undergoing a remarkable technology transition since 2000. Large subsidies to both research and development, and to strategic roll-out, have resulted in more than half of all new capacity additions globally by MW and by value being in renewable electricity in recent years.[5] This is beginning to change the nature of electricity generation from being characterized by synchronous fossil-fuel generation (from coal, oil and natural gas) to one where both dispatchable renewable (for instance, biomass) and increasingly intermittent renewable (for instance, wind and solar) generation dominate additions of generation in OECD countries.

5. See REN21 (2019, p. 33).

The nature of these generation technologies is discussed in Chapter 12 by Nils May and Karsten Neuhoff. They discuss the remarkable decline in the cost of both wind and solar generating capacity, which has seen these technologies reach cost parity with fossil fuels (especially with carbon pricing) in many jurisdictions, including in the developing world. May and Neuhoff analyse the prospects for onshore and offshore wind, solar photovoltaics (PV) and concentrated solar power, biomass, geothermal technologies, and wave and tidal power within the electricity system. They note that challenges remain if these technologies are to rise to dominate the electricity system. These include local opposition to the siting of facilities, their intermittency (across the day and the season) and their high upfront financing costs. However, there is good reason to be optimistic of continuing technological progress and successful roll-out, especially where this is combined with market expansion, demand flexibility and storage.

Since the oil crisis of the 1970s, energy conservation and efficiency have been a policy priority in many jurisdictions. Recent developments with renewables on the supply side has refocused attention on demand side technologies to not only reduce demand (relative to business as usual) but also to make it more flexible. This is the focus of Chapter 13 by Fereidoon Sioshansi. Annual and peak electricity demand are now below peak levels in many OECD countries, partly because of slower industrial demand growth, the impact of more energy-efficient appliances, low-energy lighting and more recently the diffusion of prosumers — that is, consumers that self-generate (part of) the electricity they consume by typically installing rooftop solar. Sioshansi discusses how self generation, rising numbers of electric vehicles (EV) and distributed batteries could add further — often behind the meter — flexibility to the electricity system and allow it to better match demand to intermittent electricity supply. He documents several nascent technologies such as ground source heat pumps and remote digital control technologies, which offer promising sources of local energy and supply and demand matching. While the timing of any mass take-up of demand-side technologies remains highly uncertain, it is clear that in densely populated cities, such technologies seem much less likely to be significant than in more sparsely populated regions where prosumagers — that is, prosumers with their own storage — might make economic sense.

Next, the attention turns to future changes to the market context in which electricity systems will be operating. A major driver of new technologies in electricity are policies that explicitly or implicitly promote decarbonization of the sector. This is the subject of Chapter 14 by Kathryne Cleary, Carolyn Fischer and Karen Palmer. The authors introduce and compare a range of policies that governments have been using to promote decarbonization. These include carbon taxation and trading mechanisms, renewables subsidies and portfolio standards, energy efficiency measures and policies targeting nuclear and coal. As the authors point out, these policies have very different levels of efficacy if the ultimate goal is decarbonization (early phase-out of existing nuclear power plants by pro-renewables governments, for instance, is a pro-carbon policy). Often, governments enact a range of policies simultaneously that conflict with one another and would benefit from policy rationalization (cap-and-trade plus renewables subsidy can result, for example, in more expensive decarbonization than is necessary). The authors conclude that putting a price on CO_2 emissions remains the most efficacious policy for decarbonization, while recognizing that other market failures such as those arising from myopia may justify policies to help investments in capital-intensive renewables and energy efficiency.

What impact will renewables have on the operation of electricity markets? The nearer-term effects of this are discussed in Chapter 15 by Richard Green. Green analyses how the rise in renewable energy supply (RES) will affect electricity market design. First, context is important. While some jurisdictions have seen large rises in their RES share in total production, globally low-carbon electricity supply is dominated by hydro and nuclear. Biomass is also significant. However, it is the rise of intermittent RES that poses new challenges for the electricity system by shifting supply to when the wind and the sun are available. Rising intermittent supply will impact prices that will encourage demand to be more flexible. In turn, this will provide incentives for electrical energy storage investments and further investments in transmission interconnection capacity. Green suggests that in the medium term there is plenty of scope for the existing market design to accommodate rising RES shares in many jurisdictions.

Market design for electricity markets is not just about matching aggregate electrical energy supply and demand, it is about maintaining power quality at every node in real time as well. Thus, power markets must also procure voltage and constraint management services. This is the focus of Chapter 16 by Michael Pollitt, who discusses the extent to which increasingly distributed electricity generation from intermittent RES and locally flexible electricity demand (in the presence of storage and EVs) can be accommodated within the two benchmark market designs that we currently see in Europe and in the US (as exemplified by PJM). He discusses two contrasting visions of the future (drawing on ideas from Fred Schweppe and Ronald Coase, respectively): one where more use is made of spot granular power prices at the nodal or device level; and one where the system operator makes more use of longer-term flexible control contracts. Reflecting on the experience of the pricing and rationing of the Internet, he suggests that at very high levels of intermittent RES, a new future market design that combines price signals with non-price rationing of intermittent renewables that match device demand in priority order would seem to be more acceptable within many regulatory systems than pure price-based rationing.

The future of the electricity supply industry is not just a function of technology or market design but is also importantly determined by the success of the business models that the companies within it adopt. The future of various electricity business models is the focus of Chapter 17 by Jean-Michel Glachant. Glachant unpacks and distinguishes a range of different business models within both the competitive and regulated parts of the electricity supply sector. These include the business models being pursued by generators in onshore and offshore wind (for the many and for the few), solar PV at utility scale and on rooftops. These new business models also involve aggregators moving from retail into wholesale markets, peer-to-peer bypassing of conventional utilities and the emergence of behind-the-meter territories. In this changing environment, grid companies are facing regulatory pressures to adapt their business models. These include the need to focus on the cost-effectiveness of grid capacity additions and strong revenue incentives for quality of service. The author argues that this fundamentally changes their business model from 'fit-and-forget' asset owners to companies engaged in seeking asset-light innovations.

What are the prospects for the electrification of transport? This subject is addressed in Chapter 18 by Bentley Clinton, Christopher Knittel and Konstantinos Metaxoglou. Transport consumes a considerable amount of the world's fossil fuels and much of surface transport could in theory be electrified. The authors focus on the prospects for electric vehicles. Passenger cars represent 50 per cent of surface transport vehicle energy demand and recent technological developments have seen a take-off in sales of battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV). EVs have substantial challenges to overcome such as the current price of the batteries (around $200 per kWh storage in 2019), their range and the time taken to charge them. The authors show that many electricity systems could likely cope with 100 per cent penetration of BEVs in the time frame over which such a rise in penetration is likely (to 2040) but that EV life cycle economics remains challenging over the next ten years. Beyond passenger cars, electrification of buses and trucks remains at least as difficult in part due to the much higher battery capacity required. A key issue raised by transport electrification is the need to replace the lost transport fuel tax revenue.

What are the prospects for the electrification of residential and commercial heating and cooling? This is the issue discussed in Chapter 19 by Mathilde Fajardy and David Reiner. The authors outline the scale of the heating challenge. Current global non-electrified heating demand is twice as much as current electricity demand: thus, the electrification of heating would significantly increase the demand for electricity. Worse than this, peak heating demand can be five times higher than peak electricity demand. Technologies do exist to decarbonize heating and cooling, including electric heat pumps, district heating, PV, green hydrogen from renewables via electrolysis or with blue hydrogen from natural gas with carbon capture and sequestration, and the use of biomass and biomethane. On the demand side, building energy efficiency and heating and cooling appliance efficiency can be increased. However, none of these routes to decarbonization are cheap or quick to implement. The authors conclude by showing that all major possible opportunities come with associated challenges (for example, more use of peak load pricing to encourage energy consumption shifting and storage poses challenges in public acceptability given energy poverty concerns).

We go on to examine the issues facing the electricity sector beyond OECD countries. Chapter 20 by Ignacio Pérez-Arriaga, Divyam Nagpal, Grégoire Jacquot and Robert Stoner focuses attention on the problem of how to achieve universal access to electricity. Despite extensive efforts to improve electricity access, 840 million of the world’s population lacked access to electricity in 2017. The authors argue that the key to promoting electricity access is to empower local distribution grids, via what they call an integrated distribution framework (IDF). The chapter notes that traditional grid extension, mini-grids and stand-alone electricity systems can all play a role in providing access. The IDF approach is all about ensuring that the appropriate mix of access provision (and associated revenue recovery mechanisms) is employed within a local distribution company area to achieve near total electricity access, especially when the unserved are in increasingly difficult-to-reach areas. Countries such as Sierra Leone and Uganda are successfully extending access in this way. The authors conclude by suggesting that the IDF approach can improve on the current projection (in 2019) that 650 million people will still be without access to electricity in 2030.

China has emerged as the world’s electricity super-power. In 2019, more than 27 per cent of the world’s electricity was produced in China, only slightly less than the US and Europe combined. China’s electricity sector has grown spectacularly since 2004, but it remains a state-owned and heavily regulated sector. Chapter 21 by Xu Yi-chong discusses the recent history of the Chinese electricity industry and its prospects for reform. The short-lived State Power Corporation (SPC) was broken up in 2002 to form two grid companies – State Grid Company of China (SGCC) and China Southern

Grid (CSG) – five generation companies and four power service companies. While both final prices and generator prices remained heavily regulated following the 2002 reform, there were strong incentives to build new assets for both generators and grid companies. This underpinned the rapid growth of the sector. By 2015, this system had given rise to high costs and high prices, causing the government to embark on a new round of reform, introducing pilot provincial wholesale electricity markets and large reductions in the regulated prices. Recently, China has also sought to internationalize its electricity sector by buying up overseas electric utilities and by building power plants abroad, in line with its 'One Belt, One Road' initiative. The author concludes that the current contradiction between China's desire to participate in global electricity markets and its slowness in creating a domestic electricity market is a function of China's unique history and the considerable influence of the Chinese Communist Party within the state-owned electricity system.

The final chapter focuses on Africa, where over half the population lacks access to electricity and consumption per capita is very low (although electricity production and consumption vary enormously between countries). Chapter 22 by Vivien Foster, Anton Eberhard and Gabrielle Dyson discusses the prospects for the electricity sector across Africa. The chapter begins by noting that things have been changing in the final years of the decade to 2020: Chinese investment in the power sector has been significant (in line with the previous chapter) and the prospects for solar power have improved enormously. Nonetheless, there are still great opportunities to improve regional power pools via more extensive transmission interconnection, in part to exploit the huge regional RES potential; in addition, access to electricity is on average still rather low – it was around 60 per cent in 2017 – because many choose not to connect to the grid due to cost, unreliability and lack of demand. Although some countries have shown notable improvements – Kenya went from an access rate of 22 per cent to 75 per cent between 2010 and 2018 – the lack of effective power sector reform often represents a key barrier to development. A lack of competition, private ownership and industry restructuring persists in many countries, leading to low prices (for those lucky enough to receive on-grid electricity), under-investment and poor quality of service. The authors suggest that low-cost renewable technologies combined with innovative business models might allow poorly served African countries to avoid the need for expensive centralized grid expansions, spurring electrification despite (or indeed, because of) a lack of reform.

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Together, the chapters of the handbook offer a global tour of an industry on which much of the world's hopes for decarbonizing the global energy system depend. We are very grateful to our authors for writing their chapters specifically for this book and hope their efforts provide food for thought and inspiration for what might be possible by way of power market developments in the coming years.

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CHAPTER 2. Strengths and Weaknesses of Traditional Arrangements for Electricity Supply

Richard Schmalensee

This chapter provides a broad-brush comparison of performance under traditional arrangements for electricity supply with those that emerged after the wave of restructuring that began in the 1990s, in which competition played a much more important role. It places an emphasis on comparisons within the US, where both traditional and restructured arrangements exist. It considers both the historical regime, in which almost all generation capacity is dispatchable, and, more briefly, the emerging regime, in which variable renewable energy (VRE), particularly wind and solar generation, is dominant.

1. Traditional Arrangements

Before restructuring, electricity supply industries (ESIs) differed substantially between and even within nations. In the US, the ESI was dominated by vertically integrated, regulated, investor-owned utilities. Trades in electric energy did occur, but not in organised markets.

2. Restructured Alternatives

All restructured ESIs have created formal wholesale power markets. While markets provide strong incentives for efficiency, they may provide more scope for the exercise of market power. Most (and perhaps all) restructured ESIs have imposed separation between the ownership of generation plants and the operation of transmission facilities. Transmission systems are generally planned and managed by non-profit entities. Ownership of generating plants was often restructured horizontally as well in the interest of effective wholesale market competition.

In distribution, the delivery function – i.e., the construction and operation of the physical network – is universally performed either by a regulated investor-owned utility or a public enterprise, while the supply of electricity has been unbundled from delivery and opened to alternative vendors in some areas.

3. The Historical Regime

Restructuring in the historical regime essentially involved attempting to use competition, rather than regulation or public ownership, to improve the performance of well-understood systems. It turned out to be much more complex than many had expected.

a) Generation Operations

Strong evidence indicates that deregulation plus competition served to reduce generators' operating costs. The development of organised wholesale power markets seems to have dramatically increased both the volume of and gains from trade. All wholesale markets in the US (though not in the EU) have moved to nodal pricing systems with considerable benefits.

There have been significant exercises of market power in some wholesale markets, particularly in the early days of restructuring. All US wholesale power markets are now monitored for significant competitive problems, and market power is not generally considered a major issue. While it seems likely that gaps between wholesale electricity prices and marginal costs are larger than under regulation or public ownership, it is at least plausible that restructuring has, on balance, lowered wholesale electricity prices.

b) Generation Capacity

In the face of concerns about market power, all US markets imposed caps on wholesale prices. This reduced incentives for investment and led to reliability concerns. In response, most organised markets have established markets for capacity or related mechanisms to supplement energy market revenues. These mechanisms, which are often modified, rest on the administrative determination of capacity requirements, as in traditional arrangements.

c) Retail Pricing

Traditionally, regulated and publicly-owned electric utilities charged retail prices that were constant over time, and in the US generally involved only nominal fixed charges. Most customers had no choice of retail supplier. After restructuring, almost half of US states adopted some form of retail competition. However, many subsequently restricted or abandoned competition. Retail competition has not always worked well for residential customers. Movement toward more efficient time-of-use pricing has been mainly confined to large customers.

4. The Emerging Regime

While restructuring originally involved attempts to improve the performance of well-understood systems, under the emerging regime both traditional and restructured institutions have been tasked with transforming historical-regime ESIs into VRE-dominated systems for which there is no operating experience. ESIs with traditional arrangements now need to work with their regulators to solve the technical problems posed by VRE generation. Restructured ESIs and their regulators will also need to modify the detailed market designs created for the historical regime and develop efficient solutions to the new problems of the emerging regime.

A comparison of two jurisdictions committed to aggressive decarbonisation and where VRE already represents an important share of the generation mix can be useful to illustrate the similarities and the differences in the challenges posed by the transition to the emerging regime. Let us then take the case of traditional public utility regulation in Hawaii and the case of California's restructured electricity system.

a) Generation Operations

California utilities have been required to buy specified quantities of battery storage, but general rules to enable storage to participate in wholesale markets remain a work in progress. The vertically integrated Hawaiian utility has not been required to acquire battery storage, and its regulator has not had to develop general rules for its use. Instead, the utility has been able to get solar-plus-storage facilities approved on a project-by-project basis.

b) Generation Capacity

Capacity market designs associated with the historical regime will need significant changes to cope with high-VRE systems with storage. California has added specific requirements for three types of flexible capacity. The Hawaii utility and its regulator are engaged in a detailed long-run planning process, which guides project-by-project investment decisions.

c) Retail Pricing

Because of greater wholesale-level volatility in the emerging regime, both California and Hawaii would benefit substantially by transitioning away from flat per-kWh rates, but neither has moved aggressively in this direction. Neither California nor Hawaii has retail competition for small customers in place.

5. Some Tentative Conclusions

Overall, restructuring seems generally to have produced positive – but not dramatic – net benefits in the historical regime. Generation costs have been reduced, and it seems unlikely that those gains have been erased by a greater exercise of market power. Administrative supervision plays a significant role in the provision of generation capacity, as it did under traditional arrangements, and capacity mechanisms seem to have reduced reliability risks to tolerable levels. However, restructuring has not led to more efficient retail pricing for most small customers, though large commercial and industrial customers seem to have had increasing access to tariffs that reflect system conditions.

