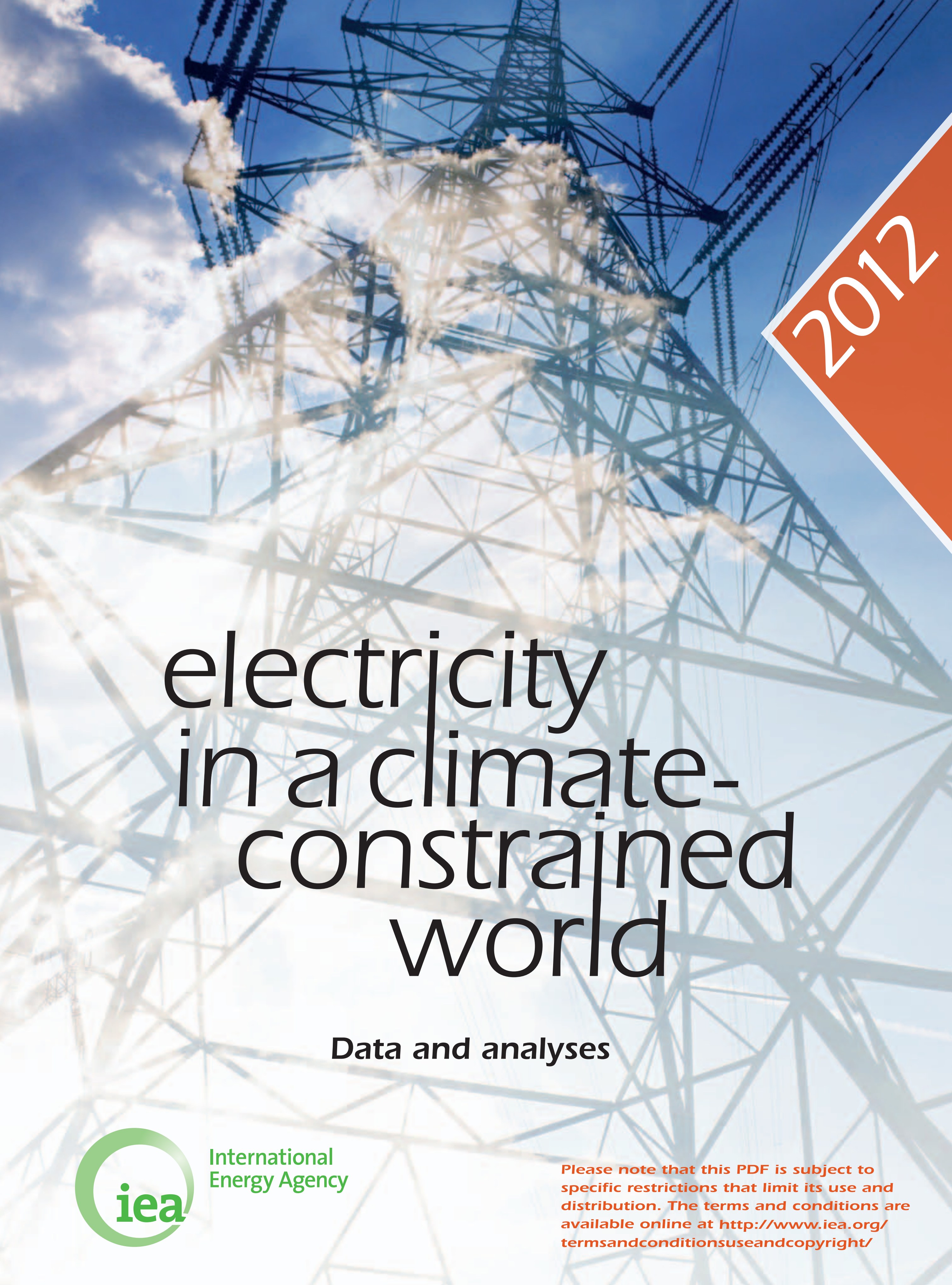

2012

electricity in a climate-constrained world

Data and analyses

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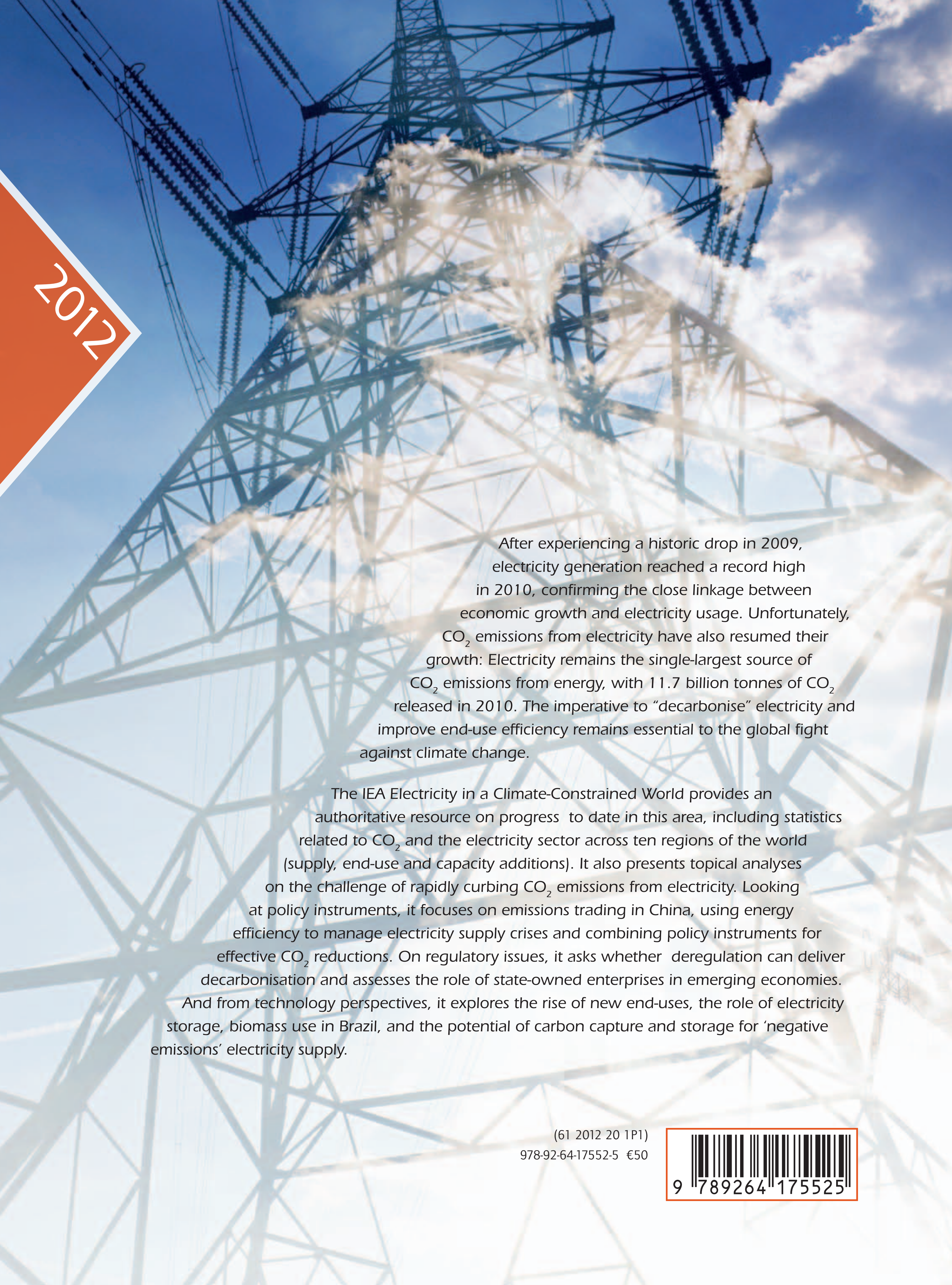

2012

After experiencing a historic drop in 2009, electricity generation reached a record high in 2010, confirming the close linkage between economic growth and electricity usage. Unfortunately, CO_2 emissions from electricity have also resumed their growth: Electricity remains the single-largest source of CO_2 emissions from energy, with 11.7 billion tonnes of CO_2 released in 2010. The imperative to "decarbonise" electricity and improve end-use efficiency remains essential to the global fight against climate change.

The IEA Electricity in a Climate-Constrained World provides an authoritative resource on progress to date in this area, including statistics related to CO_2 and the electricity sector across ten regions of the world (supply, end-use and capacity additions). It also presents topical analyses on the challenge of rapidly curbing CO_2 emissions from electricity. Looking at policy instruments, it focuses on emissions trading in China, using energy efficiency to manage electricity supply crises and combining policy instruments for effective CO_2 reductions. On regulatory issues, it asks whether deregulation can deliver decarbonisation and assesses the role of state-owned enterprises in emerging economies. And from technology perspectives, it explores the rise of new end-uses, the role of electricity storage, biomass use in Brazil, and the potential of carbon capture and storage for 'negative emissions' electricity supply.

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2012

electricity in a climate-constrained world

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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Foreword

The future direction of the electricity sector is closely tied to the constraints of climate policy. The title of this publication series *Electricity in a Climate Constrained World* is a reflection of the multiple aspects of the electricity and climate relationship: it is about delivering secure electricity supply while making the transition to low-carbon generation, protecting the world's climate through effective CO_2 reduction efforts, and ensuring the resilience of the energy sector against climate impacts.

One key aspect in both electricity security and in reducing emissions from the electricity sector will be to decouple economic growth from growth in demand. For the first time in several decades, the world consumed less electricity in 2009 than it did the previous year, largely as a result of the economic recession that hit many countries. However as GDP picked up in 2010, so did electricity generation. Our statistics show that the electricity use per unit of gross domestic product has barely moved over the past two decades.

Significant efforts have gone into improving the efficiency of our end-uses, yet demand is increasing because the practical and versatile nature of electricity make it an increasingly attractive option in almost all sectors, and new electricity end-uses are also appearing. Meanwhile, CO_2 emissions from the use of coal, gas and oil in electricity plants reached record levels in 2010. Electricity now accounts for almost 40% of global CO_2 emissions, against a third in 1990.

This year's IEA *World Energy Outlook* confirmed the critical role of electricity in reaching emission levels consistent with limiting the global average temperature increase to 2 degree Celsius: half of the required emission reductions are to be found on the electricity supply side (renewables, carbon capture and storage, nuclear or fuel switching); another quarter of the reductions should come from electricity savings. *Electricity in a Climate Constrained World* draws on IEA expertise to shed light on the policy and technology challenges that this represents.

The last few years have also provided multiple examples of the importance of a secure electricity supply in today's economies and societies: the earthquake that hit Japan in 2011 and forced a dramatic and rapid adjustment to electricity supply and demand; the black-out that struck India last summer; and hurricane Sandy, which also showed the impacts of climate on our energy systems. As the world is committed to some level of global warming, the energy sector and the electricity sector will be increasingly constrained by climate.

Electricity in a Climate-Constrained World 2012 is published under my authority as Executive Director of the IEA.

Maria van der Hoeven

Executive Director

International Energy Agency

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The publication would not have been possible without the contribution of IEA and other colleagues who authored concise and thought-provoking analyses on a diverse and fascinating set of topics. Thanks also go to the following IEA colleagues for their comments and contributions to the finalisation of the publication: Rebecca Gaghen, Laszlo Varro, Cheryl Haines, Marilyn Smith, as well as Muriel Custodio, Bertrand Sadin, Astrid Dumond and Jane Barbière.

Table of contents

Introduction: electricity and climate change "as time goes by"

Philippe Benoit, Energy Efficiency and Environment Division
and Richard Baron, Environment and Climate Change Unit

The sobering story continues

Electricity in a Climate Constrained World opens with a sobering message: the latest IEA energy statistics show that total energy-related CO_2 emissions reached their highest global level at 30.5 gigatonnes ($GtCO_2$) in 2010, a 5% increase from 2009. The 1.8% drop in 2009, largely a result of the global economic crisis, was unfortunately not indicative of a new trend. Electricity accounted for about half of the global growth in emissions in 2010.

The growth in electricity demand (and associated heat production) rose again in 2010, reaching an estimated 23 192 terawatt-hours (TWh), 6.5% above the 2009 level. Unsurprisingly, much of the growth comes from the most vibrant economies, especially China and India, where coal contributes most of the additional electricity supply. The rapid expansion in non-hydro renewables (with a record annual growth of 17.6% in 2010, an addition of 108 TWh), combined with additional hydro and nuclear generation (up 244 TWh), was unfortunately insufficient to match the additional demand for electricity: a staggering 1 412 TWh, more than twice the entire production of the African continent. As fossil fuels still dominate power generation on the global scale, 2010 broke another record in CO_2 emissions from electricity generation at 11.8 $GtCO_2$.

The same message is being repeated year after year: greenhouse-gas (GHG) emissions are growing, and more quickly than anticipated. This growth is taking us further away from the trajectory needed to limit the global average temperature increase to two degrees Celsius, the goal set by the Parties to the United Nations Framework Convention on Climate Change at their meeting in Durban in December 2011. Accounting for existing policies, and assuming that countries meet the emission pledges made in Copenhagen in 2009, the latest *World Energy Outlook* projections indicate that the world is currently headed for a four-degree temperature increase (IEA, 2011b).

Much of the source of this problem continues to lie within the electricity sector where, despite an impressive increase in renewable energy sources, coal dominates new generation, followed by gas. The implications are numerous.

Cleaner electricity key to the two-degree goal

The electricity sector needs to get cleaner, and needs to do it quickly. Observations from the last two decades are ambiguous: today's CO_2 emissions level corresponding to one kilowatt-hour (kWh) of electricity is higher than it was in 1990, but this indicator has been going down, albeit slowly, since 2007. Despite the impressive deployment of renewables, at 507 grams of CO_2 per kWh the global average fuel mix for power generation (and associated heat) remains much too CO_2-intensive.[1] According to the most recent IEA *Energy Technology Perspectives*' scenario for a two-degree average global temperature increase (the "2-degree scenario" or 2DS), electricity generation should emit 60 grams of carbon dioxide per kilowatt-hour (gCO_2/kWh) in 2050 and provide approximately 40 000 TWh of energy, 70% more than in 2010. Fossil fuels would only supply a quarter of total output (half coal, half gas), and 63% of the coal and 18% of the gas capacities would have to be fitted with carbon capture and storage (CCS) (IEA, 2012). The imperative decarbonisation of electricity would also promote biomass-based electricity fitted with CCS (BECCS), a means of generating electricity while removing CO_2 from the atmosphere (see Guivarch and Heidug, 2012 in this volume).

Although not without its challenges, the roadmap for global decarbonisation is well known. *Energy Technology Perspectives 2012* illustrates this roadmap and also explores alternative routes in case certain technologies do not deliver as expected (IEA, 2012). Delivering effective and least-cost decarbonisation of power generation will require effective energy efficiency measures to curtail demand growth; stable research and development (R&D) and investment frameworks to encourage low-carbon technologies; and a price on CO_2 to discourage fossil fuel

1. The growing percentage of renewable sources added to the energy mix represents progress, but we need to look beyond electricity generation to measure the CO_2 emissions intensity of our overall energy usage. Looking at the carbon intensity of primary energy use reveals that the energy sector's carbon intensity – or ESCI, measured as the ratio of energy-related CO_2 emissions to primary energy demand – has remained largely stable over the last twenty years, notwithstanding the advent of climate policies and the formidable expansion of renewables. The IEA is exploring how this measure can be used as an effective metric to measure our progress towards a low-carbon future.

plants (unless they rely on carbon capture and storage) in electricity policy environments where an economic instrument makes sense.

Making room for all: decoupling global inclusive growth from increased GHG emissions

Economic growth, an expanding middle class and poverty alleviation must be decoupled from GHG emissions growth. We have seen over the last 20 years a marked and welcome increase in the number of people living above the poverty line. According to World Bank estimates, there are currently 2.7 billion more people living above the poverty line than in 1990 (World Bank, 2012). With our current energy supply and overall consumption patterns, this increase in population and attendant increase in consumption has inevitably led to an increase in GHG emissions.

In negotiations under the United Nations Framework Convention on Climate Change (UNFCCC), this challenge of increasing emissions had been cast in equity terms between developed countries, the 'historical emitters', and developing countries, including many countries with large and growing economies that are projected to become major emitters in the future (the 'emerging emitters'). The Durban UNFCCC meeting has initiated an important shift away from the developed/developing taxonomy that underpins "common but differentiated responsibilities and respective capabilities", to one that recognises that these capabilities are changing dramatically and will continue to do so. How to achieve an equitable result is not obvious, but is clearly needed in order to move to more aggressive emissions reductions. Improving the quality of life of all, and particularly reducing the number of people in poverty, remain global priorities. Global inclusive growth should be our aim, but advancing in a manner that limits GHG emissions remains a challenge.

Change which starts at home will need to be financed from home: the importance of domestic finance

Energy Technology Perspectives 2012, World Energy Outlook 2011 and other IEA publications indicate that the greatest low-carbon investments will be needed in China, India and other non-OECD countries, as they will account for the vast majority of growth in primary energy consumption. Consequently, policies promoting low-carbon investments in these countries will be key. Although there is much discussion in international forums on how to increase financial flows from Annex I countries to support mitigation and adaptation in developing countries, especially those less developed, it is clear that domestic resources must play a critical role in the larger emerging economies. Recent estimates, such as the Climate Policy Initiative's useful attempt to measure current climate financing flows (less than USD 90 billion) or that of the Green Climate Fund (with its target taken with other Copenhagen pledges to total an additional USD 100 billion per year), are dwarfed by estimated low-carbon investment needs of over USD 1.5 trillion per year beginning in 2021 (IEA, 2012). China, India and other emerging economies will be focal points in the mitigation effort, and Chinese, Indian and other domestic funding will be central to financing those investments.

What goes around comes around: how climate change will impact electricity and the need to build resilience

Much of the discussion over the past decade has rightfully been dominated by the expected change in climate triggered by emissions from electricity and other energy activities. But we must also better understand how changes in climate – even under a two-degree scenario – will affect the electricity sector and how to make this sector more resilient to these climate-induced impacts.

The reality of climate change cannot be ignored. The global average temperature has already risen by 0.7 degrees Celsius in the last 100 years, and the projected increase in greenhouse-gas concentrations commits us to more in the coming years; the global mitigation effort will, in all likelihood, only affect the magnitude of the increase. Climate change is anticipated to affect our electricity sector through a variety of means:

- Electricity demand is expected to change, perhaps dramatically in some areas, as a result of increasing temperatures, changing weather patterns, etc. This will particularly affect cooling demand and other end uses.
- Electricity supply will be subject to changing conditions and production, including reduced efficiency of thermal plants, cooling constraints on thermal and nuclear plants, and pressure on transmission systems; electricity generation from hydro, wind and biofuel production will also be affected.
- Electricity infrastructure could be exposed to more numerous/intense extreme weather events that damage generation, transmission and distribution infrastructure and lead to outages.

Strengthening the resilience of the electricity sector to climate impacts – 'climate-hardening' our assets – needs to be initiated today in order to be adequately prepared for tomorrow's changes, even under a 2-degree scenario.

Some adjustments in technology and policy will be needed, especially since the electrification of our end-uses is an important component of an efficient energy strategy to cut global CO_2 emissions (see IEA, 2011a).

Understanding a four-degree increase: assessment, not acceptance

Given recent increases in emissions and current energy policies, the possibility of a four-degree increase in global temperature is growing. More resources need to be dedicated to identifying and assessing the potential impacts of this larger temperature increase on electricity supply and demand (and on other human activities). However, it is important to ensure that our capacity to evaluate and quantify these impacts does not inadvertently lead to acceptance of a four-degree scenario.

Electricity in a climate constrained world: new analyses from the IEA

Over the past year, the IEA has been active in a number of areas relevant to the broad electricity and climate policy agenda. The papers in this volume present important policy and technology issues in an attempt to move this agenda along. Addressing policy first, energy efficiency is treated from two perspectives: delivery of rapid electricity savings as a response to supply disruptions, and the need to address standby electricity use from computer networks. Other policy issues in this volume include: the role of state-owned enterprises in delivering climate-change mitigation in emerging economies; the implications of electricity market deregulation on decarbonisation; the design of an emissions trading system to deliver effective emissions reductions in China's power generation sector; and how policy instruments (efficiency, carbon markets, technology support) can be combined to formulate a least-cost, practical approach to lowering CO_2 emissions from electricity. With respect to technology developments, we first track our overall progress on the road to decarbonisation, then review the status of electricity storage, the potential for bioelectricity production from sugarcane in Brazil, and the future role of negative emissions technology in electricity, combining biomass use and CCS.

We hope readers will recognise both the magnitude of the challenge of continuing to deliver sufficient, secure, cost-effective electricity in a climate-constrained world, and the diversity of the solutions put forward to address it.

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ANALYSES

PART 1

Saving electricity in a hurry: an update

Sara Bryan Pasquier and Grayson Heffner, Energy Efficiency Unit

Prolonged electricity shortfalls can undermine economic activity by creating uncertainty in electricity supply and increasing electricity costs. In Saving Electricity in a Hurry (2005), the IEA presented case studies of countries that mitigated the negative impacts of electricity shortfalls by implementing emergency energy-saving programmes. These programmes used a range of tools such as rationing, price signals and information campaigns that stimulated and enabled consumers to curb wasteful energy practices, delay electricity-consuming activities to non-peak times and replace old technologies with more energy-efficient ones. Countries achieved energy savings ranging from 0.5% (France) to 20% (Brazil).

In the years since Saving Electricity in a Hurry was published, electricity shortfalls have continued to occur. For example, Japan is in the midst of perhaps one of the most severe electricity shortfalls in history. This article updates IEA analysis, highlighting findings from recent electricity shortfalls in Japan, the United States, New Zealand, South Africa and Chile. It draws on these case studies to reinforce three well-established steps to developing energy-saving programmes: (i) understanding electricity shortfall cause and duration; (ii) identifying energy-saving opportunities; and (iii) implementing a package of demand-side energy-saving measures. This article presents insights into best practice for emergency energy-saving programmes and recommends how officials can use communication, price, rationing and technology tools to achieve fast energy savings. It also describes how emergency energy-saving measures can lead to sustained energy savings.

Steps for mitigating electricity shortfalls

Recent electricity shortfalls reinforce three well-established steps officials should follow when developing an energy-saving programme:

- **Step 1:** analyse the cause and duration of an electricity shortfall before designing an energy-saving programme. Each electricity shortfall has a different character, and not all energy-saving measures are appropriate for every crisis.
- **Step 2:** identify opportunities for energy savings, including the sectors and end-users from which energy savings can be captured at the least economic, social and political cost.
- **Step 3:** implement a comprehensive and balanced package of energy-saving demand-side tools. These tools can include rationing, price signals, information campaigns, technology replacement and market mechanisms.

Step 1: analyse the cause and duration of an electricity shortfall

Analysing the cause and duration of an electricity shortfall is critical to determining which energy- saving measures should be put in place. A country facing a capacity shortage (*e.g.*, electricity shortfalls during peak hours) should focus on measures that decrease electricity consumption during those key times. Many Japanese industries, for example, have shifted operations to evenings and weekends when electricity demand is lower. Such load shifting helps to reduce demand during peak-power periods, but does not decrease overall electricity consumption.

In the case of an electricity shortfall caused by a drought and/or fuel disruption, such as the 2007/08 shortfall in Chile, officials must aim to reduce overall electricity consumption. Conservation measures such as turning off non-essential lighting, reducing shower length and modifying thermostats can be effective.

Calculating the anticipated duration of an electricity shortfall helps determine appropriate policy responses. Some measures can quickly reduce demand, but only for a short period of time; others take longer to put in place, but lead to longer-term savings. In Juneau, Alaska, officials knew that the electricity shortfall would end with the repair of the transmission line and short-term measures would be enough to mitigate the crisis. Ultimately, the repairs were undertaken within six weeks and the crisis ended. In Chile and New Zealand, officials had no influence over the droughts and focused on short- and medium-term energy-saving measures to avoid shortfalls. In Japan and South Africa, shortfalls result from long-term capacity constraints and require a range of demand- and supply-side solutions.

Various measures are known to be effective in the short, near and long term to achieve energy savings.

- Short-run, no-cost or low-cost changes: turn off lights, unplug electronics, use electricity at different times of day;
- Medium-term, medium-cost changes: install weather stripping, switch to CFLs, purchase a programmable thermostat;
- Long-term, infrastructure and policy changes: make window and building envelope improvements, strengthen energy-performance requirements in building codes.

Step 2: identify opportunities for energy savings

In planning an electricity-shortfall response, officials should quickly identify the sectors in which the greatest energy savings can be captured at the least economic, social and political cost.

Energy-saving opportunities vary widely depending on a country's economic structure, climate, social practices, etc. Consider, for example, the diverse economic structures of New Zealand and South Africa. Industry accounts for 37% of electricity consumption in New Zealand while the residential sector accounts for 33% (IEA, 2010c). In South Africa, the industry share is much higher (58%) and the residential share lower (20%). As a result, emergency energy-saving programmes in these two countries must necessarily differ.

Availability of detailed data on sectoral end-use consumption is critical to identifying energy-saving opportunities. The IEA recommends countries develop detailed electricity final consumption data on the major consuming sectors, including time-of-use variations. As these data can take years to collect, it is important to gather data on an ongoing basis and well in advance of a potential crisis. For example, customer surveys conducted in the years preceding the 2007/08 crisis helped to inform officials in Chile as to which sectors to target and which measures to consider during the electricity shortfall.

In Japan, the energy utility did not release sector-specific load curves; thus, it was unclear how much and in which sectors electricity savings were needed. The government had to convene experts to estimate load curves, predict energy-saving potential for each sector and develop specific recommendations for saving electricity. Had these data been available at the time of the electricity shortfall, the energy-saving campaign could have been more quickly implemented.

Once electricity consumption by sector and end-use is known, policy makers can focus on specific measures. Chile estimated lighting and refrigeration accounted for 60% of residential electricity consumption and targeted these two end-uses in its energy-saving programme.

Time of electricity use is especially important in countries facing capacity constraints. In South Africa, residential consumers use more electricity during the early morning and the late afternoon (ESMAP, 2010), a usage pattern that coincides with the timing of capacity constraints. Targeting electricity savings during those peak hours is an effective capacity-shortfall remedy.

Prior to implementation, promising energy-saving measures identified in priority sectors should be screened for feasibility and practicality. Regulations, infrastructure and political realities make some tools or measures impossible or ineffective in some communities. For example the residential sector in New Zealand held a large potential for energy savings, but the use of fixed-tariffs made it impossible to use price signals to influence residential-consumer behaviour. In another example, because alternative heating infrastructures were already in place in most homes, the majority of Juneau residents were able to save electricity by switching to other fuels for space and water heating. Such examples underscore the importance of flexibility in pricing frameworks and energy-using technology.

Step 3: implement a package of demand-side energy-saving tools

Analysis of electricity shortfalls underscores the importance of a comprehensive crisis management approach including measures to address both supply and demand. Supply-side measures include reducing energy production losses and removing transmission bottlenecks (ESMAP, 2010). The following five demand-side tools (Table 1) are the focus of this paper: price signals, behaviour change, technology replacement, rationing and market mechanisms.

These demand-side tools complement one another and are often used simultaneously to mitigate electricity shortfalls. Rationing, for example, is often implemented in conjunction with price signals. Information campaigns often reinforce technology replacement programmes. The mix of measures put in place depends on the shortfall context and opportunities for energy savings.

Price signals

Increasing the price of electricity can both inform consumers of an electricity shortfall and create incentives for users to reduce consumption. Literature on the price elasticity of demand makes it possible to estimate the amount of energy savings that will result from such price signals. Estimates of price elasticity derived from a variety of market circumstances and alternative pricing plans suggest that, in the short run, doubling prices can prompt electricity savings of 10% to 20% (Neenan and Eom 2008).

Table 1

Demand-side tools for managing electricity shortfall

Measure	Description	Prerequisites
	Price signals	
Industrial tariffs	Signal crisis intensity through prices.	Ability to adjust prices and advanced billing systems and metering.
Residential tariffs	Signal scarcity to residential users through prices.	Ability to adjust prices, data on residential price elasticity, political will, time of use (TOU) pricing, smart meters.
	Behaviour change	
Information campaigns	Raise public awareness, advocate voluntary energy-saving measures.	Ability to select/coordinate media and messages.
	Technology replacement	
Lighting replacement	Replace less efficient bulbs with more efficient ones (CFLs, LEDs, traffic lights, street lights, etc.).	Requires a promotion capability, financing scheme, distribution channels and a mechanism for disposing of old bulbs.
Appliance and equipment replacement	Replace targeted inefficient appliances and equipment.	Requires a promotion capability financing scheme, distribution channels and a mechanism for disposing of scrapped appliances.
	Rationing	
Voluntary rationing	Request voluntary reductions in electricity use.	Requires analysis to set reasonable reductions by customer type commensurate with economic impact.
Compulsory rationing	Mandate restricted electricity use.	Requires analysis to set reasonable reductions commensurate with economic impact, social safety nets and penalties for non-compliance.
Load shedding	Engineered electrical power outage.	Easy to implement but can cause large and unpredictable economic losses, considered a rationing tool of last resort.
Load control	TOU or dispatched current limiters or appliance control.	Need to identify end-uses to control, feasible control algorithms and compensation.
	Market mechanisms	
Bilateral trading of power quotas	Large energy users are afforded an opportunity to trade load reductions between themselves.	Requires contractual mechanisms, a third party referee, a basis for verification, and compensation.
Secondary markets	Over the counter or other mechanism for trading load reductions among multiple end-users.	Requires creation of a trading desk or OTC mechanisms, contracts, third party arbiter, and a basis for verification.

Source: adapted from ESMAP, 2010.

Price signals can better stimulate electricity savings under certain conditions. Price signals for end-users should be tied to a wholesale market mechanism to ensure prices reflect supply and demand. Many liberalised markets include a direct link between wholesale markets and large users, but may have no such link to smaller (residential and commercial) users. In New Zealand, liberalised electricity markets allowed shortfalls to prompt increased spot prices, which often translated into increases in retail prices for large industrial users. The same was not true for residential and commercial consumers that benefit from regulated electricity prices or are supplied on fixed-price tariffs.

Officials should ensure that the retail price structure and level (hereafter referred to as a tariff) prompt consumers to use electricity rationally and to invest in energy efficiency. In much of Latin America, increasing-block tariffs – in which the price of electricity changes with the level of consumption – help to ensure the poor can afford a minimum amount of electricity. For increasing-block tariffs, the price of electricity is lower for consumption up to a certain limit. Consumption exceeding this limit is charged a higher price. In order to preserve incentives for the efficient use of even small amounts of electricity, the price of the first block should be greater than the direct avoidable costs of the electricity (ESMAP, 2010).

Administrative, political and technical obstacles to changing electricity tariffs may make it impossible to implement large price increases in a short-term emergency situation. Even if tariffs are increased, there is a further delay as smaller users receive the price signals infrequently –when their monthly electricity bill is delivered. This delay can limit the impact of a price signal in short-term crises.

Shortfalls caused by capacity constraints can often be addressed through time-differentiated price signals. These price signals encourage reduction in energy use at certain times of the day and year when demand is highest and electricity shortages may exist (IEA, 2004). Several pricing options can reduce demand during peak hours:

- **time-of-use (TOU) pricing,** in which price varies according to a preset schedule, *e.g.* time of day, day of week and season;
- **real-time pricing (RTP),** in which the end-user price is linked directly to hourly spot prices in a wholesale market;
- **critical-peak pricing (CPP),** a hybrid of TOU and RTP in which a TOU rate is in effect all year except for a contracted number of peak days (exact dates unknown) during which electricity is charged at a higher price.