In principle, traditional systems may be more agile in the transition to the emerging regime, since utilities and their regulators can engage in long-term planning and case-specific decision-making without needing to devise complex new general rules. Of course, the information advantage of utilities over their regulators is likely to be substantial during the transition. Regulation is rarely agile in practice and the lack of competitive constraints may lead to higher than necessary rates.

CHAPTER 3. Optimal Wholesale Pricing and Investment in Generation: The Basics

Paul L. Joskow and Thomas-Olivier Léautier

This chapter presents the basic microeconomic theory underlying the formation and the structure of efficient wholesale power prices and optimal investment in dispatchable generating capacity[1]. The presentation is designed to be accessible to non-economists interested in understanding the basic economics of electricity supply and demand. The chapter uses examples and graphics rather than mathematics to articulate the relevant microeconomic principles. The chapter also provides a theoretical link between the 'old world' of vertically integrated regulated electricity monopolies and the 'new world', based on vertical and horizontal restructuring to support competitive wholesale markets.

1. Pricing a Non-Storable Good with Variable Demand

Over the last two decades, many countries have moved to restructure their electric power sectors to replace investment, operation and pricing of electric generation services through internal, often non-transparent, regulated monopoly 'hierarchies' with transparent unregulated competitive wholesale market mechanisms. The conceptual basis for the design of organised wholesale electricity markets during the late 1990s and early 2000s can be traced directly to the mid-twentieth century economic-engineering literature on optimal dispatch of and optimal investment in dispatchable generating facilities and the associated development of marginal cost pricing principles for generation services. While these models were developed to apply to pre-restructuring vertically integrated electric utility monopolies subject to some kind of regulation, including government ownership, these models of generation dispatch, marginal cost pricing and investment have also guided the design of decentralised wholesale markets. That is, the basic microeconomic principles developed to facilitate efficient decisions regarding investment, generation dispatch and optimal pricing of generation services have not changed. Instead, they must now be applied to the design of wholesale markets rather than serving as guides to electric utility management and regulators governing the behaviour of vertically integrated electric power monopolies.

One of the key insights from the microeconomics of electricity production is that the structure of wholesale power prices is similar to that of other non-storable goods for which demand varies significantly across time, such as hotel rooms or plane tickets: the price is set close to the variable cost of production when capacity exceeds demand, while it is set by the value for the marginal unit consumed when demand is exactly equal to capacity. For example, the price for a room at the beach on Cape Cod is close to the cost of clean-up in the winter and goes much higher in the summer.

1 Extensions of these models to integrate intermittent or non-controllable generating capacity and electricity storage are discussed in Chapter 2, 15 and 16 of this handbook. See also Léautier (2019) Chapter 8, Joskow (2019), Newbery et al. (2018) and the references they cite.

This particular price structure is called 'peak-load pricing' in the power industry. The main difference between electric power and other non-storable goods is the magnitude of the peak price: the summer price may be three to four times the winter price for a room at the beach, while the peak price for power may be 50 or even 100 times the off-peak price[2]. Thus, while electricity supply and demand have a number of unique attributes, we can find analogies in markets for many other goods and services.

2. Optimal Pricing in a Simple Setting

This chapter begins with a very simple model to illustrate the peak load pricing results: price responsive demand and a single generating technology. Despite its simplicity, the model yields important insights into optimal short-run and long-run pricing, optimal generation dispatch and optimal investment in long-run equilibrium. Since price is equal to the variable cost for the off-peak hours, when capacity exceeds demand, operating profit is equal to zero in these hours: all the operating profit is realised during the on-peak hours, when demand is equal to capacity. These are typically two per cent of the total hours in the power industry, a much lower fraction than in other comparable industries. In the long-run equilibrium, free entry implies that the expected operating profit per megawatt (MW) of installed capacity is equal to the fixed cost of this capacity: amortised capital cost for the technology (depreciation, return on investment, taxes, etc.) plus fixed operation and maintenance costs (O&M). This free entry condition provides a useful benchmark and should be met on average over the life of assets.

3. A More Realistic Story

The remainder of this chapter then introduces a number of more realistic features that also play an important role in the design of wholesale markets. These include the introduction of non-price responsive demand, an important consideration if consumers are not faced with wholesale spot prices due to metering or political constraints, multiple generating technologies, transmission congestion and security of supply considerations. While each of these features adds more realism to our story, they do not fundamentally alter the peak-load pricing logic.

Considering non-price responsive consumers implies that demand does not adjust naturally to installed capacity. Instead, the system operator curtails excess demand when demand exceeds capacity and sets the price to the Value of Lost Load (VoLL). If demand is perfectly inelastic (i.e., does not respond to prices at all), operating profit is positive only during curtailment hours. Expected operating profit per MW of installed capacity is equal to the VoLL minus the variable production cost times the expected number of curtailment hours.

When considering multiple technologies ordered by increasing marginal costs:

2. An additional difference between the wholesale spot price for power and the retail price for hotel rooms or plane seats is that hotels and airlines are also able to price discriminate among users: two passengers seated next to one another may have paid vastly different prices for their seat. This type of price discrimination does not exist in wholesale spot markets for electricity where 'the law of one price' holds at any point in time. A more precise formulation of the above statements would be 'the minimum price for a room in the winter is close to the cost of clean-up'.

- The electricity price is set by the variable cost of the last megawatt-hour (MWh) produced when capacity exceeds demand, and is set by the value of the MWh consumed when demand equals capacity. With multiple technologies, this story repeats itself for the cumulative capacities up to each technology. Operating profit for any technology is positive only when this technology produces at capacity.

- The free entry condition implies that each technology's operating profit per MW is precisely equal to its fixed cost.

The peak-load pricing logic can be extended to the transmission network in case of congestion: when the flow on a transmission line is lower than its capacity, the price of transmission service is equal to the variable cost of transmitting power, which is equal to zero in a first-order approximation. When the flow on the line is equal to its capacity, the implicit price of transmission service is the difference in power prices at the line's extremities.

4. Optimal Pricing Needed More Than Ever

As the structure of power systems evolves, one fundamental pricing principle continues to prevail. This is the role of prices that vary widely with variations in supply and demand. Producers capture their highest profits when consumers desperately need electric power to heat (or cool) their houses. This is likely to be even more critical for producing market revenues sufficient to cover the total costs of new zero-carbon generating technologies, as the short-run marginal costs of wind and solar are essentially zero. If the market price is zero, no net revenues are produced to cover generators' capital costs. Thus, scarcity pricing – incidents of very high prices necessary to clear the market – must play a more important role in the future to satisfy generators' balanced budget constraints. Economists argue that this outcome is perfectly acceptable; in fact, it is optimal. Consumers and their elected representatives have a different opinion. They argue that profiteering from consumers' need is amoral, hence unacceptable.

Resolving this tension is essential to the future of the power industry. Consumers (some at least) and policymakers are looking forward to the decentralisation of the power industry: consumers equipped with green and decentralised generation and storage (an electric car in their garage) will be active participants in the power markets. How do we coordinate the decisions of millions of economic agents? Prices reflecting the value of power at every instant and every location seem the most natural approach. This requires policymakers and consumers to reconcile themselves with possibly extremely high prices at some instances in some locations. Otherwise, the decentralisation of the electricity system will prove an elusive goal.

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CHAPTER 4. Wholesale Electricity Market Design

Frank A. Wolak

International experience after more than 25 years of wholesale electricity market design has revealed several factors that are crucial to achieving lasting improvements in industry performance and tangible economic benefits to electricity consumers. These factors are: 1) the match between the short-term market used to set prices and dispatch generation units and how the actual electricity network is operated; 2) the effective market and regulatory mechanisms to ensure long-term generation and transmission resource adequacy; 3) the appropriate mechanisms to mitigate system-wide and local market power; and 4) the mechanisms to allow active involvement of final demand in the short-term market.

1. Match Between Market Mechanism and Actual System Operation

An important lesson from electricity market design processes around the world is the extent to which the market mechanism used to dispatch and operate generation units is consistent with how the grid is actually operated. In the early stages of wholesale market design in the US, all of the regions attempted to operate wholesale markets that used simplified versions of the transmission network. Single pricing zone or multiple pricing zone markets assumed infinite transmission capacity between locations in the transmission grid or only recognised transmission constraints across large geographic regions. These simplifications of the transmission network configuration and other relevant operating constraints created opportunities for market participants to increase their profits by taking advantage of the fact that the actual configuration of the transmission network and other operating constraints must be respected in real time.

These simplified markets set a single market-clearing price for a half-hour or hour for an entire country or large geographic region, despite the fact that there are generation units with offer prices below the market-clearing price not producing electricity, and units with offer prices above the market-clearing price producing electricity. This outcome occurs because the location of demand and available generation units within the region and the configuration of the transmission network prevent some of these low-offer-price units from producing electricity and require some of the high-offer-price units to supply electricity. The former units are typically called 'constrained-off' units and the latter are called 'constrained-on' or 'must-run' units.

Multi-settlement wholesale electricity markets that use locational marginal pricing (LMP), also referred to as nodal pricing, largely avoid these constrained-on and constrained-off problems, because all transmission constraints and other relevant operating constraints are respected in the process of determining dispatch levels and locational prices in the wholesale market. This market design has become the de facto standard market design in all US markets and many international markets. A number of countries in Europe are currently considering transitioning to this market design.

2. Mechanisms to Ensure Long-Term Resource Adequacy

What is different about electricity markets that justifies the need for a long-term resource adequacy mechanism? The answer lies in how markets for other products operate relative to the market for wholesale electricity. The limitation on the level of short-term prices and the way that supply shortfalls are dealt with in wholesale electricity markets create a 'reliability externality' that requires an explicit regulatory intervention to internalise.

Two general approaches have been developed to address this reliability externality. The first is based on fixed-price and fixed-quantity long-term contracts for energy signed between generation unit owners and load-serving entities at various horizons to delivery. The second approach is a regulator-mandated capacity mechanism. Typically, the regulator requires that load-serving entities purchase sufficient firm generation capacity, at a magnitude defined by the regulator, to cover their annual peak demand. Generation unit owners receive a regulator-determined payment for the capacity they provide to the load-serving entity. Differing degrees of regulatory invention are used to determine this USD/KW-year payment across the existing capacity payment mechanisms.

Capacity markets are poorly suited to regions with a significant share of intermittent renewables. In these markets, it is rarely, if ever, the case that there is a capacity shortfall in the sense that there is insufficient installed generation capacity to meet peak demand. The more common problem is insufficient energy, typically in the form of water stored behind a dam, to meet anticipated demand. With wind and solar photovoltaic generation units, capacity shortfalls are also extremely unlikely. It is more likely that the sun does not shine or the wind does not blow for a sustained period of time. In both cases, the problem is not a capacity shortfall but an energy shortfall. Ambitious renewable energy goals in many regions are causing regulators in those regions to consider transitioning to energy contracting-based approaches to long-term resource adequacy.

3. Managing and Mitigating System-Wide and Local Market Power

The configuration of the transmission network, the level and location of demand, as well as the level of output of other generation units can endow certain generation units with a significant ability to exercise unilateral market power in a wholesale market. A prime example of this phenomenon is the constrained-on generation problem described earlier. The owner of a constrained-on generation unit knows that regardless of the unit's offer price, it must be accepted to supply energy. Without a local market power mitigation (LMPM) mechanism, there is no limit to the offer price that could be submitted by the generation unit owner and be accepted to provide energy. Consequently, all offer-based electricity markets in the US require a LMPM mechanism mechanism to limit the offers a generation unit owner submits when it faces insufficient competition to serve a local energy need. Implementing an offer-based short-term market without an LMPM mechanism in place would be imprudent.

4. Active Involvement of Final Demand in the Wholesale Market

The active involvement of final consumers in the wholesale market can reduce the amount of installed generation capacity needed to serve them and reduce the cost of integrating an increasing amount of intermittent renewable generation. There are three necessary conditions for the active involvement of final consumers. First, customers must have the necessary technology to record their consumption on a time scale similar to that of the wholesale market products. Second, they must receive actionable information that tells them when to alter their consumption. Third, they must pay according to a price that provides an economic incentive consistent with the actionable information to alter their consumption.

CHAPTER 5. The Evolution of Competitive Retail Electricity Markets

Stephen Littlechild

Competitive retail electricity markets followed very different trajectories in the various jurisdictions that introduced them. This chapter considers three main issues. First, how to open retail markets? Second, how to handle some ongoing issues with retail competition? Third, how to prepare for the new era of hybrid markets, prosumers and electrification of energy end-uses?

1. How to Open Retail Markets

The 1980s saw the first debates on whether to open competitive retail electricity markets. Some energy economists such as Stephen Littlechild promoted the idea, while others, such as Paul Joskow and William Hogan, were doubtful whether it was appropriate for residential customers.

Great Britain was first to open its retail market to competition, on a phased basis beginning with the largest industrial customers in 1990 and moving on to residential customers in 1998. A temporary price cap was put in place in case competition did not materialise, but existing regional suppliers competed in other regional areas, and new players entered the market with cheaper offers. After two years, the scope of the price cap was reduced, and after another two years was removed entirely.

When Texas opened its retail market in 2002, it established what was in effect a minimum price cap – a 'price to beat' – which applied to incumbent suppliers for five years, or until they lost 40 per cent of their customers, thereby enabling competitors to enter the market and grow. In 2004, the European Union made it mandatory to open up the retail market for all non-residential customers and extended this to all residential customers in 2007. The law left the actual process of market opening up to the discretion of individual Member States. Nordic countries established retail markets with no price cap and no retail price monitoring. By contrast, France opened its retail market but maintained regulated tariffs for all residential and small non-residential customers who did not opt for an energy supply on the free market. At the end of 2021, two thirds of French residential customers were still supplied under regulated tariffs.

Many other issues attracted the attention of regulators and practitioners over the years. For example, should metering be a competitive or regulated activity? Should residential customers be served on the basis of a load profile, or should real-time metering be introduced? How should access to liquid wholesale markets best be provided to new players who were not vertically integrated with generation? Different countries have adopted very different approaches to these and other questions.

2. How to Handle Some Ongoing Issues with Retail Competition

Retail competition posed some new challenges to energy regulators, governments and legislators. For example, some critics argued that active consumers switched suppliers to achieve lower prices, whereas inactive consumers remained with their existing suppliers and paid a higher price. They argued that regulators should take steps to limit prices, either on an absolute or relative basis – for example, by stopping suppliers from offering lower prices to new or more active customers. Others countered that the products offered at lower prices were often different – for example, they were available only online and not including any discount for low-income households. Or they argued that the lower prices came from suppliers who were often new, unknown and riskier (as subsequently proved to be the case).

There have also been moves to protect particularly vulnerable consumers, as acknowledged, for example, by European law. In the US State of New York, ever more stringent regulation of energy service companies was introduced over the period 2014-19.

Increasingly, electricity consumers are served by new types of suppliers, sometimes characterised as 'asset-light' companies, that is companies without generation assets and often even without significant financial resources. They are fully digitalised and seem to deliver different or lower-cost products compared to the old, asset-heavy, incumbents. These new suppliers do not necessarily target consumers with the same consumption profile as those served by incumbents. They may also hold different positions in the wholesale market and adopt different hedging strategies regarding wholesale price volatility and the risk of price spikes.

It is questionable whether energy regulators are sufficiently skilled and agile to intervene in this landscape. Any intervention by the regulator vis-à-vis contracts and prices offered by new suppliers or incumbents must take all these complex factors into account.

This is not a trivial task, as exemplified by the consequences of the price cap introduced in the British market in 2019, which followed an erroneous diagnosis of the competitive retail market by the Competition and Markets Authority in 2016. Initially, the price cap seemed beneficial: protection was offered to those customers who were less active, while intense competition led some companies to offer prices below the cap to those customers who were more active. However, this was an artificial consequence of a falling wholesale market. When wholesale prices started surging in summer 2021, the unduly severe and inflexible price cap pushed almost 30 new energy suppliers (with over 2.5 million customers) into bankruptcy.

On the other side of the world, in California, retail competition was stopped in 2001 because an inappropriately inflexible price cap caused the bankruptcy of some incumbent suppliers. More recently, the integrated incumbent supplier PG&E went into bankruptcy in 2019 as a consequence of its mismanagement of heat waves and wildfires. Mistrust of incumbent utilities appears to be on the rise in California, and more than ten million customers have already left them in favour of 'Community Choice Aggregation', a solution where local public authorities negotiate long-term supply contracts with new generators investing in renewables.

3. How to Prepare for the New Era of Hybrid Markets, Prosumers and Electrification of Energy End-Uses

Retail competition was invented nearly 40 years ago in order to pass on to customers the benefits of wholesale competition without the costs and distortions of conventional regulation. Other chapters in this handbook suggest that developments in technology and the policy push for decarbonisation via renewable generation are causing a shift towards a new regime of 'hybrid markets'. Some residential consumers are investing to become generators and cover autonomously (part of) their energy needs. They are the so-called 'prosumers'. What kind of retail contracts and services can suppliers offer them for the remaining and uncovered part of their consumption? Could asset management services integrate their generation and storage assets into a virtual power plant, activated and optimised by some innovative suppliers?

Electrification of final energy uses via electric vehicles (EV), heat pumps and so on might amplify these effects of hybridisation. A car manufacturer could become an EV charging supplier or an electricity aggregator. A smart charging supplier might also become an aggregator, selling back the flexibility of final consumption on the wholesale market or directly to the system operator of a grid. Heat pumps and heat storage in buildings could follow similar trends, where demand and supply work two ways and not only one.

All this will revolutionise retail markets. Customers will be able to take more active roles than those foreseen at the time of the industry restructuring. However, how keen will customers be to take those roles and participate? Surely, participation will be easier to achieve in a market where customers are already accustomed to engaging actively in the selection of the best products and suppliers. And where retail suppliers are accustomed to the process of discovering which products, services and marketing approaches appeal to customers and which do not. The way forward is undoubtedly to build upon retail competition and customer choice, rather than to prohibit or restrict it.

CHAPTER 6. Strengths and Weaknesses of the British Market Model

David Newbery

The British model has evolved to cover the island of Great Britain (England, Wales and Scotland), while Northern Ireland has evolved into a quite different market model covering the island of Ireland in its Single Electricity Market (SEM). This chapter discusses the British market. The emphasis here is on England and Wales, which experienced the main restructuring. Scotland had two vertically integrated regional state-owned utilities which retained their unbundled structure after privatisation.

1. Electricity Restructuring in Great Britain

Before restructuring and privatisation in 1989-90, the state-owned Central Electricity Generating Board (CEGB) owned all generation and transmission in England and Wales. Transmission and site location of new generation was coordinated by the CEGB, although the main high tension (440 kV) grid had been largely completed by the 1960s with substantial spare capacity. Similarly, the intense period of building large power stations was predicated on continued growth in demand of eight per cent per year that had come to an abrupt halt with the first oil shock in the 1970s. The stations under construction would deliver substantial excess capacity once completed. Distribution and supply (retailing) were managed by 12 Area Boards, who paid the CEGB the Bulk Supply Tariff, an efficient multi-part capacity and energy charge with useful lessons for the future electricity system with high volumes of low marginal cost generation.

The CEGB's performance had been strongly criticised for its inefficiency, particularly in delivering timely and cost-effective investment and under-pricing its output. After the success and lessons learned from earlier utility privatisations, the CEGB was ripe for restructuring to create competitive wholesale and retail markets, and regulated transmission and distribution networks. It had adequate generation and transmission capacity so needed little investment, used high-cost domestic coal that was rapidly displaced by gas and imported coal, while RPI-X incentive regulation had matured and was well suited to regulating distribution companies that could be benchmarked against each other. Transmission regulation gradually improved with incentives, and both networks invested and also improved their quality of service.

2. A Never-Ending Reform Process

Market power was a continuing problem for the wholesale market until the duopolists divested to create a workable competitive structure, just before the regulator and government, despairing of reforming the Electricity Pool and concerned with market power, replaced the centrally dispatched 'pool' model with capacity payments by an energy-only market and a two-priced balancing mechanism.

Subsequent vertical integration of generation and supply discouraged entry of new players, unstable energy policies discouraged increasingly needed investment to replace aging fossil and nuclear power plants, while the shift to the costly Renewables Obligation failed to deliver the renewables target. In response, the Electricity Market Reform (EMR) reintroduced capacity payments set at annual auctions. It replaced renewable obligation certificates with a variant of feed-in tariffs, which, after auctions were introduced, lowered costs and made the UK the second largest EU producer of new renewables. Under pressure from the Climate Change Act, the 2011 budget introduced the Carbon Price Support (CPS), a tax on the carbon content of fuels used to generate electricity.

The combination of the CPS, falling demand and growing renewables had a dramatic impact on the coal share, which fell from 41 per cent in 2013 to 1.8 per cent in 2020. The capacity auctions delivered new generation at 40 per cent of the anticipated price, largely because of a distortionary subsidy provided to small distribution-connected generation. It took over three years for the regulator to remove that distortion.

3. Lessons Learned

The British privatised electricity system is now over 30 years old and today offers a good moment to take stock of its successes and weaknesses. The premise of privatisation was that private owners would invest and operate more efficiently than state-owned enterprises, and that by escaping the dead hand of the Treasury they could access more investment funds, would choose more cost-effective investments, and would cease unprofitable activities sooner while responding to new opportunities more quickly. These potential benefits would have to be weighed against the increased cost of private capital and a possible loss of concern over distributional issues and environmental impacts, unless market players were motivated to take them into account.

Economic historian Avner Offer argues that the private sector is well placed to invest where the credit time horizon is attractive to private lenders, defined as the time to pay back the loan. Roughly speaking, private finance is twice the cost of public finance, so the private pay-back period, simply computed, is half that of the government. Government guarantees or their regulatory equivalent (such as the US model of rate-of-return regulation underpinned by a constitutionally backed rule of law) can offer reassurances, lower the cost of capital and extend this credit horizon. The British electricity supply industry in 1989 was well placed to reap many of the benefits of private ownership, and, initially, to avoid many of the downside costs. Spare capacity avoided the need for costly durable generating capacity and the risk of an inappropriate credit time horizon. The arrival of cheap combined cycle gas turbines (CCGTs) of modest scale, rapid delivery and high efficiency, at a time of falling gas prices, made any such investments lower risk. Even then, these investments relied on long-term contracts and a captive franchise market. The more capital-intensive and durable networks were assured of financeability through licence conditions, obligations on the regulator and a credible dispute resolution process. Distributional concerns emerged, and were, with varying degrees of success, met with licence conditions on utilities, inquiries by the Competition and Markets Authority, and price caps.

Environmental concerns were met with increasingly stringent emissions standards on pollutants, the EU Emission Trading System, various EU directives, and the Carbon Price Support.

Problems emerged when new capital-intensive generation investment was needed to meet carbon and renewables targets and to maintain reliability. The ideology of the market initially led to auctions for renewables that were remarkably effective at driving down costs, but less so at delivering adequate volumes. The shift to renewable obligations pulled through more delivery but at a high cost of finance. It took over 20 years to learn from experience elsewhere that long-term contracts at assured off-take prices would lower the cost of capital and with it the delivered cost of renewable electricity.

Nuclear power and carbon capture and storage (CCS) demonstrated the force of Offer's credit time horizon. No nuclear power station has ever been constructed without strong and credible underwriting from either the government or a utility empowered to pass the cost through to final consumers. In Britain, Hinkley Point C has staggered on since before privatisation, and only secured its final investment decision after one of the costliest ever financing arrangements with government guarantees. Given a possible construction period of ten years and a subsequent life of 60 years, possibly followed by centuries of waste management, nuclear power busts Offer's credit time horizon comprehensively. CCS has had an even worse experience, with over a decade of unfulfilled promises to deliver a commercial-scale plant. Even conventional CCGTs now need 15-year capacity payments to encourage investment, so that to a greater or lesser extent all new generation now receives under-written guarantees by the government for all or part of the output.

Critics argue that this reflects a betrayal of the original aims of privatisation, while realists and, very belatedly and to a limited extent, the government argue that durable essential infrastructure like electricity needs access to low-cost finance that only government-backed or guaranteed finance can assure. Perhaps the most useful lesson from the privatisation of electric utilities is that the UK has evolved a system of regulating at least part of the infrastructure (the natural monopoly pipes and wires) that works reasonably well and has delivered high levels of investment at modest rates of interest. It would be encouraging to think that the UK can continue to learn how better to finance the necessary capital-intensive zero-carbon energy to meet our climate goals in a timely fashion.

CHAPTER 7. Strengths and Weaknesses of the PJM Market Model

William Hogan

The American PJM Interconnection in the Mid-Atlantic states enjoys iconic status as a major innovator in electricity restructuring. Building on its long history as a major power pool, PJM demonstrated the capability to provide the necessary coordination for competition in electricity markets. The core of the PJM market design, a bid-based-security-constrained-economic-dispatch-with-locational-marginal-prices (BBSCEDLMP) model, works in theory and in practice. It is the only electricity market design that integrates engineering and economics to support efficient markets under the principles of transmission open access and non-discrimination. This market design was eventually adopted in every organised wholesale electricity market in the United States. The development of this market followed a process combining analysis, experimentation and learning. The evolutionary process continues to meet new challenges.

1. Brief History of the PJM Wholesale Power Pool

Electric utilities started out local, typically in a single city, and grew. Given the variability of electric load and the diversity of generating plants, it became the norm for interconnection arrangements to share generating, transmission and other resources. The power pool called the Pennsylvania-New Jersey Interconnection was established in 1927. Later, the Federal Energy Regulatory Commission (FERC) encouraged efforts to build on power pool operations for electricity markets.

The initial PJM market model called for a single market-clearing price (MCP) across the entire pool. This does not work in theory, and it did not work in practice. In 1998, after a year of operations under this flawed single market-clearing price design, PJM converted to an economic dispatch with locational marginal prices (LMP) applied to load and generation at each location. The new LMP market was accompanied by the introduction of financial transmission rights (FTR) and an early installed reserve capacity market.

2. Transition to Open Access and Non-Discrimination

In the last decade of the 20th century, electricity reform was in the air, especially after the decision to create a wholesale power pool in England and Wales in 1990. A key feature of this policy in support of wholesale competition included access to the high voltage transmission system. The discussion began with the assumption that generators and loads would be able to make bilateral arrangements for contracts of various durations and then arrange for transmission rights, much as had already been done under the open-access regime for interstate natural gas pipelines. The term of art was the ‘contract path’, whereby market participants would identify a path through the grid and make arrangements to utilise the available transmission capacity. However, unlike natural gas flowing along a specific pipeline, the movement of electric power is completely different.

The essential problem is that power injected at one location and removed at another would travel along every parallel path, distributing itself according to the laws of physics to (roughly) equate the marginal losses on every path. From an economic perspective, the defect of the contract path created material market externalities. Individual bilateral transactions would interfere with all other transactions. The contract path model might have been a convenient fiction when there were only a few members of the club of cooperating utilities, but the open-access market would be overwhelmed when new entrants responded to the perverse incentives created by the externality.

3. Electricity Markets and Economic Dispatch

With a market-clearing price, the best choice for the buyer is the quantity at the competitive equilibrium; similarly, the best choice for the supplier is at the same competitive equilibrium point. Prices then support the dispatch.

In any system under open access and non-discrimination principles, market participants will have the freedom and discretion to buy and sell power according to their own interests. If market prices support the economic dispatch solution, then the private interests will operate as with the 'invisible hand' to follow the efficient outcome. The LMP prices are precisely the market prices that support the economic dispatch. Any other pricing approach would, necessarily, create incentives to deviate from the efficient outcome.

4. Price Formation and Market Design Challenges

PJM will likely maintain its process to prioritise and improve on a number of electricity market design challenges. An example of them is provided by scarcity pricing.

Scarcity pricing refers to conditions when load is close to using all available generating capacity, including capacity reserved to meet contingency constraints. In textbook theory, prices should rise to reduce demand and ration the available supply. In PJM, an Operating Reserve Demand Curve (ORDC), based on valuing the impacts of outages and reserve shortages, provides a practical way to address scarcity pricing within the framework of current economic dispatch models.

The challenges posed by the decarbonisation of the electricity mix include dealing with the intermittent supplies that can increase stress on the system. The arrival of increasing volumes of zero marginal-cost renewable resources prompts a concern that this will drive down energy prices and unravel the fundamental market design.

A notable feature of the economic dispatch is the lack of any specification of the details of the underlying cost functions. The model is quite general and the basic analysis from first principles is unaffected by the arrival of low or zero-variable cost resources. A principal conclusion of a closer analysis is that the importance of scarcity pricing escalates with the increasing penetration of zero-variable cost resources.

The PJM real-time and day-ahead market economic dispatch models are deterministic. The models are based on bids and offers, and on expected system conditions. The real dispatch faces uncertain conditions over the near future in real time, and over the day in the day-ahead problem. The treatment of operating reserves in real time and day ahead in PJM is an example of building in approximations that serve to proxy for some of the major effects of uncertainty while maintaining a simplified representation in a deterministic model.

5. Conclusion

The physics of power transmission systems makes existing electricity markets unlike markets for other commodities. Markets cannot solve the problem of electricity market design, and simple analogies to other markets can lead design astray. PJM has been at the forefront of applying first principles of engineering and economics in the context of providing coordination for competition as needed to support efficient markets. PJM strives for the best approximation of a successful market design organised around bid-based-security-constrained-economic-dispatch-with-locational-marginal-prices. The evolution of market design to accommodate the changing mix of load and generation resources should avoid the mistakes of the past and continue to emphasise the fundamentals.

CHAPTER 8. ERCOT:
Success (So Far) and Lessons Learned

Ross Baldick, Shmuel Oren, Eric S. Schubert and Kenneth Anderson

The experience of the restructured electricity market in the Electric Reliability Council of Texas (ERCOT) region, which covers most of Texas, is analysed in this chapter, which is divided into three parts: 1) an overview of ERCOT; 2) the challenges of creating a self-sustaining power market; and 3) how ERCOT has met those challenges.

1. Overview of ERCOT

The Electric Reliability Council of Texas, Inc. (ERCOT) is a non-profit corporation that manages the flow of electric power to more than 26 million Texas customers who are located within the Texas Interconnection, which has only limited asynchronous connections to the rest of North America.

In 1995, the Texas Legislature acted to deregulate the wholesale generation market within the Texas Interconnection, and the Public Utility Commission of Texas (PUCT) began the process of expanding ERCOT's responsibilities and capabilities to enable wholesale competition and facilitate efficient use of the power grid by all market participants. Several changes followed, culminating in the Texas Legislature enacting Senate Bill 7, which required investor-owned utilities (IOU) to unbundle their functions (generation, delivery, and retail sales of electricity). By 1 January 2002, the same Bill ordered the creation of a competitive retail electricity market to give customers the ability to choose their retail electricity providers.

A day-ahead 'scheduling' process was established in 2001 whereby market participants provided matched generation and consumption information for each 15-minute interval in the following day and made offers to provide ancillary services. After the initial operation of the ERCOT wholesale market without any representation of transmission limits, in 2002 ERCOT was divided into four zones for the purposes of dispatching and pricing power purchases from generators and sales to retail customers. Supply was specified based on portfolios of generation in each zone and demand was also specified zonally. A 'balancing market' then sought bids and offers to deviate from the day-ahead schedules.

It soon became evident that such a system of zonal portfolio dispatch was inefficient in maintaining grid reliability and expensive for wholesale market participants. As a result, in September 2003 the PUCT ordered ERCOT to develop a nodal wholesale market design. The new market opened, after considerable delays, on 1 December 2010, and included unit-specific dispatch, locational marginal pricing for generation, a day-ahead energy and ancillary services co-optimised market, day-ahead and hourly reliability-unit commitment, and congestion revenue rights. The real-time market prices and dispatches generation in 5-minute periods and settles in 15-minute increments. Instead of zonal portfolio offers and bids as in the previous market design, the nodal market required offers specifically from each generating unit.

2. Challenges of Creating a Self-Sustaining Power Market

There are two main policy goals related to customer choice in ERCOT, namely, implementing retail choice and facilitating the integration of new technologies. The challenges in meeting these goals include the following:

- Coping with the unpredictability of evolving markets that are open to market forces rather than regulatory decisions.

- Adaptability to the rapid deployment of new technologies, including smaller-scale generation, and waves of technological adoption.

- Engineering challenges in a policy context, including the extent to which technical considerations and constraints should be reflected in the commercial model underlying the market, specifically relating to features that are unique to electricity, such as almost total non-storability, its locational character, and inherent barriers to competition in electricity markets.

- Commercial challenges in enabling decentralized commodity markets and integrating new technologies.

3. How Texas Addressed the Challenges

This section describes how Texas, and specifically ERCOT, has addressed the above challenges.

a) How Texas Culture and Geography Assisted the Development of the ERCOT Power Market

Texas culture and geography have played an important role in the development of the ERCOT power market by providing policymakers with abundant degrees of freedom to make choices that facilitate good market outcomes for Texas energy producers and consumers.