Technologies such as metering, communications and data-processing systems must be in place for these more dynamic pricing options such as RTP and CPP to work. Until recently, only a few customers other than large energy users have had access to such technologies.

In market-based electricity systems, shortfalls can result in price spikes. These price increases help to mitigate shortfall emergencies, but they can be devastating for low-income households. Direct and indirect subsidies can be used in conjunction with market-based pricing and rationing to induce energy savings while guaranteeing minimum electricity supplies for the poor. In Chile, the government allowed electricity prices to increase, but introduced a direct subsidy to protect poor residential consumers.

Behaviour changes and information campaigns

Experience shows that measures to request changes in behaviour, most often through tools such as information campaigns, can lead to large energy savings, especially during short-duration electricity shortfalls. Information campaigns can be used to build awareness about the electricity shortfall and advocate for a wide range of energy-saving actions – from transferring time of use, to decreasing or even eliminating use. Information campaigns supplement and reinforce all of the other demand-side tools.

When deciding what kinds of electricity-saving measures to ask of consumers, officials should remember that consumers are more willing to be inconvenienced during an electricity shortfall than in a normal situation (IEA, 2005). Requests for energy savings should reiterate that changes in behaviour will be needed only temporarily; however, information and awareness campaigns can also point out the continuing benefits of energy-saving practices even after the shortfall is over.

Information campaigns are very effective at stimulating energy-saving behaviour. They can be designed and launched quickly, and impact large number of consumers by reinforcing messages via multiple media (*e.g.* television, radio, newspapers, road shows and the internet).

When designing and implementing an information campaign, officials should focus on four areas: analysing the determinants of desired behaviour change; identifying the target group; choosing the most effective communications channels; and conveying urgency while keeping an upbeat tone (Mikkonen *et al.*, 2010).

Past campaigns demonstrate the very wide range of measures that can be implemented to achieve energy savings including resetting thermostats to reduce heating or cooling demand, turning off non-essential lighting, reducing shower time, drying clothes on the line rather than in a dryer, unplugging freezer, second refrigerator and other appliances, shifting hours of operation, etc.

Experience shows that every electricity shortfall is unique. The energy-saving measures promoted in information campaigns should take into account the electricity shortfall context and energy-saving opportunities, including how electricity is used and when it can be saved. Regular collection of data related to energy consumption will help campaign organisers better target the message and audience. Combining information campaigns with other tools such as price signals and incentives for purchasing energy-efficient technologies will increase overall energy savings.

Technology replacement

When electricity shortfalls are expected to persist, investing in high-efficiency or demand-response technology can complement price signals and information campaigns. Technology replacements take longer to implement than changes in behaviour, but they provide more reliable and sustainable electricity savings.

In some cases, the same implementation arrangements used to deliver non-emergency energy efficiency improvements can be used to deliver emergency technology-replacement programmes. These arrangements include trained staff, distribution networks, installation services and financing arrangements.

Some proven technology replacement emergency measures include:

- **deploying energy-efficient lighting,** especially compact fluorescent lamps (CFLs) and light-emitting diodes (LED);
- **replacing old equipment (ranging from refrigerators to traffic signals) with new,** more efficient technology;
- **retrofitting** and/or adjusting existing equipment to make it more efficient;
- **installing load-control devices** on selected appliances and equipment.

The 2011 electricity shortfall in Japan led to record sales of LED lighting. LED share of lighting sales reached 40%, double the pre-crisis share, and for the first time surpassed incandescent-lamp sales.

Rationing

Rationing allows officials to influence electricity consumption in a very direct way, by controlling the amount or timing of energy supply or obliging consumers to control their consumption subject to penalties (Table 2). Rationing can be specific, *e.g.* administrators decide which users will cut back, when and by how much (ESMAP, 2010), or more general, *e.g.* an entire geographic area, economic activity or load type is targeted. Rationing can be voluntary, although it is usually mandatory, and different approaches can be used for different consumers (residential, commercial, industry, public sector, etc.). To maximise efficiency and cost effectiveness, rationing should provide an incentive for consumers to reduce their lowest-value consumption (ESMAP, 2010). Price signals are often used simultaneously with rationing. In short, rationing is a flexible tool that can be tailored to help alleviate many energy-shortfall situations.

Because rationing strategies affect economic activity and livelihoods, they all have some level of negative effects on consumers and the economy. However, some rationing strategies are more desirable than others. Consumption rationing via quotas or entitlements is a commonly accepted approach because it is easy to understand and largely equitable. Under consumption rationing, an entire class of end-users (*e.g.*, households or businesses) are required to reduce their consumption by the same amount, subject to penalties. Another rationing strategy – block load shedding - is commonly implemented but should be avoided. Load shedding is easy to implement and can prevent system collapse by cutting off electricity to blocks of customers. However this form of rationing causes economic losses, reduces reliability and damages customer morale (Heffner, 2009). Reliance on load shedding also has negative environmental impacts, as it often forces customers to invest in polluting and expensive diesel-generated back up power supplies.

Consumption rationing has proven flexible and resilient in many electricity shortfall situations. In Japan, the government announced a consumption-rationing scheme for the summer of 2011 and published electricity-saving targets[1] of 15% for most sectors. A smaller target reduction rate of 5% to 10% was requested of certain vulnerable end-users such as hospitals, nursing homes, public transport and sewage and water utilities. For industry consuming more than 500 kW, the government implemented Article 27 of the Electricity Business Act, which authorises the government to restrict electricity use. The government

Table 2

Advantages and disadvantages of various rationing strategies

Rationing strategy	Advantages	Disadvantages
Block load shedding	Easy to implement	Unpredictable, inefficient, unpopular
Consumption rationing via quotas or entitlements	Largely equitable; easy to explain and implement	Inefficient, potentially harmful to vulnerable groups
Market-based rationing (quota and trade)	Efficient; sustainable; minimises economic impact of shortfalls	More difficult to implement; requires strong leadership and good technical capacity
Incentive/reward schemes (*e.g.* California's 20/20 rebate programme)	Equitable; sustainable; encourages energy investment	More expensive in the short run

Source: adapted from Heffner, 2009.

1. Officials had initially announced an energy-savings target of 25% for industry. This number was revised as TEPCO estimated it could increase supply capacity by 53.8 GW by the end of July, necessitating electricity savings of 10.3%.

is requiring this sector to cut electricity consumption by 15% compared with the same period last year (1 July-22 September) between 9:00 and 20:00 or face penalties of up to JPY 1 million (approximately USD 12 500) for each hour in which the target is not met.

In 2001, Brazil implemented a "quota system", which obliged each class of customer to reduce year-on-year monthly consumption relative to a baseline. Customers were subject to penalties for multiple months of non-compliance. Different customer classes were given different baselines, and the smallest residential customers were excluded altogether. This quota system, together with other demand-side tools, produced a 20% reduction in electricity consumption over a nine-month period (Maurer, Pereira and Rosenblatt, 2005).

Market mechanisms

Market mechanisms can be combined with other demand-side tools to lower costs, improve effectiveness and reduce economic impacts of electricity shortfall management. For example, a consumption-rationing scheme can be supplemented and improved by providing the means for bilateral trading or secondary markets for buying and selling power entitlements.[2] Such market mechanisms allow large energy users to exercise their relative preferences for power entitlements. Trading among large energy users willing to pay more for or be compensated for using less than the rationed amount of electricity is a much more economically efficient solution than applying a fixed baseline to all customers. This market-based supplement to the Brazilian quota system has been credited with reducing the impact on GDP of consumption rationing by as much as two-thirds, from 2.4% to 0.8% (Heffner, 2009).

The 20/20 rebate programme used during the 2001 California power crisis is another example of a market mechanism. This simple and ingenious market mechanism provided a 20% reduction on the unit electricity price for any customer who reduced their year-on-year monthly summer electricity usage by 20% or more. The programme was unique both in its simplicity and in the fact that participation was automatic and available to all customer classes. Overall, almost one-third of all customers received a rebate in at least one month, and many more customers were motivated to reduce their consumption. Analysis suggests that the rebate programme accounted for as much as one-third of the total energy savings achieved in California, at a cost of about one-third of the wholesale electricity price over the period (Goldman, Eto and Barbose, 2002).

2. Under bilateral trading, one energy user can purchase part or all of the power entitlement of another energy user. An organised secondary market makes it possible for multiple energy users to buy and sell power entitlements.

Conclusions and recommendations

No country is immune to electricity shortfalls: they can occur anytime and be caused by many factors. However, the economic and social impacts of such shortfalls can be minimised by implementing carefully planned emergency energy-saving programmes. The IEA recommends that governments lay the foundational work for emergency energy-saving strategies well before a crisis arises, and in doing so consider the following questions:

What kinds of electricity shortfalls are most likely given country context?

Governments should consider the possible causes and effects of electricity shortfalls as part of emergency planning for the energy sector. Electricity-shortfall planning is particularly important if a country is highly reliant on power sources whose availability may be affected by weather conditions (*e.g.*, New Zealand, Chile) or fuel imports (Chile). Governments should consider plausible scenarios for the scope and duration of electricity shortfalls, and develop contingency plans to manage electricity demand until the crisis ends.

If, for example, power plants are located on fault lines or tsunami-prone areas (Japan), transmission lines run through avalanche zones (Alaska) or demand growth exceeds supply investments (South Africa), leaders should consider scenarios in which capacity constraints lead to electricity shortfalls during peak electricity-demand hours. In these situations, measures should aim to cut electricity demand during specific times of the day.

How and when is energy used, and where are emergency energy savings possible?

Understanding end-user demand is critical to identifying opportunities for emergency energy savings. Systematic collection of indicators and compilation of demand curves by sector and subsector can inform long-term energy policy and expedite action in crisis situations (Chile). Having a detailed understanding of customer and end-use load curves and the potential of energy-saving measures can avoid delays in selecting and implementing effective emergency energy-saving programmes (Japan).

Data on electricity use is especially helpful when preparing contingency rationing schemes. In the event of a crisis, these rationing schemes can be quickly tailored to reflect the duration and severity of the electricity shortfall.

Which measures can lead to the most energy savings in the shortest time/lowest cost?

Once officials have a good grasp of how electricity is used – by whom, for what and when – specific energy-saving measures can be identified. In a country with heavy industry facing capacity peak-hour constraints, shifting industrial processes to the evening and weekends can be effective (Japan, South Africa). In a country with high residential electricity consumption, asking residents to change practices by taking shorter showers, line-drying their clothes, turning off lights in rooms not in use can, etc. can lead to large energy savings (Alaska, New Zealand). Some measures can produce results almost overnight, while other measures may take weeks or months. Some measures, such as block-load shedding, should be avoided except as a last resort (Japan, South Africa).

Which combinations of emergency energy-saving tools (price signals, information campaigns, technology replacement, rationing, and market mechanisms) are effective?

Not all tools are quickly available in every country. Governments should take into account country context (institutional frameworks and technical and human capacity), to ensure energy-saving measures are implemented. For example, regulations or lack of metering infrastructure may prevent tariff increases or dynamic pricing in certain sectors (Alaska, Japan, New Zealand, Chile and South Africa). A highly efficient lighting, appliance and equipment stock may limit energy savings possible through technology replacement campaigns (Japan), as can a lack of access to more energy-efficient products (Alaska).

If officials identify these limitations in advance, they can develop contingency regulations that will be enforced only in the event of an electricity shortfall. Japan, for example, created Article 27 of the Electricity Business Act before the 2011 shortfall, thereby authorising the government in crisis situations to limit electricity use in large industry (more than 500 kW).

Who will be tasked with managing the emergency energy-saving campaign? Which stakeholders will provide support to the lead, and how?

Case studies reveal many different models for entities tasked with planning, implementing and overseeing emergency energy-saving campaigns. Entities with some independence from government and energy utilities appear to be effective as long as they enjoy a strong mandate, capacity and support from government and key stakeholders (Alaska).

Prior to an electricity shortfall, officials should consider the form and duties of such entities, and consult eventual participants about their roles and responsibilities. This will help the emergency-management team hit the ground running in the event of a crisis.

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How can we make an Internet-surfing microwave oven go to "sleep"?

Vida Roside, Energy Efficiency Unit

This seemingly bizarre question appears to be totally out of place in a publication dealing with electricity and climate. Yet, it actually goes to the heart of an important emerging issue in the area of energy efficiency. While network-connected microwaves may seem to be more in place in a science fiction novel than in a kitchen, household appliances and consumer electronics are increasingly being connected to networks.[1] These "smart" network-connected appliances are dubbed as such due to their capability to access information from, as well as provide it to networks, other appliances, users and even electricity providers. Expert projections indicate that the number of networked appliances could reach 100 billion over the next 5 to 10 years (Hammersmith Group, 2010). Networked homes where a number of appliances are connected and controlled via a network already exist today. To stay connected to a network, most appliances today need to be switched to "on" to receive network signals. Consequently, they do not power down to lower energy modes and will consume the same amount of energy irrespective of whether they are being used or just waiting to be used.

Things that go blip in the night

In 2001, the International Energy Agency (IEA) published a book with this intriguing title. It explores the phenomenon of standby power and explains why little blinking lights on appliances are a cause for concern. Standby power consumption is the energy used by products when they are turned off but have the capacity to be quickly reactivated, usually via a remote control. In the late 1960s, manufacturers began designing televisions with "instant on" technology, eliminating the need for the one- to two-minute warm-up previously required. This technology began a trend towards a standby mode in other appliances.

Twenty years ago, concerns were raised about the energy implications of the increasing number of appliances that continued drawing power when not in use. Researchers discovered that a staggering 10% of residential electricity consumption was due to electronic equipment drawing power while waiting to be reactivated. Global standby power consumption reached 200 to 400 terawatt-hours (TWh) per year in just a few decades – equivalent to 1% to 2% of global electricity consumption, with corresponding emissions of around 100 to 200 megatonnes of carbon dioxide ($MtCO_2$) (IEA, 2009). If not addressed, global standby energy consumption of networked products is projected to reach 850 TWh per year by 2020 (Bio Intelligence Service, 2011), or approximately one-fifth of total final residential electricity consumption.

The range of standby energy consumption among similar products is considerable, with a twentyfold difference not being unusual. In extreme cases, the most efficient product in standby mode used over 60 times less power than the least efficient one.[2] Cost-effective design changes and

How small devices drive up energy demand

A television's set-top box is a classic example of a networked appliance. Set-top boxes transform signals from cable, satellite or other service providers into images on the television screen. More than 160 million set-top boxes were consuming energy constantly in the United States in 2010, all of them operating at near full power even when no one was watching TV or recording a broadcast. Collectively, when in standby, these boxes consumed an estimated 18 TWh in one year (equivalent to the annual output of six 500-megawatt [MW] coal-fired power plants), at a cost of USD 2 billion to consumers and CO_2 emissions of approximately 9.14 Mt (NDRC, 2011). The challenge is to get set-top boxes and other appliances to "go to sleep" – i.e., *power down to low energy modes – while still providing necessary network capability.*

1. In this article the term appliance is used to cover household appliances such as refrigerators and consumer electronics such as computers, as well as lighting products. In addition to appliances, equipment such as motors and heating and ventilation systems can also have network connectivity, but these products are outside the scope of this article. This article also does not cover network equipment such as servers and modems, whose network connectivity is an integral part of their primary function (the main energy efficiency issue with such products is therefore reduction of energy use in active rather than standby mode). The term device is used in this article to designate mobile products such as cellular phones, while the term product is used to cover both appliances and devices.

2. Standby power variations are shown to be in the range of 0.01 W to 30 W in Harrington and Nordman (2010). See also LBNL (2012), Standby Power Summary Table: http://standby.lbl.gov/summary-table.html.

technological improvements could cut this consumption by 75%, but in some cases energy savings as high as 90% are possible without any reduction in services or functionality (IEA, 2001).

In 1999, the IEA launched the 1-Watt Initiative which served as a rallying call for governments to ensure that no appliance draws more than 1 W when in standby mode. Many countries have implemented policies to this effect, and some countries, for example South Korea and the EU member states starting in 2013, are moving towards a 0.5 W limit. The impact of these measures on the market is already visible. For example, average passive standby power of televisions was reduced from over 4 W in 2000 to well under 1 W by 2011 in several markets (Figure 1).

Smart appliances

An increasing number of appliances are connected to networks. There are many different types of networks. The two most used network types are Local Area Networks (LAN) and Wide Area Networks (WAN). A LAN connects devices or appliances over a relatively short distance, while a WAN, such as the Internet, spans a large physical distance. While network connectivity enables a range of valuable services such as remote access and transferral of information, it also leads to increased standby electricity consumption.[3] To be part of a network, appliances need to be able to receive a signal from the network and react to it. This means that many networked appliances do not power down to lower energy-consuming modes: they remain in higher power modes for extended periods, often 24 hours a day, seven days a week. In a networked future, appliances that traditionally do not need standby power will require it.

All types of appliances could potentially have inbuilt network capability. The area of home automation could expand rapidly and could encompass communications, entertainment, security, convenience, and information systems. Currently, the types of electronic products that can connect to networks are very diverse, but growth is most substantial in home entertainment (such as set-top boxes, televisions and game consoles) and information and communication (phones, computers), as well as network products themselves such as servers and routers.

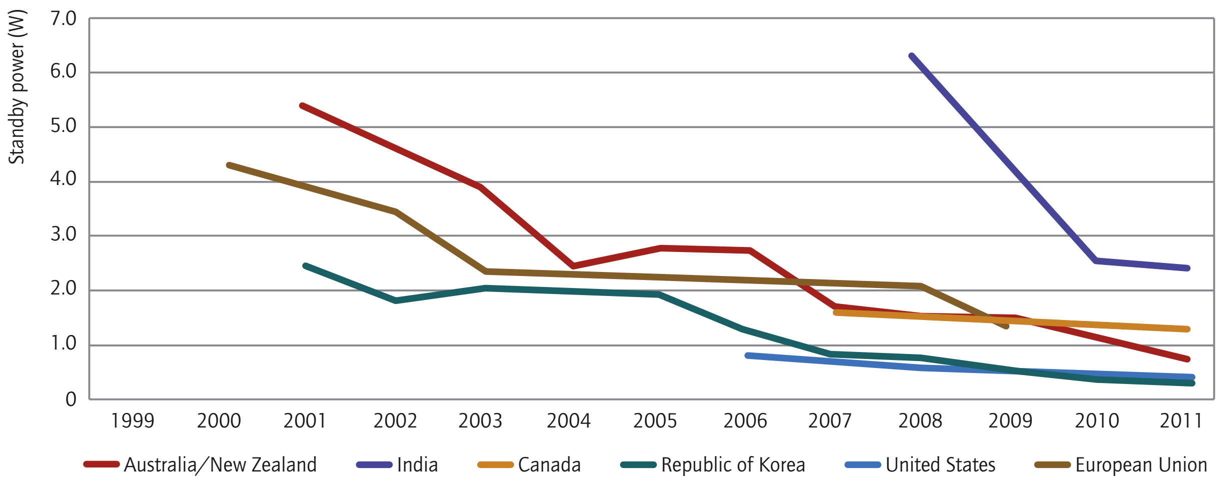
While communicating refrigerators may not be an integral feature of the typical kitchen for some time to come, there is a growing global appetite for smart products. A few years ago practically no one had heard of a smart phone, while in 2011 total shipments of smart phones exceeded 491 million units, 60% above 2010 (IDC, 2012). Today, almost half of all cellular phone users in the United Kingdom have smart phones (OFCOM, 2011). Globally, there are already more than 1.5 billion net-enabled PCs and 1 billion cellular phones with network capability (Hammersmith Group, 2010).

Smart systems

Uptake of smart appliances will increase in line with the roll-out of smart meters and the development of smart grids and smart buildings. Over 52 million smart meters

Figure 1

Average standby power of TVs (CRT, LCD and plasma)



Source: IEA Implementing Agreement for Efficient Electrical End-use Equipment (4E), Mapping and Benchmarking Annex 2012.

3. Network standby is defined as the various low-power modes of appliances connected to networks when not delivering their primary function.

will be installed in the United States by the end of 2012. In addition, 19.5 billion smart meters are scheduled for worldwide deployment between now and 2015 (Smith, 2012). There is a range of potential energy efficiency and climate benefits connected to smart systems. Smart metering provides end users with real-time pricing information which, coupled with differentiated pricing, could be instrumental in decreasing peak electricity consumption, as well as motivating consumers to reduce consumption overall. Pilot projects indicate that smart meters can cut residential electricity consumption by 10%. Home automation, *i.e.*, a number of appliances connected to a central hub, can potentially ensure better control and a more rational use of energy. Smart grids can thus pave the way to increased deployment of renewable energy.

Network-connected appliances can play an important role in smart grids. For instance, there is a research project in Australia on the development of smart fridges that are capable of maintaining average temperature while regulating power consumption from renewable energy generators. Such fridges could work as a distributed network, each fitted with control technology allowing communication via a network and smoothing out fluctuations in renewable energy supply by turning on and off at the right time.[4]

How much electricity will be consumed globally?

Globally, the standby energy consumption of networked products is projected to reach 850 TWh (which is just slightly less than the current annual electricity use of Russia) with corresponding emissions of 425 $MtCO_2$ per year by 2020 (BIO Intelligence Service, 2011). Based on IEA *World Energy Outlook 2011* projections on global electricity consumption, networked standby could constitute 3.5% of the total global electricity consumption of 24 213 TWh per year by 2020 under the current scenario. Deploying more efficient technology and integrating power management into appliances could cut this amount by 60%, a savings of more than the current yearly electricity consumption of France (BIO Intelligence Service, 2011).

These conservative estimates cover only the residential sector, do not include major technological shifts and do not factor in a predictably far higher rate of global uptake of networked appliances. Fuelled by the roll-out of smart grids and the development of smart buildings and home automation, an increasing number of products could have network capability in the near future. The area of home automation could expand rapidly as technologies converge to encompass communications, entertainment, security, convenience, and information systems. According to estimates, the smart household appliances market is projected to grow globally from USD 3.06 billion in 2011 to USD 15.12 billion in 2015. The global market by 2015 for smart washing machines could reach USD 3.54 billion, while the market for smart refrigerators is projected to reach USD 2.69 billion (Zpryme, 2010). In Korea, for instance, thousands of smart homes where appliances are connected to home gateways that can be controlled remotely via a smart phone already exist, and it is planned that 61% of the total households (10 million households) will have home networks in the near future (MOCIE and KEMCO, 2010). The global smart-home market is projected to undergo rapid expansion from a current market of USD 25 billion to USD 60 billion by 2017 (Juniper Research, 2012).

Simultaneously, changes in the role and use of information and communication technologies (ICTs) may lead to a radical increase of network-enabled appliances. ICT developments that may affect the uptake of net-enabled products and associated energy consumption include the Internet of Things (IoT), distributed applications such as cloud computing, Machine-to-Machine (M2M) communication and the further digitalisation of entertainment.

Future growth in network power consumption may be particularly rapid in developing countries and emerging economies, where market demand for net-enabled technologies is projected to increase dramatically. Estimates indicate that by 2020, almost a third of the global population will own a PC (currently one person in 50 owns one), 50% will own a mobile phone and one in 20 households will have a broadband connection (Climate Group, 2008).

How to reduce electricity consumption of networked appliances

A variety of technical solutions could radically slash networked standby power consumption. Significant savings can be achieved by lowering the power consumption in networked low-power modes, and by enabling products to power down to energy-saving modes as quickly as possible and remain in that mode for as long as possible. For consumers, however, standby power consumption is not a priority when making purchasing decisions. Furthermore, as home appliances and appliance networks become more complex, it is increasingly difficult for the end user to know which switches to turn off or which plugs to pull out to save energy.

Manufacturers produce products with features that consumers demand or are expected to demand. In some cases, there is a fortunate correlation between consumer

4. *Research conducted by CSIRO Intelligent Energy team.*

demand and energy efficiency. For instance, mobile products have become increasingly energy efficient due to consumer demand for longer battery life and smaller size. However, for appliances such as televisions and microwaves that are connected to the power system there is no such consumer demand. Some form of government intervention is needed to induce appliance manufacturers to decrease standby power consumption. A rapid response is required to avoid the projected doubling of standby consumption in the next ten years (Figure 2).

The development of effective policies in this area is challenging first of all due to technical complexity, and then because of the need to simultaneously address the design of both networks and appliances, while keeping the end user in mind. Interfaces between networks and appliances, appliances and other appliances, and users and appliances are all to be considered. The energy performance of an individual networked product is not only determined by its design and how it is used, but also by the type of network-appliance configuration it is part of and the software and network protocols used. The information exchanged between appliances or devices on a network is governed by rules set out in communication protocols. Communication protocols designed to promote energy efficiency can reduce the power needed for network links, allow products to go into lower power modes and reduce power in low power modes. Energy efficiency is typically not, however, a central feature in the development of communication protocols, with notable exceptions such as the energy efficient Ethernet. Users also need to be considered. Several technical options for reducing standby electricity consumption entail longer transition time (the time required for the product to "wake up" from low power modes and provide services to the user), which can be perceived by the user as a reduction in service quality. For some products, the transition time users are willing to wait is very short (*e.g.*, a television), while it is longer for other types of products (*e.g.*, a printer) (Krick *et al.*, 2011).

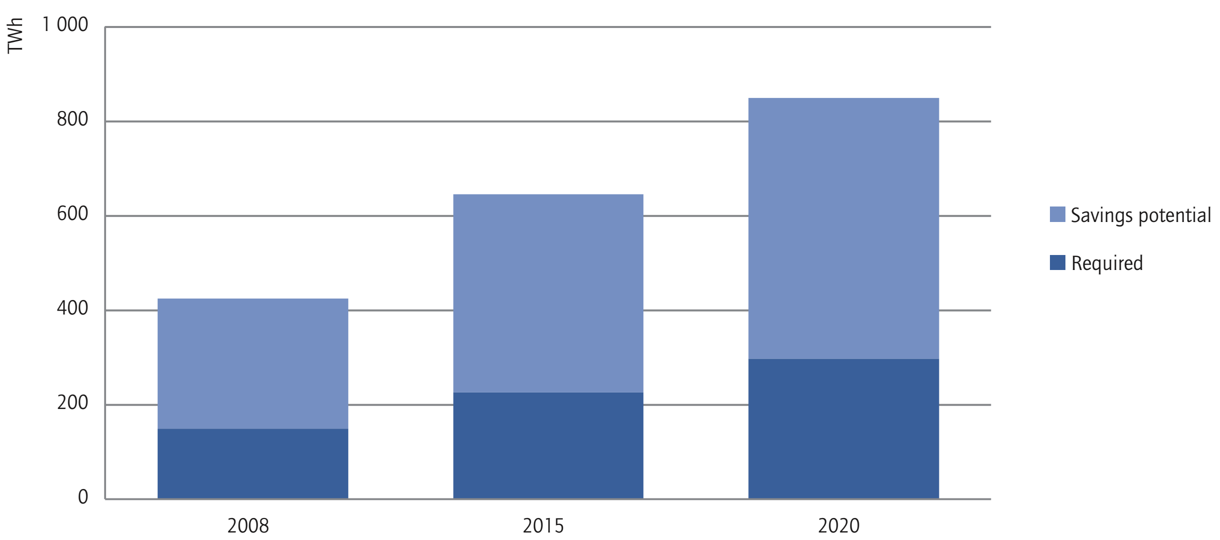
Policy making for efficient networked appliances

Policies are in the process of being developed in the European Union and Korea. Electronic appliances and ICT equipment are globally traded goods. International policy alignment is crucial to avoid a situation where manufacturers of smart appliances have to cater to a wide variety of differing policies in different regions, or where less efficient smart products are dumped in markets with less ambitious policies.

Progress in limiting electricity consumption of networked appliances requires robust technical processes, including systems for measuring and monitoring the associated energy consumption, both on a product as well as on an aggregated level. The types of data required to design, implement, monitor and evaluate effective policies aimed at reducing network standby power consumption must be identified. Dialogue with experts from governments, industry, standardisation organisations, and research institutes is also necessary.

Figure 2

Global standby power consumption of networked appliances



Note: residential appliances, based on estimation of 65% savings potential; includes use and deployment of best-in-class and near-to-market technology.

Source: BIO Intelligence Service, 2011.

How smart is smart and how to avoid the power-sucking hippopotamus

While ICT could deliver a 15% reduction in global CO_2 emissions by 2020 (Global Action Plan, 2009), the carbon footprint of ICT and ICT-enabled systems is growing rapidly. ICT-enabled solutions are attractive: they could boost energy efficiency and contribute to the accelerated deployment of renewable energy generation. However, it is crucial that these solutions are themselves as efficient and carbon-neutral as possible. The risk that the issue of network standby highlights is the creation of a system which itself consumes an unnecessarily high level of energy. "Smart" seems to be a misnomer for a system where everything must be left on to draw power all the time, but this does not have to be the case. The technical solutions for highly efficient systems exist, and further progress is possible. For instance, smart systems can be combined with energy harvesting, which is a process that captures small quantities of energy that would be otherwise lost as heat, light, sound, and vibration, to power processes or enable wireless sensor networks. Motivation is, however, an essential factor in the equation. Unless effective drivers in the form of regulations, agreements or incentives are created, we may end up with less-than-smart systems that, as explained in "Korea's 1-Watt Plan - Standby Korea 2010", are a "potential power sucking hippopotamus"(MOCIE and KEMCO, 2010).

To foster international dialogue and to explore and develop approaches to tackle the issue of excessive network standby power consumption, the IEA is currently working together with the IEA Implementing Agreement for Efficient Electrical End-use Equipment (4E) Standby Power Annex, Clean Energy Ministerial (CEM) and the International Partnership for Energy Efficiency Cooperation (IPEEC) task force Super-Efficient Equipment and Appliance Deployment Initiative (SEAD) working group on network standby. A publication on this topic is planned for 2013.

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State-owned enterprises and their domestic financial base: two keys to financing our low-carbon future

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The figures are daunting: the world will need to mobilise USD 140 trillion over the next four decades for investments in the power, buildings, transport and industry sectors to keep our energy consumption and related emissions at levels consistent with supporting global growth while maintaining the global temperature increase below two degrees (IEA, 2012, p. 137). State-owned enterprises (the "quasi-public" sector) will have a central role to play in funding and implementing these investments, and domestic financial resources will be a key source of capital; both of these factors are particularly important in emerging economies that are at the centre of any future efforts to limit climate change. The analysis in this article (i) introduces this quasi-public sector; (ii) provides an overview of global low-carbon funding needs and the increasing weight of non-OECD[1] countries; (iii) summarises the traditional public/private financing schematic, which fails to give adequate attention to the quasi-public sector; (iv) describes the important role of quasi-public enterprises in the sectors and emerging economies that are central to a low-carbon future; (v) delineates some of the dynamics that drive investment decisions by state-owned enterprises; (vi) highlights the importance of domestic sources of funding for these companies; and (vii) proposes several mechanisms to incentivise low-carbon investments by state-owned enterprises.

Presenting state-owned enterprises and the related role of domestic finance[1]

Discussions about the substantial funding needed for low-carbon investments have often emphasised the importance of private sector financing and the need for the public sector to adopt policies to catalyse these private flows. One segment that has not received the attention it merits is the "quasi-public" sector, namely the state-owned power, cement, steel, banking, transport and other enterprises which are dominant in many of the countries that are pivotal to achieving global low-carbon objectives, such as China and other emerging economies. Although there remain reservations regarding the economic efficiency of state-owned enterprises (see for example the discussion below regarding the non-commercial drivers of quasi-public sector corporate action), these companies are and will likely remain for the foreseeable future major actors in the energy producing and consuming sectors. As a consequence, it is important to motivate these quasi-public companies to invest in a low-carbon future. Furthermore (as also described below in this article), because these enterprises draw principally on funds from within their own country to finance their activities, greater attention should be paid to creating the frameworks to increase domestic resource mobilisation for low-carbon investments, in particular in emerging economies.

1. OECD is the acronym for the Organisation for Economic Co-operation and Development. The term "non-OECD countries" refers to those countries that are not members of the OECD, and includes many emerging economies and other developing countries.

Low-carbon investment needs and the increasing weight of non-OECD countries

As described in various IEA publications (notably *Energy Technology Perspectives 2012* and *World Energy Outlook 2011*), a massive amount of investment is required in the power, buildings, industry and transport sectors to support global growth in a manner that limits to two degrees the global temperature increase resulting from greenhouse-gas (GHG) emissions (the 2-Degree Scenario [2DS] in *ETP 2012*). Over USD 2 trillion is required per year through 2020, increasing to over USD 3 trillion per year from 2021 through 2030, and even larger amounts thereafter. Total investments through 2050 are estimated at USD 140 trillion (IEA, 2012) (Table 1).

Most of the investment will need to be made in emerging economies and other developing countries, not in OECD countries. For the current 2010 to 2020 decade, non-OECD countries represent over half of the investment needs in the 2DS (Table 2).

Under the 2DS, USD 116 trillion in investment will be required over the succeeding three decades, with over USD 70 trillion needed in non-OECD countries. China and India together represent about one-third of the total, and over half of the requirements for non-OECD countries (Table 3).

Subsumed in these aggregate figures are the large levels of investment that will be needed to support global growth even under scenarios that will yield higher global temperature increases. For example, when the investment

Table 1

Investment requirements in the 2DS

Sector	Investments (in USD billions)			
	2010 to 2020	2020 to 2030	2030 to 2050	Total
Power	6 500	8 700	20 700	35 900
Buildings	6 200	6 900	14 700	27 800
Industry	3 100	2 700	5 400	11 200
Transport	8 100	12 500	44 400	65 000
Total investment	23 900	30 800	85 200	139 900

Notes: industry includes iron and steel, chemicals, cement, pulp and paper, aluminium. Transport includes the cost of the powertrain only.

Source: IEA, 2012, p. 137.

Table 2

Total investment needs in the 2DS, 2010-20, for power, transport, buildings and industry

USD billion	Power	Transport	Buildings	Industry	Total all specified sectors
United States	850	1 300	900	250	3 300
European Union	950	1 800	1 300	250	4 300
Other OECD	650	1 150	900	250	3 000
China	1 800	1 450	900	850	5 000
India	500	300	300	300	1 450
Latin America	300	350	300	200	1 100
Other developing Asia	250	600	450	300	1 600
Middle East and Africa	450	550	400	500	1 900
Other non-OECD	600	650	700	250	2 200
Total all regions	6 350	8 100	6 100	3 100	23 700

Note: totals may not add up due to rounding.

Source: IEA, 2012, p. 139.

Table 3

Total investment needs in the 2DS, 2020-50, for power, transport, buildings and industry

Region	Total all specified sectors (USD billion)
United States	14 800
European Union	17 700
Other OECD	13 000
China	27 300
India	11 400
Latin America	4 600
Other developing Asia	7 100
Middle East and Africa	9 400
Other non-OECD	10 700
Total all regions	116 000

Source: IEA, 2012.

needs under the 2DS are compared to the requirements under a scenario that could result in a temperature increase of about six degrees (the 6-Degree Scenario [6DS] in ETP 2012), the former requires over USD 36 trillion from 2010 to 2050, or about USD 1 trillion per year in additional investments, principally for more efficient low-carbon technologies (Table 4). The relative shares for non-OECD countries (about 60%) and for China and India specifically (about 33%) of this additional amount mirror their shares of the overall total of USD 140 trillion over the same period.

The identification of the "additional" investments required to achieve the 2DS as compared to a business-as-usual 6DS reveals areas where incremental efforts will be required (*e.g.*, the additional USD 2.25 trillion in power sector investments in China and India). However, whether investments are viewed as "within" or 'additional to" the business-as-usual scenario, they will need to be funded. Accordingly, the critical target from a resource mobilisation perspective is the entire USD 140 trillion in investments needed through 2050.

As these figures indicate, the total financing effort at a global level under the 2DS will be massive. Annual investments in 2035 are projected in the range of USD 4 trillion, approximately what China currently invests yearly in all sectors.[2] More than USD 30 trillion will be required over the next 40 years in the power sector alone, with about USD 20 trillion in non-OECD countries. Even when looking at a sub-sectoral level and an annual basis, the figures remain large; for example, about USD 330 billion per year will be needed in developing countries for power generation.[3] The next section looks at the current discussion on possible financial sources to provide this funding.

A traditionalist's view of financing: the public/private schematic

Much of the discussion on funding investments for a low-carbon future has focused specifically on the need to mobilise private sector capital – a discourse fuelled in part by the budgetary constraints that will limit public sector financing for low-carbon investments in many donor countries within the OECD. This discussion reflects the 'traditional" market allocation of responsibilities between the public and private sector, in which the former provides the policy conditions to facilitate and support investment by the latter. Indeed, the private sector will need to fund much of these investments, including in the buildings sector and in the vehicles sub-sector.

As a corollary to this type of approach, the discussion often revolves around the reduction of political and regulatory risk. This mitigation is particularly emphasised when considering the needs of OECD investors for projects in developing countries. Insurance and political risk mitigation agencies – such as the US Overseas Private Investment Corporation, the Multilateral Investment Guarantee Agency, the World Bank with its guarantee programmes

Table 4

Additional investment needs of selected countries in the 2DS compared to the 6DS, 2010-50, for power, transport, buildings and industry

USD billion	Power	Transport	Buildings	Industry	Total all specified sectors
United States	1 150	1 900	1 500	200	4 800
European Union	1 200	2 200	2 300	200	5 900
Other OECD	600	1 500	1 700	200	4 000
Sub-total OECD					14 700
China	1 200	4 500	1 550	400	7 700
India	1 050	1 900	750	200	3 900
Latin America	300	500	600	100	1 500
Other developing Asia	100	700	1 300	100	2 250
Middle East and Africa	1 300	800	900	100	3 150
Other non-OECD	400	1 550	900	100	3 000
Sub-total non-OECD					21 500
Total all regions	7 350	15 700	11 550	1 600	36 200

Note: totals may not add up due to rounding.

Source: IEA, 2012, p. 139.

2. Total investment in China was 54% of its GDP in 2011, i.e., about USD 4 trillion (CIA, 2012).

3. Drawn from IEA, 2012.

and export credit agencies – often become important players in this environment. This focus on political risk mitigation frequently results in complex project structures with heavy transaction costs.

Many workshops and roundtables are held where various traditional players – private sponsors and banks from OECD countries, multilateral development banks, civil society, and government representatives from both OECD and non-OECD countries – discuss how to increase funding for low-carbon projects in developing countries. Many interesting and novel ideas and initiatives have been emerging from these efforts, such as the OECD effort to target pension funds that hold trillions of dollars, or the blending of different financial instruments with climate-specific products (including under the Clean Development Mechanism).

Total annual net capital flows into emerging economies for investments in all sectors has been estimated at about USD 1 trillion for 2011, including over USD 900 billion in private flows (IIF, 2012), of which only a portion was for green investments. The Climate Policy Initiative (CPI) provides a revealing estimate of the amount of OECD monetary flows to non-OECD countries specifically for this area of climate change mitigation. In its 2011 report, *The Landscape of Public Finance*, CPI estimated that there were about USD 90 billion in 2010 in monetary flows from developed to developing countries for GHG mitigation (Buchner *et al.*, 2011).[4] In parallel, the discussions at the Copenhagen Climate Change Conference in 2009 surrounding the Copenhagen (COP 15) pledges and the Green Climate Fund (GCF) proposed an aggregate of USD 100 billion per year in additional funding from developed countries beginning in 2020 to be provided through a variety of mechanisms, including carbon markets, investments and grants; this funding is to be split between support for mitigation and adaptation, and targeted at less developed countries.

While these numbers are large in absolute terms, they remain small relative to the overall investment requirements under the 2DS. Neither international capital flows nor the GCF can be expected to fully fund the USD 3 trillion per year required for investments beginning in 2021, many of which will need to be made in China and other emerging economies. Much of the funding must be found elsewhere, notably from domestic resources and, as described in the next section, many of the investments will be made by state-owned enterprises that dominate the energy producing and consuming sectors of these emerging economies.

4. The analysis provides an aggregate figure of about USD 97 billion, which includes some limited financing for adaptation, as well as some flows among developing countries. After deducting these amounts, the remaining figure for flows from developed to developing countries specifically for mitigation is closer to 90 billion.

The quasi-public sector: a major player in a low-carbon future

State-owned enterprises constitute a major portion of the national economy of many countries. Their weight in the economy varies by country, with a relatively important role in many emerging economies. For example, it has been estimated that state-owned enterprises in China are responsible for 35% of all the fixed-asset investments made by domestic companies (*The Economist,* 2012). These enterprises are especially active in high-carbon sectors, such as the power generation, oil and gas, transport and other energy-intensive sectors of emerging economies such as China, Russia and Brazil, as well as in various OECD countries. State-owned enterprises are also major players in the financial sector that helps to fund investments.

In Brazil, Eletrobras and its various subsidiaries remain the dominant force in generation and transmission, with additional large holdings in distribution; it is by far the largest energy company in the country alongside the other large-scale state-owned energy company, Petrobras, which operates in the oil sector. In Mexico, Comisión Federal de Electricidad operates as a vertically integrated power utility in a sector where private participation is largely limited to independent gas and wind power producers (IPPs). In India, Power Grid Corporation of India Limited is at the centre of the electricity system. In China, the power generation subsector is dominated by public-sector companies, and the state-owned national grid company connects over a billion customers. State-owned enterprises are also major players in some OECD countries, such as France with its power utility Électricité de France (EDF), and Norway with its national oil company, Statoil.

The major role played by state-owned industrial enterprises also extends to the financial sector: national development banks provide large amounts of financing. For example, the Brazilian development bank, *Banco Nacional de Desenvolvimento Economico e Social* (BNDES), lent nearly USD 80 billion in 2011, more than the World Bank and the Inter-American Development Bank combined. Quasi-public financing for low-carbon investments, specifically in electricity, is also large: in 2009, BNDES provided over USD 8 billion to finance renewables and energy efficiency, including over USD 4.7 billion for medium and large-scale hydropower plants (BNDES, 2012). Funding of large-scale investments in power and other sectors can often involve one quasi-public enterprise lending to another. In China and other non-OECD economies generally, much of the USD 330 billion per year required for low-carbon investments in power generation will likely come from domestic state-owned banks for investments made by state-owned utilities.

In addition, state-owned enterprises are major consumers of energy, especially in the energy-intensive cement, steel and other heavy industry sectors in China and elsewhere. When combined with the more traditional public sector (schools, hospitals, public administration buildings, military, etc.), the public and quasi-public sectors combined are a major consumer of energy and, consequently, are important players in end-use energy efficiency actions that are central to lowering GHG emissions.

While recognising the preponderance of state-owned enterprises in many of the sectors that are central to low-carbon investments, it is important to note the concerns that have repeatedly been raised regarding the inefficiencies of these companies, precisely because of the non-commercial nature that often characterises the incentives frameworks of government-owned companies. This aspect is described below.

What are state-owned enterprises looking for?

In order to encourage greater investment by the quasi-public sector in low-carbon assets, it is important to understand some of the drivers of state-enterprise action and how they differ from those that influence private sector companies.

While private sector companies typically look to maximise profitability and, by extension, equity value for their shareholders, state-owned enterprises respond to a variety of dynamics which reflect to varying degrees three principal factors: governmental shareholding, public service and, similar to private companies, the commercial/industrial nature of their operations. State-owned enterprises answer to a political board of directors. This board of directors is generally populated by government officials and other political stakeholders who, typically, are not seeking the equity maximisation that is critical to a publicly listed private company. In fact, profitability is often not a key performance indicator for state-owned enterprises. Rather, these companies are driven by considerations such as greater service provision, as well as political goals (*e.g.*, ensuring quality sewage service for neighbourhoods with key political constituencies), and often fill employment and other objectives. Many of these enterprises operate in non-competitive domestic markets (*The Economist*, 2012).

An important related distinction of the quasi-public sector is the role of the government in providing funding. Although state-owned enterprises operate in commercial sectors where they generate goods for sale in both domestic and international markets, these revenues are frequently supplemented by cash support from the government (including indirectly through national development bank loans).[5] This is often the case in the energy sector, where large capital investments are required. While state-owned enterprises typically benefit from privileged access to government funding, the government often makes demands on these enterprises; for example, governmental policy in many countries provides for below-cost electricity tariffs, and in exchange governments agree to allocate funding to compensate the utilities (albeit often inadequately).

One of the major differences between state-owned power utilities and private electricity providers (even those operating in highly regulated environments) is that the former often appear to be more interested in asset expansion projects than equity value maximisation. As a result, a state-owned enterprise may be interested in building a larger, less profitable power plant that provides more electricity to the economy. Indeed, it seems at times that "bigger" rather than "more profitable" is the touchstone for state-owned enterprises.

In the financial sector, private and state-owned banks also differ. The latter are often focused on financing domestic investments that support an important national goal. For example, many national development banks will finance hydropower and other renewables plants with preferential support systems. The financial segments of the quasi-public sector often act in concert with state-owned industrial companies to promote government objectives (such as the construction of hydropower plants in Brazil). One critical distinction between these state-owned banks and foreign private banks especially is the assessment of domestic political risk, which plays a less important role in the credit analysis for state-owned banks but can be a major hurdle for foreign banks in financing large-scale, long-term investments.

The distinction between private and state-owned companies has often been at the heart of World Bank efforts to promote economic reform. Since the 1990s, the World Bank's strategy has been to encourage governments to transform inefficient state-owned enterprises into more productive actual or virtual private sector companies through performance contracts, management contractors and other tools, often with a view to eventual sale to private investors. These efforts at encouraging reform of state-owned enterprises have met with varying degrees of success – although it can be argued that the broader overall effort to open up and diversify economies has led to strong growth in many emerging economies (such as Brazil and Mexico) and developing countries (such as Uganda and Tanzania) notwithstanding the continued presence of numerous state-owned enterprises in these countries. In the more recent past, state-owned companies have regained some ascendency. This evolution is particularly evident in the petroleum sector, where state-owned oil companies now hold over 70% of oil reserves (Jaffe, 2007).

5. There are, of course, situations where governments inject funding into private sector companies, such as the US government's injection of moneys into the auto industry in the 1980s and again in the 2000s.

In describing the quasi-public sector, it is important to recognise that not all companies behave the same, and that this will vary by country and by sector of activity. For example, Norway's state-owned oil company, Statoil, prides itself on its "commercial" approach, notwithstanding its state ownership. PEMEX in Mexico plays a critical role for the population in maintaining national sovereignty over its petroleum resources (as witnessed in the heated debates in 2008 surrounding the proposed reforms to allow PEMEX to partner with private sector companies to develop its oil reserves), and in providing the population with gasoline at controlled prices. Different development banks around the world agree to fund public sector projects after different degrees of due diligence. China continues to rely heavily on a centrally planned expansion strategy for its power sector, in which individual state-owned generators submit proposals for new plants, including running hours and price. Approval of a proposal carries the prospect of a loan from a state-owned bank. Eletrobras in Brazil operates in a more liberalised environment, with public and private sector companies partnering and competing.

The structure, governance, operating environment and corporate culture of state-owned enterprises in emerging economies differ in many ways from those that characterise the typical OECD investor exploring a low-carbon investment opportunity in a developing country. These factors should be analysed more fully to inform the development of more effective incentives to encourage low-carbon investments by these enterprises.

Funding quasi-public sector investments: the importance of domestic resources

Much of the revenue of state-owned enterprises is generated from domestic resources. There are three basic sources of money. First, most of the actual money available to these enterprises is internally generated from the sale of goods and services into the domestic market, such as kilowatt-hours of electricity, litres of gasoline, transport services, cement, etc. This dimension is often not sufficiently emphasised in evaluating potential funding sources. The second is funding provided by the government, either directly through equity injections or indirectly through targeted loans provided by quasi-public financial institutions. The third is funding provided from the domestic capital market, including through commercial loans and the issue of bonds to mobilise private capital.

A balance-sheet analysis of many major state-owned power utilities (such as Comisión Federal de Electricidad in Mexico, Eletrobras in Brazil or Power Grid Corporation in India) points to the preponderance of domestic funding sources. Direct foreign investment and international lending (including from multilateral development banks) do have a role to play, but the weight of these sources is small compared to the funds generated from the sale of goods in the domestic market and from capital mobilisation from the domestic financial sector. For example, in 2008 Eletrobras received over USD 6.5 billion from the domestic sale of electricity and raised less than one-sixth of that amount from foreign borrowings that same year (Eletrobras, 2009).

Because state-owned enterprises in emerging economies will have an important role in funding low-carbon investments and because they rely heavily on domestic financial resources, more attention should be paid to developing mechanisms to mobilise domestic capital in these economies for low-carbon investments.

How to get the quasi-public sector to invest in a low-carbon future

There are various ways to encourage low-carbon investment by quasi-public entities, several of which apply equally to private sector companies.

Government policy. Arguably, the first, second and third keys to encouraging low-carbon investments by the quasi-public sector lie with government policy. A state-owned enterprise generally (although not always) responds to its government shareholder. Governments should adopt clear policies that promote sound low-carbon investments, and reinforce these with clear directions issued to state-owned enterprises and the banks that finance them. Governments also need to follow up by monitoring and evaluating enterprise action to ensure that the right low-carbon investments are made and then properly implemented.

Profitability. In spite of the public-sector aspect of state-owned enterprises, profitability generally remains a concern: these companies face the basic commercial constraint of generating revenues to finance expenditures, in particular when government injections of capital are limited. Accordingly, it is important to establish a pricing and overall commercial/financial environment that allows for profitability (including through various financial support mechanisms such as off-take agreements with other state-owned enterprises). Often, even state-owned enterprises will resist investments that result in losses in spite of government preferences. However, in contrast to the private sector, investments do not necessarily need to be the most profitable if they are supported by a clear government directive. Similarly, generating dividends for shareholders and bonuses for company executives are less of a driver for managers in state-owned enterprises which use different incentives and compensation systems than private sector companies.

Predictable and balanced regulatory frameworks. A sound regulatory environment that provides for predictability can incentivise effective action by state-owned enterprises. Investments in low-carbon technologies are often capital-intensive, involving long construction periods and requiring numerous years of profitable operation to repay the initial investment; a predictable framework is particularly important in this context. In prompting state-owned enterprise action, however, it is important to draw the right balance between promoting sound investments and subsidising inefficient ones. In these companies, the challenge often is to choose the right investment, and then to give managers the reassurance that the plant will be built and that it will generate sufficient revenues to keep operating.

Promoting a shift from brown energy. Financial and other penalties/incentives to discourage investments in carbon-intensive activities in favour of low-carbon ones can be useful tools to drive state-owned enterprise action. Incentives can include feed-in tariffs, carbon pricing and cap-and-trade schemes, fiscal advantages/penalties, import and export duties, and targeted government outlays. State-owned enterprises do respond to signals and incentives, but their mode of response differs somewhat from a private sector company's reaction to classic market levers (for example, as noted above, government policy directives are arguably as influential for state-owned enterprises as carbon or other pricing is for private sector companies).

Domestic resource mobilisation. Many state-owned enterprises rely on domestic resources, rather than direct foreign investment or other international monetary flows. It is therefore important to unlock domestic capital where possible to fund low-carbon investments. Tools could include national development bank funding, development of local bond issues, and mechanisms to attract capital from local pension funds. Because of the role the domestic private sector can play in funding state-owned enterprise investments, it is important to foster an environment in which private sector financiers feel confident that a government enterprise will repay its obligations (*i.e.*, mitigating the political risk of non-payment by the quasi-public sector).

Domestic public financial institutions. National development banks are particularly important, but there are also other public sector financial institutions whose resources can be mobilised to support low-carbon investments, such as public pension funds; these sources merit further exploration. Again, the right balance must be drawn between financial mechanisms to support low-carbon investments (including potential concessional lending) and sound credit policies that support the financial sustainability of the bank or other funding institution.

Foreign investment. Foreign financing and investment are significant sources of funding for low-carbon operations. Traditional investment flows from OECD to non-OECD countries will remain important, as will investments between OECD countries (*e.g.*, bond issues to finance power sector investments that attract foreign investors). Greater attention should also be paid to promoting funding among non-OECD countries, and to the potential to increase flows from these countries into the OECD.

National/sub-national layers. One impediment to comprehensive state-owned enterprise action is that many companies are owned and operated by different levels of government, including national, provincial and municipal entities. Sending a consistent directive through all levels of government to promote low-carbon investments is important.

Green as a public good. Finally, as is implicit in the term "quasi-public", the actors do have a mandate of public support. Inculcating within state-owned enterprises a culture of service to a low-carbon future will likely be an important element in transforming government policy directives into sound concrete actions.

Conclusions: the quasi-public sector – the non-traditional investor who will actually fund much of our low-carbon future

This article is an initial foray into the importance of state-owned enterprises in funding our low-carbon future. Large emerging economies especially are where a lot of the investment in low-carbon technologies will be needed. Power, transport and energy-intensive industries such as cement are the high-carbon sectors that are most in need of mitigation efforts. It is in these sectors in these emerging-economy countries that state-owned enterprises are particularly dominant. While pursuing reform of state-owned enterprises for overall economic efficiency goals, we must in parallel look to influence the carbon-related investment patterns of these companies. We need to better understand the corporate decision-making processes, the drivers of investment selections, and the modes of operation of these enterprises in order to develop sound and effective incentive frameworks to promote low-carbon investments. Because these enterprises differ depending on the country and sector contexts, there is no "one-size-fits-all" solution from a policy perspective. There are, however, various aspects that are largely common to these enterprises, including the importance of domestic resources in funding their investments. Greater attention needs to be given to this quasi-public sector that will be central to our efforts to achieve a low-carbon future.

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From deregulation to decarbonisation of the electricity sector

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Over the last 25 years, electricity sectors in many countries have been restructured and liberalised with the objective of improving their performance. This liberalisation has succeeded in reducing costs and attracting investments in new generating capacity (mostly in gas-fired power plants), although some challenges remain. More recently, growing concern about climate change has led to the development of renewable-energy policies. Despite the introduction of carbon dioxide (CO_2) pricing in Europe, attracting sufficient investment in low-CO_2-emitting power plants has required greater regulatory intervention, while at the same time the increasing share of variable renewables requires further integration of the electricity markets. This paper examines how these various climate-change and industrial policies interact with the electricity markets, and identifies challenges as the electricity sector works toward decarbonisation.

The era of vertically integrated monopolies

After World War II, rapid economic growth prompted governments to meet fast-growing electricity demand with a non-competitive environment. Under the umbrella of public service in some countries, vertically integrated regulated utilities, both private and state-owned, prospered. British Energy, Electricité de France (EDF), Edison, Exelon, Rheinisch-Westfälisches Elektrizitätswerk (RWE), Tokyo Electric Power Company (TEPCO) and Korea Electric Power Company (KEPCO) have all benefitted implicitly or explicitly from state guarantees allowing them to finance massive investments at relatively low cost. Much of installed coal and nuclear generating capacity, the backbone of electricity systems, has been inherited from this period.

But during this time of rapid growth, utilities paid too little attention to efficiency issues. Some of them were slow to adapt to the decelerating electricity demand of the late 1970s and early 1980s and continued to invest, creating excess capacity. Others were accused of inefficient overspending ("gold-plating"). Many were perceived to have poor operational efficiency due to excess staff, mediocre service quality and low plant availability.

In addition, since optimisation of electricity generation and networks was realised by geographic monopolies over a specified area – generally a state – there was little development of inter-regional electricity trade. As a result, international interconnections have been developed for system supply security reasons, *i.e.* mutualisation of primary/spinning reserves. This has resulted in very divergent electricity mixes, with some countries dominated by coal and others by nuclear or hydropower generation.

The standard prescription to deregulation

The United Kingdom was the first country to restructure and privatise its electricity sector. In 1990, the assets of the Central Electricity Generating Board (CEGB) were broken up into three new companies: Powergen, National Power and National Grid Company. Price regulation was removed and free entry in generation and commercialisation activities introduced. The only remaining monopoly segment was the transmission network owned by the National Grid Company, which was too costly to duplicate.

This model of electricity market restructuring has subsequently been applied in many OECD countries and states, including New Zealand, part of Australia, the province of Ontario in Canada, the Nordic countries, Spain and the Netherlands. Several South American countries (Argentina, Chile, Brazil, Peru) have also followed the same restructuring principles, although the full standard prescription package has not always been implemented everywhere.

In the United States, only about half the states have reformed their electricity industry. During the electricity crisis in California in 2000, market manipulations associated with poorly designed regulation caused a shortage of electricity. Since then, most of the remaining states are no longer considering deregulation. Most deregulated markets in the United States, including the Pennsylvania, New Jersey and Maryland (PJM) interconnection, New England, Electric Reliability Council of Texas (ERCOT) and Midwest Independent Transmission System Operator (MISO) zones, have adopted the standard market design proposed by the Federal Energy Regulatory Commission (FERC) in 2002 and initially deployed in the PJM interconnection. In this design, in addition to the standard prescription, spot power prices are not set on a power exchange, but by the system operator, and can be different in each node of the network (there are about 8 000 nodes in PJM). Such centralisation of the power exchange and system operation enables computing least-cost dispatch while taking into account network losses and grid reliability constraints. This locational marginal pricing model is currently viewed as the benchmark for power market design.

Following the UK example, other EU member states agreed to reform their electricity industry. To that end, the EU created an internal energy market to introduce competition between European utilities. Progressive unbundling of networks, creation of independent regulators and development of competition across frontiers have been the first steps toward furthering electricity market integration. Three successive energy packages have progressively introduced most features of the standard restructuring model. Although competition develops slowly, power-market coupling between France, Belgium, the Netherlands and Germany is a major step towards the completion of the internal electricity market.

In most non-OECD countries, the electricity sector is still growing rapidly and, like in OECD countries in the 1960s and 1970s, governments remain focused on capacity or resource adequacy issues and timely investments to meet rapidly increasing demand. In those countries, little progress has been made in liberalisation.

Electricity market reforms have improved performance

Very few comprehensive assessments of electricity market reform are available. The IEA (2005) provides a description of lessons learned from liberalised electricity markets, and investment in generation has been analysed by Sioshansi and Pfaffenberger (2006). Erdogdu (2011) performed an econometric analysis of the impact of reforms on cost margins and Joskow (2008) summarises qualitative lessons learned. Despite methodological difficulties inherent in any ex-post assessment, several studies focus on specific indicators (labour productivity in distribution, plant availability, integration of wholesale markets). This paper takes these assessments into account in its evaluation of the overall benefits of the reforms. Electricity sector performance – where system restructuring and competitiveness have been well designed and implemented – can be expected to improve in terms of operating costs, physical network losses, generator availability, quality of service, investment, price level and structure. It must be recognised that performance improvements are not always tangible for the final consumer, as many factors influence the electricity bill. For some regulated vertically integrated monopolies that perform quite well, restructuring may have little positive effect on performance. In addition, successful reform does not necessarily mean that retail electricity prices will be reduced. Price analysis must take into account all exogenous cost drivers, especially increased fuel costs. Market integration over a wider area can lead to increased prices in some markets, and lower prices in others.

Regional market integration facilitates synergies between adjacent electricity systems

Integration of power markets over a wider geographic area, such as over several states, is a powerful lever to improve performance of the electricity system. The gains may be particularly high with the integration of zones exhibiting different and complementary electricity mixes, although such market integration can be hindered by limited interconnections which cause congestion. This reinforces the case for locational pricing, as exemplified by multilateral market coupling in several European countries.

It is worth noting that market integration encompasses several markets on which power plants can sell products, including forward electricity markets; capacity markets; intra-day trading, after the closure of day-ahead markets; balancing markets managed by ISOs; and reserve markets.

While forward and day-ahead-markets are already harmonised between adjacent countries, further integration of these markets requires defining compatible and homogenous products in network codes in Europe. But for existing markets, harmonisation of product definition and monitoring procedures takes time.

Some remaining market design issues

Although progress in restructuring has improved the performance of electricity sectors worldwide, a number of issues have been raised by the new industrial organisation, calling for continuous improvement of the regulatory framework. Even where the standard prescription to deregulation has been fully applied, a lively debate on market design issues continues.

Firstly, market power continues to be a significant potential problem in electricity markets. No market can be efficient without an adequate number of competitive electricity generation providers – at least four to six. Market power results from transmission constraints that limit the geographical extension of competition. This was an issue in the United Kingdom in the 1990s, where two generators were setting the pool price, and in California between 2000 and 2001, where market power contributed to the explosion of prices, as well as in almost all other electricity markets.

Secondly, incentives to invest in peaking units and ensure security of supply remain a concern. The introduction of price caps and certain operational rules used by transmission system operators (TSOs) may prevent energy prices from reaching the high level necessary to recoup fixed costs. This creates a potential deficit of revenues known as the "missing money problem". Little evidence is available to reveal the extent of this problem, given the infrequency of observed prices spikes. This lack of empirical evidence may be partly explained by the existence of excess capacity. However, there is a perception that the increasing share of intermittent renewables in the coming years will continue to depress prices, further reducing the incentive to invest in and maintain adequate capacity margins.

A growing number of countries are therefore considering the introduction of capacity mechanisms. Their aim is to create an additional source of revenue for peaking plants running only a few hours per year but contributing to meet power peak demand. Another motivation of these capacity mechanisms is sometimes to provide enough system flexibility to accommodate increasing shares of variable renewables.

However, as discussed below, the standard deregulation and restructuring approach does not resolve other issues associated with optimal transmission network expansion. In addition, a new regulatory framework does not necessarily create the conditions conducive to the development of demand response or low-emissions generation investment.

How to deliver low-emissions investments in deregulated electricity markets

While in the 1990s electricity reform focused mainly on introducing competition and increasing efficiency, the role assigned to the electricity sector has evolved: it must now reduce CO_2 emissions to fight climate change.

Climate change mitigation calls for a massive reduction of carbon emissions from electricity, by taking advantage of low-CO_2-emitting technologies such as hydro, wind and solar energy to generate electricity. It is noteworthy that one-third of the electricity is already derived from low-emissions nuclear and hydro sources inherited from the era of regulated monopolies. Currently, however, most low-carbon technologies are not cost-competitive in many circumstances.

The EU emission trading scheme price: too low

In Europe, concern over climate change has resulted in the creation of the EU emission trading scheme (EU ETS), a cap-and-trade system. Under this system, a cap on CO_2 emissions sets the maximum level of CO_2 emissions for some industrial sectors, representing half the total and including electricity. Once allocated, trade in the quotas, taking the form of EU Allowances (EUAs), puts a price on carbon. This price, added to fuel costs, increases the marginal cost of fossil fuel power plants. For instance, with a CO_2 price of EUR 20 per tonne of CO_2 (tCO_2), the marginal cost of producing electricity rises by EUR 16 per megawatt-hour (MWh) for a coal plant emitting 800 grams of CO_2 (gCO_2) per kilowatt-hour (KWh) and by EUR 8/MWh for a Combined Cycle Gas Turbine (CCGT) plant emitting 400 gCO_2/ KWh.