Self-governance has been a force driving the policies of the Texas Legislature and the PUCT across the retail, wholesale, and wires parts of the ERCOT market. This approach is part of a long tradition dating back to the early days of the Texas Interconnection when the evolving Texas grid became a separate interconnection based on the desire for Texans to manage their own electric power system issues outside of the jurisdiction of the Federal Power Commission, which later became the Federal Energy Regulatory Commission (FERC). This was enabled by the historical pattern of interconnections, which were primarily driven by Texas geography, and that allowed interpretations of the Federal Power Act in a way to limit FERC jurisdiction.

b) Overseeing the Simultaneous Evolution of Two Complex Phenomena in Organised Power Markets

The simultaneous and fast-paced evolution of these two complex phenomena – reliability and commerce – associated with organised power markets, has challenged regulators and legislators across the globe. Arguably, the governance needed to nurture evolving power market ecosystems while maintaining grid reliability is radically different from the traditional regulation of the power industry. Traditional regulation has the tools and structure to address complicated, static matters well (such as determining and allocating costs of new generation and transmission construction in cost-of-service proceedings and managing incremental power trades across balancing authorities from dispatchable, utility-scale generation). However, traditional regulation has not developed the tools and structure to address complex issues (such as assessing static optimal capital investment or managing evolving dynamic market ecosystems and grid reliability of power pool resources associated with the deployment and use of intermittent renewables, distributed generation and active energy management) in a timely and effective way.

The three-tier governance that has emerged in Texas to oversee the ERCOT market is exceptionally well-suited for governing a complex phenomenon, especially given the rapid technological changes that are occurring in the power industry. This unique governance approach has addressed the uncertainties and challenges associated with two evolving, complex systems (grid reliability and commercial power markets) over the past 20 years. The following section provides five key examples of how this structure has met the various challenges.

c) Meeting Current Challenges: Five Key Examples

i) Changes in Protocols to Facilitate Wind Integration

Several changes in the protocols resulted in no overall increase in the need for frequency regulation reserves despite greatly increased levels of wind production. The principal change was the shift from 15-minute clearing intervals in the zonal market to 5-minute clearing intervals in the nodal market.

ii) Operating Reserve Demand Curve

Following the start of the nodal market on 1 December 2010, the most significant enhancement to price formation in ERCOT's energy-only market has been the adoption of an Operating Reserve Demand Curve (ORDC) in 2014, which was chosen over other mandatory actions such as a minimum reserve margin.

iii) Market Performance and Tight Reserve Margins in Summer 2019

Occasional high prices in ERCOT have resulted in the development of market-based demand response that has generally enabled the ERCOT grid to avoid involuntary interruptions, despite, for example, tight reserve margins in 2019.

iv) Integrating Distributed Energy Resources

Distributed energy resources play an increasing role in the supply-demand balance and various reforms have been introduced or are planned to enable deeper participation by such resources in the market, principally involving settlement.

v) ERCOT vs Multi-State Regional Transmission Organization

In ERCOT, a single regulator (PUCT) reports to a single legislative body (Texas Legislature). Subject to that legislative oversight, the PUCT oversees the grid operator, the wholesale and retail market designs, as well as the construction and cost allocation of new transmission lines. This combination has given Texas the ability to address the challenges of integrating low-carbon resources such as almost 25 GW of wind farms in an integrated, logical way and to maintain a consistent market-oriented approach over time without the complexity of multiple jurisdictions that occurs in other states and regions of the US.

CHAPTER 9. Australia's National Electricity Market: Strengths and Weaknesses of the Reform Experience

Paul Simshauser

1. Generation

Australia's National Electricity Market (NEM) commenced in 1998. The centrepiece of NEM's reforms was the restructuring of vertical monopoly electricity utilities and the creation of an energy-only wholesale market and associated forward contract market. The reforms largely followed the British model with four key restructuring steps undertaken over a five to ten-year window, commencing in the early to mid-1990s:

- State-owned monopoly Electricity Commissions were commercialised.
- Commercialised monopoly utilities were vertically restructured into three segments: generation, transmission and distribution/retail supply.
- Competitive segments of generation and retail supply were horizontally restructured into a number of rival entities within each of the NEM's four 'regions'.
- Businesses were privatised and retail price controls removed.

Post-reform, a series of capital markets-driven mergers and acquisitions (M&A) occurred across horizontal lines (i.e. mergers of retailers to create 'scale') and vertical re-integration (i.e. mergers of retail and generation). Looking back, an 'electricity market arms race' played-out over the period 1995-2015. The NEM's 'Big Three' retailers (or gentailers as they are commonly known) emerged as winners from a string of horizontal, vertical and geographic privatisation and M&A events over this 20-year period. Vertical reintegration was the visible trend. Not only did the three incumbent retailers pursue vertical integration with merchant generation, but vertical integration also became the dominant strategy amongst incumbent merchant generators – many of which now have large retail businesses in their own right. A further 15-20 new entrant pure-play retailers form the competitive fringe.

A defining characteristic of the NEM is its governance arrangements. Policy, rulemaking, regulation, and system and market operations are segregated as follows:

- Policy – Energy ministers from each NEM State and the Commonwealth form the members of the Energy Council.
- Rulemaking – the Australian Energy Market Commission (AEMC) operates on behalf of the Energy Council as the market rulemaking entity and policy advisor; it has established an open-source platform for doing so.

- Regulation – the Australian Energy Regulator (AER) enforces wholesale and retail supply rules, and is the economic regulator of the NEM's regulated networks.

- System and market operations – the Australian Energy Market Operator (AEMO) is the Independent System and Market Operator, responsible for coordinating dispatch, power system operations and wholesale market operations, including the spot electricity market and eight Frequency Control Ancillary Service (FCAS) markets.

The NEM is classed as a real-time, energy-only gross pool market (i.e., there is no day-ahead market), with 5-minute multi-zonal spot prices formed under a conventional uniform first-price auction clearing mechanism. In addition to the spot market for electricity, there are eight co-optimised spot markets for FCAS. Being an energy-only market, there is no centrally organised capacity mechanism. Investment in future generation capacity is guided by the NEM's forward markets and AEMO projections; derivative contracts are traded both on-exchange and over-the-counter, and have historically exhibited a turnover of between 300 per cent and 500 per cent of physical trade, albeit with considerable variation between seasons and regions.

By virtually any metric, the wholesale market operated like a marvel of microeconomic reform throughout most of its history. A vast oversupply of generation capacity was cleared, unit costs plunged, generating plants availability rates reached world-class levels, requisite new investment flowed when required, investment risks were borne by capital markets rather than captive consumers, and reliability of supply – in spite of an energy-only market design – was maintained with few exceptions. One could conclude with considerable justification that the reform objectives of enhancing productive, allocative and dynamic efficiency were achieved.

If there was a caveat to this set of observations, it would be the period 2016-19, when wholesale prices struggled to remain within politically tolerable limits, and one region (South Australia) experienced a black system event. However, NEM market mechanisms remained truthful throughout this period, because prices largely reflected the physical and economic realities of the circumstances in which the market found itself. What is more interesting is the underlying causes which preceded the 2016-19 period:

- Adverse effects of climate change policy discontinuity, which adversely impacted generation entry (and exit).

- Sudden and uncoordinated divestment of coal-fired power plants.

- Turmoil in the adjacent market for natural gas through excess liquified natural gas (LNG) export capacity, which would otherwise serve as the transitional fuel and shock absorber required for coal plant exits.

The supply-side response to high prices was significant – during the period 2016-21 there were 135 projects totalling 15 939 MW or USD 26.4 billion in renewable investments. However, this rapid pace of investment would also create a 'rate of change' problem through the velocity and pace of new inverter-based entry, manifesting in sharp adverse movements in system strength and a visible deterioration in the dispersion of the power system’s frequency (i.e., 50 Hz +/-0.15 under normal operating conditions), all of which would require careful management.

2. Transmission and Distribution

Transmission and distribution (T&D) networks servicing the NEM’s 10 million business and residential customers are regulated by the Australian Energy Regulator (AER) in rate cases of five years’ duration. Capital deployed by networks tends to be dominated by residential segment peak loads. Conversely, adoption of rooftop solar PV has been prolific in the residential sector; more than three million households have installed a rooftop PV system (i.e., one in three households), giving Australia among the highest take-up rates in the world. This matters, because solar PV systems greatly reduce energy (kWh) demand, but in certain regions only marginally impact peak capacity(kW) demand. Consequently, two-part tariffs dominated by a volumetric variable charge are not well suited vis-à-vis rate stability.

Network policy, network regulation and overall network performance have been amongst the most contentious aspects of Australia’s energy market reforms, especially from 2007 to 2015. This period coincided with an enormous increase in the combined T&D regulatory asset base (and therefore price rises). Key policy and regulatory decisions underpinned this increase, including: 1) policy decisions by the State Governments of Queensland and New South Wales to tighten reliability standards following network-related blackouts in their capital cities; 2) the decision to revalue network assets in the mid-1990s before the opening of the market; and 3) a policy decision by all state governments in 2006 that had the effect of making network regulation formulaic. Once the effects of a tightened reliability standard became clear to regulators and policymakers, a series of material policy and regulatory changes would follow. Both Queensland and New South Wales abandoned their tightened reliability criteria, essentially reverting back to a probabilistic and not deterministic approach. The AER maximised the low-interest rate environment and pushed the allowable weighted average cost of capital (WACC) in each determination down from 2015 – with returns falling from roughly 10 per cent to a range between four and six per cent. The AER also adopted a hard line on capital and operating expenditure allowances, routinely rejecting as much as 30 per cent of the figures proposed by network companies.

3. Retail

Competition in the retail segment formed a key component of Australia’s energy market reforms and was based on Great Britain’s approach to contestability. Incumbent retail supply companies started with a monopoly franchise over their customer base, but this franchise would gradually diminish. In order to ensure an orderly transition, retail electricity market contestability was phased in over a timetable comprising four to six tranches of consumers (starting with the largest customers) and spanning four to eight years. The final tranche of customers (i.e., residential) had added policy scaffolding in the transition to a fully contestable market – a ‘regulated tariff cap’ – retained as a transitional measure until the so-called mass market was deemed to be workably competitive. The mass market would be deemed workably competitive by reference to measures such as: 1) consumer awareness of their ability to switch supplier; 2) the number of rival retailers; 3) array of products and the depth of discounting; 4) customer switching rates; 5) market share of incumbent retailers; 6) the number of customers remaining on the default tariff, and so on.

On balance, the deregulated retail electricity market performed well, but default tariffs for retailers, which apply to a relatively small percentage of customers, received a disproportionate level of political attention. Policy solutions of re-regulating prices through price caps followed (and are unlikely to end well for those consumers active in the market as retailers progressively re-adjust their market segmentations and profit strategies). This is not to suggest the retail market is operating without fault; vulnerable rusted-on customers represent a misallocation problem (i.e., low-income households are on a tariff designed for an inelastic segment), and discounts are no longer anchored to a common price. Both of these matters are serious policy problems that require further work by retailers and policymakers, respectively.

4. Strengths of the Reform

The reform of the Australian electricity sector shows four strengths:

- The NEM's energy-only, gross pool market design with a very high value of lost load and the associated market for forward derivatives has delivered resource adequacy and withstood a wide array of economic and technical conditions. Whether it is suited to a high renewables market is an open question: the weight of opinion suggests it is not.

- The NEM's core governance structure and approach to open-source rulemaking have had the beneficial effect of minimising misguided political interference and ensured rule changes have purposefully thought through economic trade-offs.

- Capital markets determined vertical business boundaries.

- Competition in the NEM's retail markets has generally performed well, especially in the industrial segment.

5. Weaknesses of the Reform

The reform of the Australian electricity sector shows five weaknesses as well:

- Rising levels of intermittent renewables required a wider array of essential system services to be procured. Market designers were too reactionary.

- Although not discussed in detail above, the lack of a coordinated policy on gas markets and LNG export capacity produced unnecessary gyrations in the gas market (which impacted generator unit costs).

- Policy discontinuity, design errors vis-à-vis climate change policy, and a general lack of a united climate and energy policy architecture created uncertainty vis-à-vis (clean) generator entry and (emissions-intensive) generator exit.

- Coal plant exit could have been better managed in the NEM if the gas market had been functioning properly. But regardless, transparency around exit timing needed to be greatly improved.

- Network regulation in the NEM proved to be a weakness throughout the period 2004-15. Critical errors were made by certain state governments vis-à-vis reliability standards, and the rules were too formulaic to deal with large shocks.

CHAPTER 10. Strengths and Weaknesses of the Nordic Market Model

Chloé Le Coq and Sebastian Schwenen

The Nordic power market comprises the national electricity markets of Norway, Sweden, Finland, Denmark and, more recently, the Baltic States. It is characterised by relatively low market prices and high shares of low-carbon generation, majorly hydropower, nuclear power and increasing shares of wind power.

Its unique multi-national architecture and governance are its strengths and weaknesses. There are clear benefits from pooling low-carbon technologies across borders, having one Nordic wholesale pricing system, and being under one regulatory body. However, strong coordination between countries and neighbouring system operators is required, especially concerning cross-border trading, balancing and congestion management.

1. A Multi-National Market with Multi-Partner Governance

The Nordic power market, the so-called 'Nord Pool', comprises the national electricity markets of Norway, Sweden, Finland, Denmark and, more recently, the Baltic States. The different national markets have been liberalised and integrated successively, mainly by adapting and aligning national regulations. Sweden and Norway first established a joint power exchange in 1996, Finland joined in 1998, and Denmark integrated fully in 2000. The integration of the Baltic States was done gradually, with Estonia in 2010, Lithuania in 2012, and Latvia in 2013. Nord Pool continued to expand with trading arrangements and interconnections with Germany, the Netherlands, Poland and the UK.

The governance of Nord Pool is unique due to its bottom-up multi-national approach. The Norwegian regulatory authority is the regulatory body, but the respective national regulatory authorities enforce market rules, and congestion management is the task of national transmission system operators (TSO). Until 2020, the physical power exchange Nord Pool was an independent entity owned by a consortium of Nordic and Baltic power system operators. The European stock market operator Euronext owns 66 per cent of the Nord Pool group, while the TSOs own 34 per cent.

2. Hybrid Architecture and Zonal Pricing

In the Nordics, electricity is traded via bilateral contracts and on a centralised power exchange. Trading on the Nordic wholesale electricity market takes place on a sequence of cross-border markets, followed by a set of national real-time markets. Producers, retailers and energy-intensive consumers can gradually adjust production and delivery plans by trading on day-ahead and intraday markets. Ninety-five per cent of the produced electricity is traded on the day-ahead market, even though the intraday market is increasing in volume. Since 2014, day-ahead prices have been determined jointly, with most EU power markets using the common price coupling algorithm EUPHEMIA (see Chapter 11 for an overview of the EU electricity market model).

The Nordic market currently exhibits 15 price zones. The configuration of zones follows national borders but also includes multiple zones within some individual countries.

Finally, in Finland and Sweden, transmission system operators procure some reserve capacities to be used in case of immediate risk of capacity shortage. To avoid any competitive distortion, the capacity included in such 'strategic reserves' does not participate in the commercial part of the market.

3. Low Price and Ambitious Climate Goals

The relatively low market price usually observed in the Nordics is mainly explained by the flexibility potentials across the seven Nordic and Baltic countries. There is a clear dominance of hydropower (around 50 per cent of total production) and, to a lesser extent, nuclear power (about 20 per cent). Wind, fossil fuels and biomass contribute around ten per cent, eight per cent, and four per cent of electricity production. Hydropower resources are so vast that they often lead to low market prices. There is also relatively limited evidence of abuse of market power at the Nordic level. Demand response programs are currently not well developed, despite the access to smart meters and the deregulation of the retail market.

The Nordic countries share ambitious climate policy targets, with the common goal to reduce energy usage from fossil fuels close to zero by 2050. Sweden committed to no net emissions by 2045. Denmark aims to be independent of fossil fuels by 2050, when Norway envisages becoming carbon neutral. Denmark implemented a support scheme for renewables early on, in 1993. With their large hydro and nuclear assets, Norway and Sweden instead opted for a joint green certificate market in 2012.

The Nordic market has been a frontrunner when it comes to decarbonisation. Although this market has historically exhibited relatively low-carbon generation due to its vast hydro resources, the Nordic countries (and to a lesser extent, the Baltic States) have actively pushed for the construction of other low-carbon assets, mostly from wind energy. While the Nordic markets are well-endowed with a portfolio of carbon-free technologies, a major challenge to their generation capacity will be to replace the nuclear power generation in Sweden (about 40 per cent of national production), which is to be phased out by 2040. In addition, safeguarding secure supply is dealt with foremost at the Nordic rather than the European level. The Nordic model has relied on strategic reserve and market mechanisms and is considered an energy-only market. Whether that mechanism will ensure capacity adequacy once the share of wind and solar power is higher is a hotly-debated issue (see Chapters 15 and 16).