Many institutions, analysts and research centres are carefully monitoring CO_2 market development, including the clean development mechanism (CDM) and exchange of quotas between industrial sectors covered by the EU ETS. Like any other commodity, CO_2 prices fluctuate according to anticipated economic growth and prices of other commodities. Interestingly, during the second phase of the EU ETS (2008 to 2012), due to the depressed industrial output of many European countries, all industrial sectors ended up with allowances in excess of their actual emissions. The only sector in deficit was the electricity sector, which purchased CO_2 quotas and maintained a demand high enough to sustain a non-zero CO_2 price.

Since its introduction in 2006, the EU ETS has reduced CO_2 emissions in the electricity sector, mainly through coal-to-gas fuel switching. Gas power plants emitting less CO_2 have been used more than higher-emitting coal power plants, at least until 2012.

But existing carbon prices fail to stimulate the high-capital-expenditure/low-CO_2 investment needed to decarbonise electricity generation. Burning more gas and less coal in existing plants is progress in the right direction, but to reduce CO_2 emissions significantly – by 20% to 30% in 2020, and more than 80% by 2050 – investment in new emissions-reducing equipment is especially important.

Regrettably, there are still too few statistical observations since 2006 to assess actual CO_2 market impacts. However, most commentators and financial market experts generally agree that current CO_2 prices do not provide sufficient incentive to invest in low-emissions power plants. Several reasons have been proposed to explain the failure of CO_2 markets to provide sufficient incentives:

- **carbon prices are too low** to trigger investments in low-emissions power plants, given the high cost of renewables;
- **carbon prices have been too volatile**, resulting in increased electricity market price risk and increased cost of capital;
- **emission caps are subject to political intervention**, which may undermine the credibility and visibility of the future price of CO_2;

▶ **the absence of a CO_2 allowance market beyond 2020** deters investors considering long-run investments.

Many proposals have been made to cope with the lack of credibility of CO_2 prices. One possible solution is the introduction of a carbon tax or carbon price floor over 20 years to provide sufficient visibility to investors. In the United Kingdom, such a measure was introduced in 2011. This carbon price floor is an important step to providing long-term visibility to investors. However, this floor takes the form of a tax and, like any tax, constitutions usually prevent governments from committing to a set level of taxes over such a long period. A carbon price floor alone does not fully resolve the lack of credibility of CO_2 prices for private investors.

Back to regulation of generation investment?

A growing proportion of the generation mix is determined by governmental policies targeting specific technologies (Figure 1). Renewable policies and nuclear policies influence the mix most significantly.

Several fundamental objectives underpin public policy supporting the deployment of renewable energy sources:

▶ **near-term CO_2 emissions abatement** in the electricity sector;

▶ **long-term CO_2 emissions abatement**, through increased capacity that promotes learning, reduces future costs of large-scale development, and leads countries to plan for future export of products, technologies and competencies;

▶ **security of energy supply**, with renewable energy reducing dependence on imported fuel.

It is efficient to subsidise renewables if "the discounted future benefits outweigh the additional costs that are borne earlier on" (Neuhoff, 2008). Adding renewable capacity triggers unit cost reduction, thanks to the learning-by-doing effect. The expected benefits are competitive low-emissions generation costs in the future, and industrial development. However, market interventions could result in overinvestment in renewable generation and reduced incentive for investment in the remaining, unregulated fraction of the electricity mix.

Renewable policies are squeezing conventional plants

Since 1998, Germany and Spain have installed 80 GW of renewable capacity. These massive investments have not been driven by the electricity markets, and have not been based on demand forecasts and decentralised technology choices. Rather, they have been pushed by governments. After the beginning of economic crisis in 2008, when electricity demand fell, government policies on renewables stimulated economic growth. But more recently, governments in Spain and Italy had to cut renewable support to control the cost of renewables. The disconnection between market needs and investment risks re-creating the excess capacity that justified the liberalisation of the electricity industry 20 years ago in some countries.

Nuclear power remains a matter of energy policy

Decisions about the use of nuclear power remain largely in the hands of governments, and are influenced by public opinion, as witnessed with Germany's nuclear phase-out after the Fukushima Daiichi accident. For countries contemplating new nuclear investments, such as the United Kingdom, it is becoming clearer that governments – not the market – will determine the role of nuclear energy.

The British government, while having been on the forefront of liberalisation, provides the following arguments in favour of a more regulated approach to launch the construction of new nuclear power plants:

▶ "the current market price for electricity is driven by fossil plants [...]. Investors in non-gas-fired generation are also disadvantaged by being exposed to more volatile and uncertain returns when compared to gas";

▶ "high construction costs and market illiquidity make it more difficult for low-carbon generation to compete with fossil fuels and impede market access";

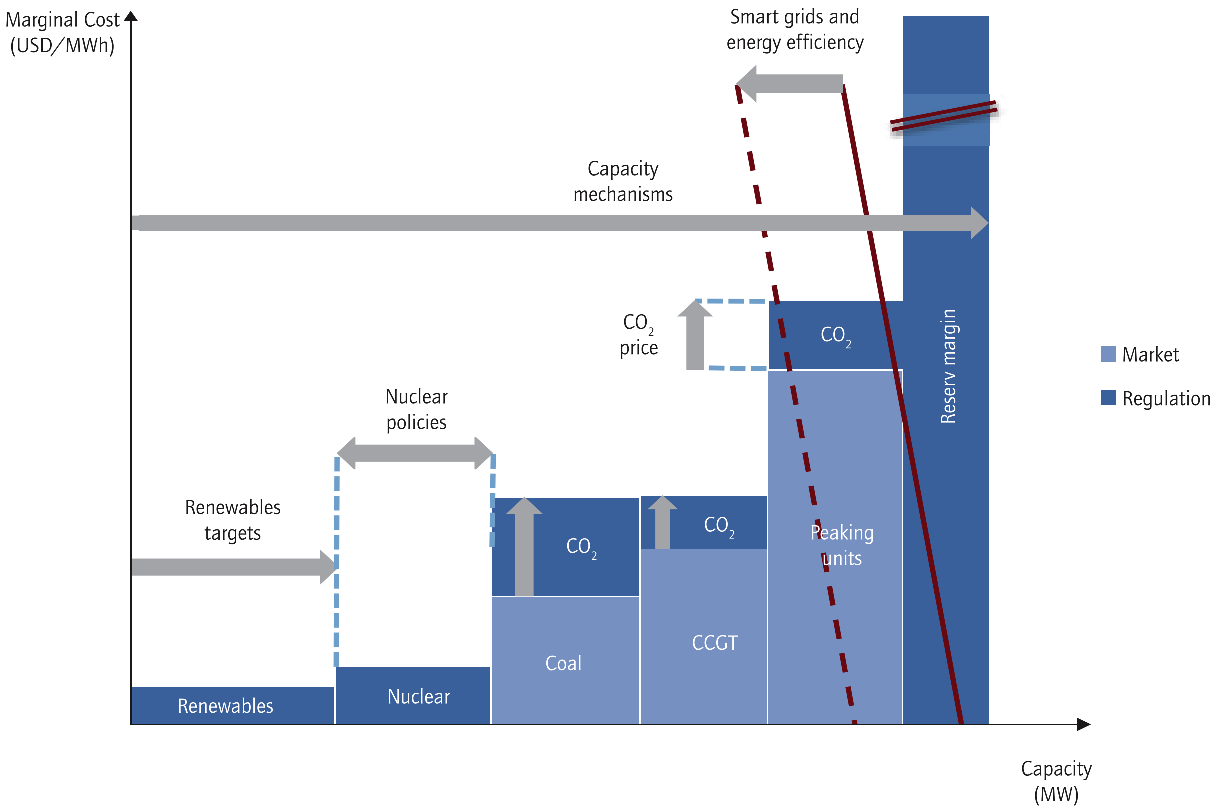
▶ "the social cost of carbon is not fully reflected in the market price";

▶ "the capacity and appetite of existing market participants to finance the unprecedented levels of investment needed is uncertain" (DECC, 2011).

These considerations have led the UK government to propose central planning for future construction of nuclear and off-shore wind capacity. The proposal is based on a feed-in tariff, with a "contract-for-difference" component which would guarantee an electricity price adequate to encourage investment in nuclear power plants. The possibility of competitive pricing for building the first units remains limited. UK administration is therefore considering regulating the feed-in tariff on a plant-by-plant basis.

Figure 1

The impact of regulations on the electricity market (illustrative)



Integration of regional power markets facilitates integration of renewables

High shares of wind and solar power amplify the weekly, daily and short-term (minutes to hours) variability of electricity systems, adding variability on the supply side to that already existing on the demand side. Until costs of electricity storage have decreased sufficiently, maintaining electricity security will become increasingly challenging. Indeed, system operators have to procure increasing quantities of reserves, generators need more flexible plants able to ramp up or down quickly, and system operators must ensure enough capacity to meet demand in the absence of wind or sun.

To mitigate risks to system security, further improvements of current market designs can help keep system costs as low as possible. Well-designed markets, integrated over wider geographic areas, can mobilise existing flexibility potential.

Integration of neighbouring markets gives access to competitively priced balancing energy – energy which can be deployed on short notice to compensate for imbalances between generation and load. Further integration of ancillary services markets over a synchronous area would also reduce costs, beyond primary reserves for automatic frequency control. Balancing and system services costs typically represent EUR 1-3/MWh and could easily be reduced by 10% to 20%. If these costs seem low compared to the energy cost, they can rapidly increase with higher shares of renewables.

Conclusion

Restructuring and integration of electricity markets have been tried in most OECD countries, and experience shows that market reform has improved performance significantly. While higher fossil fuel prices and development of renewables have led to diverse electricity prices, it is generally acknowledged that the introduction of competition has reduced operational costs, improved plant availability and ensured better use of existing generating assets. Competitive electricity markets have also prompted investment in new capacity, mainly in gas-fired turbines.

Although power market reform remains in progress in many countries, the focus of governments has evolved significantly over the last ten years. Before the economic downturn, mitigating climate change had risen in priority for policymakers. They responded by adding a layer of regulatory measures such as feed-in tariffs or renewable obligations; political considerations also continue to influence decisions to either phase out or build new nuclear plants. At the same time, many countries are considering the introduction of capacity mechanisms to ensure the security of their electricity supply. Naturally, these instruments reduce competition in the electricity market because part of the energy mix now depends on quantitative objectives set by the government.

More regulation of investments does not imply that restructuring and market integration do not work and should be discarded for the old-fashioned, integrated, regulated utility paradigm. Power markets, balancing markets and ancillary service integration, as well as efficient network congestion management, are becoming even more important to ensure and improve the efficient integration of renewable power.

Restructuring and integration of the power market involves more regulatory institutions and more regulatory instruments. A certain degree of complexity in regulation may be necessary, given the multiple objectives pursued by the electricity sector in terms of efficiency, competitiveness, electricity security and climate change mitigation. These overlapping policies could, however, add some uncertainty which may undermine market-based incentives to timely investment to ensure enough capacity is available. Well-designed market policies will be essential to ensure the security of electricity supply, an issue that is high on the IEA agenda.

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An emissions trading system for China's power sector

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One result of the recent rapid economic development in China has been a marked increase in energy usage. This higher demand is being met primarily by coal-based electricity, and CO_2 emissions have risen accordingly. China has taken a pledge to curb its emissions intensity, and is exploring an emissions trading system (ETS) to enact this pledge. Although electricity is a logical participant in this market-based system, electricity generation is a largely government-controlled activity. Effective implementation of emissions trading in China's electricity sector requires understanding (a) the structure of the sector, dominated by state-owned enterprises under a prescriptive regulatory regime; (b) the operation of the sector and the opportunities for mitigation of CO_2 emissions, which lie largely with the smaller and less efficient coal-fuelled generators; and (c) the steps needed to prepare regulators and actors for a market-based approach. With some adjustments, an ETS could work effectively in China.

Climate policy and the role of electricity in China

China recognises the threat posed by climate change on its development objectives, and has pledged to reduce the CO_2 intensity of its gross domestic product (GDP) by 40% to 45% from its 2005 level by 2020. Economic growth remains an imperative for the country, and its aspiration to a low-carbon economy presents a significant policy challenge. As its economy has grown at impressive rates over the last twenty years, China's energy-related CO_2 emissions grew by 50% between 1990 and 2000, and then doubled in the last decade, reaching 7 billion tonnes of CO_2 in 2009, as shown in figure 1.

The electricity sector is at the heart of the country's development and climate-change challenge. Dominated by coal, electricity generation accounted for 44% of China's total CO_2 emissions in 2010 – a higher share than the global average. China has adopted very ambitious goals to control the sector's emissions: it aims to at least double the installed capacity of carbon-free electricity sources between 2010 and 2020 to 600 gigawatts (GW), higher than total coal-fired capacity in 2008. Even with these additions, new coal capacity will be needed to meet the rising electricity demand; part of the solution will lie in controlling growth on the demand side. Overall, lowering the CO_2 intensity of electricity remains central to the achievement of China's climate goals.

China is has decided to explore an emissions trading system, among other options, to confront this issue, as stated in the country's 12th Five-Year Plan (2011-15). The National Development and Reform Commission (China's key ministry in charge of economic policy and planning) has launched carbon market pilots, currently in development in two provinces and five cities. These pilot programmes are likely to include the electricity sector, in large part because of its importance in China's emissions. Experience in other countries confirms that power generation is a natural candidate for emissions trading.

Regarding emissions trading, China has experience with a domestic SO_2 trading system (Schreifels, Yu and Wilson, 2012), and has been a host country to many projects under the Clean Development Mechanism. Based on this experience, and its ambitious emissions targets, China is interested in analysing how an ETS could work to reduce emissions while supporting efficiency improvements in the electricity sector.

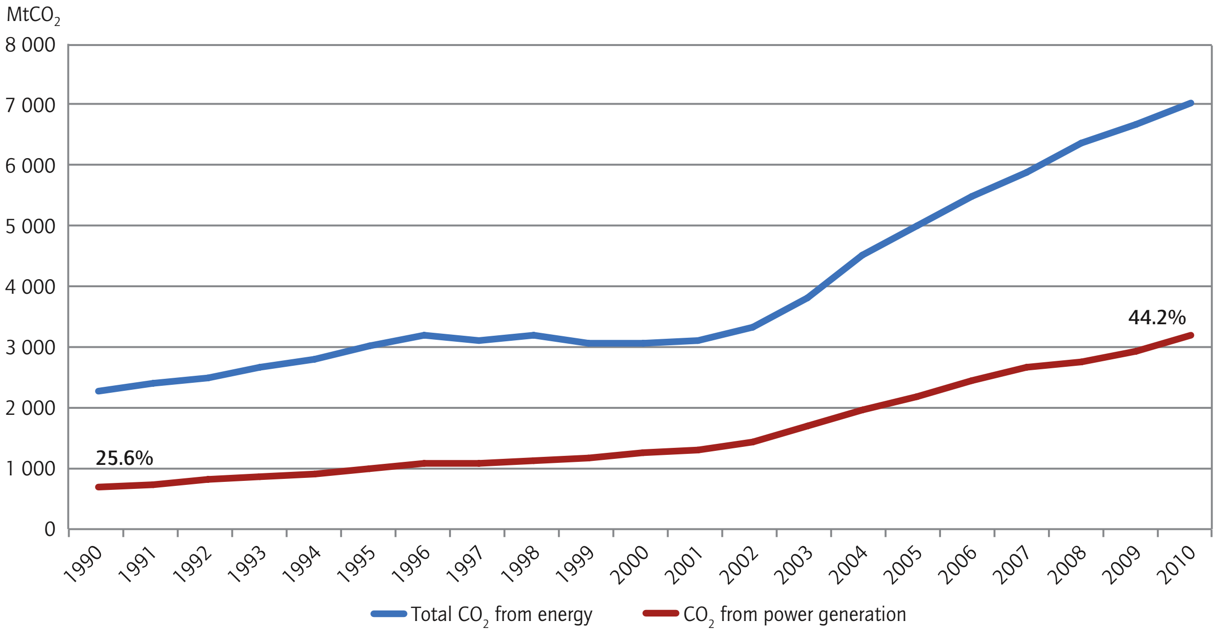
Emissions trading: how it works and how it helps

Emissions trading is promoted for its theoretical potential to achieve an environmental goal at least cost, through an efficient allocation of efforts among sources to reduce emissions. Under an emissions trading system, emissions sources (facilities, plants or firms) are capped: allowances are provided to each source to accommodate the agreed emissions target. Sources then have the possibility to buy and sell these allowances, and must surrender allowances matching their actual emissions in order to be in compliance. Once an emission source is granted an emission objective and a matching number of emission allowances, it can pursue measures to meet this objective at least possible cost, with the option of trading allowances with other sources in the system. As every source should

1. This article is based on joint work undertaken by the IEA and the Energy Research Institute of China (Baron et al.*, 2012). The authors would like to thank Jiang Kejun and Zhuang Xing at China's Energy Research Institute, Jonathan Sinton and Nina Campbell at the IEA for their contribution to this project, and Philippe Benoit for his useful suggestions on this summary.*

Figure 1

Energy and electricity-related CO_2 emissions in China (1990-2010)



Source: IEA statistics.

compare the cost of reducing its emissions with the cost of buying allowances, the system generates a uniform price for emission reductions, reflected in the market price for allowances.

In the electricity sector, emissions trading systems control emissions principally through their impact on the dispatch of existing plants and on the generation mix (through decommissioning and new construction). The electricity sectors of all countries contain a mix of CO_2-free and high- and low-emissions generation plants, among them base-load plants and a reserve margin of less-used plants which are used to meet peak demand and are often the most polluting. How these plants are called upon to provide power to the grid ("dispatched") determines how much CO_2 the sector emits; an ETS should alter dispatch patterns to favour lower-carbon generation units. An ETS can also alter the composition of the installed generation base by changing the economics of the decommissioning and new construction of plants.

Emissions trading – whether for CO_2, SO_2 or other pollutants – has a proven track record in delivering a price signal and allowing full integration of the cost of pollution into economic activities. These systems, like taxes on pollution, are in theory more cost-effective than command-and-control approaches, which either mandate technology choices and deter innovation, or fix emission limits without consideration for differences in cost among sources. This explains the interest of many countries in emissions trading as a means to curb greenhouse-gas emissions.

Features and challenges of China's electricity sector

China's electricity sector has certain characteristics that will affect the design and operation of any trading system. These relate to the energy mix of the sector and proposed expansion path, the dominant role of state-owned enterprises, and the highly planned and regulated nature of the sector.

A coal-dependent power mix

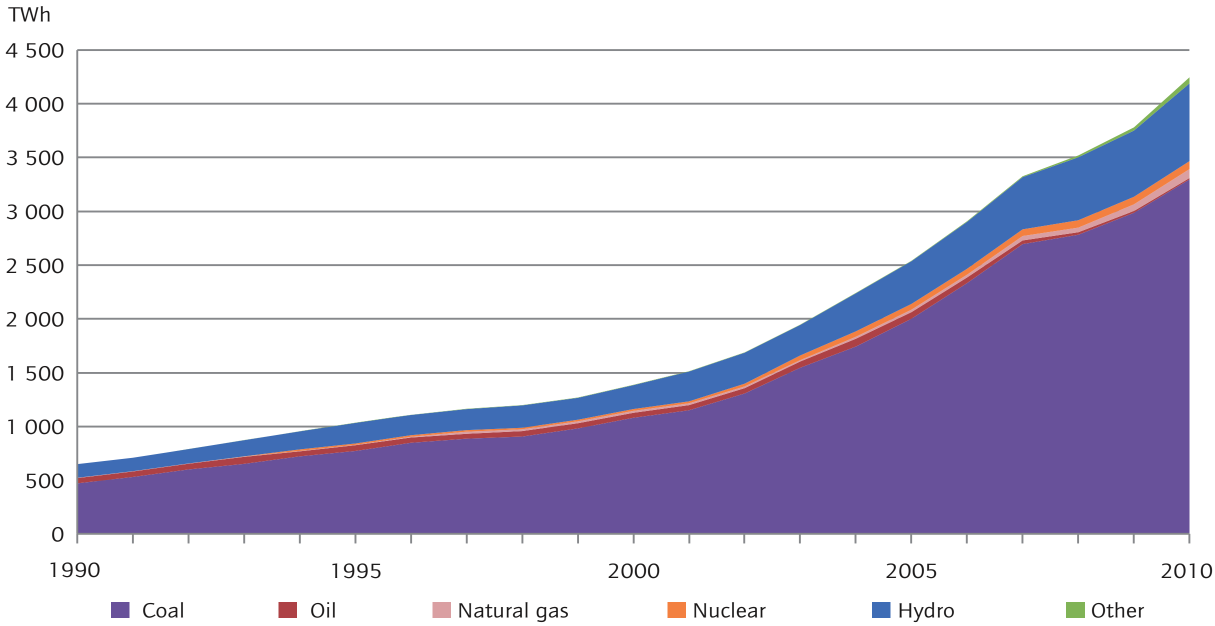
As shown in figure 2, coal remains the fuel of choice in power generation, in spite of long-standing efforts to reduce its share. Objectives for the development of nuclear, hydro, wind and solar are not enough to obviate the need for growth in coal-based capacity, projected to rise from 710 GW in 2010 to 1 190 GW by 2020. Even with efficiency gains through the construction of larger, more efficient ultra-supercritical plants (USC) and continued closures of small plants, substantial growth in CO_2 emissions will follow during this period.

State-owned enterprises dominate

The power generation sector of China is dominated by five state-invested companies (frequently referred to as state-owned enterprises or SOEs): Huaneng, Datang, Guodian, Huadian, and China Power Investment Corporation. This group of five companies owns 50% to 60% of

Figure 2

Electricity in China: the unabated dominance of coal



Source: IEA Statistics, 2012; ERI, 2012.

generation assets. Other major power companies include China National Nuclear Corporation, China Three Gorges, Guangdong Yuedian Group, Zhejiang Provincial Energy, Shenhua, and China Resources Power Holdings, also all state-owned. These 10 companies accounted for 450 GW of installed capacity in 2008, out of a total of 780 GW for China as whole. They were responsible for 1.4 gigatonnes of carbon dioxide ($GtCO_2$) emissions (Greenpeace, 2009). The remaining half of the sector's CO_2 emissions are emitted by other power companies of a much smaller size, invested by provincial or municipal governments throughout the country. The two main grid companies, the State Grid Corporation of China and China Southern Grid, are also state-owned.

The dominance of state-owned enterprises presents both challenges and opportunities for controlling CO_2 emissions with emissions trading. One advantage is that state-owned enterprises typically have direct access to funding, including for low-carbon investments. On the other hand, state-owned enterprises may not always respond to economic incentives in the same manner as enterprises driven by profit maximisation. This makes the operational and investment responses to market-based policy instruments, such as an emissions trading system, unpredictable.

Many small and inefficient generators

Small and medium-size, less efficient coal plants still make up much of the electricity sector's generation capacity. China has adopted a programme to address the inefficiency of these plants, the so-called "building big, closing small" programme. This has led to the closure of 77 GW of small, inefficient coal plants over the course of the 11th Five-Year Plan (2006-10), and their replacement by large high-efficiency generating units, including USC plants. Decommissioning of this magnitude in such a short time is unmatched in any country. As of 2010, however, there still remained 68 GW of small coal plants (unit sizes below 100 megawatts [MW]), and 138 GW of medium-size plants (100 MW to 300 MW) also targeted for closure, but which are meanwhile a source of significant emissions.

Regulatory framework

Certain attributes of the regulatory system will affect the design of the ETS and determine its effectiveness. China has an extensive regulatory framework governing the operation of electricity sector agents, including state-owned companies. Some rules are set at the national level, while other actions are controlled at provincial or lower local levels; for instance:

- Construction and commissioning of large power plants are authorised by the National Development and Reform Commission (NDRC) which, through its price department, grants a price for electricity that allows an adequate financial return. Coal plants face a price set on a province-by-province basis. Plants relying on other technologies (hydro, gas, nuclear, solar and wind) are granted a specific price.
- Each provincial Development and Reform Commission (DRC) draws an annual generation plan specifying the

dispatch of each of the plants on its grid. Adjustments are made during the year to balance supply and demand. Provinces also have the power to approve construction of small plants, so long as they conform to national guidelines regarding minimum size, fuel, technology and other characteristics.

These rules have allowed the government to encourage capacity additions while keeping prices under control. However, they do not necessarily lead to least-cost generation for any given power mix, as dispatch also has to balance the economic interest of all the plants that have been commissioned. Any ETS would need to be integrated into and work effectively with this regulatory framework.[2]

Recent policy developments have sought to improve the efficiency of the sector, particularly coal-fired generation but also transmission and distribution, and to encourage new capacity development to maintain secure, uninterrupted supplies. Despite massive closures in recent years to raise efficiency and reduce pollution from the sector, a large number of relatively small, inefficient local coal plants remain in operation.

Key challenges for electricity under an ETS: dispatching of plants and electricity prices

The electricity generation sector faces two key challenges relevant to a CO_2 emissions control policy: (i) inefficiencies in its dispatch system and (ii) concerns regarding electricity price increases.

Under China's regulatory framework, dispatch is driven principally by local mandates on generation time. This leads to economic and technical inefficiencies when plants are not operated on the basis of their costs. The dispatching of plants, based on local governments' annual plans prescribing the running hours of each plant, does not typically provide for least-cost dispatch within the regions served by system operators. Recognising this issue, the Chinese government issued trial rules to test a more "rational" dispatch of plants, designed to save energy and to reduce local pollution: the "Energy Saving Dispatch Rule Method (Trial)" (ESDR). The trial began in 2008 and was carried out in five provinces.

The ESDR has achieved remarkable energy savings and CO_2 emissions reductions in some of the five provinces, but this new dispatch method has raised an important equity issue which stands in the way of national implementation: compensation for those plants that would be dispatched less and would face a reduction in earnings (Zhang, Schreifels and Yang, 2012). This problem cannot be left unresolved if emissions trading is to work effectively.

2. See Kroeber (2008) for a description of China's power generation challenges.

The impact on electricity prices is another sensitive point when considering a cap on CO_2 emissions from power generation. While coal prices have largely been deregulated, electricity prices have not, as they are an essential part of the country's control of inflation. The financial losses incurred by some coal-based generators facing high coal prices has at times led them to curtail their output, resulting in instances of power shortages at the expense of economic activity. After protracted negotiations, electricity prices have been adjusted upwards a number of times, typically by small increments, usually only for certain classes of users, and often only in certain regions. Under China's current regulatory and ownership structure, generating companies clearly cannot count on rising tariffs to respond to increasing costs and may feel compelled to reduce generation as a result. This is particularly relevant to the design of an ETS system, which is typically meant to achieve its aims by influencing generators' costs of production.

Can an ETS address China's electricity challenges?

An effective and sustainable ETS must be designed to ensure political acceptance and operational sustainability by minimising adverse impacts on the operation of the electricity sector. In China, generators cannot respond to price signals simply by adjusting their tariffs. What is more, the aim of state-owned generation companies is not to maximise shareholder equity, but rather to balance financial sustainability with a mandate to provide a secure electricity supply for equitable long-term economic and social development. To be effective in China, an ETS should address the persistence of small, inefficient coal plants, as well as the rigidities in the pricing system that can lead to power shortages.

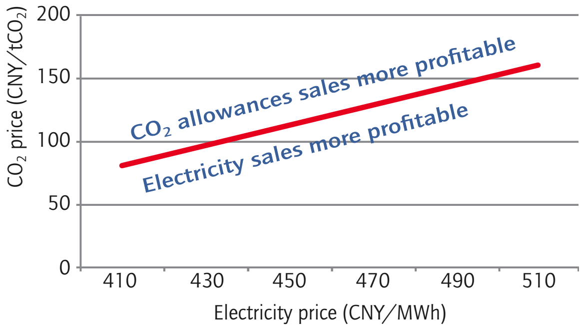
Enhancing the efficiency of coal-based generation

China has ambitious plans for the deployment of emissions-free electricity sources (nuclear, hydropower and other renewables) with dedicated policy instruments and incentives. The ETS would only directly affect fossil-fuelled generators, namely the coal, oil and gas plants that emit CO_2. One obvious potential for CO_2 emissions reductions among these plants is the continued switching away from less efficient, small coal plants towards larger, centralised, more efficient coal plants, up to large-scale ultra-supercritical plants.

As of 2010, large, more efficient coal plants were operated about 5 000 hours per year on average, leaving some margin for increased output. Less efficient units of 300 MW and below were run at least 4 000 hours on

Figure 3

CO_2 switching price: compensating less efficient plants for loss of revenues



Notes: a coal price of CNY 700 per tonne of coal equivalent (tce) is assumed. A higher price for coal would lower the CO_2 switching price.

average. Experience shows that improvements from this sub-optimal dispatch (from an emissions perspective) are possible, provided that compensation is given to small coal plants. Emissions trading could be the vehicle for such compensation. This would require granting free allowances to existing plants, allowances they could sell if they decided to lower their output. The price of CO_2 allowances, if restricted to power generation, would need to reach a level that would compensate these plants for the loss of electricity revenues, minus fuel costs. Figure 3 shows the CO_2 price range that would adequately compensate a small coal plant as it makes way for electricity from a USC plant – the CO_2 "switching price".

The impact of CO_2 costs on electricity prices

The main challenge for the power sector under an ETS is the management of the carbon cost and the potential electricity price impact. The price of CO_2 will add to the financial burden of most power generators, even if some technical efficiency gains and economic gains may be achieved in the near term by large companies.

Whenever an ETS has been applied to power generators in a deregulated wholesale electricity market, it has led to a pass-through of the CO_2 price to the electricity price.[3] As electricity prices are regulated in China, however, the question is how the regulated electricity prices could be adapted in a way that would not deter public acceptance of the system and would enhance its effectiveness. If prices remain at their usual level without compensating for the CO_2 cost, an additional cost will be borne by generators that cannot be recouped through higher prices. Past curtailments of electricity generation due to rising coal prices demonstrate the gravity of this problem. An ETS would be untenable if power generators were to curtail overall output due to losses from CO_2 costs, but the method of accounting for the CO_2 cost in the electricity price must be carefully considered.

In order to balance the simultaneous needs of sustaining investment in new capacity, meeting the CO_2 emissions intensity objective, and providing the incentive of a higher electricity price to low-emitting generators, China could consider adjusting the way electricity prices are set for fossil-based generation. While this challenging topic is beyond the scope of this paper, Table 1 provides orders of magnitude of the CO_2 cost that would be borne by a high-efficiency ultra-supercritical coal plant under various assumptions.

Table 1

How high could the cost of CO_2 be for an ultra-supercritical coal plant?

CO_2 costs (% of electricity revenues)		CO_2 price assumption (CNY/tCO_2)	
		40	150
Allocation scenario	90% free allowances	0.7%	2.7%
	0% free allowances	7.3%	27.4%

Notes: the CO_2 costs illustrated are combinations of assumptions: low and high CO_2 price (CNY 40-150 per tonne of carbon dioxide [tCO_2]), and 90% and 0% free allowances. The power plant is assumed to run 5 100 hours per year. Higher running hours would increase CO_2 allowance costs, but also revenues.

Features of an ETS for power generation in China

An effective ETS relies on many key elements, several of which are:[4]

▶ **A cap on emissions.** This is the starting point of the ETS, as it defines the environmental goal that the ETS should deliver. It defines the overall level of effort and ensuing costs that apply to all covered emission sources.

▶ **Plant-level allocation of emission allowances.** The total emission cap is then allocated to individual sources in the sectors covered by the ETS. Each source has the obligation to surrender allowances equal to its emissions during the commitment period.

▶ **Ability to trade.** No ETS will function, and no robust price will emerge, unless sources are allowed to trade allowances on a wide basis – in China's case, across sectors

3. *See Ellerman, Convery and de Pertuis (2010).*

4. *See Aasrud, Baron and Karousakis (2010) for a broader discussion of the building blocks of emissions trading systems.*

and provinces. This requires an information infrastructure (a registry for transactions) and a specific legal framework.

- **A monitoring,** verification and reporting system for CO_2 emissions, the cornerstone of a credible emissions trading system.

- **An enforcement mechanism,** *i.e.*, a penalty to deter non-compliance with emission goals.

The CO_2 price is generated through the implementation of these elements. It will differ from forecasts, as abatement costs cannot be known with precision beforehand, and economic and other price developments (for coal, gas, alternative electricity technologies) may differ from expectations.

Overall cap: key elements in power generation

The cap defines the environmental effort of the ETS: this upper limit on emissions creates an economic value for these emissions. It is itself defined by the both the coverage of the system (which sectors and which plants are to be included), and the overall emission reduction effort required. While the effort can be set "politically" as a percentage reduction from a baseline, in accord with a country-wide emissions goal, an inventory of plants to be covered and historical energy and emissions data are required for its elaboration. The setting of the cap can also be influenced by the projected total cost of reducing emissions: the cost of abatement in various sectors, the impacts on electricity prices and on the macro-economy, and socio-economic costs and benefits.

In the case of electricity, creating CO_2 scarcity requires taking into account several elements. For instance, CO_2 emissions levels in electricity generation will be affected by any new capacity in nuclear, hydro, wind, and solar that will reduce reliance on fossil fuel-based capacity. Further, whether or not small and less efficient coal plants will be included in the ETS is critical in defining the near-term potential for emission reductions. The challenge is to balance the mitigation potential presented by such plants with a manageable measurement, verification and reporting system. Also of consideration is the future of natural gas in China, which could have a significant impact on the power sector's CO_2 emissions intensity.

Looking beyond the supply side, end-use energy efficiency could substantially reduce future electricity demand. China has initiated a number of efforts in this area as well, such as the newly announced "Top 10 000 Enterprises" programme.

The CO_2 emissions goal for power generation risks being either too lax or too stringent depending on the success of other policies in the electricity sector. The setting of the emissions cap must therefore be based on as much information as possible on the projected contribution of generation technologies and policies that could affect CO_2 emissions from electricity.

The price of CO_2 and the cost of the overall system will also depend on whether, and which, other CO_2-emitting sectors (*e.g.* steel, cement, petro-chemicals, refining) will be included in the ETS. The potential for CO_2 reductions in these other sectors will be technically different from that of power generation, and so will the cost of tapping that potential.

The initial allocation method to fossil-fuel plants

The allocation of allowances is a major design feature in any ETS because it defines the distribution of emission reduction efforts among plants. In the case of China, addressing climate change is largely about addressing emissions from new plants; their treatment will be critical.

- As shown above, in the near term the cost of compliance with the emission cap could essentially be the cost of acquiring CO_2 allowances freed up by small and less efficient coal plants.[5] This implies a sufficient allocation of allowances to these existing and less efficient plants in the initial phase of the ETS. These allowances would compensate these plants financially as they progressively close and leave room for more efficient, low-CO_2 technologies.

- New plants ought to be subject to a different treatment. Granting them free allowances based on their projected emissions would not lead to emission reductions. For new plants, an allocation below the level needed to cover emissions corresponding to standard operating hours should encourage the purchase of CO_2 allowances from existing, less efficient plants. Allocation to new plants could be based on a benchmark, combining a performance standard (in tCO_2/MWh) uniform for all fossil-fuel plants and based on a standard running time, with an emission reduction factor.

- With an 11% growth in electricity output in the last ten years, the number of new plants potentially coming under the ETS is much higher than in any other existing or planned ETS. The Chinese ETS should plan for the inclusion of an uncertain number of CO_2-emitting plants, to balance emissions mitigation and electricity system reliability as demand grows.

In existing systems, regulators have established a limit over the total quantity of allowances that can be attributed to new entrants, called the New Entrants' Reserve. In the case of China, setting the reserve of allowances too low risks

5. For plants that curtail output to sell emissions, the cost will be the loss of electricity sales, minus the revenues from CO_2 allowance sales.

preventing the addition of new power generation when it may be needed. The opposite risk of setting too high a reserve could be managed without compromising the environmental goal: all allowances remaining in the reserve at the end of the commitment period could be taken back by the government. Alternatively, the quantity of allowances in the reserve could also be indexed to actual GDP growth, as a means to automatically adjust it upward and downward.

Monitoring, verification, reporting and enforcement

Emissions trading requires a robust, credible and verifiable system to measure emissions from the covered sources and assess their compliance with emission goals. There are two possible means of assessment. First, power generators are already subject to extensive reporting on their fuel use, which would provide sufficient information to estimate CO_2 emissions from combustion – a method that has been used experimentally on an ultra-supercritical coal plant in a Clean Development Mechanism (CDM) project. Second, power generators must operate continuous emissions monitoring systems to measure SO_2 emissions; these systems can be upgraded at limited additional cost to also measure CO_2 emissions (Zhang and Schreifels, 2011).

There is, however, no systematic verification protocol in place for these two measurement methods. Whichever option is deemed acceptable for China, it will require a robust system of verification to ensure the validity of reported emissions. If any doubt is cast on the validity of the measurements, the sources subject to the emission cap will question the value of allowances traded, and could object to paying a price for such allowances.

The ETS must also include a financial penalty for non-compliance, both to deter cheating and to encourage reliance on less costly compliance alternatives, including the purchase of allowances. Penalties have traditionally been set at a much higher level than the projected price of CO_2. In the EU ETS, the penalty is currently EUR 100/tCO_2 plus future surrender of missing allowances; in Australia, the penalty will start at 1.3 times the relevant permit price and increase over time.

Managing the evolution of the system

Emissions trading systems are effective, yet complex policy tools. They are vulnerable to unforeseen external or internal events, and must therefore plan for regular design-feature reviews. External shocks have clearly affected other ETSs. For example, in the European Union, the economic recession and generous early allocations to some sectors created a surplus of allowances. This led to a low allowance price, which undermines the system's long-term goal. China may learn from its provincial and city pilots, but a prompt-start, nation-wide system that contributes to its 2020 emissions reduction goal may not fully allow for this. In any event, the design of a Chinese ETS should allow for revisions, including accounting for any unexpected developments in the way the electricity generation sector operates and reacts to the system.

China could build timelines and adjustable processes into its Five-Year Plans to allow for the revision of key elements when needed. Elements for revision may include:

- overall cap, and possibly an associated long-term goal;
- coverage of the ETS and possible inclusion of other sources of emission reductions;
- mode of allocation to various sectors (*e.g.*, the treatment of new entrants and closures);
- possible linkage of ETS with other systems.

Making an emissions trading system work in China

As an economic instrument, an ETS is meant to change behaviour and lower pollution through changes in relative costs; this could happen through three channels:

- first, by making fossil-fuel generation more expensive as a result of the CO_2 cost, and therefore less attractive to the grid operators;
- second, by lowering the profitability of fossil fuel-based generation through a lower level of free allocation and/or a rising CO_2 price;
- third, following from the previous point, by enhancing the relative profitability of low-CO_2 technologies.

As indicated above, some changes will be required to fully exploit these channels:

- a change to the regulation of plant dispatch to allow shifting from high-emissions to low-emissions sources as the price of CO_2 changes their respective profitability;
- a reasoned adjustment of electricity prices to reflect the new cost of emission caps.

Lastly, it will be important to monitor how the allocation of CO_2 caps and the price put on emissions affect power generators in China, both for operations and investment choices. ETS experience so far has mostly been with companies driven by maximisation of shareholder value. Attention to how the state-owned power generation sector in China reacts to the price incentive will be required to gauge the effectiveness of the system.

Conclusions

An emissions trading system can be an effective, low-cost tool to mitigate CO_2 emissions from the power sector in China, provided that some of the challenges of applying a market instrument to state-regulated power generation are addressed. To be effective, the introduction of the ETS should be accompanied by enhanced flexibility in power plant dispatch, and some adjustment to the electricity prices faced by fossil fuel-based generation in the near term. The main question for the future will be whether the price of CO_2 and the cost generated by the ETS has directly affected investment in cleaner generation sources, a sign of the system's effectiveness.

Further analysis, monitoring and evaluation of actual implementation experiences with Chinese institutions and companies will give lessons in how to further develop and refine an effective ETS, to control emissions while supporting China's growth objectives.

Outside of China, a number of countries have established or are in the process of building their own emission trading systems. In parallel, Parties under the United Nations Framework Convention on Climate Change (UNFCCC) are seeking to develop a new market mechanism as well as a framework for market-based and other approaches to emissions mitigation. At the moment, China's effort to develop a carbon market appears to be driven by the need to meet its domestic greenhouse-gas objectives. In the future, the international carbon market will increasingly look to China as a major player: its power generation emissions in 2010 amounted to more than one and a half times the CO_2 emissions covered by the European Union's system, the largest ETS to date. China's experience is bound to influence both how other countries (especially emerging economies) approach this instrument, and how the international carbon market will develop, through bilateral links and/or in a more integrated fashion under the UNFCCC.

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Managing policy interactions in the electricity sector for least-cost climate response

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Meeting the enormous challenge of decarbonising electricity systems worldwide will require rapid global expansion of investment in clean-energy technologies. Mobilising these investments will be a daunting task, and it is important to undertake the transition at the lowest cost possible. In real-world electricity sectors, multiple policies are generally needed to deliver this least-cost outcome, including broad measures such as carbon pricing or clean energy standards, policies to support emerging technologies and lower their costs over time, and focussed programmes to unlock cost-effective energy efficiency potential. These multiple policies can overlap and interact, either supporting or undermining one another. Selecting the right policy mix and managing interactions among these policies are therefore critical to a least-cost climate policy response. Based on Hood (2011), this paper argues for the use of multiple policies in coherent policy packages, and addresses how policy interactions can be managed.

The "core" policy mix for the electricity sector

In an ideal market setting, broad-based **carbon pricing** is the key element of a least-cost response to curbing carbon dioxide (CO_2) emissions. A key strength of carbon-pricing mechanisms is their wide reach: pricing pollution appropriately gives all producers and consumers the incentive to reduce greenhouse gas emissions, while allowing flexibility in the technical and business solutions used to make these reductions. Because carbon pricing engages actors in all parts of the value chain, it provides incentives for efficient investment and operational decisions, as well as consumption choices, with no one paying more for mitigation at the margin than anyone else. Compared to regulatory command-and-control approaches that run the risk of "freezing" technologies, carbon pricing can cope more effectively with climate and economic uncertainty because it allows innovative responses (Duval, 2008). As discussed later in this paper, close proxies (such as a clean energy standard) that retain many of the benefits provided by a carbon price, can also be implemented.

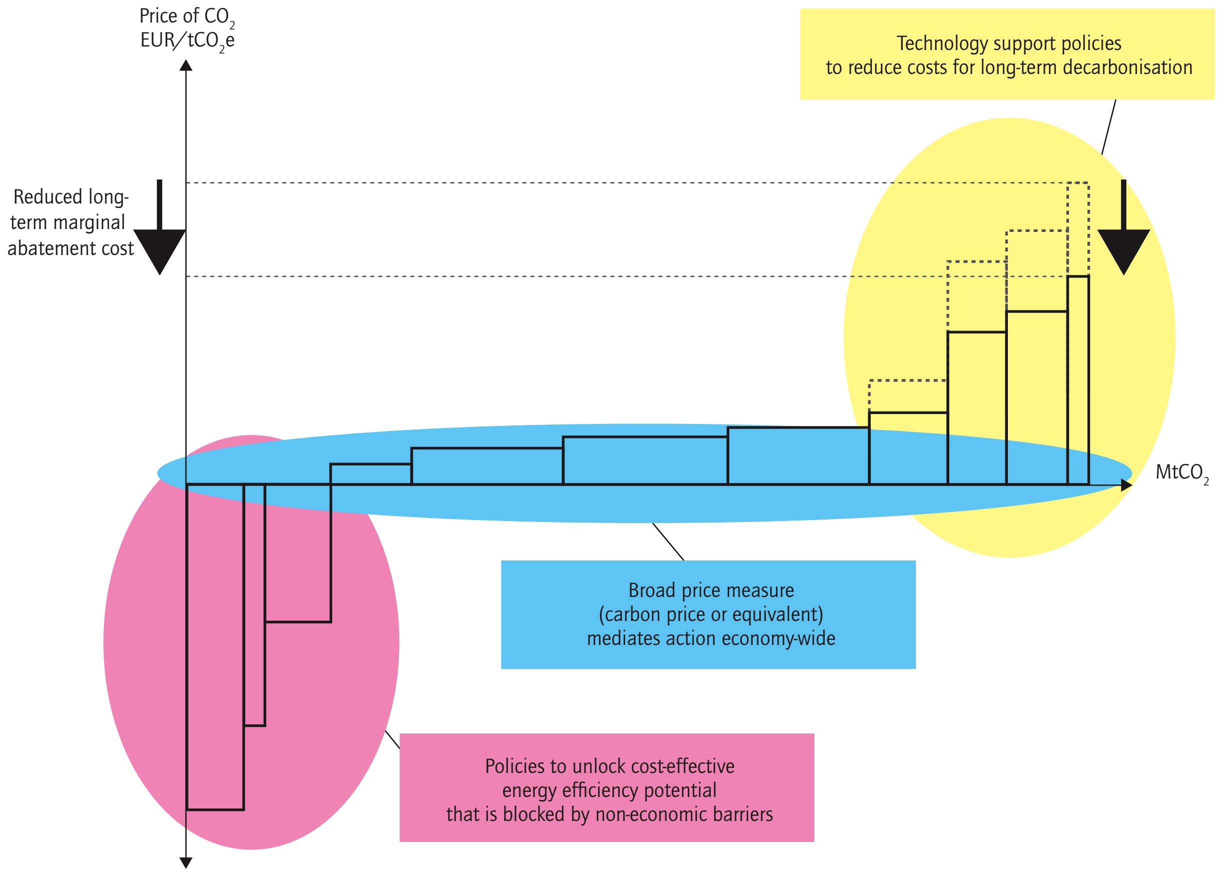
Although a broad-based price mechanism (carbon pricing or equivalent) may be the cornerstone, IEA analysis has consistently found that there are benefits in complementing this with further policies. Although the details of a cost-effective policy package will vary among countries and regions, adding cost-effective energy efficiency and technology policies (*i.e.*, RD&D support and technology deployment policies) is generally recommended to improve the short- and long-term cost-effectiveness of emissions reduction (Matthes, 2010; Hood, 2011). This **core policy mix** comprising carbon pricing, energy efficiency and technology support is illustrated schematically in Figure 1. This figure shows abatement potential and the cost of abatement measures, and illustrates how the three components of the core policy mix work together.

Targeted **energy efficiency** policies can reduce the short-term costs of climate change mitigation by unlocking energy savings that are blocked by market failures and non-economic barriers, and therefore not responsive to price signals. These barriers include: split incentives between parties responsible for paying energy bills and those responsible for energy efficiency investments; information failures that mean cost benefits are not apparent at the time of investment; and behavioural traits that cause consumers to not always act in their own best economic interests (Ryan *et al.*, 2011). Where these barriers can be overcome cost-effectively and the blocked energy savings exploited, the direct cost of implementing abatement actions is lower, and a lower carbon price is needed to achieve climate targets.

The case for **targeted technology** support is that it improves the cost-effectiveness and feasibility of climate policy over the long term. There are two dimensions to this. First, thanks to learning effects, the cost of new technologies declines over time with increased deployment. Second, some technologies may require early deployment to enable them to scale up over time to the level required for a cost-effective response, building the supply chains and infrastructure that will be needed to deliver these new technologies at scale. Although technology deployment policies may increase energy costs in the short term, their purpose is to deliver significant reductions in the cost of new technologies over subsequent decades, with the goal of significantly lowering the overall long-term cost to society of deep emissions reductions. This does not justify any arbitrary level of early support: the cost-effective level of support will depend on the rate of learning, the total abatement potential of the technology, and the stringency of the climate goal. Targeted technology policies also

Figure 1

The core policy mix: a broad price measure, energy efficiency and technology policies



Source: Hood (2011).

clearly should be phased out as each technology matures (IEA, 2012).

Justification can be made for **supplementary policies** beyond this core set. Such policies could be designed to address areas not covered by pricing policies, to prevent lock-in of high-emissions infrastructure, to overcome barriers to financing, to minimise costs to consumers, to compensate for policy uncertainty, to integrate the climate policy package with a wider set of policy priorities, or to improve political acceptability. However, before implementing such supplementary policies, their costs and benefits, and interactions with the core policy set need to be assessed. The transaction costs or negative interactions of certain policies may outweigh their benefit, even when the policies may be theoretically justified.

Policy interactions

Policies can be mutually reinforcing, can work against one another, or can be redundant depending on how they are designed and implemented. Understanding and managing the interactions within the core set of policies is therefore crucial to a secure least-cost response.

Policy interactions are particularly strong where the carbon pricing policy is based on a fixed *quantity* of emissions or energy (such as emissions trading [ETS] or clean energy standard [CES] systems) rather than a fixed price (such as a carbon tax). Under these quantity-based policies, permits are issued corresponding to the total allowed level of emissions (for an ETS), or permits must be surrendered by power suppliers corresponding to a required percentage of clean energy (for a CES). In both cases trading of permits establishes a price, providing a financial incentive for clean investment. The addition of energy efficiency and renewable energy policies does not result in additional emissions reductions in the short term, rather they displace some of the abatement that would have been delivered by the ETS or CES market, hence reducing permit prices.

While low permit prices indicate that the emissions or clean energy target is being easily met, low costs in the short term could lead to increased costs over the long term. Low permit prices could risk locking in high-emissions infrastructure

Clean energy standard

Where the direct pricing of emissions is not politically feasible, close proxies for a carbon price can be implemented that retain many of the same benefits. For example, a clean energy standard (CES) for the electricity sector could work in a very similar way to an emissions trading system (ETS).

In an ETS, each permit corresponds to one tonne of emissions and there is a maximum number of permits available (a cap on emissions). Under a CES it is the inverse: permits are awarded for each unit of clean electricity generated, and correspond (roughly) to avoided emissions compared to a baseline of thermal generation. Although similar in design to renewable energy standards (RES), clean energy standards include crediting for all low-carbon generation including nuclear and carbon capture and storage, and can include partial credits for gas-fired generation. Electricity suppliers in the CES are required to surrender permits corresponding to a required share of clean energy. The US federal CES proposal recently introduced by Senator Bingaman is of this type.

However, unlike ETSs, CES systems (like renewable energy standards) generally have an intensity goal: they seek to increase the proportion *of electricity generated from clean sources, rather than requiring an absolute quantity of clean generation. Some CES designs have proposed inclusion of energy efficiency and advanced technologies directly within the CES market, rather than as separate policy mechanisms, mirroring a common approach used in markets for renewable energy obligations (C2ES, 2012). In this model, verified energy savings are awarded CES credits, and higher-cost technologies can be awarded multiple credits to encourage their deployment.*

Because CES schemes do not raise energy prices by as much as ETS schemes in their early stages, they sacrifice some emissions reductions that would have resulted from reduced consumer demand. From a macro-economic perspective, however, these price rises can have negative consequences, particularly if ETS schemes are not well-designed. This has led some to argue that a CES could be more cost-effective (Parry and Krupnick, 2011).

that would later need to be retired before the end of its lifetime, at high cost (IEA, 2011), or could create energy security concerns if price uncertainty stalls investment altogether. Given that low-carbon generation is typically highly capital intensive, a higher cost of capital due to carbon price volatility is detrimental to the financing of these investments.

Such policy interactions are particularly significant in the electricity sector, because emissions are determined not only by climate policy, but by total consumer demand for electricity. If energy efficiency policies reduce overall electricity demand, this displaces the need for some baseload generation (which is typically higher emissions). Policy-driven introduction of variable renewable generation reduces the load-hours of gas plants, as they move from being baseload or shoulder plants to supporting the variable renewable plants. If climate policy targets (such as ETS caps or CES goals) are set without taking into account these electricity market interactions, the caps could easily be set too loosely to provide additional incentive for low-carbon investment.

Climate policies also affect prices in competitive electricity markets. Introducing low running-cost renewable energy into the market reduces electricity prices by displacing higher running-cost fossil-fuelled generation that would otherwise determine the market price (this is known as the "merit order effect"). On the other hand, carbon pricing raises electricity prices, as long as fossil-fuelled plants are setting the market price (Philibert, 2011). These competing effects introduce further uncertainty for electricity sector investors, and lead to the conclusion that electricity market structure may need to be reassessed to accommodate low-carbon generation (Hood, 2011b).

Interactions with ETS and CES schemes are slightly different, so they will be considered separately.

Policy interactions with an emissions trading system (ETS)

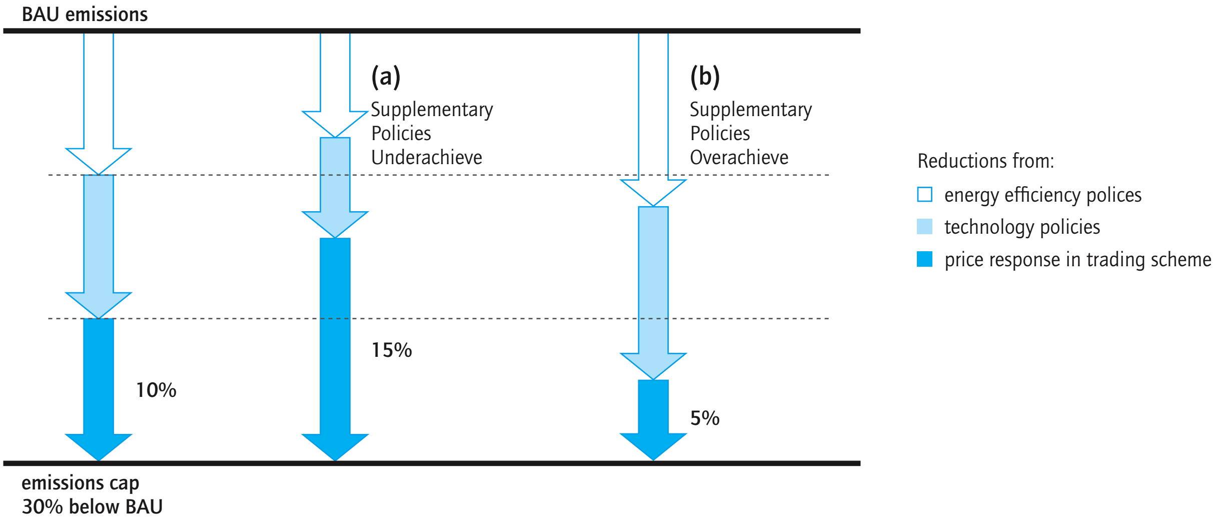
In an ETS with a fixed emissions cap, energy efficiency and technology support policies within the core policy set can strongly affect permit prices. As discussed above, these policies deliver some of the emissions reductions required to meet the ETS cap, however it should be stressed that they do not lead to additional abatement in the short term, rather they displace abatement that would have been be delivered by the ETS market. This reduces the demand for permits in the ETS market, and hence reduces permit prices These policies also act through the electricity market to displace high-emissions generation, further reducing pressure on the ETS market and suppressing permit prices.

Uncertainty in the delivery of energy efficiency or technology support policies can also create uncertain demand for permits in the ETS, and hence more uncertain permit prices (Figure 2). In this example, a 30% emissions reduction target is delivered in part by energy efficiency and technology policies[1], with the ETS market delivering the balance. If the energy efficiency and technology policies deliver only 75% of their expected emissions reduction, the pressure on the trading scheme increases by 50%;

1. For example, a renewable-energy or carbon capture and storage mandate, or policies to underwrite nuclear construction.

Figure 2

Policy interactions can significantly impact ETS permit prices



Source: Hood (2011).

conversely, if they deliver 25% greater emissions reduction than forecast, pressure on the trading scheme halves.

This variation in demand for abatement from the trading scheme could have a significant impact on permit prices, and hence on incentives to investors. The magnitude of the carbon price risk arising from such policy interactions is explored in detail by Blyth and Bunn (2011), who use stochastic simulations to explore a range of policy, market and technical risks in the EU ETS. They conclude that policy risk is particularly strong when carbon prices are low, while market risks (such as fuel prices) tend to dominate when carbon prices are high. This is consistent with Figure 2, with permit prices being more susceptible to policy uncertainty if the energy efficiency and technology policies provide a high proportion of abatement (that is, when permit prices are lower).

The delivery of some abatement by energy efficiency and technology policies also makes the permit price more sensitive to variations in (or miscalculations of) business-as-usual (BAU) emissions. If BAU emissions are lower than forecast (due to decreased electricity demand, for example), this reduces the pressure for reductions to reach the cap and lowers permit prices. Some variation of allowance prices is expected with normal economic cycles, and is something market participants can manage. However, if energy efficiency and technology policies deliver a significant proportion of reductions towards the cap, relatively small changes in economic conditions can have a large impact on the level of abatement that must be delivered by the trading scheme. Such fluctuations create an additional risk for investors, and have been shown to delay investment decisions (IEA, 2007).

Policy interactions with a clean energy standard (CES)

The use of intensity (rather than absolute) targets, as is typical in CES schemes, can decrease the severity of interactions between the trading scheme and energy efficiency policies, and reduce the impact of changing economic conditions. This is because the clean energy obligation is indexed to the quantity of electricity sold: reduced electricity demand resulting from energy efficiency or economic conditions does not directly substitute for the requirement to deploy clean energy. As such, energy efficiency policies and economic conditions do not directly change the pressure on the CES market. Technology policies can, however, create a direct interaction: if some clean technology is deployed by technology support policies, this contributes directly to achieving the CES target, reducing demand for CES permits, and hence their price.

Interactions through the electricity market still apply in this situation: the energy efficiency policy will tend to displace higher-emissions thermal baseload plants from the electricity market, increasing the proportion of clean energy in the system and decreasing pressure on the CES permit market. Similarly, deployment of additional clean power generation through alternative policy support (*e.g.* carbon capture and storage mandates, or additional tariff support for high-cost renewables) would displace higher-emissions generation from the electricity market. This would contribute to meeting the CES target, even if the additional generation did not receive CES permits.[2] As with ETS schemes, lower permit prices indicate that targets are being met easily in the short term – the challenge is to balance the desire to minimise short-term costs with keeping CES permit prices high enough to stimulate private investment in long-lived low-carbon assets that minimise costs over the longer term.

Some CES designs have been proposed that include energy efficiency and support for advanced technologies directly within the CES market. In theory, this approach has the appeal of providing a single market framework that allows supply and demand solutions to compete on an equal footing. However, it makes policy interactions more complex: without the certainty of knowing how many permits will be delivered by energy efficiency and advanced technology deployment, private investors will find it difficult to anticipate CES permit prices and plan clean-technology investments. Moreover, the optimal deployment rates for energy efficiency and advanced technologies depend not only on decarbonisation objectives, but also on other benefits such as energy affordability, employment, and industrial competitiveness (Ryan and Campbell, 2012). Maintaining separate policy targets for energy efficiency, technology deployment and emissions reductions allows for easier management of interactions and greater investment certainty, and allows target levels to be set with these wider priorities in mind.

Creating and maintaining coherent policy packages

Having identified the ways in which policies can interact, it is now possible to offer solutions, including how to identify and manage policy interactions over time. A schematic of the policy process is outlined in Figure 3.

The core policy set consists of a carbon price or equivalent, supplemented by energy efficiency and technology support policies. These policies interact, so need to be aligned with one another. Where the pricing policy is market based (ETS or CES), the trading scheme target should be set to ensure that a reasonable degree of demand for permits remains after emissions reductions from the energy efficiency and technology policies are taken into account. Modelling to test target settings over a reasonable range of circumstances (delivery of energy efficiency and technology policies, BAU emissions) is important.

Energy efficiency and technology policies also need to take into account the carbon price: for example, phasing out renewable energy support as carbon and electricity prices increase, to avoid over-payment. Such policies should also be designed for certain delivery of CO_2 reductions to reduce unnecessary price uncertainty in the trading scheme.

Beyond this core set of policies, further measures will likely be needed to prevent infrastructure lock-in and address the need for increased investment capital. Supplementary policies such as additional carbon taxes or emissions standards might also be considered to bolster weak permit prices, given the significant short-term emissions reductions that are necessary if the 2°C global target is to be achieved. If measures to supplement a weak permit price are introduced, it should be made clear that these are short-term and transitional, due to their potential to undermine the market mechanism that will be necessary for long-term cost-effective emissions reductions. Their phase-out could be linked to progress in implementing carbon pricing globally. The number of supplementary policies should be minimised, as the difficulty in maintaining policy coherence increases with the number of policies.

Impacts on the wider economy, and wider policy priorities, also need to be considered: though efficient, some policies could have wider macro-economic or social implications that make them more costly or politically unacceptable, necessitating adjustments to the policy package. In this case, for example, the core settings may need to increase emphasis on energy efficiency and reduce reliance on some technologies (or vice-versa) to deliver the same level of emissions reduction.

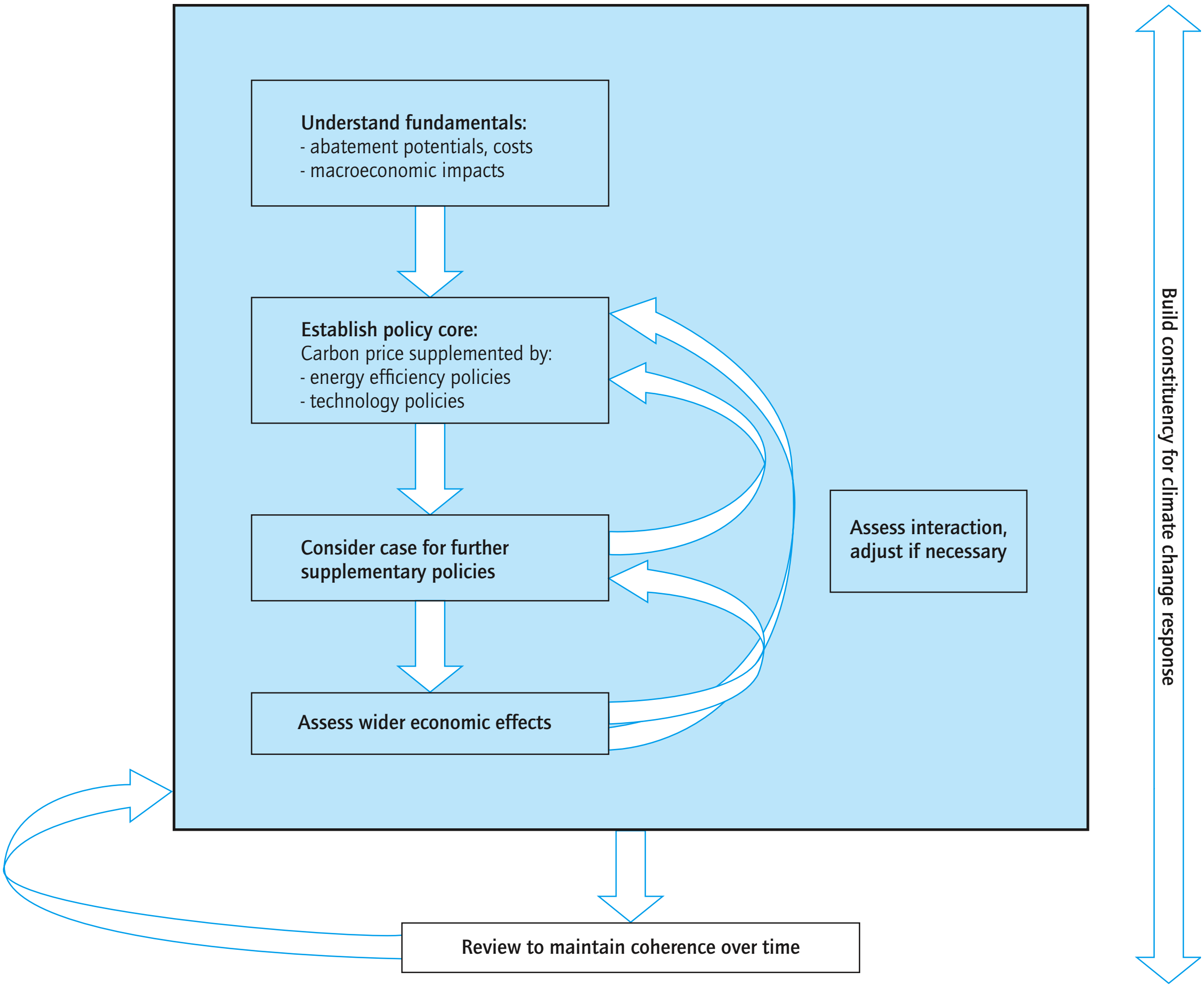
Finally, given the strong interactions within the policy package, any initial calibration is likely to drift out of alignment over time, or become significantly misaligned by unforeseen shocks, such as the recent global financial crisis. For investment certainty, resetting emissions targets and permit allocations should generally be initiated only at scheduled reviews, and be subject to criteria well-understood by all involved. The supplementation of emissions trading schemes by ceiling and floor price mechanisms can assist in maintaining coherence between scheduled reviews, as carbon prices cannot diverge widely from anticipated values. The frequent tracking and updating of energy efficiency and technology policies can ensure they remain both effective and cost-effective.