CHAPTER 11. The Evolution of the European Model for Electricity Markets

Fabien Roques

The European model for electricity markets has taken three successive shapes that can be termed as: 1) liberalisation of national markets with open borders; 2) Europeanisation of national markets via EU legal packages and common grid codes; and 3) hybridisation of national markets to reconcile public policy objectives and planning with competitive markets.

1. Liberalisation of National Markets with Open Borders

With the Single Act of 1986, all the EU Member States agreed to open their economies and remove trade barriers. This movement to create a single market reached the electricity industry in 1996 with the adoption of the first directive concerning common rules for the internal market in electricity. The directive gave European countries significant freedom regarding the specific approach and process for liberalising their electricity industry. Indeed, EU directives typically define the key principles and targets, but let each Member State find its way with its own national laws and rules in a process termed 'national transposition', usually with a two-year deadline. The implementation of the first electricity directive led to the emergence of different national market systems, depending on the countries' national industry structure and organisation, their energy resources and foreign partnerships. As a result, from 1996 to 2009, different types of national markets co-existed across Europe, with two fundamental rules in common: cross-border trade had to be allowed, and no discrimination against producers and suppliers on the basis of national origin was permitted. This legal framework resulted in a patchwork of market rules and organisation across the different countries, with, for example, central dispatch and mandatory pools in some countries and self-dispatch and voluntary exchanges in others, continuous intraday trading in some countries and discrete auctions in others, different approaches for contracting and activating reserves, etc.

2. Toward an Integrated EU Electricity Market, via EU Legal Packages and Common Grid Codes

Whilst the liberalisation of national electricity markets was on its way, their integration into a single electricity market at the continental level made little progress. By the end of the 1990s, it was increasingly clear that further harmonisation of national market designs was necessary to facilitate market integration. In 2004, the European Commission developed a set of proposals to support what became the European 'Target Model' for electricity markets. The aim of the target model was the gradual integration of markets through the adoption of a set of common rules and network codes. In 2009, the 'Third Energy Package' represented a decisive step, because it established a process to develop a common set of rules for European energy markets. The Third Package mandated the unbundling of electricity grids from generation and supply, and confirmed the obligation to create independent national energy regulators responsible for controlling third-party access to the grids. In addition, the Third Package established an Agency for the Cooperation of Energy Regulators (ACER) to foster their Europeanisation. A European Network of Transmission System Operators for Electricity (ENTSO-E) was set up with a similar purpose: to Europeanise the relations between national grids. Both ACER and ENTSO-E were also mandated to define common grid codes, providing the detailed rules for 1) the connection of generation assets to the grids; 2) the calculation and allocation of interconnection capacity; 3) the operation of systems for congestion, crisis and black-out management; 4) the facilitation of power market operation for forward, day-ahead, intraday and real-time horizons, etc.

An important step forward in the integration of the EU market was represented by the implementation of 'market coupling', which allows energy traders to implicitly bid for grid capacity through their energy bids instead of bidding in two separate auctions. In coupled national markets, national transmission system operators (TSO) define the level of firm interconnection capacity for the next day. National power exchanges use that level as an input to the common price algorithm, together with all the bids submitted by the sellers (and buyers) located within the involved national markets. The algorithm then ensures that the cheapest generators are dispatched, irrespective of their national location, as long as sufficient interconnection capacity is available.

Despite the gradual extension of market coupling, the integration of trading arrangements always remained somewhat limited, because energy policies are primarily defined at the national level. This choice affects, for instance, the process of developing critical infrastructures such as interconnections or the definition of the generation mix.

3. Hybridisation of Markets to Reconcile Public Policy Objectives and Planning with Competitive Markets

In parallel to the gradual integration of EU power markets, the 2000s saw the emergence of environmental decarbonisation objectives, combined with a revival of security of supply and competitiveness concerns. This new policy context marked a profound shift, because the creation of a competitive internal market for electricity was not an end objective in and of itself anymore but would instead serve the other policy objectives – namely ensuring a reliable and affordable supply of energy to European citizens and working towards the long-term decarbonisation of the energy sector.

In concrete terms, these new policy objectives led policymakers to intervene in electricity markets via a set of uncoordinated national policy interventions which got in the way of further market integration and led to a range of new approaches being explored for market design across Europe. The primary motivations for public intervention comprise three main drivers in most European countries:

- The need to overcome the perceived market failures that undermine investment in sufficient generation capacity to satisfy growing load needs and maintain security of supply.

- The determination of part of the generation mix through support for renewable or low-carbon technologies.

- System planning to optimise generation and transmission system development.

Despite the diversity across European countries of market reforms and state interventions, a new market model based on the same fundamental principles seems to emerge almost everywhere. This model features competition in two steps, with ‘competition for the market’ (i.e., for investment in new generating capacity) in the form of tenders for long-term contracts followed by ‘competition in the market’ (i.e., to organise an efficient system operation) based on the set of existing integrated wholesale markets.

The first step, competition for the market, typically involves the tendering of long-term contracts based on the technology and infrastructure indicative planning processes at national or, in an ideal future, regional and European levels. Long-term commitments help facilitate investment and financing of low-carbon generation capacity as well as storage and other flexibility resources. Such long-term contracts and auctioning processes involve different products depending on the local electricity system needs, and there is currently a great diversity of approaches across Europe. One key issue is to ensure that these contracts are designed in a way that minimizes any potential distortions of the markets.

Going forward, a new hybrid European target market model could emerge which would coordinate and harmonise the types of contracts and their interface with short-term market. This new regime of wholesale electricity markets is characterised as ‘hybrid’ because it mixes forms of public planning and public policies with a strong role for the competitive process both to induce efficient investment decisions (through tendering) and operation of the system (through a set of integrated energy markets).

CHAPTER 12. New Technologies on the Supply Side

Nils May and Karsten Neuhoff

New technologies based on renewable energy sources are revolutionising electricity supply. They increasingly substitute for the thermal power plants that emit greenhouse gases which in turn drive climate change, and can reduce dependency on fossil fuel imports. This chapter discusses: 1) the portfolio of new technologies; 2) the economic and regulatory factors determining their deployment; and 3) how system friendly designs allow for high shares of renewable power generation.

1. Evaluation of the Portfolio of New Technologies

The emerging role of different renewable technologies is determined by their current and projected costs, their resource and energy potential and their positive and negative externalities. Wind and solar power are the most promising energies. Conventional renewable energies such as hydropower, traditional biomass and waste incineration continue to play large roles globally, but have limited growth potential, which limits their relevance compared to newer renewable energy technologies. Wind and solar power have seen tremendous cost reductions over the last decades, making them the central technologies for decarbonising electricity systems. For example, the IEA's New Policies Scenario anticipates a nine-fold increase in their deployment.

Biomass also exhibits favourable attributes, particularly dispatchability, which makes integration into electricity systems built around thermal power plants easier. However, the higher value of its use in aviation and freight transport, its use as chemical feedstock, as well as easy storability for decentralised and seasonal energy needs, such as heating, suggest that limited potential remains for deployment in the electricity sector, considering that the overall potential for sustainable biomass is limited.

Further technologies possess interesting characteristics but are more limited by their resource potential or technological and economic development stages. Geothermal energy holds more promise for heating purposes than for generating electricity. Electricity generation from geothermal energy is constrained to specific locations. Tidal energy, while potentially also generating electricity reliably, depends on specific local topology and involves large engineering-type investments that exhibit limited cost reduction potential. Therefore, it does not have the resource potential to cover a significant share of global electricity demand. Lastly, wave energy, while in principle presenting a large resource potential, is at an early technology stage and has yet to overcome technological challenges and demonstrate its economic viability.

2. The Economics of Renewable Technologies

The decreased costs of renewables have significantly improved their competitiveness against conventional technologies and have been changing the role of remuneration mechanisms. Initially, policy support was granted because renewable energies produce electricity without greenhouse gas emissions, because countries wanted to establish a national industry, and to support learning with the hope that costs could go down over time. This support was all the more warranted because negative externalities generated by the use of coal, natural gas and nuclear power plants such as greenhouse gas emissions, import dependency and nuclear waste were not reflected in the prices of the electricity produced.

Nowadays, investments into wind and solar power increasingly often cost less than new investments into conventional thermal capacity, even if environmental and security externalities are not priced. With cheaper renewable energies and rising carbon prices, this indicates the competitiveness of wind and solar energy and puts a question mark over the economic sustainability of investments into thermal power plants. The main determinant for the economic viability of private sector investments in renewable energy is now the relative financing costs for renewable and conventional projects. These costs are largely determined by regulatory choices – such as the electricity market design, the development of the electricity grid, the environmental policies put in place and the available remuneration mechanisms. Hence, despite the societal benefits of an accelerated shift to a portfolio of renewable technologies, investment choices to realise these benefits may still be hindered if governments fail to address regulatory risks adequately.

3. System-Friendly Renewable Energy Deployment

The output of wind and solar power plants is intermittent, such that power systems with limited flexibility and significant shares of wind and solar generation capacity exhibit relatively lower electricity prices when it is windy or sunny and relatively high prices when it is not. In the northern hemisphere, wind and solar power are often complementary – e.g., wind power generates mostly in fall and winter, while PV solar generates mostly in spring and summer. On a daily level, the wind blows strongest at night, whereas the sun shines exclusively by day. These complementarities explain the benefit of a renewable technology mix. Portfolios of several technologies can also pay off long-term when any individual technology's potential is limited.

Besides portfolios of renewable energy technologies, there are many approaches to dealing with intermittency. System-friendly wind and solar power plant designs and locations shift their production to hours with lower supply. To decrease correlation with the output of other solar panels, alternative orientations west and east instead of south (in the northern hemisphere) are discussed, which sacrifice some output in terms of MWh achievable in exchange for higher market values for the power produced. The market design can support the flexible ramping of conventional plants and facilitate the exchange between regions and countries. Demand-side management can adjust demand to electricity prices and reduce or shift demand when high prices occur. Storing electricity, for example in batteries or in pumped-hydro stations, shifts supply of electricity from hours where supply is relatively high to hours where it is relatively low. Required storage levels are not extremely high when system operators are allowed to curtail small amounts of renewable energy production.

CHAPTER 13. New Technologies on the Demand Side

Fereidoon Sioshansi

The demand side of the electricity sector has traditionally been treated as passive and inelastic, with consumers receiving the energy to satisfy all their needs from the network to which they are connected, and paying a bundled regulated tariff that includes all components of service (i.e., generation, transmission, distribution and retail service). This narrative is breaking down because many consumers are becoming prosumers or even prosumagers. New demand-side technologies and intermediaries enable this transition, which has significant implications for the sector.

1. Why and How Consumers and Demand are Changing?

Historically, every customer relied on the network to which she was connected for all her electricity services. This included generation of energy, its transmission and delivery as well as metering and billing and other services, typically from a single, vertically integrated and regulated monopoly. The customer used to pay for this 'bundled' service primarily through a volumetric and regulated tariff. The electric utility used to consider the customer as a passive consumer with inelastic demand and used to invest in adequate infrastructure upstream of the meter to serve the customer's needs under any normal circumstance.

This arrangement, which still prevails in many parts of the world with state-owned and vertically integrated utilities, was convenient and simple to manage and operate when the industry was centralised and most generation came from thermal plants in one-way flows to final consumers. It provided sufficient revenues to recover fixed and variable costs, and to finance and operate the infrastructure upstream of the meter. Few technologies or incentives existed to manage demand or shift it from one hour to the other. Customers had virtually no options but to buy from the network at the tariff set by the regulator and/or government.

This paradigm is gradually changing because some customers now have options to produce some or most of the electricity they consume, making them prosumers, and/or producing and storing some of that generation, making them prosumagers. The former is made possible primarily due to the falling cost of rooftop solar PVs; the latter due to the falling cost of storage, not only in batteries but in water tanks, in electric vehicles (EV), and so on.

As an example, over three million consumers in Australia now have rooftop solar panels, with projections for this number to double by 2030 (see Chapter 9 for more information on the Australian electricity market). The number of prosumers in the US now exceeds 2.3 million and a similar trend is visible in Germany and other European countries. The next development on the demand side will be distributed storage: California already has over one million EVs, which are simply storage on wheels.

2. How is the Transition of Customers and Demand Enabled by New Intermediaries?

Because of the digitalisation of appliances which are increasingly connected and addressable via the Internet, customer demand can now be monitored and managed. This has led to the emergence of smart intermediaries using sophisticated software – such as AI and machine learning – to aggregate large portfolios of customer loads and optimise them, based on wholesale prices, congestion on the transmission or distribution network and variable retail prices, which are becoming commonplace in many restructured electricity systems.

The significance of the intermediaries and aggregators is that they make it easy for consumers, prosumers and prosumagers to become active participants in electricity markets, e.g. by offering products and services to the network, rather than buying from the network. This has led to the rise of virtual power plants and digital platforms to trade electricity, manage congestion on the distribution network, use storage energy in EVs to meet peak demand, and a variety of other options not previously available to customers.

3. What are the Implications of the Transformation of Customers and Demand?

The implications of the transformation of passive consumers into active participants enabled by new demand-side technologies and smart intermediaries are profound. For example, in South Australia, on many sunny and/or windy days, the entire electricity demand is met by renewable resources, most of them distributed rooftop solar panels. In those hours, wholesale prices fall significantly, to rise again as soon as the sun goes down. In California, on the contrary, the projected deployment of 7.5 million EVs by 2030 will offer a massive storage potential that could soak up much of the excess solar generation on sunny days and feed it back to the grid after sunset. The consequence, in this case, could be a flattening of the famous 'duck curve' of wholesale electricity prices.

These behind-the-meter developments, which are currently concentrated in a few countries, are expected to spread around the world as the cost of distributed generation paired with storage continues to fall. Importantly, they will not only offer new opportunities to customers: if properly managed, they will also make it easier for grid operators to manage the electricity system in a future increasingly dominated by variable electricity generation. With the help of digital platforms and smart intermediaries, active consumers will be able to provide new sources of flexibility to the system in a rather effortless way. By reacting to prices and incentives, customers will contribute, to a much larger degree than in the past, to the balancing of supply and demand and to the solution of local congestion or any other issue occurring on the grid.

CHAPTER 14. Tools and Policies to Promote Decarbonisation of the Electricity Sector

Kathryne Cleary, Carolyn Fischer and Karen Palmer

As the threats posed by climate change intensify worldwide, many governments are looking to decarbonise electricity generation, which has historically relied largely on the burning of fossil fuels. In addition to being considered the 'low-hanging fruit' of economy-wide decarbonisation, reducing emissions from electricity generation can also enable greater reductions in other sectors, as transport and buildings pursue electrification. This chapter explores the various policy mechanisms currently in use and under consideration around the world for decarbonising electricity generation.

1. Price-Based Mechanisms

Market-based pricing policies are typically more cost-effective at reducing emissions than less flexible regulatory or technology mandates, and have been applied successfully around the globe. Carbon pricing can be implemented through the establishment of cap-and-trade mechanisms or the adoption of carbon taxes, as well as tradable performance standards that set explicit emissions intensity standards. Market mechanisms can also be used to achieve targets for a mix of technologies, including clean energy standards and renewable portfolio standards (RPS).

Policies that set a price directly on the carbon source leverage the most opportunities for reducing emissions, from encouraging the use of more efficient and less polluting sources to reducing electricity consumption overall. Carbon taxes and cap-and-trade programs involve different design choices – such as determining stringency, allocating revenues, or allowing alternative compliance options – but they can theoretically achieve the same efficiency outcome if the price on emissions is equal to the marginal damage inflicted by carbon emissions. Around the world, 64 carbon-pricing instruments are already in operation, fairly evenly split between carbon taxes and emission trading schemes.

Tradable performance standards require the power sector to meet a specific emissions performance requirement or intensity target. They can be cost effective in many situations, as the trading of credits across individual power plants or electricity retailers aligns incentives on the margin to reduce emissions. However, they are not as efficient as direct carbon pricing because the benchmark credit allocation functions as an implicit subsidy to generation. By diminishing the pass-through of average embodied carbon costs into electricity prices, price signals are less likely to encourage conservation as a means of avoiding emissions. Some systems, like the nascent Chinese emission trading scheme, also differentiate benchmarks in ways that present higher-emitting sources with higher intensity targets. While this differentiation may alleviate some distributional concerns, it comes at an additional efficiency cost, because more generous 'de facto' subsidies for higher emitters discourage fuel switching as a means of reducing emissions.

Portfolio-based policies, such as clean electricity standards and renewable electricity standards, require a certain percentage of electricity sales or generation to be carbon-free or low-carbon or come from a certain subset of clean technologies. While they can be effective at reducing emissions, these policies are less efficient than direct carbon pricing because they exclude incentives for some low-cost types of emissions reductions, like reducing the emissions intensity of fossil fuel sources, reducing energy use, or taking advantage of low-carbon generation alternatives that, while cheaper, are not eligible for credit under the policy.

When emissions leakage is a concern, policies like tradable standards or other forms of output-based rebating of emissions revenues can be a useful tool for encouraging generation of electricity in areas covered by the policy and thereby discouraging increased power imports from unregulated regions. An alternative mechanism, used by California, is border carbon adjustment, which imposes carbon pricing on the emissions associated with imported electricity. This approach allows for fuller pass-through of carbon price signals to end users.

2. Technology-Specific Mechanisms

Other policies that target specific technologies have been used in many parts of the world, particularly when the technologies are nascent and have not yet achieved maturity. This group includes policies that target support for renewables or the phasing out of carbon intensive technologies that burn fossil fuels such as coal.

Technology-focused policies have been particularly popular for promoting renewables. A renewable promotion policy that has become widespread throughout the world is the feed-in tariff (FiT), which provides a guaranteed subsidy payment per kWh of electricity generated from renewable energy sources such as solar and wind. Although FiT expenditures have been costly, there is evidence that such price guarantee enhances adoption of fossil-free energy. Today, auctions are emerging as an efficient means for setting the level of support prices. In the US, many states have RPS programs, while the federal government offers tax credits for wind and solar.

Policies on nuclear power vary across the globe. In some locations, nuclear power receives financial support for its carbon-free attributes; in others, it is being purposefully phased out due to concerns about the safety of the facilities and of spent fuel. For example, several US states provide support for uneconomic nuclear plants in the form of zero emissions credits, while Germany and Switzerland are choosing to phase out nuclear power due to safety concerns.

In general, policies that target specific technologies rather than the outcomes associated with using those technologies, such as lower emissions, are costlier strategies for reducing emissions compared to carbon pricing or performance-based policies.

3. Energy Efficiency

While certain policies, such as carbon pricing, do provide incentives to reduce energy consumption, many others do not; policies that promote particular technologies could even encourage consumption by lowering electricity prices. Moreover, research suggests that households and businesses tend to underinvest in energy efficiency measures for numerous reasons and thus fail to realise cost-effective energy savings that could help to lower the costs of the energy services they consume, as well as overall emissions. In order to both reduce energy-related emissions and to address concerns about market failures in the adoption of energy efficient solutions, many jurisdictions set specific targets for energy consumption and implement specific measures fostering energy efficiency. Such measures include building codes and appliance standards that require minimum performance levels. Another policy popular in Europe and in several US states is the energy efficiency resource standard, which, like an RPS, requires that a utility achieves a certain minimum percentage of electricity savings and may facilitate credit trading for each MWh of electricity not consumed.

Other measures are targeted at households and businesses, including subsidies for energy efficient equipment, information campaigns and labelling, as well as behavioural nudges such as home energy reports that use insights from behavioural economics to change consumer choices about energy use.

4. Policy Interactions

The effects of the policies described here are often studied independently, but jurisdictions rarely introduce any one of these policies in isolation. Whether or not the implementation of multiple policies in concert provides additional emissions reductions or enhances economic efficiency more generally depends on the design of the policies (specifically if they rely on fixed prices or market-determined prices) and if also they target market failures other than the environmental ones.

For example, combining renewable support with a cap-and-trade program will not lead to additional emissions reductions, due to a ‘waterbed effect’. Since the expansion of renewables reduces demand for emission allowances, the market responds with a lower carbon price, which decreases the incentive to cut emissions by other means. By contrast, with a carbon tax, additional renewable support can generate additional emissions reductions, because the price of carbon does not change in response to market conditions.

Even if interacting policies do not lead to additional emissions reductions, they can still provide societal value if they address different market failures. For example, if the market has failed to deliver an efficient level of innovation, then a policy targeted to address that failure can work together with the emissions cap to provide additional societal value.

Policy interactions need to be treated with caution, as they can have unintended consequences, such as increasing costs to society. However, if designed and introduced carefully, a suite of the policies described here could benefit society by first reducing the cost of nascent technologies and then helping to introduce and gradually ratchet up a robust carbon price.

CHAPTER 15. Shifting Supply as Well as Demand: The New Economics of Electricity with High Renewables

Richard Green

The demand for electricity has always varied according to the season and time of day, and fossil-fuel and hydroelectric generators have adjusted their output to meet it. Wind and solar generation are needed to reduce carbon dioxide emissions, but their output is limited by the weather, raising the following issues. First, how will this change the pattern and level of prices? Second, what do system operators have to do to keep the power grids running smoothly? Third, how would the growth of electricity storage affect the way in which prices are set?

1. How do Renewables Affect Price Setting

Electricity wholesale markets have been built on a model of supply and demand in which the quantity demanded varies over time and is not very sensitive to prices. Only a few electricity consumers pay retail prices that vary with the wholesale price, and so most have no reason to reduce demand when wholesale prices rise. On the supply side, the power stations available do not change very much in the short term, but they only generate when the price is high enough to make generation worthwhile. When demand is low, it can be met from power stations with low variable costs, and prices are also low. Higher demands require more expensive stations (in terms of their variable costs) to be turned on, and prices rise. Chapters 3 and 4 in this handbook show how the highest prices at peak times can allow all generators to recover their costs in full, as long as we have the right capacities installed.

Wind and solar generators are not always available; PV panels generate nothing at night, and the amount of wind output varies strongly with the wind speed. This means that the industry's supply curve now shifts over time and may not be correlated with demand. Countries with a lot of solar PV may have relatively low prices in the middle of the day, followed by much higher prices if demand rises as the sun goes down.

This can affect the average revenue per kWh generated that different power stations receive. Most nuclear stations produce the same output all the time and so earn very close to the time-weighted average price (obtained by adding all the hourly prices over the year and dividing by 8 760). Fossil-fuelled power stations generate more when prices are high, and so their output-weighted prices are higher than the time-weighted average. Because renewable generators typically produce at similar times and reduce the market price when they do, they tend to earn less than the time-weighted average price for each kWh they generate.

This is a long-run effect, which means that having a levelised cost of electricity equal to the market price (so-called 'grid parity') may not offer sufficient income for wind or solar generators to compete without government support. This effect is separate from the ‘merit order effect’, which is the short-run consequence of adding renewable capacity to a market and reducing average prices until the capacity of other generators has adjusted to make up for it (markets almost always see lower prices if supply is growing faster than demand).

2. What do System Operators Have to do to Accommodate Renewables

When the electricity industry started, power stations had to be very close to consumers, but once long-distance transmission became possible, the exploitation of economies of scale in generation started to occur. The connection of a large number of consumers and power stations to the same grid then reduced the importance of individual changes in demand or station availability.

Long-distance transmission allows stations to be built in the most suitable places, such as close to fuel sources. This is even more important for renewable generators, since their output depends on the strength of the sun and the wind, which can be strongest a long way from where most consumers are located. Building new transmission lines can take a long time if people living along the route have to be consulted about it. If an area has more renewable output than the transmission system can carry, some of that output cannot be used. Setting local or nodal prices, rather than a single market-wide price, can help to signal the value of electricity in different places.

To keep a power system stable, the operators make sure that they always have some stations in reserve, and are able to increase output quickly in response to a fault or a change in demand. If renewable output is more variable than other sources, more reserve capacity will be needed, increasing costs. The ‘free’ inertia provided by the spinning turbines of fossil-fuel, hydro and nuclear generators slows the rate at which the system frequency falls or increases after a fault. If there is too little inertia available, system operators may have too little time to deal with any problems before the frequency becomes too low or too high. As wind and solar PV generators have no inertia, this limits the proportion of output that they can provide in a certain system. Ireland’s system operators sometimes have to spill renewable output for this reason, although they have also bought fast-acting reserves to reduce the amount of inertia they need.

3. How does Electricity Storage Change Price Setting

Batteries are a good source of fast-acting reserves, and their costs have been falling dramatically in recent years. A number of companies are therefore investing in grid-scale battery systems. They can arbitrage between periods of high and low prices, charging when electricity is cheap and discharging when it is more expensive. Put another way, they can store electricity when renewable generation is high relative to demand and discharge it later when less output is available. In many countries, pumped storage hydro schemes have been doing the same thing for decades, pumping water to an upper reservoir when prices are low and generating when they are higher. Adding electricity demand when prices are low and supply electricity when they are high makes those prices less volatile.

For most generators, the variable cost of electricity is dominated by the cost of buying their fuel (or replacing the stocks that they will burn if they generate, as it is the current cost that matter, not the historical one). Hydro generators get their 'fuel' for free, of course, but they face an opportunity cost as the water used at a certain point in time cannot be reused later. In the Nordic countries, which have a very high share of hydro generation, this opportunity cost is known as the 'water value' and is a key driver of prices. When the reservoirs are full, prices can be low, but if water is scarce, higher prices help reduce demand and reflect the higher marginal cost of producing a greater share of output from other generators.

The economics of hydro pricing can be extended to the case of rechargeable storage, such as batteries. The value of electricity in storage reflects the price that will be paid for it when the storage is discharged. It must also take into account the cost of charging. If a battery is 90 per cent efficient, then the cost of 10 MWh used in charging must be lower than the revenue it expects to earn from discharging 9 MWh. In other words, the price at the time of charging must be less than 90 per cent of the price when discharging, and the difference must be greater some of the time if the battery is to recover its fixed costs. Electricity storage will be able to smooth some of the price fluctuations caused by variations in renewable generation, but it cannot get rid of them all. The fundamentals of electricity market design are not affected by the rise of renewable generation, but some changes to market rules are likely to be helpful, as discussed in Chapter 16 of this book.

CHAPTER 16. The Future Design of the Electricity Market

Michael G. Pollitt

This chapter explores some of the issues confronting the future design of the electricity market, building on the previous chapter. In doing so it assumes that the market design will have to cope with increasing amounts of intermittent renewable electricity generation, driven by concerns about fossil fuel emissions, the relatively low costs of renewable electricity generation, and the increasingly flexible nature of electricity demand characterised by EVs, electric heating and electrical energy storage.

1. An Evolving Electricity System

We have in mind developments in three major electricity markets: Europe, the US and China. Collectively, these represented more than 58 per cent of world electricity consumption in 2016[1]. In Europe, the 2030 energy and climate goals suggest that 55 per cent of electricity will come from renewable energy sources by 2030 (see Newbery et al., 2018). In the US, individual states such as California, New York and the New England states have similarly bold plans for the addition of renewable energy to their electricity grids[2]. In China, ambitious targets for the reduction of local air pollution and decarbonisation imply a large increase in the share of renewable (and nuclear) electricity generation[3].

What each of these markets have in common is that they currently have electricity systems based on fossil fuels. The US and Europe have market designs for wholesale electricity trade that were developed with fossil fuel generation in mind. Chapter 2 discusses the evolution of this traditional model of the electricity market and Chapter 4 details the current state of learning on existing wholesale electricity markets of this type. These chapters draw heavily on the extensive experience of wholesale electricity markets in the US. As China attempts to introduce comprehensive electricity markets for the first time (see Chapter 21), debate is still under way as to which market design to adopt, with many provinces in the process of introducing a combination of spot markets based on the model of the American PJM and contract markets based on European power exchanges.

2. Many Possible Designs

In this chapter, we begin by discussing why market design for electricity markets is

1. Source: IEA Electricity Information 2018 (OECD Europe, US and China).
2. California, New York and Connecticut have 50 per cent, 70 per cent and 48 per cent targets for the share of renewable electricity by 2030 (see for example: https://www.eia.gov/todayinenergy/detail.php?id=38492).
3. In 2018, China's National Development and Reform Commission (NDRC) proposed an increase in total renewable energy across the economy to 35 per cent in 2030 (as against 32.5 per cent in the EU) (see https://www.bloomberg.com/news/articles/2018-09-26/china-sets-out-new-clean-energy-goals-penalties-in-revised-plan).

so difficult. We will then go on to compare the PJM market design (described in detail in Chapter 7) – which is based on centralised markets run by an independent system operator (ISO) – with the European market design that is based on self-dispatch. Next, we discuss how intermittent renewables and flexible demand are stress testing current market designs. We go on to discuss the concerns of regulators and how these relate to market design, emphasising how regulators have multiple policy objectives which include a desire to limit high (and low) prices and price discrimination. In the following section, we examine the nature of the firm and market choices, and how these are directly relevant to future market designs. Here, we point out that electricity economists emphasise flexible market arrangements which maximise welfare, whereas electrical engineers tend to favour mechanistic pricing arrangements. These later arrangements often favour producers' interests (who can better understand how to game them). We conclude with a discussion of potential new market arrangements that are radically different from current market designs, drawing on ideas from the management of the Internet, and hybrid arrangements which combine elements of current market designs with radically different arrangements.

3. Two Alternative Views

It is quite fashionable among electrical engineers to suggest that the future of the electricity market involves more use of time-of-day and locational price signals than we see today (following Schweppe et al., 1988). This is because the nature of intermittent renewables and flexible demand will mean that there is more value in signalling underlying system costs more clearly. The idea is that these types of price signals will be more necessary in a world where consumers can vary when and where they charge their storage devices and electric vehicles; where investors can choose where to place their power plants; and where network companies are under pressure to decentralise their operations and outsource certain network functions wherever possible (see, for example, EPRI, 2015; MIT, 2016).

In line with the ideas expounded by Ronald Coase in 1937, the economists of today need to explain just how extreme this view of future spot markets is. Currently, most products are subject to simple pricing, and customers expect the providers of the products to manage their own internal costs of provision to different customers. Only certain types of price discrimination are acceptable and worth doing, in conditions where simple advertising messages, corporate trust and perceived fairness in pricing are important considerations for corporate pricing policy. That is not to say that some providers of services to the electricity system cannot be exposed to prices that vary in terms of time and space, but the opportunity to expose all parties to these sorts of prices is limited.

Engineers advocating such spot markets also fail to take seriously the reality of market power and the linkages between markets. As discussed at length in Chapters 2 and 4, market power is pervasive in the electricity system and was one of the original reasons for the introduction of regulation. Market power tends to increase where there is market fragmentation. It can be handled in different ways. One way is to bring production in house and regulate the overall activity; another is to have wide area markets with suppression of nodal pricing. Finally, there is no reason to assume that unregulated markets for related activities, such as energy, non-energy ancillary services and network investments, cumulatively add up to a social optimum, according to the theory of the second best. Indeed, it is only under extreme conditions that the general equilibrium will be efficient overall. Advocates of the use of extremely granular prices should remember that.

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CHAPTER 17. New Business Models in the Electricity Sector

Jean-Michel Glachant[1]

Since around 2010, the electricity industry has entered a new revolutionary phase, as big as the one triggered 20 years before by the introduction of combined-cycle gas turbines (CCGT) and the creation of open markets for power. This new revolution can be characterised, like the previous one, by the deployment of new generation assets (in this case mostly intermittent and distributed renewable energy sources like wind and solar photovoltaic), and a new transaction frame, as permitted by the growing digitalisation of generation, consumption and trade. In such a context, existing business models can change and new ones can be invented, tested and adopted. These new models are linked to the new assets being used to green the electricity generation mix, and to the new product characteristics that digitalisation allows. Therefore, a simple way to follow the renewal of business models in the electricity sector is first to track the new assets being deployed and the revenue streams nurturing them, and then to track the new product characteristics which digitalisation makes possible for targeted customers. Between these two strong avenues of change stand the electric grids, both transmission and distribution, which also have to reinvent their business models but, because they are both regulated, do not have a free hand to do so.

1. New Assets and New Revenue Streams for Greening Electricity

Renewables like wind and solar favour distributed generation (DG) and permit deployment of much smaller generation units, opening the electricity industry to new types of investors, including local authorities, communities and individuals. However, the cost structure of these assets (mainly fixed capital costs to be paid upfront) and their intermittent output place a question mark over the viability of such investments. Public policies have been designed in this regard: eager to support the decarbonisation of the energy sector, policymakers have been prone to regulate in favour of guaranteed revenue streams such as feed-in tariffs, renewables portfolio standards, or net-metering (see Chapter 14). After more than a decade of improvement in the technologies and the manufacturing of these new generation assets, several ‘utility-scale’ projects are now being built purely on a merchant basis, while other investors prefer to continue securing their revenues with long-term contracts, either on a purely private basis, as with bilateral or multilateral ‘power purchase agreements’ (PPA), or in a public-private partnership, where a public entity underwrites a ‘contract for differences’ (CfD). Meanwhile, the transformation of ‘feed-in tariffs’ into a ‘feed-in premium’ has accelerated the professionalisation of investors, who now have to be able to maximise their revenues on open wholesale markets.