However, it is also possible that a misalignment within the core set of energy efficiency, technology and carbon price (ETS or CES) policies, or misalignment with economic conditions could be so severe that the benefits of re-establishing policy balance outweigh the damage to investment certainty caused by intervening in the market. In this case, having pre-established criteria for such interventions could help maintain investor confidence.

2. If these generators did receive CES credits, the abatement needed from the CES scheme would be further reduced, as would permit prices.

Figure 3

Establishing and maintaining a cost-effective policy package



Source: Hood (2011).

Conclusion

Carbon pricing (or a close equivalent) is a cornerstone policy in climate change mitigation, but is not a complete solution on its own. The short- and long-term cost-effectiveness of carbon pricing can be enhanced by cost-effectively overcoming barriers to energy efficiency deployment, and by accelerating the development of new technologies that can allow lower carbon costs in the future. In addition, in real-world implementations of carbon pricing there will always be incomplete coverage or design compromises that may warrant supplementary policies.

In policy design, interactions must be understood and accounted for initially, and the package must be regularly reviewed and updated to maintain calibration over time. Combining policies to give least-cost, realistic responses can assist governments in lowering the cost of action while stepping up the rate of emission reduction.

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Tracking clean energy progress in the electricity sector

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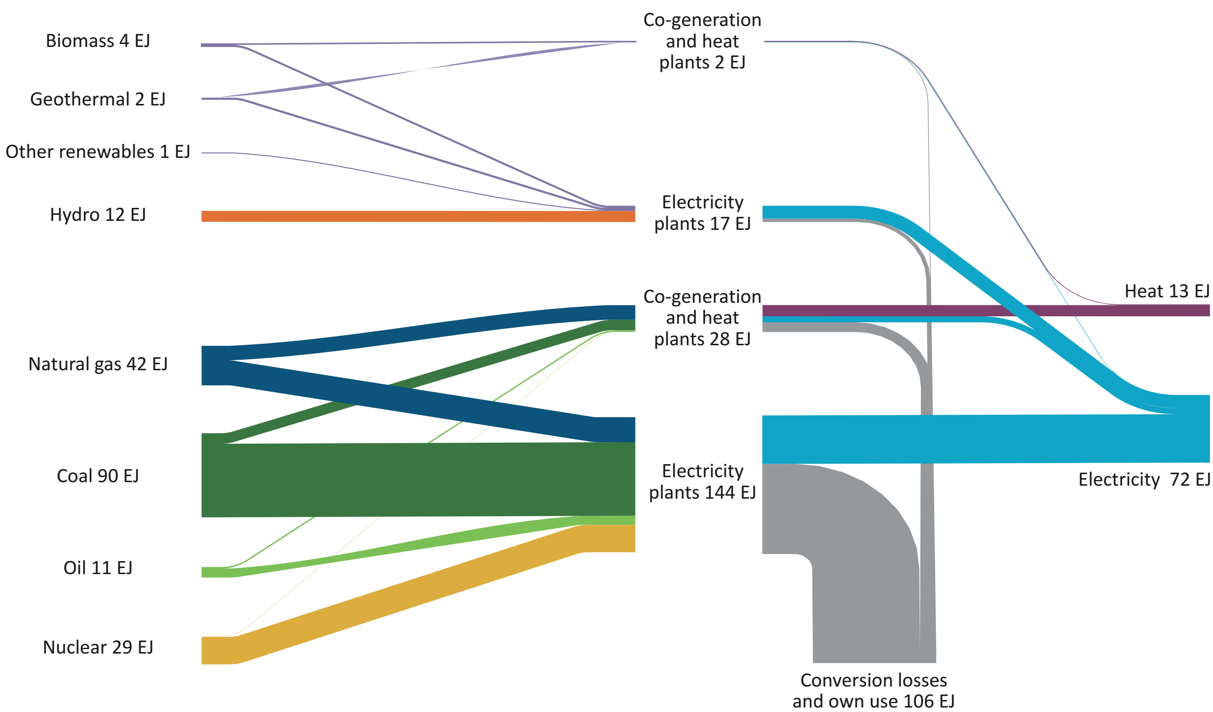
The electricity sector will play a central role in the transition towards a clean energy economy. Power underpins the functioning of most economies, allowing industrial productivity, functioning transportation systems, operation of buildings and households, and effective service sector performance. With rapidly increasing power demand, current systems are being pushed to their limits. In addition, current electricity generation remains dominated by fossil fuels. Rethinking the way in which electricity is produced and consumed, and transitioning towards a lower-carbon, more flexible electricity system is essential – not only to address climate change, but also to ensure the security and reliability of our electricity supply. Where do we stand in achieving a transition towards a cleaner power generation sector?

The power sector today

Electricity is a central element of today's energy system. In 2009, around 20 000 terawatt-hours (TWh) (or 72 exajoules [EJ]) of electricity were produced globally, meeting 17% of the final energy needs in the industry, transport, agriculture and buildings sectors. Around three-quarters of the energy consumed in the power sector (including co-generation and centralised heat plants) was from fossil sources, with coal alone accounting for almost half of the sector's fuel use (Figure 1). Losses in electricity generation are high: 106 EJ or 56% of the fuel consumed by the sector is lost in the conversion to electricity or centralised heat. These conversion losses, in combination with the high reliance on fossil fuels, are the main reason that the power sector accounted for almost 40% of global primary energy needs in 2009 and was the main emitter of energy-related carbon dioxide (with a share of 38%).

Figure 1

Sankey diagram of energy flows in the power sector, 2009

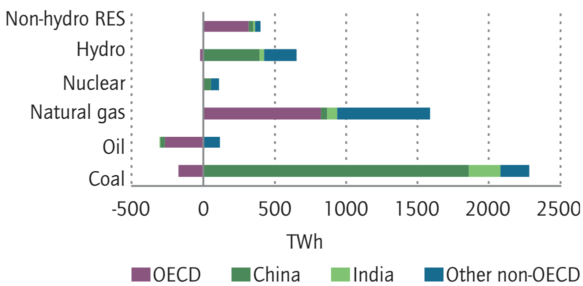


Notes: other renewables comprises wind, solar and ocean energy. Following IEA energy balance conventions for autoproducer co-generation plants, calculations consider only the fuel input for electricity and heat sold; the fuel input for heat used within the autoproducer's establishment is not included, but is accounted for in the final energy demand in the consuming sector.

Source: unless otherwise noted, all tables and figures in this chapter derive from data and analysis undertaken for Energy Technology Perspectives 2012 (IEA, 2012a).

Figure 2

Changes in sources of electricity supply by region and globally, 2000-09



Notes: non-hydro RES = renewable energy sources other than hydropower; TWh = terawatt hours.

Global electricity demand grew by more than 4 000 TWh, or almost one-third, between 2000 and 2009. China alone was responsible for almost half of this increase, largely driven by electricity use in industry. The economic recession led to an absolute decline in electricity demand between 2008 and 2009 in OECD member countries, whereas in emerging economies, such as China and India, electricity demand continued to increase. In China, demand rose at a slower rate compared with previous years.

From a supply perspective, the majority of the increase in electricity demand was met by coal (45%) and natural gas (34%) (Figure 2). If current trends continue, global power demand is projected to increase by about 50% by 2050, with a more than doubling in coal consumption. This trend is clearly unsustainable (IEA, 2012a).

A major transition of the electricity sector is necessary not only to avert climate change and pollution, but is also essential to address challenges related to ageing electricity infrastructure, increasing energy insecurity resulting from resource unavailability, price volatility, and enhanced pressure on existing systems due to supply and demand imbalances. In many economies, global access to electricity remains a basic objective, requiring expansion of existing networks and generation capacity. A more flexible and cleaner electricity system that promotes energy efficiency is therefore essential.

Electricity generation under a 2°C scenario

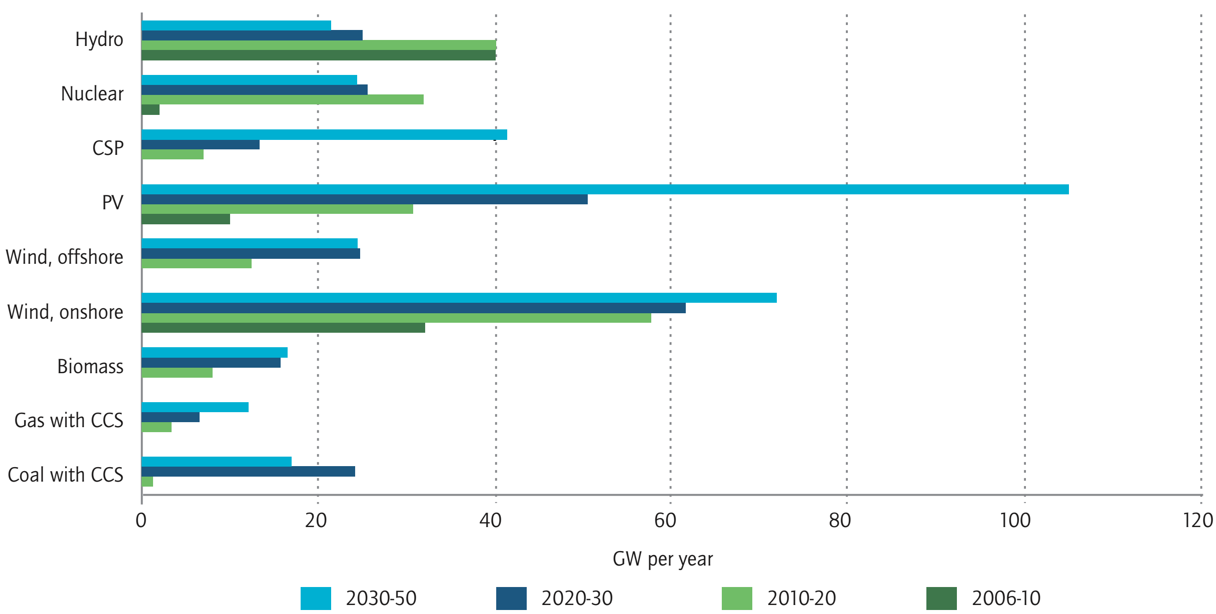
Energy Technology Perspectives 2012 (ETP 2012) analyses what requirements in the global energy sector are necessary to limit long-term global mean temperature increase to 2°C (in the 2°C Scenario, or 2DS).

The electricity sector in the 2DS is characterised by enhanced power generation efficiency, a switch to lower-carbon fossil fuels, increased use of renewables and nuclear power, and the introduction of carbon capture and storage (CCS) (Figure 3). More than 90% of the global electricity demand in 2050 is supplied by low-carbon technologies: renewable technologies reach a share of 57% in the world's electricity mix, nuclear power provides around 20%, and power plants equipped with CCS contribute 14%.

In the 2DS, more efficient use of electricity in the industry and buildings sectors also leads to a reduced electricity demand of 34 TWh in 2050. These efficiency improvements

Figure 3

Average annual capacity additions in the 2DS



in electricity use are partially countered by increased electricity demand from electric vehicles in the transport sector, as well as the rising use of heat pumps for heating and cooling purposes in the buildings sector. As a result, the share of electricity in final energy use increases from 17% today to 26% in the 2DS in 2050.

Tracking progress: where does the electricity sector stand in achieving the 2DS objectives?

Achieving the *ETP* 2012 2DS objectives is technically feasible, but action must start today to ensure that carbon-intensive power infrastructure is not locked in for the longer term, and that emerging low-carbon technologies are developed and deployed at the pace required. Some positive progress has been made in this regard, but analysis suggests that few power generation technologies are currently on track to meet the 2DS 2020 milestones necessary to reach the longer-term 2050 goals (Table 1).

- A portfolio of renewable power technologies has seen positive progress over the past decade, and is broadly on track to achieve the 2DS objectives by 2020. In particular, cost reductions over the past decade and significant annual growth rates have been seen for onshore wind (27%) and solar photo-voltaic (PV) (42%). Maintaining this rate of progress will be challenging but necessary.

- The technologies with the greatest potential for saving energy and CO_2 emissions, however, are making the slowest progress: CCS is not seeing the necessary rates of investment into full-scale demonstration projects and nearly one-half of new coal-fired power plants are still being built with inefficient technology.

- While most governments continue to see nuclear as an important and growing part of their future electricity mix, significant public and private sector efforts to ensure safety in response to increasing public opposition will be required to turn plans into reality.

The following section provides a more detailed assessment of progress in higher-efficiency lower-emissions coal, renewable power, nuclear power, and CCS in power generation.

Table 1

Summary of progress in the power sector

CO_2 reduction share in 2020*	On track?	Technology	Status against 2DS objectives	Key policy priority
36 %	not on track	High-efficiency, lower- emissions coal power (HELE)	Efficient coal technologies are being deployed, but almost 50% of new plants in 2010 used inefficient technology.	CO_2 emissions, pollution, and coal efficiency policies required so that all new plants use best technology and coal demand curtails.
	not on track	Nuclear power	Most countries have not changed their nuclear ambitions post- Fukushima. 2025 capacity projections 15% below 2DS objectives.	Transparent safety protocols and plans; measures to address increasing public opposition to nuclear power.
	on track	Mature renewable power	More mature renewables are nearing competitiveness in a broader set of circumstances. Progress in hydropower, onshore wind, bioenergy and solar PV are broadly on track with 2DS the objectives.	Continued policy support needed to bring down costs to competitive levels and deployment to more countries with high natural resource potential required.
	not on track	Advanced renewable power	Less mature renewables (advanced geothermal, concentrated solar power [CSP], offshore wind) not making necessary progress.	Large-scale research development and demonstration (RD&D) efforts to advance less mature technologies with high potential.
	not on track	CCS in power	No large-scale integrated projects in place against the 38 required by 2020 to achieve the 2DS.	Announced CCS demonstration funds must be allocated. CO_2 emissions reduction policy, and long-term government frameworks that provide investment certainty will be necessary to promote investment in CCS technology.

not on track *improvements but more effort needed* *on track but sustained support and deployment required to maintain progress*

High-efficiency and lower-emissions coal

Progress assessment

Coal is a low-cost, available and reliable resource, which is why it is widely used in power generation throughout the world. It continues to play a significant role in the 2DS, although its share of electricity generation is expected to decline from 40% in 2009 to 35% in 2020, and its use becomes increasingly efficient and less carbon-intensive. High-efficiency, lower-emissions (HELE) coal technologies must be deployed – including supercritical pulverised coal combustion (SC), ultra-supercritical pulverised coal combustion (USC) and integrated gasification combined cycle (IGCC) (Figure 4).

From a positive perspective, HELE coal technologies increased from approximately one-quarter of coal capacity additions in 2000 to just under half of new additions in 2011. By 2014, global SC and USC capacity will account for 28% of total installed capacity, an increase from 20% in 2008. Given their rapid expansion, China and India will account for more than one-half of combined SC and USC capacity. In 2010, however, just below one-half of new coal-fired power plants were still being built with subcritical technology. Given that CCS technologies are not being developed or deployed quickly, the importance of deploying HELE technology to reduce emissions from coal-fired power plants is even greater in the medium term.

IGCC technology, in the long term, offers greater efficiency and greater reductions in CO_2 emissions, but very few IGCC plants are under construction or currently planned because costs remain high.

Significant variation persists in achieved efficiencies of installed coal power-plant technologies, but the gap between designed and actual operational efficiency is closing. Based on a sample of plant estimates, the efficiency of India's installed subcritical plants stood at 25% in the 1970s, while those installed in 2011 achieve efficiencies up to about 35%; efficiency of the SC and USC among OECD member countries improved from about 38% to close to 45% over the same period. Poor-quality coal resources and inefficient operational and maintenance practices often result in lower operational efficiency. Given the long life span of existing coal infrastructure, improving the operational efficiency of existing plants offers obvious energy and cost-savings opportunities without significant investments.

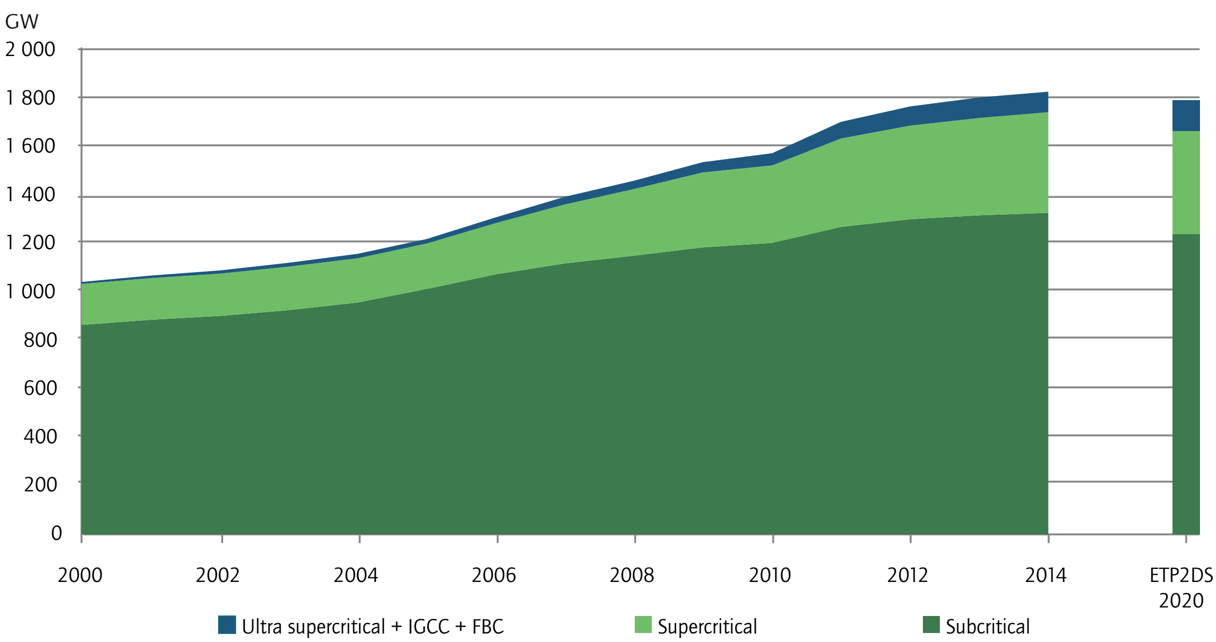
In summary, although the rising share of more efficient coal technologies is positive, policies must be put in place to stop deployment of subcritical coal technologies, curtail increased coal demand and further reduce associated CO_2 emissions.

Recent developments

From 2009 to 2011, demand for coal has continued to shift, particularly to China and India. Since 2000, China has more than trebled its installed capacity of coal,

Figure 4

Coal technology deployment by technology (2000-14) and in the 2DS



while India's capacity has increased by 50%. On an optimistic note, China has built more SC and USC capacity (40 gigawatts [GW]) than subcritical capacity (30 GW), and the share of power capacity from coal has slowed slightly, as its policy of diversification to nuclear and renewable sources takes effect.

As of 2009, 25% of India's population still had no access to electricity. To meet this large latent demand, India has rapidly increased construction of new coal-fired power plants, with 35 GW of additional capacity in 2011 (a threefold increase over 2010 additions). Until 2010, all new plants in India were built with subcritical technology, but from 2010 to 2011, 8.5 GW of SC capacity was installed, in parallel with 36 GW of new subcritical capacity.

Since 2000, coal prices have increased significantly (with OECD steam coal import prices increasing from about USD 33/tonne in 2000 to over USD 120/tonne in 2011), which if sustained, may provide greater impetus to build high-efficiency plants and operate existing plants more efficiently. If power prices are kept low, however, the additional capital investments required for higher-efficiency plants may prove challenging as profit margins are squeezed or losses incurred.

A number of OECD member countries are starting to shift away from coal to gas, due to lower natural gas prices (particularly in the United States), emerging emissions legislation and the need to balance greater deployment of variable renewables (in Europe).

Scaling up deployment

A combination of CO_2 emissions reduction policies, pollution control measures, and policies to halt the deployment of inefficient plants is essential to slow coal demand and limit emissions from coal-fired power generation. Governments are starting to adopt such policies, but must accelerate implementation to avoid locking in inefficient coal-fired infrastructure. To highlight a few examples:

- In China, 77 GW of small, inefficient coal-fired power generation was shut down by 2010 as a result of policies of the 11th Five-Year Plan. The 12th Five-Year Plan (2011-15) continues to call for the retirement of small, ageing and inefficient coal plants and sends a strong message about the introduction of a national carbon trading scheme after 2020. In 2011, six provinces and cities were given a mandate to pilot-test a carbon pricing system, which may go into effect as early as 2013. A shadow carbon price is likely to be implicit in investment calculations made by power providers.

- India's 12th Five-Year Plan (2012-17) sets the target of 50% to 60% of coal plants using SC technology. Early indications of India's longer-term policy direction suggest that the 13th Five-Year Plan (2017-22) will stipulate that all new coal-fired plants constructed be at least SC.

- In Europe, the European Union Emissions Trading Scheme (EU ETS) and increasing government support for renewable sources of power have largely eliminated the construction of new coal plants.

- In the United States, two key factors may result in limited construction of new coal power plants: the adoption of the proposed Environmental Protection Agency (EPA) CO_2 emissions standard on new fossil fuel-fired power plants, and the country's sustained shift to natural gas for power.

Nuclear power

Progress assessment

The nearly 440 nuclear reactors in operation across the world remained virtually constant over the last decade, with 32 reactors shut down and the same number of new plants connected to the grid. Overall, nuclear capacity increased by more than 6%, due to installation of larger reactors and power uprates in existing reactors.

In 2010, nuclear energy was increasingly favoured as an important part of the energy mix given its competitiveness (especially in the case of carbon pricing) as an almost emissions-free energy source. The nuclear industry experienced a number of plant life extensions, power uprates and new constructions: ground was broken on 16 new reactors, the most since 1985, mainly in non-OECD countries; in 2011, 67 reactors were under construction, 28 in China alone.

Recent developments

Since 2011, the earthquake and tsunami damage to the Fukushima-Daiichi nuclear power plant in Japan has cast some doubt over the future of nuclear power. Some countries have chosen to phase out nuclear reactors (*e.g.* Germany, Switzerland and Belgium); most confirmed that they are keeping nuclear power in their energy mix or will develop it further, albeit at a less ambitious rate than previously anticipated (Japan announced that they expect to reduce their dependence on nuclear power over the medium to long term). Some countries planning to introduce nuclear power for the first time (*e.g.* Indonesia, Thailand, Malaysia and the Philippines) are delaying and, in some cases, revising their plans.

Nearly all countries operating nuclear reactors have carried out stress tests to assess plant safety in the event of extreme natural events (earthquakes and flooding). The results, currently under review by regulatory bodies, are expected to increase the stringency of safety standards and thus require more investment in safety upgrades, especially for older plants. Overall, the outcome of the stress tests may make plant life extension more difficult and accelerate closures; may slow the start of new reactor projects (with siting and licensing expected to take more time); and may negatively affect public acceptance of nuclear energy. In 2011, construction began on only four new nuclear reactors, a significant drop in construction starts and investments from 2010 (Figure 5).

Taking into account the nuclear phase-out in Germany, Switzerland and Belgium, potentially shorter reactor life spans, and longer planning and permitting procedures, nuclear energy deployment is projected to be about 100 gigawatts-electrical (GWe) below the level required to achieve the 2DS objectives by 2025[1]. This represents a drop of about 15% against capacity projections before the Fukushima accident. At this rate, it is unlikely that nuclear deployment levels prescribed under the 2DS will be achieved.

Interest in small modular reactors (SMRs) may revive, given their suitability to small electric grids. Their modularity and scalability, with more efficient transport and construction, should lead to shorter construction duration, and lower cost and overall investment. The United States is licensing some of the more mature SMR designs, but it is unlikely at this point (given post-Fukushima re-analysis and low gas prices in the United States) that many SMR projects will launch before 2020. Large-scale nuclear plants, however, are still more competitive than SMRs in terms of cost of kilowatt-hours produced.

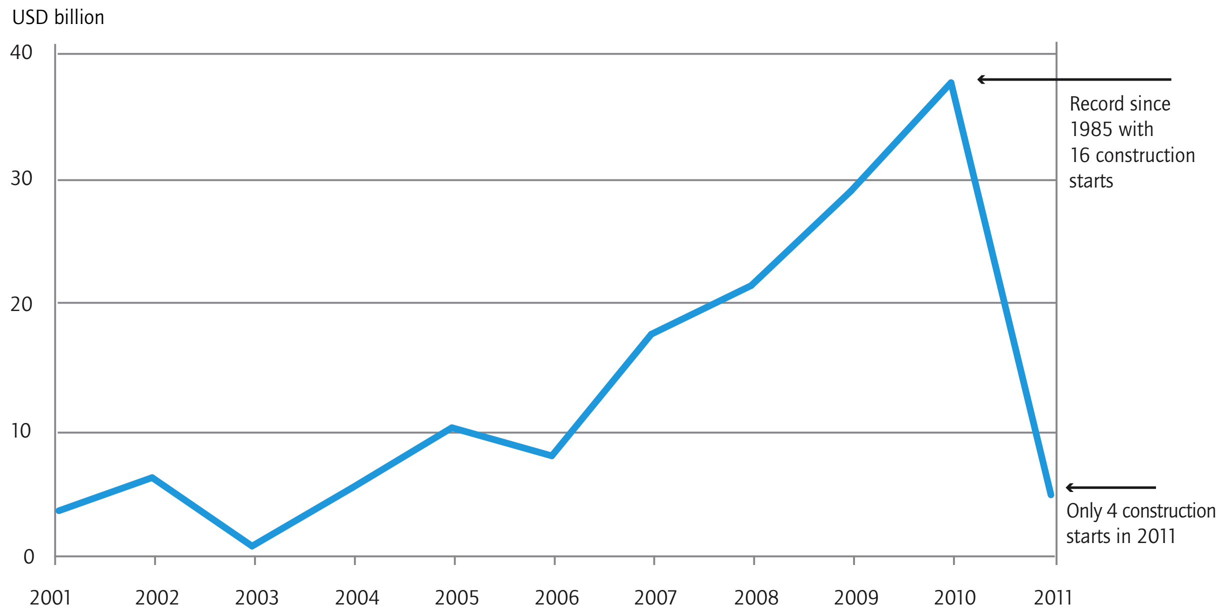
Scaling up deployment

In the post-Fukushima era, scaling up nuclear power faces increasing challenges. A 2011 survey polled public opinion of nuclear power before and after the Great East Japan Earthquake. It found that among the population sample surveyed, public opinion in favour of closing existing nuclear power plants rose from 21% in 2005 to 30% in 2011. Public opinion against building new nuclear plants rose from 39% in 2005 to 42% in 2011 (Globescan, 2011)[2]. While these findings reflect the results of one survey and should therefore be interpreted with caution, they convey an important message.

To reach nuclear generation goals, countries need to make significant efforts to convince an increasingly sceptical public that nuclear power should continue to be part of the future energy mix. In addition, rising costs associated with enhanced safety measures, difficulty in extending reactor life spans, and longer and more stringent processes for siting and licensing of new plants must be overcome. Governments and plant operators also need to increase transparency in their decision-making processes and implement updated safety and risk-management protocols. Strong, independent nuclear regulatory bodies are required for industry oversight.

Figure 5

Annual capacity investment in nuclear power

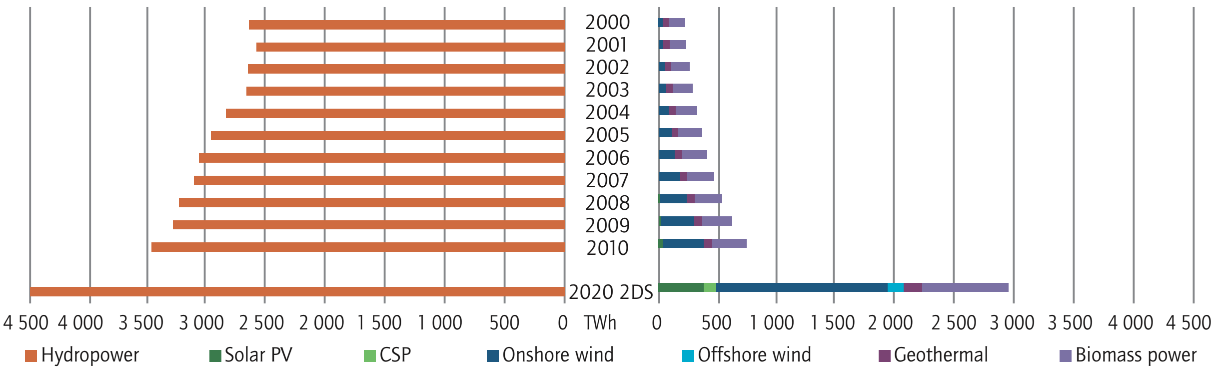


1. 2025 selected to highlight full impact of major plans to phase out nuclear energy.

2. Countries included in survey data include France, Germany, India, Indonesia, Japan, Mexico, Russia, the United Kingdom and the United States.

Figure 6

Renewable power generation and the 2DS



Renewable power

Progress assessment

Renewable power (including hydropower, solar, wind, biomass, geothermal and ocean) progressed positively in the last 10 years (posting 13% average annual growth in installed capacity). While starting from a small base, non-hydro renewables have been growing more rapidly, with generation doubling over the past five years. In 2010, their share of total electricity production remained at about 3% (Figure 6).

While the portfolio of renewable technologies is becoming increasingly competitive, thanks to favourable resource and market conditions, renewables are still more expensive than fossil fuel-based power technologies (Figure 7). The costs of some renewables dropped substantially over the past decade (in particular, solar PV which saw a 75% system cost reduction in some countries in just three years).

Recent developments

Renewable energy markets saw an active year in 2011. For the first time, global investment in new renewable power plants (USD 240 billion) surpassed fossil fuel power-plant investment, which stood at USD 219 billion (BNEF, 2011; IEA).[3] This is a positive development, but several factors point to a potentially turbulent 2012. Rapid reductions in technology cost will stimulate deployment of renewable technologies, but industry consolidation is looming as a number of smaller and higher-cost manufacturers become uncompetitive, in particular for PV and wind. The slow economic recovery across Europe and parts of North America will likely have different impacts from country to country. In those countries where long-term, effective and cost-efficient policies are implemented, renewables will be relatively sheltered from the crisis. Conversely, in countries where governments are rethinking policy schemes, investor confidence may decline. In general, the costs of financing are increasing, and developers may struggle to raise capital for renewable projects that require intensive up-front capital investments.

A number of market developments offer useful insights. In 2010 China became the world leader in total installed wind generation capacity, ahead of the United States, which had a difficult year. In 2011, China kept its lead, while the US market continued to grow compared to 2010. In China, however, out of the 63 GW of cumulative installed onshore wind capacity, only 47 GW were grid-connected at the end of 2011. The government has taken steps to remedy this situation. In general, the overall trend is clear: the centre of gravity for wind energy markets has begun to shift from OECD regions to Asia, especially China (IEA, 2011).

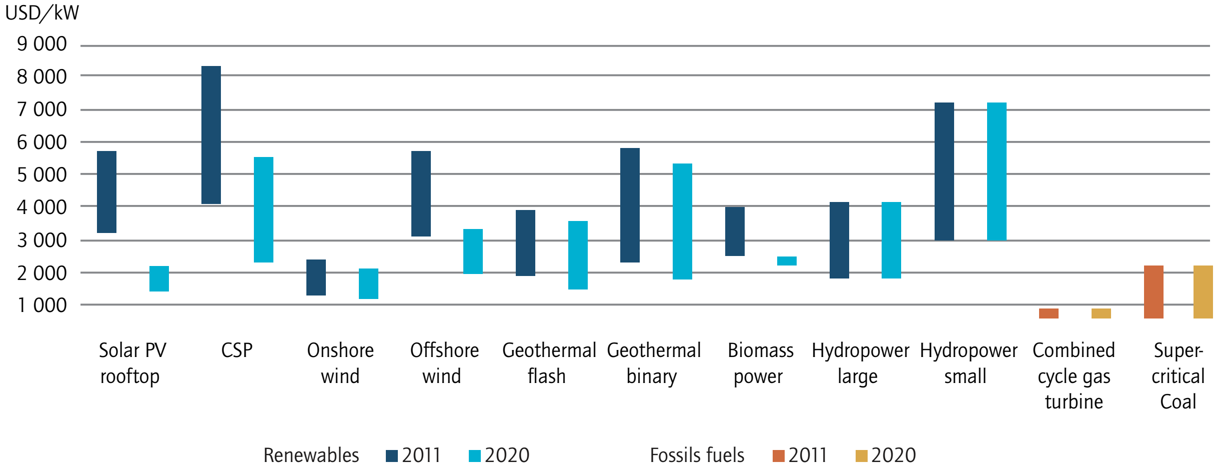
Under favourable market and resource conditions, onshore wind is also nearing competitiveness. In Brazil's 2011 capacity auctions, wind energy was more competitive than gas generation, even in the absence of specific government support for wind energy. This is promising for the future competitiveness of renewables.

Solar PV had a record market deployment year in 2011, with 27 GW of new capacity installed worldwide, an increase of almost 60% with respect to the 17 GW of new additions in 2010. Italy was the fastest growing market worldwide (9 GW), followed by Germany (7.5 GW), which remains the country with the largest cumulative installed capacity. High rates of PV deployment resulted from attractive and secure rates of return for investors, with government-supported tariffs in some countries remaining high as system prices decreased rapidly. However, so far the growth of PV has remained concentrated in too few countries. This has escalated total policy support costs, triggering an intense debate about the need to reduce tariffs and/or introduce caps to policy support. These uncertainties may reduce

3. Data for non-hydro renewables from BNEF, 2011; hydro investment estimates are derived from IEA analysis.

Figure 7

Renewable technology investment costs, 2011 and 2DS objectives



investor confidence in these markets. In the future, it is likely that European market deployment will slow, while new markets will emerge (*e.g.* China and India) and other OECD markets will increase (*e.g.* the United States and Japan).

Scaling up deployment

While progress in renewables has largely been on the upswing, the challenge of reaching or maintaining strong deployment of many renewable technologies should not be underestimated, particularly as the cumulative installed capacity grows and issues of grid integration of variable renewables (such as wind and PV) emerge in some countries. Keeping on track for the 2DS goals will require:

- in leading countries, sustained market deployment of renewable technologies that best fit their local market conditions (in terms of costs, resources and technology maturity);
- further expansion of renewables into markets with large resource potential, beyond the efforts in a few market-leading countries;
- continued research, development and deployment (RD&D) of emerging technologies, such as offshore wind, CSP and enhanced geothermal.

Carbon capture and storage (CCS)

Progress assessment

As global dependence on fossil fuels is not expected to abate significantly in the short to medium term, CCS is a critical technology to reduce CO_2 emissions and decarbonise the power sector. To achieve the 2DS objectives, about 16 GW of power generation would have to be fitted with CCS in 2020 (equivalent to about 38 medium-sized plants). By 2050, this number jumps to 960 GW, of which 600 GW would be coal-fired generation, 300 GW gas plants and the remainder biomass, either in dedicated biomass plants or in co-firing coal plants with CCS. Demonstrating CCS technology on a commercial scale and developing the CO_2 transport and storage infrastructure remains crucial.

Progress in CCS can be measured by the extent to which the technology evolves through large-scale demonstration projects. Its success depends on sufficient funding and government policies that support the demonstration and future deployment of the technology. Currently, there are no large-scale CCS plants in operation in the power sector (GCCSI, 2012), although some pilot activities are underway (Table 2). CCS technology in general, and its near-term deployment in the power sector specifically, clearly faces many challenges.

Table 2

Status of various CO_2 capture routes in the power sector (by fuel)

	Pre-combustion	Post-combustion	Oxy-combustion	Other
Gas	Concept	Pilot	Pilot	Concept
Coal	Pilot	Pilot	Pilot	Concept
Biomass	Concept	Concept	Concept	

Note: concept= conceptual design stage; pre-combustion, post-combustion, and oxy-combustion are different processes for capturing CO_2.

Recent developments

Given the high capital cost, risks associated with initial CCS projects and the fact that CCS is promoted primarily through climate policy, the technology needs strong government backing by way of CO_2 emissions-reduction policies and dedicated demonstration funding.

New funding for CCS demonstration projects peaked in 2008, when governments supported CCS technology demonstration as part of economic stimulus plans. Since this time, additional funding has been limited, and the allocation of announced funds still lags. Currently, approximately USD 21.4 billion is available to support large-scale CCS demonstration projects (mainly for projects outside the power sector), but as of 2012, only 60% of available funding had been allocated to specific projects (GCCSI, 2011). Persistent global economic challenges will further constrain government budgets, which means public funding for CCS will likely be cut back. Already, USD 0.4 billion in previously announced CCS funding has been withdrawn.

A few recent developments in CO_2 emissions policy, however, may provide some positive impetus in CCS development:

- The United Kingdom commenced an electricity market reform process in July 2011, intended to drive decarbonisation of the electricity sector, including through broad CCS deployment. Proposed measures include an emissions performance standard to ensure that no new coal-fired plants are built without CCS; a carbon price floor, intended to strengthen the incentive to invest in low-carbon generation; and a feed-in tariff combined with contracts-for-difference, to guarantee the price paid to generators.

- The Australian government passed new legislation on 8 November 2011 that introduces a carbon price of AUD 23 (USD 24.6) per tonne starting 1 July 2012, which will increase 2.5% per year. The initial price is fixed for three years before shifting to an emissions trading scheme on 1 July 2015. The government expects the carbon price to encourage investment in low-emission technologies, including CCS.

These examples are early steps towards policy architecture that is more favourable to large-scale CCS deployment.

Scaling up deployment

To scale up CCS, dedicated government funding and a broad carbon policy must be supported by a long-term strategy for CCS deployment and enabling regulatory frameworks. The IEA has developed guidance on how policy design can support CCS technology uptake from demonstration to large-scale deployment (IEA, 2012b), as well as criteria for governments to consider when developing CCS laws and regulations, through a model legal and regulatory framework addressing 29 specific issues. Three countries, Australia, Norway and the United Kingdom, are implementing comprehensive legal and regulatory frameworks, deployment programmes and policies, and have long-term CCS strategies.

For global progress to be made in CCS deployment, more countries will have to expand their CCS commitments. The private sector will be highly unlikely to take on the risks of investing in CCS demonstration projects otherwise.

Conclusion

In summary, progress in the development and deployment of the key clean energy technologies in the power sector currently falls short of that needed to achieve the 2DS objectives. The recent success of select renewable energy technologies provides a positive example of what can be achieved with the right market, technology and resource conditions.

Getting back on track will require timely and significant policy action by governments. While specific policy recommendations have been highlighted in individual technology areas, three broad policy actions will help expand the portfolio of clean energy technology options, and help achieve the 2DS goals:

- ensure that energy prices reflect the true cost of energy, accounting for the positive and negative impacts of energy production and consumption;

- unlock the incredible potential of energy efficiency – the "hidden" fuel of the future;

- accelerate energy innovation by scaling up public support for research, development and demonstration. This will help lay the groundwork for private sector innovation, and bring technologies to market.

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The role of electricity storage in providing electricity system flexibility

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Aging infrastructure, growth in peak demand and increased deployment of variable renewable generation, such as wind and solar photovoltaic (PV), are factors significantly affecting the security, cost and reliability of our electricity systems. Energy storage technologies can be used in a wide variety of applications to address concerns by providing a valuable source of ancillary services[2] and flexibility to the energy system, but storage deployment is restricted by high capital costs, inherent round-trip losses and market and regulatory barriers.

Pumped hydro is the most common storage technology at present. Other storage technologies, including mechanical and chemical conversion devices, struggle to compete with conventional electricity system technologies in cost and performance. However, in certain cases where the competing technologies are expensive, the value of storage can outweigh its cost.

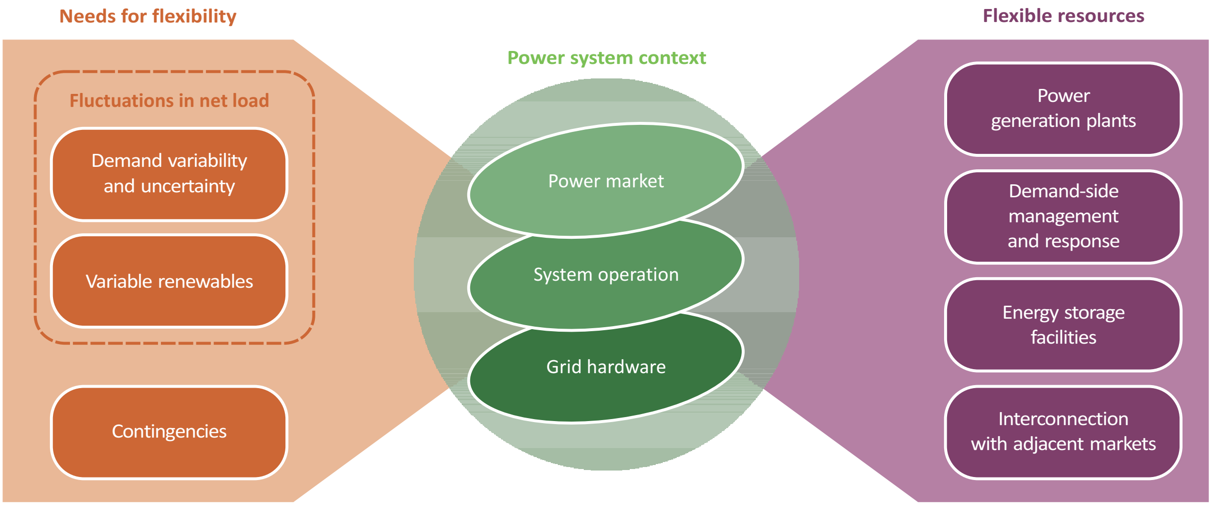
Electricity system concerns may create new opportunities for storage technologies in the development of a decarbonised electricity system, enabling increased levels of variable renewable deployments, while ensuring secure and reliable system operation. Much research and development work is underway internationally exploring new ways to achieve the benefits of storage at lower cost, to reduce the costs of new and emerging storage technologies and to address the other barriers to increased deployment.

Defining flexibility and storage

Power system flexibility "expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise. In other words, it expresses the capability of a power system to maintain reliable supply in the face of rapid and large imbalances, whatever the cause. It is measured in terms of the MW available for ramping up and down, over time (+/- MW/time). For example, a given combined cycle gas turbine (CCGT) plant may be able to ramp output up or down at 10 MW per minute" (IEA, 2011a, p. 35)[3]. Electricity systems need flexibility and employ a range of resources to meet it within their technical, regulatory and market frameworks (Figure 1).

Figure 1

Overview of flexibility needs and resources



1. *This article is a selected expansion of the discussion of electricity storage found in the chapter "Flexible Electricity Systems" in the IEA* Energy Technology Perspectives *2012.*

2. *Namely non-energy services that support the production and delivery of electrical energy* (e.g., *reactive power for voltage control and spinning reserve).*

3. *In a full evaluation of electricity system flexibility, other characteristics such as minimum stable load factor and start-up time must also be considered.*

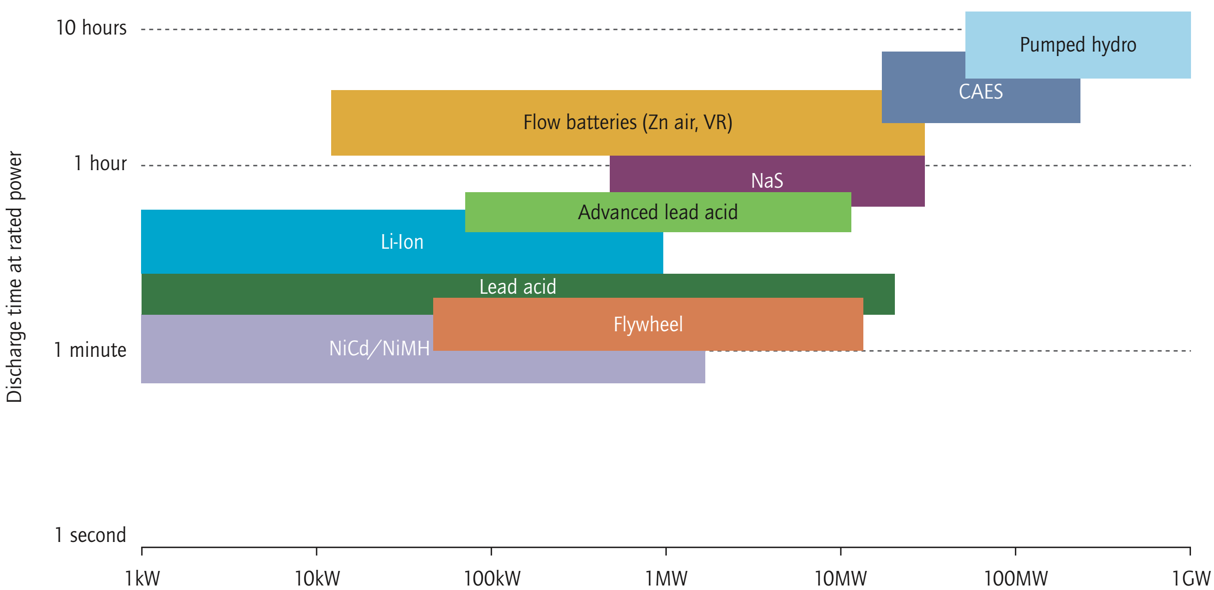
In most regions, dispatchable generation technologies that are able to adjust output on demand serve as the primary flexible resource. But, as the need for flexibility increases, it will be necessary and economical to incorporate interconnection, storage and demand response. To integrate flexibility resources into the electricity system, it is critical to look at the system in its entirety: generation, transmission, distribution and end use. Generally, a suite of solutions (based on regionally available types of flexibility) emerges, where current costs are evaluated against anticipated future costs, and current needs compete with long-term needs. Individual technologies must be examined for how they best fit flexibility needs, and must be evaluated against existing regulatory and market barriers that may prevent certain options from being considered in favour of conventional approaches.

While it is not possible to effectively store large amounts of electricity, it can be converted to other forms,[4] stored and then reconverted back into electricity with some predictable energy loss. Storage technologies distinguish between energy and capacity. Energy (in kilowatt-hours [kWh]) is the fundamental quantity delivered, while the rated capacity of a facility (in kilowatts [kW]) determines the maximum rate at which stored energy can be delivered to an electricity system. Thus, storage technologies have two fundamental characteristics that determine their technical suitability for a particular system application: the capacity at which they can discharge stored energy (in kW), and the time it takes to fully deplete the energy store at this power level (the discharge time). Storage technologies can be categorised by the range of rated capacity and their associated discharge times as shown in Figure 2 below.

For the most common past and present storage application, energy arbitrage,[5] the quantity of energy is relatively large, typically requiring high power levels over time scales of hours. This can be characterised as an energy application and pumped hydro (PH) or compressed air energy storage (CAES) could be applied here (top right-hand corner of Figure 2). In contrast, flywheels can produce power levels up to 20 megawatts (MW), but this can only be delivered over relatively short time scales, making it suitable for regulation applications (towards the bottom left-hand side of Figure 2).

Figure 2

Storage technologies by rated capacity and discharge time



Source: EPRI, 2010.

4. In compressed-air energy storage, electrical energy is converted and stored as a compressed gas. Battery technologies convert electrical energy and store it as chemical energy, using compounds such as sodium sulphur (NaS), lithium ion (Li-Ion), nickel-cadmium (NiCd), nickel-metal hydride (NiMh), and lead acid and flow batteries, such as vanadium redox (VR) and zinc air (Zn Air). Flywheels store kinetic energy (EPRI, 2010).

5. Arbitrage refers to the use of inexpensive electricity to fill a storage device (typically at night) for later release at times when electricity is more expensive (typically during the day).

Storage applications

Storage technologies can serve a range of power system applications, such as energy arbitrage, new capacity investment deferral, congestion management and a range of ancillary services. Their ability to switch from generation to consumption relatively quickly makes storage a valuable source of flexibility for the power system. The example of balancing in Figure 3 demonstrates that electricity supply and demand do not always match. During times of excess supply (shaded in green) due, for example, to high wind production during low-demand periods, electricity can be stored. During times of shortfall in high-demand periods (shaded in orange), storage technologies could act as a generation source to reduce or eliminate the deficit. In this case, storage contributes to the secure and reliable operation of the electricity system by assuring a manageable provision of power in reserve and deferring the need for additional generation capacity.

Storage technologies can also provide a range of ancillary services (regulation, spinning or operating reserves, voltage support and black-start capability) that have typically been provided as a by-product of electricity generation. Although storage technology is a versatile resource in an electrical system, its contributions to the system can equally be provided by other technologies, in particular transmission and interconnection. When assessing applications, storage must therefore be weighed against other technological measures: conventional generation technologies, transmission, interconnection, network devices (*e.g.*, capacitors and static compensation devices), operational practices (*e.g.*, forecasting, generation re-dispatch, protection measures and use of dynamic line rating information) and demand response, most of which are more mature technologies in serving system applications. Table 1 below maps many of the common storage technologies and their respective system applications or the functions they serve, and their level of maturity in performing such functions.

Storage technologies vary widely in maturity. They are generally less mature than competing technologies such as regional interconnection and system support back-up generation capacity. Storage, however, offers structural advantages. Unlike grid interconnections, it provides a self-sufficient solution independent of other grids, which is especially useful when interconnection is a challenge. Unlike compensation by back-up capacity, where a quick response is a challenge, storage can deal with troughs and peaks in intermittent outputs, possibly close to the output source, reducing stress on grids.

Current storage technologies

Pumped hydro

Conventional hydropower plants contain large amounts of stored energy which can be released when it would benefit the system, or which can be held back when cheaper resources (such as wind) would otherwise be curtailed (IEA, 2011b). Pumped hydro has many of the benefits of the two-way storage systems discussed above, but these plants are vulnerable to water availability which can vary seasonally with climatic factors such as drought (Sims *et al.*, 2011). Pumped hydro plants convert electrical energy from variable renewable energy sources, such as wind, into potential energy by pumping water from a lower reservoir to an upper reservoir during times when electricity generation exceeds

Figure 3

Hypothetical power supply and demand curves over two days

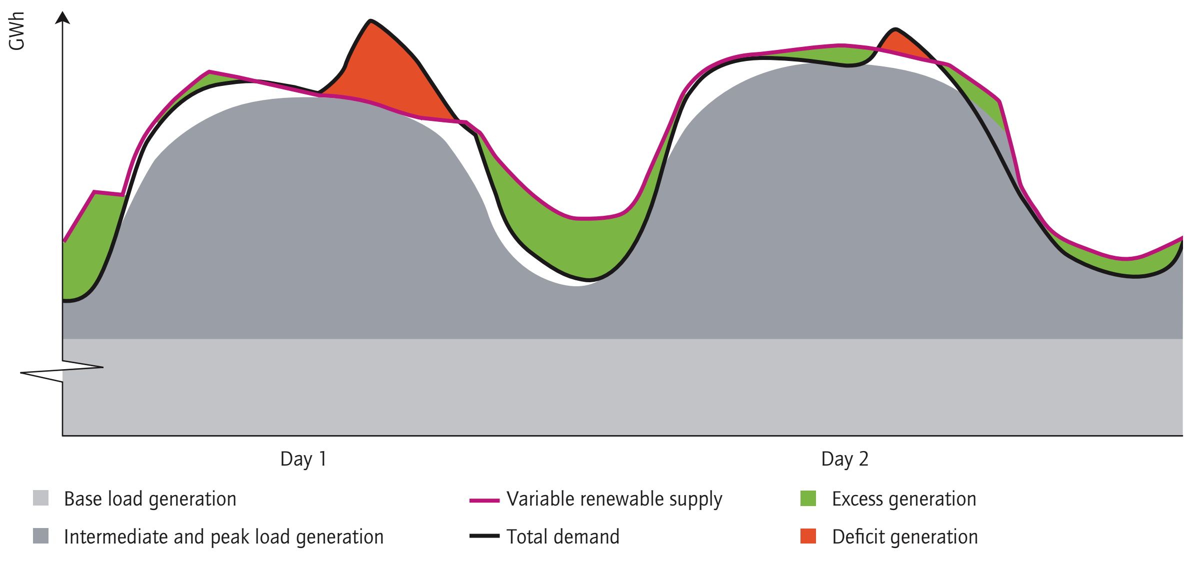


Table 1

Storage technologies by electricity system application (characterised by time frame and maturity)

			Storage application by response timeframe									
			Hours					Minutes			Seconds	
		Discharge time/duration	Energy arbitrage	Generation capacity deferral	(T&D) Investment deferral	Congestion management	Voltage support	Black start	Spinning reserve	Renewable ramp reduction	Regulation	Power quality
Storage technologies	Pumped hydro	Hours	M	M	M	M	M	M	M	M	M	
	CAES	Hours	C	C	C	C	C	C	C	C		
	Flywheel	Minutes						D	D	D	D	D
	Super capacitor	Seconds										D
	Lead acid battery	Hours										C
	Advanced lead acid battery	Hours						D	D	D	D	C
	NaS battery	Hours						C		C	C	C
	NiCd battery	Minutes									D	C
	Flow battery	Hours					R	R	R	R	R	R
	Li-Ion battery	Minutes									D	D

Technology maturity key: M Mature C Commercial D Demonstration R R&D

demand, normally at night. Electricity may then be generated whenever it is advantageous to the system by releasing water from the higher reservoir back into the lower. The process has a relatively high efficiency rating, ranging from 65% to 80%. Pumped hydro's power and storage capacities are comparable to those of conventional hydropower plants: power capacity is determined by the number and size of turbines/pumps, while storage capacity is determined by the size and elevation of the upper reservoir.

With approximately 130 GW installed worldwide, pumped hydro accounts for over 95% of the world's electricity storage capacity (IRENA, 2012). Most was developed from 1970 to 1995, taking advantage of the wide daily electricity price spread (*e.g.*, from high-priced oil peak-load plants to lower-priced nuclear base-load plants). During that period, this arbitrage opportunity justified the development of pumped hydro.

In the 1990s, the use of gas generation increased dramatically for both base load and mid-merit electricity production, using combined- and open-cycle gas turbines (CCGTs and OCGTs) for peak plants. The daily price spread narrowed as a result, undermining the incentive to build more pumped hydro capacity.

At present, energy arbitrage, the traditional driver for investment in pumped hydro, does not stand up in market conditions. Even though any storage technology connected to the grid could potentially affect price arbitrage, a certain size of pumped hydro would be required for significant revenues to be generated by the peak-time selling of power which had been stored in off-peak periods. The price difference would also have to remain large over a sustained period to generate a return sufficient to justify investment, but analysis by Pieper and Rubel (2011) has shown that this difference would have to be wider than that normally seen in markets.

Current viable scenarios for pumped hydro focus on the provision of ancillary services, such as balancing energy, following the shifting principle illustrated in Figure 3, with the precondition that there be market balancing mechanisms in place. Ancillary black-start supply services are also an option for pumped hydro, since it is not necessarily fully discharged on a daily basis. This emergency-reserve capacity could therefore generate additional revenues. Other viable scenarios are seen in very specific conditions, such as small-island power systems (Caralis and Zervos, 2007). Investments in pumped hydro for the provision of ancillary services and specific-condition usage have been increasing since 2003 (Figure 4).

Compressed air energy storage

Compressed air energy storage (CAES) is the second-largest storage capacity connected to the electricity system: with 400 MW installed worldwide, it accounts for 0.3% of total storage. Following compression, electrical energy is stored either under or above ground; the compressed air is then combined with gas to generate electricity. Being a hybrid device, CAES efficiency is difficult to calculate, but it has similar efficiencies to pumped hydro. Only two CAES plants exist in the world: in Huntorf, Germany (290 MW), and in McIntosh, Alabama, United States (110 MW). Interestingly, both were commissioned in the same period as most of the pumped hydro plants.

Both CAES plant use salt caverns, in which salt is dissolved to store the compressed air. Other geological structures may be suitable, however, including abandoned mines, aquifers and depleted gas fields. Above-ground CAES would require a purpose-built vessel. Similar to PH, the main CAES applications are in energy arbitrage and ancillary services.

Other storage technologies

Several types of batteries are used for large-scale energy storage, all consisting of electrochemical cells with different specificities and thus suitable for different applications.

At 316 MW worldwide, sodium sulphur (NaS) batteries are the next-largest (0.25%) electricity storage system after pumped hydro and compressed air energy storage. Lead-acid batteries, being reliable and cheap, are also in common use despite their smaller storage capacity. In order to obtain the most cycles possible (300-1 500) lead-acid batteries are designed to use only 10% of their storage capacity. Deep-cycle lead-acid (DCLA) batteries are currently operational in banks of up to 1 MW in wind-farm power generation (Bayar, 2011).

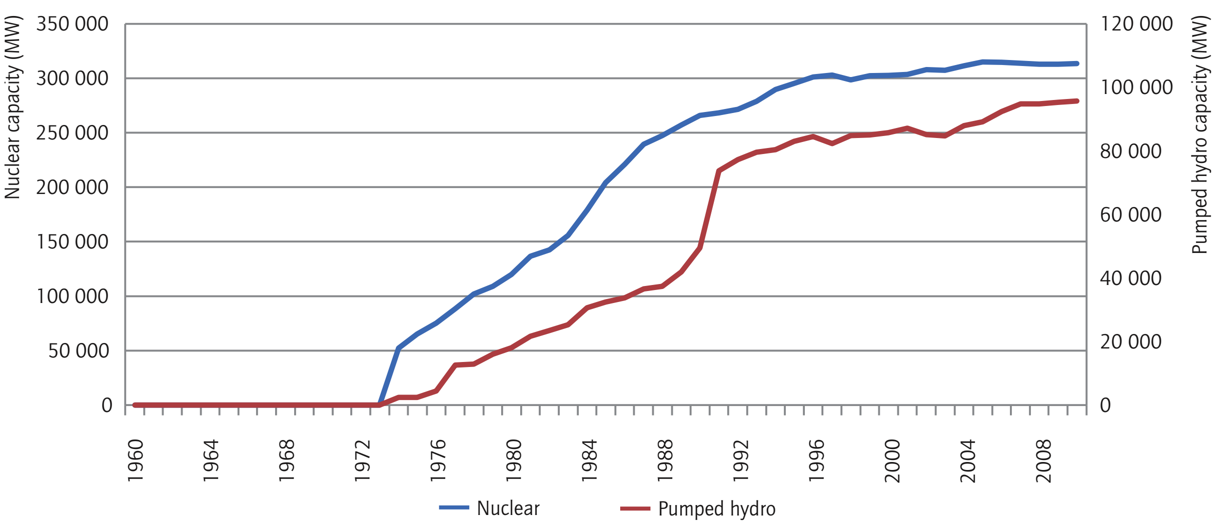
All other storage technologies combined – including battery technologies, flywheels and super capacitors – account for just 85 MW or approximately 0.07% of global capacity (EPRI, 2010). These technologies are generally employed in highly specialised ancillary services and localised power quality applications.

Battery energy storage in Alaska

A good example of a specific storage technology application is the battery system for frequency regulation on the island of Metlakatla in Alaska. In 1995 a 1.2-MW, 1-hour, lead-acid battery storage facility for Metlakatla Power and Light was built. This instalment was required to help manage the voltage and frequency fluctuations caused by variances in the electricity demand of the 1 000-person community. Small reciprocating diesel units using fuel imported on barges were used to provide this regulation service previously. The total cost of the battery storage facility was USD 2.2 million; it is estimated to have saved over USD 6.6 million in fuel over 11 years of operation (Manz, Piwko and Miller, 2012). This example demonstrates how the cost of storage can be preferable to the costs of the alternatives in specific niche situations.

Figure 4

Installed nuclear and pumped hydro in OECD countries



Barriers to energy storage

All electricity storage technologies have relatively high capital costs compared to conventional generation technologies. Costs and conversion energy losses vary widely across storage technologies. Figure 5 below illustrates the variability in cost per unit installed and per unit of energy output, while typical efficiency factors range between 45% for hydrogen and 80% for batteries (Pieper and Rubel, 2010). Both cost and efficiency factors currently constitute a significant barrier to wide-scale deployment of certain storage technologies, but the context is also a strong determinant. The appropriateness of an application is as vital as cost reduction and efficiency gains for financially sustainable deployment.