That said, the renewables sector is extremely heterogeneous. Even in the case of a

1. The author would like to thank Nicolò Rossetto for his helpful comments and kind suggestions.

single renewable source, such as solar energy, generation assets can range from a rooftop PV unit of a few kW (this category represented roughly 40 per cent of global installed solar capacity in 2020) to small utility-scale units of 1-5 MW, to large utility-scale units of 30-50 MW, and finally to gigantic concentrated solar plants of 950 MW (e.g., the Noor Energy 1 project in Dubai). In California and Germany, there is now a mass market for rooftop PV, while in Australia one-third of all households have installed solar panels on their premises. In the wind sector, similar heterogeneity is visible. Wind turbines can be as small as 500 kW or 2 MW, allowing many small and local players to enter the market (including consumer cooperatives); however, utility-scale onshore projects may be as large as 500 MW or 1 GW. In the offshore wind sector, only a few 'Renewables Supermajors' dominate, targeting portfolios of between 35 GW and 100 GW in the coming years. Mostly Europeans, these companies have the resources to build large offshore farms of between 700 MW and 4 GW. While the capacity factor of offshore wind is likely to remain between 20 and 30 per cent, recent offshore wind projects aim for a capacity factor of 60 per cent by 2030.

2. New Product Characteristics for Targeted Customers

The tradition in the electricity sector is to have a handful of players with heavy balance sheets that invest in large-scale, long-lived physical assets. Today, the sector is going in the opposite direction. Numerous asset-light players, often new to the industry, are emerging and offering particular characteristics to targeted customers. There are many examples, from aggregators to digital platforms for the management of distributed energy resources. These new players now revolutionising the electricity sector are following three distinct paths.

Path 1 is the activation of final energy demand to create products that can be sold back onto the wholesale market via a new type of intermediary, the aggregator, who basically does the opposite of what traditional energy retailers do. Path 2 is the establishment of new venues enabling direct trade between 'retail-size' sellers and buyers. This occurs with the support of another type of new intermediary: the digital platform. If that intermediary has a limited control on direct trade, it may create the bases for 'peer-to-peer' transactions. Path 3 is where retail-size units invest comprehensively in generation assets, energy storage, and controllable consumption management devices. In this case, a totally new space is created for the coordination and governance of electricity transactions, dominated by 'prosumers' and 'prosumagers'. This space is frequently called 'behind-the-meter', as it is remarkably separate, even isolated, from the electric utilities and regulators who are the traditional key decision-makers of the electricity space. This new 'behind-the-meter' territory may also be inhabited by new entrepreneurs managing in a professional manner fleets of connected assets such as electric vehicles and self-generating buildings. Equally, it may be inhabited by service companies helping prosumers to optimise the management of their private assets.

3. Between New Assets and New Product Characteristics: Challenges for the Regulated Grids

The challenges for the regulated grids (transmission and distribution) are real because they risk being squeezed between the 'Greening Revolution' upstream and the 'Digital

Venues' or 'Behind-the-Meter' territories downstream.

How will the offshore grid be conceived and organised, given the EU target for 300 GW offshore by 2050? The UK is offering offshore wind developers the opportunity to also be the offshore grid developers, and once these new transmission grids are built, it intends to auction them to other investors that are willing to manage them as regulated OFTOs (i.e., Offshore Transmission Owners).

Prosumers and self-generating units may jeopardise the revenues of distribution grids, with volumetric charges and net-metering threatening a 'valley of death' to established regulated companies. Faced with a new generation of individual storage units and dynamic use of electric vehicles, the regulated grid loses the monopoly power it has traditionally enjoyed as the essential facility to get access to energy and power. The decisions taken by the regulated company and its regulator regarding, for instance, tariffs and connection rules are no more the ultimate choice that consumers have to obey to, but become part of a patchwork of incentives, to which prosumers and prosumagers can react with new investments or new behaviours.

On the opposite side of the retail universe, in the megalopolis of New York, the regulatory authority hoped to lead a revolution of digitalised venues for micro transactions; it claimed in 2015 that the future of energy trading lay in a 'Distributed System Platform'. But seven years later, it has proved difficult to bypass the traditional political economy of 'universal access' to a 'merit good' with 'guaranteed affordability'. However, in Colorado, a cooperative has fully implemented a 'dynamic transactive energy' system which optimises individual consumption, demand response, local storage, self-generation, and electric vehicles. You can interpret this either as a 'Google-Amazon utility' that directly manages individuals' behaviour and relationships, or as a voluntary community of smart individuals responsible for their energy transition.

CHAPTER 18. Electrifying Transport: Issues and Opportunities

Bentley C. Clinton, Christopher R. Knittel and Konstantinos Metaxoglou

In this chapter, we examine the global implications of electrifying the transport fleet. Our analysis covers an array of topics, including vehicle cost considerations, infrastructure concerns, emissions consequences, and the potential effect of electrification on fuel tax revenues. We also discuss aspects of the electrification frontier, paying particular attention to the role of electricity in the medium- and heavy-duty sector and for ride sharing and autonomous vehicles.

The stock of electric vehicles (EV) worldwide increased by 65 per cent between 2017 and 2018 to approximately five million vehicles (IEA, 2019b). An expanding EV fleet represents a potentially large transition in energy demand from the established liquid transport fuel supply network to the electricity system. The IEA estimates this transition could reduce oil demand by 2.5 to 4.3 million barrels per day and increase electricity demand by between 640 and 1 110 terawatt-hours (IEA, 2019a). Such a transition requires a significant deviation from the status quo for automobile consumers and producers alike. In this chapter we take stock of the global light-duty vehicle (LDV) ecosystem and highlight issues and challenges likely to arise as electricity expands its role as a transport fuel.

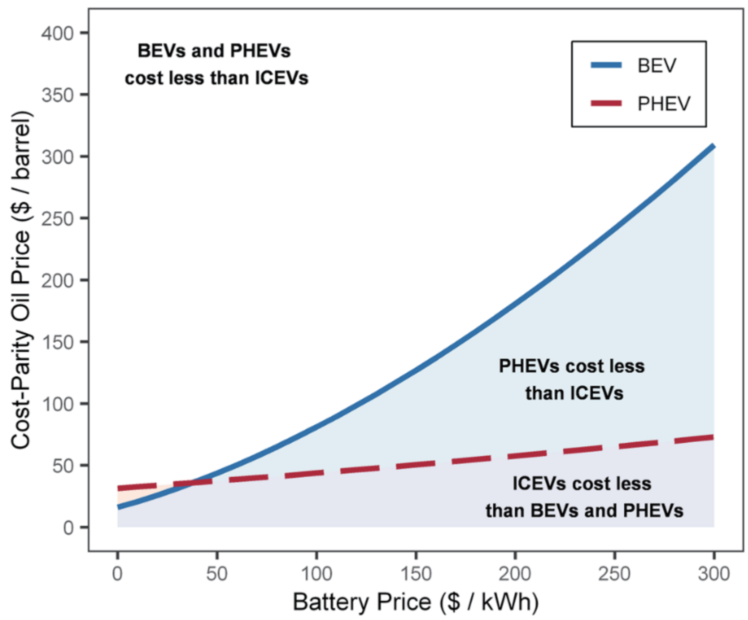
Our assessment pays particular attention to trends in vehicle stock, fuel markets, and refueling infrastructure before turning to a study of market dynamics and an analysis of catalysts and consequences of broad transport sector electrification. Three such inquiries are: 1) a comparison of vehicle cost factors and investigation of the break-even cost relationship between oil and battery prices; 2) an approximation of the energy demand effects for a range of LDV electrification scenarios; and 3) an estimate of the foregone fuel tax revenue attributable to the current EV fleet. Additionally, we discuss the benefits of EVs in the context of avoided internal combustion engine vehicle (ICEV) emissions and conclude with some thoughts on electrification in other transport sector contexts, namely, medium- and heavy-duty freight transport, and the role EVs may have in ride sharing and autonomous vehicle networks.

1. Break-Even Costs

We build on the analysis of Covert, Greenstone and Knittel (2016) to calculate the break-even price of oil for a range of battery costs. Using historical data, we map monthly crude oil prices to gasoline prices in the US and apply the resulting parameters to a model of operating costs for ICEVs and EVs. The result of this calculation is included as Figure 1. Points below the solid line represent oil price and battery price pairs where ICEVs are less expensive to operate than EVs. The opposite relationship holds for points above the line. To a first order, the relationship is close to a 1:1 mapping between oil prices and battery costs; this does not bode well for

EVs. At current battery prices (approximately USD160/kWh), oil prices would need to exceed USD135/bbl for EVs to be cost competitive. We repeat this calculation for a number of scenarios ranging from imposition of a carbon tax to incorporation of avoided maintenance costs realized by EV owners. While these do lead to more favourable break-even cost levels, the comparison remains unfavorable to EVs at current battery and oil prices. We next modify our analysis to include assumptions unique to plug-in hybrid electric vehicles (PHEVs) (dashed line, Figure 1) and find a more favorable break-even scenario for these vehicles, though we caution this result is sensitive to baseline PHEV assumptions.[1]

Figure 1. BEV and PHEV cost parity frontier



2. Energy Demand Effects

We apply existing simulations of intraday EV charging patterns from the National Renewable Energy Laboratory's EVI-Pro tool to publicly available data on EV ownership and electricity generation infrastructure to illustrate the potential effect of LDV electrification on a select group of power systems (Wood et al., 2017)[2]. Our assessment of energy and power requirements of these fleets indicates current adoption levels of EVs pose limited challenges on a grid-level scale, but the projected increases in EV adoption – and any long-term push for high-level or full electrification – will require long-range planning actions by key electricity market participants. These actions are likely to include a mixture of capacity additions, infrastructure expansion, and the introduction of load-shifting options (e.g., smart charging) and compatible incentives (e.g., time of use rates) for EV owners.

1. As part of our analysis, we developed an online tool for users to modify these assumptions. The tool can be accessed here: http://ceepr.mit.edu/research/projects/WP-2020-010-tool.
2. EVI-Pro data available at: https://maps.nrel.gov/cec.

3. Foregone Fuel Tax Revenues

A decline in reliance on liquid transport fuels necessarily decreases tax revenues derived from fuel sales, all else equal. In scenarios with high levels of EV ownership, revenue shortfalls must be recouped from other sources. We explore these issues in a number of national markets and quantify the required scale of alternative revenue-generating mechanisms. Expanding on the methods of Davis and Sallee (2019) and accounting for cross-sectional variation in fuel excise tax levels, EV fleet sizes, annual miles traveled, and ICEV fleet efficiency, we determine foregone tax revenues. Our calculations indicate electricity excise taxes or annual fees for EV owners would significantly increase current cost burdens on EV owners. While such a move has the potential to depress EV adoption rates, more information is needed to evaluate these trade-offs; we are actively pursuing such an assessment with ongoing work.

4. Conclusion

The push toward a fully electrified vehicle fleet offers a series of opportunities, but also faces many challenges. This chapter examines a number of these in the global context. Results of our work demonstrate that electricity's place in the future portfolio of transport fuel options depends crucially on EV cost competitiveness, models' availability, and forward-looking actions by the electricity supply network. In preparing for next steps toward an electrified LDV sector, stakeholders and policymakers alike will need to consider these aspects of the market along with implications for emissions and tax revenues for transport infrastructure investment.

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CHAPTER 19. Electrification of Residential and Commercial Heating

Mathilde Fajardy and David M. Reiner

Heating and cooling are responsible for 54 per cent of the world's final energy consumption, and 42 per cent of global CO_2 emissions[1]. Owing to the highly dispersed nature of these emissions in buildings, efforts to lower heating and cooling demand and associated emissions are relatively recent compared to other sectors such as power and transport. In the building sector, heating and cooling make up 58 per cent of the sector energy demand. Over the past twenty years, space and water heating demand has remained relatively constant, owing to significant efficiency improvements balancing the 65 per cent global floor area increase. However, little effort has been made to assess how this demand is met. Heating in buildings is still heavily fossil fuel dominated, with direct emissions from buildings totalling 3 $GtCO_2$. In addition, more emissions are associated with an increasing demand for cooling services: over the same period, cooling energy demand almost tripled, and indirect emissions from buildings (which include the carbon footprint of electricity) increased from 4.8 to 6.5 $GtCO_2$.

1. Electrification Still at an Early Stage

With an increasingly decarbonised electricity grid, the electrification of heating – by means of high efficiency household- and district-level heat pumps – offers a potential alternative to the incumbent heating system. Heat demand is electrified in only 11 per cent of buildings, mainly using conventional electric heaters. Renewable heating alternatives, which include heat pumps, solar thermal, biomass boilers and renewable powered district heating and cooling networks, only make up 10 per cent of current heating supply. While sales of these alternatives have expanded over the past 20 years – from two to three per cent of sales for heat pumps, and from four to six per cent for renewables – a much faster transition is required to meet global decarbonisation ambitions.

Global decarbonisation scenarios foresee a rapid decarbonisation of the buildings sector, with direct and indirect CO_2 emissions from the building sector dropping by 88 per cent in the 2°C IEA Faster Transition Pathway to 2050. By 2050, residential heating demand is expected to be met with bioenergy and solar thermal (85 per cent of installed heating capacity), heat pumps and natural gas, which will still meet 15 per cent of heating demand. While these scenarios are already very ambitious, the adoption of more stringent economy-wide net-zero targets will require even deeper and faster changes to the sector.

1. Unless otherwise noted, all data refers to 2017, which is the most recent year for globally consistent data.

2. Four Challenges to Electrification

In this context, this study explores the challenges and opportunities to decarbonise heating in the buildings sector through electrification. Four key challenges and associated actionable levers were identified to unlock the potential role of electrification to decarbonise heating.

Driven by temperature rise and a growing population in emerging economies, cooling (as well as demand for other electricity services) in buildings has risen significantly in the past 20 years. Measures to mitigate this increase include improving appliance efficiency (via standards and technology performance labels), improving building performance (via regulation and incentives), and exploiting the coincidence of solar PV production and cooling peak demand.

To this increasing demand must be added the electricity demand curve and peak demand impacts resulting from the electrification of a seasonal heat demand with high hourly variations, which could pose considerable balancing challenges to the grid. Opportunities to alleviate these impacts include synergies with alternative technologies (distributed solar PV, district heating and large-scale heat pumps), enhancing flexibility with thermal storage, and shifting peak demand to off-peak hours with smart meters and dynamic electricity pricing.

There is a high uncertainty around the adoption of higher cost heating technologies, efficiency improvements and flexible demand behaviours at the household level. Incentives for the purchase and operation of renewable heating technologies at the household level with support mechanisms, reducing the cost of new systems with market-based measures and economies of scale, and highlighting the all-year thermal comfort benefits of reversible heat pumps are examples of measures which could boost adoption of technologies and demand-side measures.

Finally, the costs associated with power infrastructure expansion (both generation and transmission) and decommissioning of an underutilised gas network are substantial. Improving efficiency of gas appliances, repurposing the natural gas grid with greener gases (i.e., hydrogen, biomethane or carbon-neutral synthetic fuels), and encouraging hybrid heat pumps which can deliver better performance are three key levers to avoid the need for a radical shift and stranded gas assets costs. In addition, electricity supply security standards play a key role in electricity generation and transmission capacity expansion: revising standards such as the value of lost load (VoLL) could reduce the system's costs associated with a higher electricity and peak demand. Finally, as these costs dramatically increase with the tightening of decarbonisation targets, such as mid-century net-zero targets, quantifying the potential for CO_2 removal to offset residual emissions is another crucial lever to consider.

CHAPTER 20. Harnessing the Power of Integration to Achieve Universal Electricity Access: The Case for the Integrated Distribution Framework

Ignacio J. Pérez-Arriaga, Divyam Nagpal, Grégoire Jacquot and Robert Stoner

Efforts to achieve universal access to electricity in emerging markets and developing economies – EMDE countries or just developing countries – are hampered in large part by failures in the distribution segment. The ability of the power sector in low-access countries to mobilise the substantial public and private investment necessary for expanding access infrastructure hinges on the viability of distribution. We believe that a new business model for distribution is needed to expand electricity access in a manner that leaves-no-one-behind, taps into new off-grid electrification solutions and smart technologies, and provides customer-oriented services to support long-term socio-economic development. To fulfil these requirements, the Integrated Distribution Framework (IDF) approach is proposed.

1. Access to Electricity and the Distribution Segment of the Power Sector

Hundreds of millions of people around the developing world – at last estimate, 759 million in 2019 – live without access to electricity, and millions more have poor quality or unreliable supply. The implications of limited energy access for socio-economic development are alarming. Access to affordable, reliable and sustainable energy is imperative to support income-generating activities, reduce drudgery and improve productivity, while also facilitating delivery of public services such as healthcare and education. Ending poverty is largely contingent upon ending energy poverty. According to all consulted studies, global investments are not on track to achieve this goal, and under current and planned policies more than 670 million people may still lack access by 2030.

Reaching universal access by 2030 and ensuring adequacy, affordability and reliability of electricity services require tailored efforts across a wide variety of contexts where the electrification challenge persists. The 'economics of electricity' has a different meaning in these situations. The economic, technical, social and political challenge is to provide electricity for all in such a way that the supply of power can enable economic growth and human development.

Electrification involves a variety of activities, a range of different technologies and business approaches, and diverse actors. Among the major power sector segments – generation, transmission, distribution (including retail), and system operation – there is ample evidence that distribution is the critical bottleneck to achieve universal access. Here, the term 'distribution' encompasses all the 'last-mile' activities necessary to supply electricity to end-users, including not only conventional on-grid distribution and retailing tasks, but also off-grid solutions (mini-grids and stand-alone systems) that involve assets, such as generation and storage, which commonly exceed the scope of distribution.

Failures in the distribution segment in many low-access countries are having a dramatic impact on universal access to electricity. Distribution companies commonly face significant financial hurdles, and this provokes viability challenges that hinder the mobilisation of the substantial public and private investment needed to expand grid-based electricity access. The lack of a proper regulatory framework, encompassing the entire distribution activity, has a negative impact also on off-grid solutions, and the recent growth of mini-grids and stand-alone systems has occurred largely in silos.

Distribution has historically attracted a very small share of private investments in the electricity sector among those countries that have not yet achieved universal access. This is especially true in Sub-Saharan Africa, where private capital flows into transmission and distribution sectors are virtually zero. To reach universal access by 2030, new business models for distribution must be defined that leave no one behind, ensure permanence of supply, integrate the various electrification modes (on-grid and off-grid), and align with a vision for the long-term, sustainable development of the power sector and the economy.

2. Value of Integration: Adopting a Holistic View of the Electrification Challenge

Developing countries are unlikely to reach universal energy access without seeking integration at different levels. First, integration of the three modes of electrification – stand-alone systems, mini-grids and large grid. Second, integration of the incumbent – typically publicly owned – utility with an external entity, where the concessions, in their various formats, are a convenient implementation instrument. Third, integration of electricity supply and end-uses, which is critical for maximising the economic and social impact of access. This requires a cross-sector view and an in-depth understanding of energy needs – power, heating/cooling and transport – in sectors critical for economic growth and human development (e.g., health and education). Finally, the fourth level of integration is centred on the coordination between countries in transmission and large generation planning and operation, since the majority of the energy being distributed continues to be supplied from the bulk power system.

The opportunity to combine the three dominant modes of electrification – large grid extensions, mini-grids, and stand-alone solutions – increases the number of possible pathways available to attain universal electricity access. Yet, these have mainly been deployed in an uncoordinated manner and with the involvement of different entities, which has tended to lead to unhealthy competition rather than complementarity between electrification initiatives.

3. The Integrated Distribution Framework (IDF)

Universal electricity access cannot be achieved without an in-depth rethinking of the electrification strategy at the distribution level. The strategy needs to result in viable business models for all stakeholders – utilities, mini-grid developers and operators, stand-alone system providers, and market development actors – so as to attract investments at the scale needed to achieve universal access. Importantly, the vision of the electrification strategy and the distribution sector should be compatible with a sound vision of the future power sector of the country. Responding to this challenge would require adherence to a minimum set of key requirements when rethinking electrification:

- *Inclusiveness*. Nobody shall be left behind. Inclusive electrification within a designated region requires the existence of a responsible distribution entity that assumes effective, not just formal, responsibility for serving all customers, irrespective of their level of demand under minimum quality conditions. The regulation of the power sector in most countries requires the incumbent distribution utilities to provide universal service but, given the existing difficulties, this legal requirement is not enforced. By contrast, this is the centrepiece of the IDF. For instance, inclusiveness can be inserted as a hard condition in a territorial concession contract.

- *Mix of electrification modes*. Distribution should leverage all possible delivery modes in order to fulfil its universal electrification objective and selectively consider grid extension, mini-grids and solar home systems. Geospatial planning tools have shown great promise in providing decision-makers with cost-efficient electrification strategies that exploit all three modes of electrification.

- *Permanence*. Solutions shall be sustainable in time. Distribution policy should have a long-term perspective and, based on financially and socially sustainable business models, be able to last for decades. This indispensable component of sustainability requires a long-term vision and commitment, as well as strong and continued political support.

- *Flexible partnerships*. Distribution companies in low-access countries must be open to developing partnerships with any relevant public and/or private structures capable of providing the technical, managerial and financial support that they need. External support will be decisive in ensuring that both universal energy access and high quality of service for all is achieved.

CHAPTER 21. Reforming China's Electricity Industry: National Aspirations, Bureaucratic Empires, Local Interests

Xu Yi-Chong

The electricity reforms implemented in China over the past four decades represent a bundle of paradoxical developments. The industry delivered unprecedented progress in providing universal access to reliable electricity services, including in the country's most remote and harsh areas. At the same time, the efficient use of resources remains problematic. The industry has developed the world's largest fleet of renewable-based power plants (32 per cent of the global total), generating 29 per cent of global renewable electricity as of 2020. Yet half of the world's installed thermal power generation capacity is located in China. The industry has produced world-class technological innovation, from supercritical thermal power plants to ultra-high voltage transmission networks. Yet it also suffers from poor-quality control. More significantly, back in the mid-1980s the electricity industry was among the first to be reformed in China and the world by lowering entry barriers to generation and introducing power purchase agreements and independent power producers. In 2003, the industry was horizontally unbundled, albeit incompletely, before its counterparts in most countries, including many OECD members. And yet, as of today, the 'market system' in China has no independent market operators or regulators, and prices are not decided by sellers and buyers.

1. The Role of Politics and Public Policy

The roots of these paradoxical developments are multiple. In this chapter, we focus on politics and public policy to explain these seeming contradictions. China is large and diversity is inevitable: what is considered possible in coastal provinces may not be feasible or even appropriate for inland provinces. Size matters when it comes to effective government. Another critical factor in explaining electricity reform in China is that it started when the sector was at an extremely low level of development. The total installed generation capacity in 1995 was 10 per cent of that recorded in 2020. Electricity consumption per capita in China was five per cent of the OECD average in 1980, 10 per cent in 1995 and 50 per cent in 2014. The effects of the rapid electricity expansion, especially in installed coal-powered thermal capacity (about 50 per cent of the world total), were widely felt by producers and consumers in China. This expansion had significant impacts on local pollution, international commodity markets, and global climate change.

Contrary to the image of an exclusively top-down decision-making system, policymaking and policy implementation in China is perhaps better explained with an analogy of herding sheep or cattle with Australian Kelpies — wise sheepdogs that have the ability to herd livestock with only general guidance from the top. They may stop or veer along the way, but they get to the destination eventually. This is what matters. In China, a general direction for any given policy often emerges after an elaborate consultation process during which debates, bargaining and compromises take place among powerful interests, whether provinces (some of which have populations of over 100 million and economies larger than most countries in the world), bureaucrats in key government institutions, large state-owned and private companies, or influential former politicians. This process is necessary to ensure the broadest support and thereby the broadest chances of success. Consequently, rather than eradicating old rules and practices, China has developed new policies to support growth and expansion over the past four decades. This has helped to avoid powerful interests exerting a veto.

2. Three Phases of Electricity Reform

The 40 years of electricity reform in China can be artificially divided into three phases. During the first phase (1984-2002), doubled energy usage supported quadrupled GDP growth, with a fast decline in energy intensity. The second phase (2002-2015) was dominated by the convergence of electricity expansion with industrial upgrading and innovation. The following phase (from 2015 onwards) has seen an alignment of climate and energy policy priorities.

Government has two types of mechanisms to help guide players in the preferred direction: carrots (incentives) and sticks (penalties). The first phase, for instance, saw a lowering of the entry barriers and the adoption of a dual-pricing system to encourage investment in electricity generation by new actors without undermining the interests of the incumbents who were, in turn, asked to operate under tighter budget constraints.

In the second phase, the State Power Corporation (a vertical monopoly) was unbundled into five generation, two grid, and four power service companies that remained state-owned. Their nominal owner – the State-owned Asset Supervision and Administration Commission (SASAC) – expected these centrally-owned corporations to become internationally competitive in their size and operation, as well as in innovation. These expectations proved more realistic than demands made of other government agencies, such as the Ministry of Environmental Protection or the State Electricity Regulatory Commission, because the assessment of the CEOs' appointment and remuneration was conducted by SASAC. This was the period when the State Grid Corporation invested in research and construction of the world's largest ultra-high voltage transmission network, and when Huaneng, a generation company, invested in an experimental advanced nuclear reactor.

In the third phase, efforts to align climate change and energy policy priorities have seen a rapid build-up in the clean energy sectors, from solar, onshore and offshore wind, and water pumps, to electric vehicle charging stations. Despite these positive developments, old problems remain. Among them are wasteful investments – the average thermal power plant utilisation rate was 48 per cent in 2020, significantly below an average of 70-75 per cent in other countries – and low energy efficiency: energy consumption per unit of GDP was nearly three times the OECD average and 1.7 times the world average.

3. The Long Road Towards Electricity Markets

The recent call to create electricity markets by allowing private investment in retailing services and direct 'sales' from generation companies to large end-users is not a new idea. The first trial to create electricity markets was implemented in 1998-99 in several regions of the country. Regional wholesale power markets were piloted in the Northeast China grid and the East China grid from 2002-06. Direct power purchasing was arranged between generators and a few large end-users. Benchmark feed-in tariffs, differential pricing for times and users, and other mechanisms were introduced. Many cite an increasing volume of 'trade' across provinces or regions as a sign of market activity. Yet, none of the reforms caused changes to the fundamental principles of the Chinese electricity industry: a combination of government policy guidelines, market forces, and bureaucratic decisions on pricing and investment.

For any market to work, prices have to signal when and how investors, producers, consumers and intermediaries need to change their actions. Prices can be regulated, and in most countries electricity prices are regulated, but they are by and large decided through exchanges between buyers and sellers. This is not the case in the Chinese electricity sector. Electricity in China is not a product like others, because its price is adjusted according to a complex calculation that takes into account the type of generator (thermal, hydro, renewable or nuclear, large, medium or small, etc.), end-user (industrial, commercial or residential) and location (coastal, inland, urban or rural). As a recent government document indicates, this will be the practice for the foreseeable future. While this choice has its merits, without a market-based pricing system investment decisions can be bureaucratic and, at times, misguided.

4. Conclusion

Because of the size of the country, governing in China is extremely difficult. Managing entangled diversities and conflicting interests by setting broad directions has so far been the preferred method, and it will continue to be the case despite bureaucratic bickering, provincial and local protectionism, and powerful interests. The direction has been set–carbon peak by 2030 and carbon neutrality by 2060. The challenges are enormous. Electricity is at the centre of them all. The introduction of an emission trading scheme for the energy sector signals a step in the right direction. Hopefully, Kelpies will eventually do the rest.

CHAPTER 22. The Evolution of Electricity Sectors in Africa: Ongoing Obstacles and Emerging Opportunities to Reach Universal Targets

Vivien Foster, Anton Eberhard and Gabrielle Dyson

Africa stands out from the rest of the world in its struggles to develop its power sector and establish new markets for power. This chapter highlights: 1) the challenges facing the power sector in Africa; 2) progress in meeting Africa's power needs; 3) progress in power market reforms; and 4) the potential for a new wave of reforms propelled by disruptive innovation.

1. Africa's Power Sector Challenges

Over half the population in Sub-Saharan Africa still have no access to electricity. Still, electricity demand outstrips supply in many African countries, which endure periodic power cuts and poor reliability. The causes of inadequate electricity supply vary from insufficient generating capacity and poor maintenance of existing generation plants, to underdeveloped transmission and distribution infrastructure.

Underlying these technical shortcomings, governance challenges – corruption, lack of rule of law, political instability, and lack of transparency and accountability – are rife, contributing to the contested political economies that surround the power sector.

Utilities are plagued with perennial financial deficits, unable to cover their costs through electricity sales. Only two countries in Sub-Saharan Africa fully recover their cost of service through their revenues.

2. Advancements in Investments in Generation, Transmission and Access

While Africa is generally short of power, progress is being made in a handful of countries and some now have generation surpluses – Ghana, Ethiopia, Kenya and Uganda among them. Around half of investment in new power comes from public funding, but the fastest growing sources of investment are from independent power producers (IPP) and from China. Traditionally, most of these Chinese investments have been in hydroelectricity, but the trend now, also with IPPs, is increasingly in solar and wind energy.

Sound planning and effective procurement frameworks are required to accelerate investment. Historically, most power projects were procured through direct, non-transparent negotiations. A number of countries experimented with feed-in tariffs to procure renewable energy projects, but now reverse auctions are more common and are delivering effective price and investment outcomes.

The transmission sub-sector in Africa has not benefited from the same influx of private investment as generation. Sub-Saharan Africa still has a combined transmission network smaller than that of Brazil.

Ongoing efforts for regional electricity interconnections remain an essential tool for supporting optimal system performance on the continent, even as distributed energy resources and decentralised grids begin to play a leading role in the power system. African countries with small power systems stand to gain the most from additional transmission interconnections to create economies of scale and enhance their energy security. For larger systems, the opportunities for electricity trade are especially interesting in the context of geographically varied energy resources. Whereas some countries benefit from ample gas reserves, others have built or planned large hydropower reservoirs, or need to draw on flexible resources to balance downtime from variable renewable plants.

Sub-Saharan Africa's efforts on electrification have struggled to keep pace with demographic growth. However, since 2015 the region has significantly accelerated its rate of electrification. The UN's Sustainable Development Goal 7.1 – which calls for universal access to affordable, reliable, modern and sustainable energy by 2030 – has galvanised national governments as well as the global community in support of intensified electrification efforts. New initiatives have emerged such as the UN's Sustainable Energy for All and the African Development Bank's New Deal on Energy for Africa. A number of countries – most notably Kenya – have made impressive strides in new electricity connections.

3. Progress in Power Sector Reforms

Electrification challenges highlight the pivotal role played by utilities in Africa's power sector, whose performance remains disappointing. Since the 1990s, countries across the continent have faced a suite of power sector reform recommendations based on the Washington consensus aimed at independent regulation, restructuring of monopoly power companies through vertical and horizontal unbundling, and the introduction of competition and private sector ownership.

To date, no country in Africa has fully adopted the earlier consensus model for power sector reforms. Working wholesale or retail power markets are nowhere to be found in Africa, with the possible exception of modest amounts of cross-border trading in some of the regional power pools. Nevertheless, more than three-quarters of countries have established an independent electricity regulator and around two-thirds have permitted private sector investment in IPPs, mostly through a single-buyer model with the incumbent state-owned utility, although some countries are now also permitting direct contracting between IPPs and large customers. A small number of countries have unbundled their utilities, and even fewer have permitted private investment in their networks, mainly through concession arrangements.

4. Potential for a New Wave of Reforms Propelled by Rapid and Disruptive Innovation

A raft of new actors and technologies is bringing unprecedented disruptions to the African power sector. These offer a hopeful, albeit daunting, outlook for the continent to meet its energy needs. Accelerated innovations in power technologies, services and markets, correlated with a sea change in the global energy mix, are upending relative prices and market shares, and the location and patterns of energy production and use. As countries integrate increasing quantities of variable renewable energy generation, smart grids will emerge in a new landscape of electricity networks interspersed with mini-grids, community grids and distributed individual generation systems.

These trends will unlock a need for new grid management approaches and rules, including for utility business models. African utilities will need to speed-up unbundling efforts and improve the capacity of independent system and market operators. Traditional regulatory models also face new challenges in the rise of distributed energy resources. These transformations are being swept along with increasing digitalisation, the arrival of proactive, self-generating consumers (so-called prosumers), and the electrification of transport and other sectors.

Africa remains a global outlier in terms of inadequate investment in power generating capacity and networks, low levels of electricity reliability, access and consumption, poor utility performance and incomplete regulatory and market reforms. However, these relative disadvantages may also furnish African countries with greater agility to react to these new innovations. Africa has the potential to adopt and adapt to these innovations with relatively lower sunk costs and fewer stranded assets. The right response can catalyse significant progress in delivering adequate, reliable and clean electricity to power economic growth and to improve the welfare of its populations.