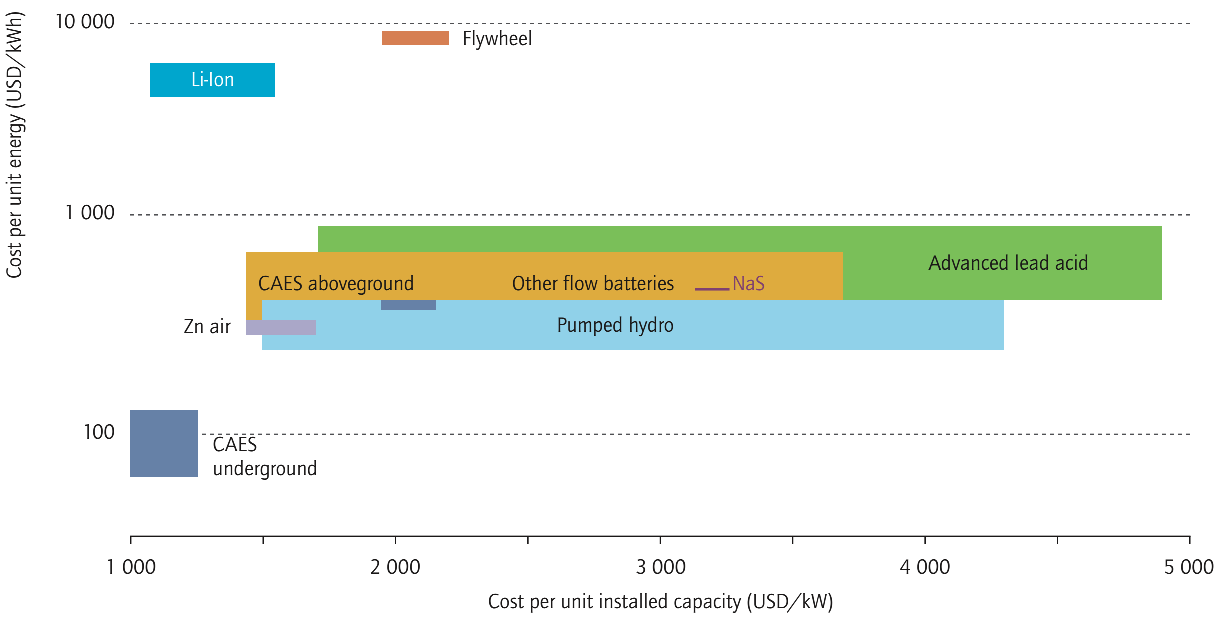
Although cost reduction is critical if storage is to play a large part in future electricity systems, much analysis to date values only the energy arbitrage potential of electricity storage. Valuation of other storage applications is ongoing, however – particularly its flexibility (Lannoye, Flynn and O'Malley, 2012). Because the characteristics of storage are so different from those of conventional generation, there are also institutional barriers hampering storage, which are being addressed by the modification of market rules. Cost targets for research programmes can be used as a proxy for future cost trends. The US Department of Energy's Advanced Research Projects Agency set a price target of USD 100/kWh, which is lower than the price of all the highlighted technologies (Figure 5). It should be noted, however, that real cost and cost projections vary widely and are difficult to verify.

The two main forms of storage deployed commercially today, pumped hydro and CAES, both depend largely on the availability of suitable geological structures, some of which may have already been exploited or may not be available at all in some regions. In the case of PH, many of the most suitable formations have been developed, leaving the remaining ones more costly to exploit. This is a possible factor in the decreasing rate of development of PH illustrated in Figure 4. Another factor may be that public opposition to the environmental impact of such developments has historically been lower compared to today's levels.

Some battery technologies depend on the availability of specialised materials. In the case of lithium-based battery technologies, the availability of the economically recoverable resource has been called into question (Sims *et al.*, 2011). Other battery technologies, notably NaS and advanced lead acid, have a limited number of charge and discharge cycles before performance is materially impaired, restricting their suitability for some applications.

Figure 5

Life-cycle costs of storage technologies per unit of installed capacity and energy



Notes: recent cost data for some technologies was not available from reliable sources. These technologies have been omitted from the graph.

Source: Data from EPRI, 2010.

Future potential of storage

Several proposals for storage are currently under development, such as 7.4 GW of pumped hydro in Europe (Deane, Ó Gallachóir and McKeogh, 2010), but few have actually been constructed. Some projects have been undertaken to retrofit existing hydroelectricity facilities with reversible pumps to create a pumped hydro facility (Estanqueiro, Mateus and Pestana, 2010; REN, 2008), or to install variable-speed pumps to increase the ability to provide flexibility. These projects recognise that, rather than pumping at a fixed load, pumped hydro stations can operate over a wider range of load levels to better accommodate renewable energy resources (Deane, Ó Gallachóir and McKeogh, 2010). In the area of battery storage, research and development of new materials and technologies focuses on reducing costs and addressing cycle limitations.

At higher penetrations of variable renewables, storage for energy arbitrage begins to make economic sense (Tuohy and O'Malley, 2011). But against other options, in particular building more transmission, the case for storage is less clear (EASAC, 2009). The increasing difficulty in building transmission for wind and solar deployment may obviate this situation (Denholm and Sioshansi, 2009). Greater interconnection of regional electricity systems may use the large existing hydro storage resources more optimally. Other more specialised applications for energy storage, such as the provision of very fast-acting reserve and virtual inertial response, particularly on isolated or weakly connected power systems, may also prove cost-effective (Wu *et al.*, 2008; Delille, Francois and Malarange, 2010). The ability of storage to increase flexibility across multiple time horizons underpins its potential value to a system with increasing flexibility needs.

The potential carbon dioxide (CO_2) emissions benefits of storage are unclear in some situations. Several studies show that storage increases CO_2 emissions,[6] but these results are system specific and depend on assumptions around fuel mixes and carbon prices (Ummels, Pelgrum and Kling, 2008). As variable renewable energy penetrations increase to high levels, storage eventually reduces CO_2 emissions by promoting the generation of electricity from variable renewables (Tuohy and O'Malley, 2011).

While storage may be a valuable source of flexibility for a power system, its deployment remains restricted primarily by high capital costs and low conversion efficiencies. Increased production from variable renewable generation and the increasing need for flexibility in the future may create new opportunities for storage. The use of storage to provide ancillary services, investment deferral and other applications still faces barriers in cost, market structure and regulation. In specific cases where the competing technologies are expensive, storage may be the most cost-effective option. Much research and development work is underway internationally to explore new ways to achieve the benefits of storage at lower cost, to reduce the costs of new and emerging storage technologies, and to address market and regulatory barriers to increased deployment.

In addition to these efforts, further work is needed to determine near-term opportunities for storage deployment and its long-term potential. These investigations must examine storage in the overall electricity system context and consider where it can best be used compared to other technologies (such as flexible generation, demand response and interconnection) that can provide the same electricity system services.

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Potential for bioelectricity in Brazil from sugarcane residual biomass

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Brazil is known for having one of the cleanest power sectors worldwide, with renewable energies accounting for 74% of installed power capacity, and over 91% of its actual power generation deriving from renewables in 2011. It is also the world's largest producer of ethanol from sugarcane, stimulated by a government programme launched in 1975 to achieve energy independence. Since 2009 more than 500 Mt of sugarcane have been processed annually to produce sugar and ethanol. The strong penetration of flex-fuel vehicles in Brazil and new international market opportunities for ethanol could double this figure by 2030.

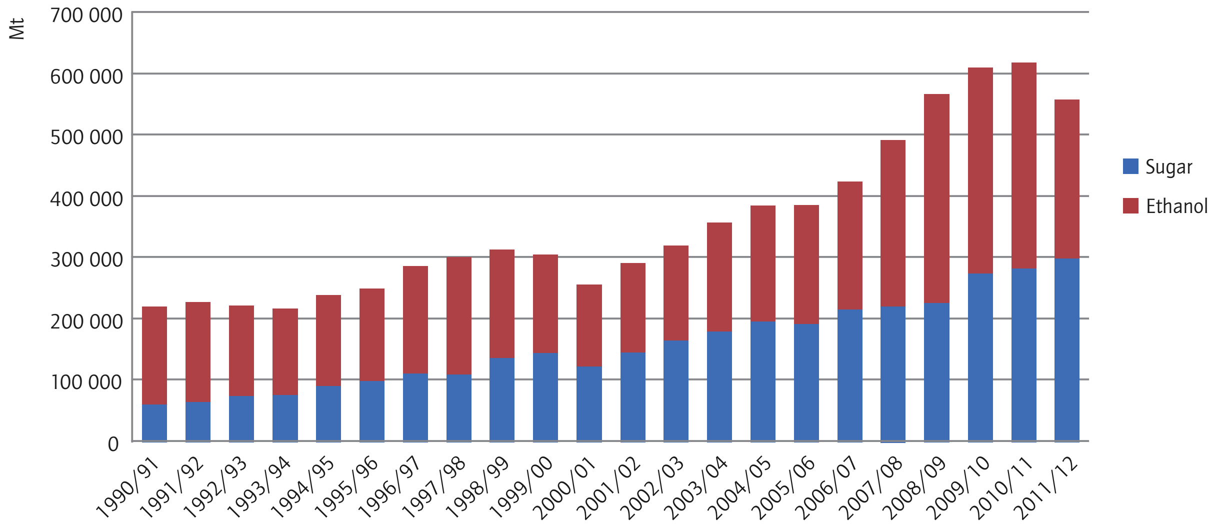
Production of both sugar and ethanol leads to large quantities of residual biomass, a by-product that can be used to generate bioelectricity, heat and advanced biofuels. With realistic assumptions on technological improvements, several studies show that sugarcane residual biomass bioelectricity could provide up to 24% of the 817 TWh projected Brazilian power demand in 2030. It could also avoid a significant percentage of projected power sector emissions by 2030.

Waste to resource: sugarcane residual biomass

The potential for bioelectricity generation from the sugar-ethanol industry depends largely on the availability of residual biomass[1], which depends, in turn, on a combination of factors related to the growing and harvesting of crops, and on how efficiently biomass residues are used at the plant. Currently, Brazil's sugar-ethanol industry comprises more than 440 mills that process sugarcane into sugar and ethanol (Figure 1). Both processes involve extraction of liquids from the raw sugarcane, which results in large amounts of fibrous waste – known as bagasse. In fact, from the total sugarcane biomass processed in the mills, around 28% ends up as residual bagasse: this means that from the 556 million tonnes (Mt) harvested in 2010-11, 167 Mt ended up as residual bagasse.

Figure 1

Total processed sugarcane in Brazil, 1990-2011



Source: UNICA and CONAB, 2012.

1. Residual biomass includes all leftover biomass from the fabrication of sugar and ethanol.

All Brazilian sugar-ethanol mills are energy self-sufficient because they burn around 90% of their bagasse in boilers with co-generation systems to produce steam and (bio) electricity to completely serve the sector's needs. In spite of this, and independent of the harvest method, the amount of bagasse available for fuel is far greater than the amount needed to meet the sector's steam and electricity demands, so it is still common that mountains of bagasse amass at the plant sites. This has led to a lack of effort in using this resource efficiently, because the more inefficient the boilers are, the more bagasse they consume, and the lower are the bagasse disposal costs incurred (Larson, Williams and Leal, 2001). Efficiency gains in mills' boilers, plus in existing co-generation systems, would therefore result in even larger mountains of bagasse left over. This means that the bioelectricity output which currently exceeds the sector's needs, could be even larger and available for insertion into the public grid.

The sugar-ethanol industry could contribute significantly to Brazil's electricity supply in the future, through the use of sugarcane residual biomass. This resource could provide a year-round[2] power source, improve the flexibility of the electricity system whenever it is available, and lower the country's energy related projected CO_2 emissions, provided existing barriers are removed.

Harvest methods and energy balances

The way the sugarcane is harvested largely determines the amount of biomass coming from the fields to the mills. Across Brazil, harvests are still largely carried out by manual labour. Because sugarcane is so dense, it is necessary to pre-burn the fields to eliminate the straw and give access to the labourers. Moreover, manual harvesters typically cut off and discard plant tops, sending into the mills only the stems from which ethanol and sugar may be most easily obtained. In terms of mass, the straw and plant tops represent 20% of the biomass available in the fields before harvest.

In fact, in terms of energy potential, the processed anhydrous ethanol represents only one-half of the potential energy available from the total biomass in the fields. The other half is contained in the bagasse, plant tops and straw (Table 1), all of which may have their energy potentials recovered either through advanced biofuels, or through combustion in boilers to generate additional heat or bioelectricity. This means the potential increase in bioelectricity output goes beyond the efficiency gains mentioned above, if the straw and plant tops are recovered and utilised together with the bagasse.

For the sake of comparison, Table 1 shows a compilation of net useful heat of some primary energy sources and energy carriers.

Table 1

Net useful heat of various materials

Materials	Net heat (KJ kg^{-1})
Gasoline	43 943
Charcoal	28 450
Anhydrous ethanol	26 784
Hydrated ethanol	19 670
Wood	23 336
Sugar cane	
Straw	15 074
Bagasse 50% moisture	7 868
Green leaves	4 930
Tops	3 327

Source: adapted from Rípoli, Molina and Rípoli, 2000.

Note: calorific values of gasoline, ethanol and other materials may vary.

Instead of through manual labour, harvesting may be carried out mechanically, which considerably affects the variables in energy and emission accounting associated with the sugarcane product's life cycle. Increased mechanisation entails a direct emission increase by diesel-burning harvest machines. Nonetheless, it eliminates the need for burning the fields, reducing overall nitrous oxides, particulate matter and methane emissions. Energy balances are also affected by mechanisation, since it ultimately substitutes human energy inputs by fuel inputs in harvest machinery, lowering the energy output/input ratios (Box 1). However, mechanised harvesting allows for the recovery of straw and plant tops, which if efficiently used would increase the net energy gained in the process, even though around one-third of the organic material is best left on the ground for soil nutrition purposes.

As Brazil's largest cane-producing state, São Paulo, passed a law in 2002 to phase out the burning of straw in cane fields by 2031, mechanical harvesting is tending to become the norm. The resulting increase in available residual biomass as a by-product from sugar and ethanol production significantly boosts the potential for bioelectricity output from bagasse. All that is needed now is the political and technological framework that would allow for the full deployment of such potential.

2. Stored biomass decomposes with time decreasing its calorific value and thus partially limiting its potential to supply power in off harvest months. The sugarcane harvest period runs from May to November, and chemical analysis studies have shown that bagasse is appropriate for power generation being for 150 days, losing about 25% of its calorific value (dos Santos et al, 2011).

Energy output/input in sugarcane processing

Sugarcane production and processing are highly energy-intensive. Under typical Brazilian conditions, the production of a tonne of cane requires the expenditure of 190 megajoules (MJ) of energy in the agricultural sector – on diesel burned in planting, harvesting, and transport machinery, as well as on fertilisers and others chemicals. Another 1 970 MJ is spent in the mills – on chemicals, power and heat, although bagasse provides nearly 100% of the power and heat requirement in the mills.

The extent to which these inputs are capable of drawing a substantive bioenergetic yield varies according to several variables. The ratio of energy return over input (EROI), or output/input, determines the net energy output of the process; the higher the value, the better the return. In energy literature, however, analyses are not fully comparable due to divergences in the assessment methods. Standardising results from prominent authors in the field, Triana (2011) indicates that between 2.6 and 8.8 units of renewable energy output are recoverable from each unit of energy put into the Brazilian sugarcane agribusiness system. Although the fuel inputs required for harvest mechanisation tend to lower the EROI, the increased output obtainable from recovering stalks and plant tops partially offsets this.

Beyond the EROI, it is important to fully acknowledge the biophysical constraints limiting the contribution of sugarcane bioelectricity. That is, the limits for arable land and nutrient availability within its fields.

Harnessing the potential

Generating the maximum surplus bioelectricity in sugarcane processing units requires three technical adaptations:

- sugarcane fields must be harvested unburned, and a reasonable fraction of the straw and plant tops must be recovered to supplement bagasse for power generation;
- efficiency in processing cane into sugar and ethanol must be improved to generate more surplus bagasse;
- efficient technology must be used to generate power, boilers must be suited to burn leaves and tops effectively, which may require pre-treatment.

A schematic of the basic energy and material flows occurring in bioelectricity generation from sugarcane under optimal conditions is shown below (Figure 2). It considers mechanical harvesting (recovering straw and tops) as well as efficient processing of sugarcane into ethanol and sugar in combination with efficient heat and power generation.

Despite the obvious advantages of accelerating generation of residual sugarcane bioelectricity, deployment progressed less than what was possible. Several barriers, to be discussed below, still hinder the full deployment of this renewable energy source.

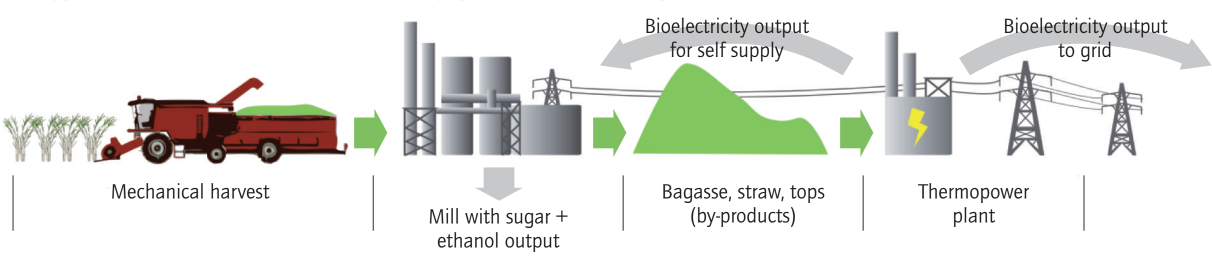
The Brazilian electricity market

Brazil's main power supply auctions (for base-load power) are generally dominated by hydropower offers. In recent years, however, environmental concerns have constrained the construction of new large-scale hydro reservoirs, many of which intended to flood fragile northern basins within the Amazon region. Several large hydropower plants were converted into run-of-the-river plants, such as Jirau, Santo Antônio and Belo Monte (PDE, 2011), generating concerns about their productivity due to region's marked seasonal periods of decreased rainfall. Consequent low seasonal hydropower supplies are now expected to entail increased demand from other sources, either from other renewables or from fossil power plants, raising concerns about increased emission levels.

Beyond base load, reserve-power contracting auctions determine which plants will supply projected energy demands into following years (with a surplus safety margin). In recent years, the government has put in place policies that aim to increase the participation of wind, biomass and small hydropower. The Program of Incentives for Alternative Electricity Sources (PROINFA), in force since 2004, guarantees purchasing from such renewable projects

Figure 2

Energy and material flows in bioelectricity generation from sugarcane



in 20-year contracts with fixed prices. PROINFA's effect on bioelectricity output from sugarcane residual biomass was lower than anticipated; electricity auctions between 2005 and 2007 incorporated only 26.5% of the total power sugarcane biomass capacity listed in the PROINFA programme (Teixeira and da Conceição, 2009).

As a result, the government substituted (from 2007 onwards) PROINFA's fixed-price contract model with specific alternative source auctions for reserve power to complement base hydropower in meeting current and projected demand. This move has placed bioelectricity, fossil-fuelled power plants, wind power and small hydroelectric plants in equal conditions to compete in supplying complementary power loads for peak and base demands.

Renewables have since gained ground. From a total of 92 projects contracted (3 962 MW) in the latest auctions for reserve power and new power in 2011, the breakdown is as follows: 78 were wind power farms (1 928 MW); 11 were sugarcane bioelectricity units (554 MW); two were natural gas units (1 029 MW); and one was an addition to an existing hydropower plant (450 MW). Average contract prices – all acquired with record low prices – were approximately USD 50 per megawatt-hour (MWh) for wind power, USD 51.6/MWh for natural gas and USD 50.5/MWh for sugarcane bioelectricity (CCEE, 2011).

For the first time, wind power and sugarcane bioelectricity have overtaken natural gas in offering the lowest average prices. Obviously, only a portion of competing projects will be contracted; but the percentage of capacity contracted from each primary energy source offers an insight into how successful the investors were in different power niches. Wind power had 31% of its capacity offer contracted and natural gas had 23%, while sugarcane biomass bioelectricity had only 20% of its offered capacity contracted (EPE, 2011).

This small percentage of contracted projects indicates that a combination of the three technological adaptations proposed above is required for the success of bioelectricity. The first point (recover straw and tops) increasingly occurs, but still lacks countrywide policy enforcement. The second point (increase cane processing efficiency) improved considerably due to the government incentive to modernise boilers, but currently progresses slowly mostly due to financing barriers. The last point (efficient power generation) also lags behind, mostly due to the fact that it depends on a parallel effort and investment for connecting power plants to the grid. Connection costs has thus become one of the key bottlenecks limiting bioelectricity contribution. This is further discussed ahead.

Current role and advantages of deploying bioelectricity

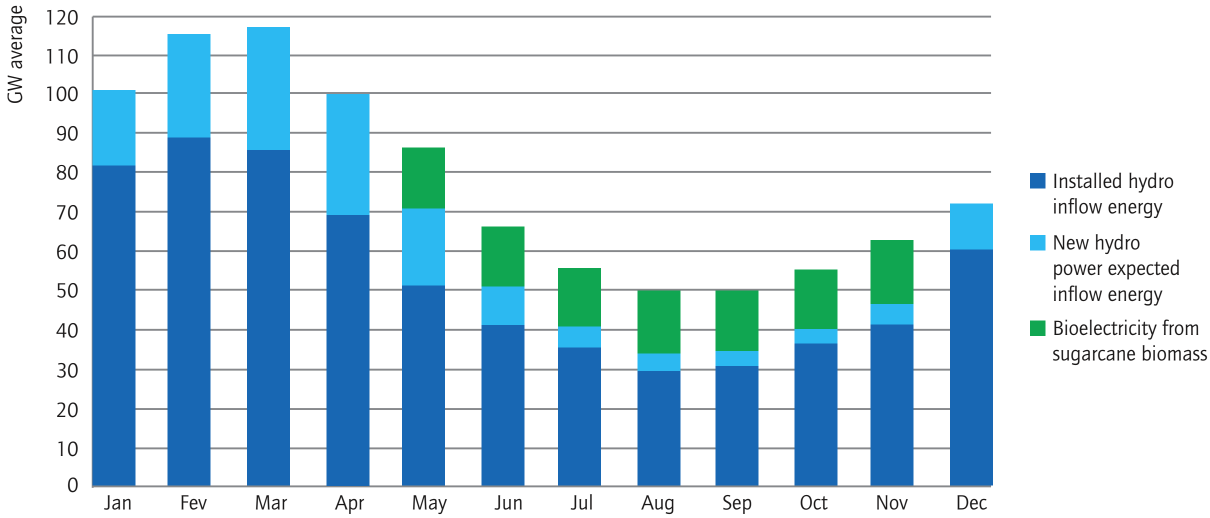
Sugarcane mill power plants currently have approximately 8 gigawatts (GW) installed capacity, representing 6.2% of Brazil's total electricity generation capacity (ANEEL, 2012). In 2011, these units produced around 22 terawatt-hours (TWh) in total, out of which almost 10 TWh were commercialized for the public grid, representing 2.3% of the country's total consumption in that year. Considering that only around 150 out of the existing 358 sugarcane mills actually export electricity into the grid, it is possible to infer that the other 208 are mostly operating inefficient systems, having not yet been retrofitted to export surplus power generation. In rough terms, if 150 mills exported 10 TWh, another 58 TWh/year could already be generated if all these inefficient plants were retrofitted.

Brazil's electricity policy configuration is set to dispatch hydropower as its main source of base-load electricity, marginally complemented by nuclear and variable renewable sources (such as wind). Other thermal power plants which include mostly gas, oil and biomass-fired are meant to act as back-up supply, given their capability to store fuel and their relative flexibility to ramp up power output when needed. Within this category of back-up supply, renewable biomass-fired plants are limited in their capacity of ramping up and down, due to technical limitations of boilers. Their contribution is also limited to the availability of excess generation beyond the sector's heat and power needs. Despite such limitations, biomass plants enjoy, under Brazil's regulatory framework a dispatch preference over fossil fuel plants. However, the 150 bioelectricity plants that are currently dispatching power to the grid do not operate year round, because they burn all of their biomass within the sugarcane harvest season. The combination of the three technological adaptations proposed above would allow these plants to have more biomass, and thus to store some beyond the harvest season. This permits the national system regulator to activate biomass plants also in off-harvest season, offsetting some fossil power generation.

The strong reliance on hydropower results in striking seasonal variation in power availability, as the country is relatively susceptible to periods of restricted rainfall. Typically, the power system regulator requires the back-up thermal generation in these times, giving dispatch preference to bioelectricity, but relying on fossil fuels for effective ramping up and down in short periods. Coincidentally, the sugarcane harvest periods suitably match the country's drier periods (Figure 3). This means that bioelectricity already has a role in balancing the seasonal variation of hydropower, partly avoiding the use of fossil fuels during that period.

Figure 3

Complementarity of hydropower and sugarcane biomass capacity in 2008



Source: GESEL, 2009

Aiming to increase the share of bioelectricity in the country's overall production of electricity, the government aided the sugar-ethanol sector to replace old low-pressure boilers with modern high-pressure ones, in line with the second technological adaptation proposed above. The effort yielded poor results in terms of bioelectricity output increase, largely because incentives were weak for the other two adaptations. Under this scenario, more biomass accumulates as few incentives exist for efficient co-generation and combined cycle systems to maximise electricity production from it, and the problem still exists of connecting these units to the public grid.

Transmission deficiencies in handling variable frequency over long distances are a major shortcoming of Brazil's electricity system. Several blackout events occurred during the past decade as transmission lines failed to connect the scattered and distant hydropower supply with large demand centres. Such transmission shortcomings can be partially tackled by the further insertion of bioelectricity into the power grid since most of the sugar-ethanol industry is located in the state of São Paulo. Being close to large power consumption centres - chiefly the cities of São Paulo and Rio de Janeiro - bioelectricity requires less transmission lines and enhancing security of supply.

Financial and policy barriers to the deployment of bioelectricity

A combination of factors is responsible for the low penetration of sugarcane bioelectricity in the market. Beyond the technical barriers to be overcome through the three technological adaptations mentioned above, critical non-technical barriers exist and are interrelated in what they require financing. One is the level of financial risk perceived by traditional producers when considering retrofitting an existing sugar/ethanol plant to incorporate a modern bioelectricity generation plant. The second is the need to upgrade/expand transmission lines to connect bioelectricity plants to the grid. Regarding the latter, a political struggle is in progress on the pivotal issue of who should pay.

Regarding risk percipience, there is an increasing potential for power generation resulting from the compulsory mechanisation of harvests, but different generations of sugarcane producers see this through different perspectives. In fact, processing straw along with the stalks decreases the quality and value of the sugar output. For traditional sugar producers who are used to dealing with sugar as their core commodity, this is seen as a setback. For them, power generation is seen as a high-risk investment with high upfront expenditure. To consider the retrofit of a mill and its power plant according to the technological specifications listed above, these plant owners must assess the additional revenue from increased power output in relation to retrofit costs and possible losses in sugar revenue. In contrast, new investors who focus on bioelectricity and ethanol, venture in growing markets and see bringing straw, plant tops and bagasse together in efficient units as an opportunity to boost revenues from power output.

Regarding need to upgrade/expand transmission lines, it is possible to observe a disconnect between the sugar-ethanol industry and power distribution utilities. Installing transmission lines is costly and there are legal and technical barriers that utilities have to deal with to allow for electricity to flow both ways and to pay users that insert more power into the grid than they consume. The mills that are currently connected to the grid show that sugarcane investors and utilities overcame these barriers in several instances, but these represent the "low-hanging fruits". It is likely that future installations will be more costly for requiring greater connection efforts to deliver power to end-users.

While sugarcane investors, the general population and the government all share interests in the further insertion of renewable energies into the grid, including bioelectricity, the question arises of who should absorb the associated costs. If this matter is left to market forces, only low-risk investments are likely to be pursued – and at a slow pace. The government faces an important challenge to supply steeply rising power demands, but may be in an impasse, as alternatives seem limited in the short term. Wind power has grown steadily, but still fulfils a small part in the country's supply. New hydropower plants take time to be installed, natural-gas and solar power additions are more expensive, and coal- and oil-powered additions are restricted by environmental laws. Seeing that the government is limited in terms of electricity generation options, new investors in sugarcane bioelectricity demand more incentives and consider high discount rates when offering power, in order to assure a quick return on their investment. The government may now decide to accelerate the deployment of sugarcane bioelectricity by the use of policy mechanisms.

As several mechanisms may lead to the desired results, further analysis is needed to pinpoint what type of action would produce best results. Options include: financing instruments that give access to capital; feed-in tariffs to support technological transitions; positive incentive policies to reduce taxation on more efficient equipment; minimum efficiency standards; and a range of other policy designs. Importantly, a policy action would attach a value to the energy security, power-sector flexibility and environmental benefits of bioelectricity, in line with overarching national strategies. The confidence of other investors and market players would be boosted as a result. As contracted bioelectricity gets commercially proven and tested, discount rates considered by private investors tend to be lowered and bioelectricity offered at more competitive prices in the next auctions.

Deployment scenarios: riding the wave of growing sugarcane production

Despite recent production recessions due to dry weather conditions, the annual amount of cane processed is expected to resume its upward trend from 2012 onwards. Pre recession governmental projections point to a rise in sugarcane production from 558 Mt/year in 2011-2012 (UNICA, 2012) to 1 273 Mt/year by 2030 (MME, 2007), which would require 100 new sugarcane processing units to be added by 2020. Demand for ethanol was expected to rise accordingly, from around 25 billion litres per year (L/yr) to 66 billion L/yr in 2030 (MME, 2007). The sector has however developed slower than planned in 2007, but may recover growth rates following a recent fall of the import tariff on Brazilian ethanol in the United States (UNICA, 2011), and other potential international markets such as South Africa. The extent to which the above expectations are realized will largely determine the potential to generate bioelectricity and to reduce electricity-related emissions. As stated above, financing the required investment is the fundamental challenge.

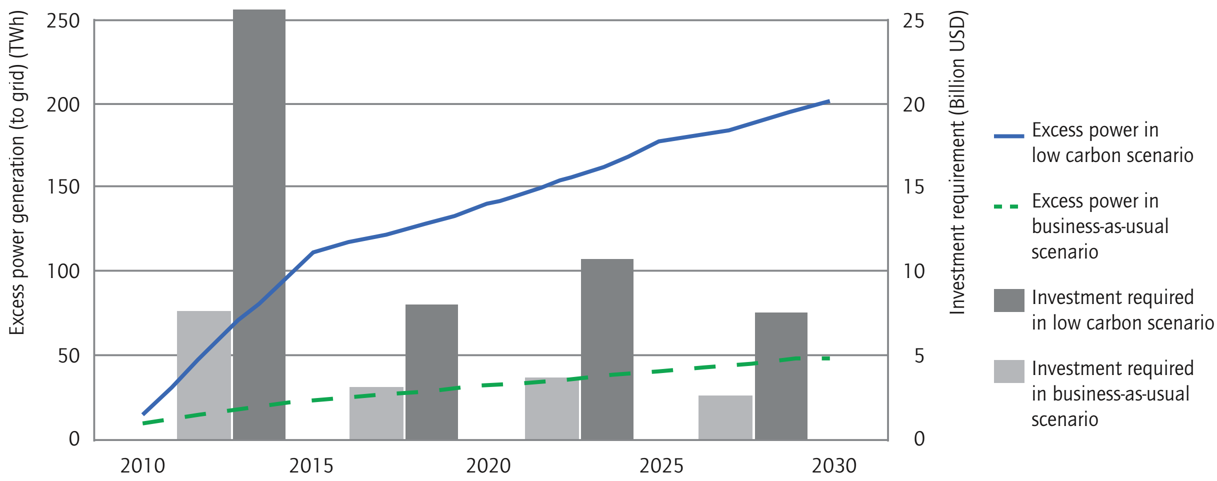
Several studies have considered different conditions to assess the potential contribution of sugarcane biomass in power generation, with a range of results (Carpentieri, Larson and Woods, 1992; Ensinas, *et al.*, 2007; ESMAP, 2010; Larson, Williams and Leal, 2001; Maués, 2009; Palacios-Bereche, *et al.*, 2009; Pellegrini and Oliveira Jr., 2007). In its low-carbon scenario, ESMAP (2010) projects that the installed capacity in sugarcane sector could build up to 39.5 GW, capable of generating in excess of 200 TWh by 2030 (Figure 4). This would correspond to 24% of the projected Brazilian power demand of 817 TWh in 2030 in the World Energy Outlook Current Policies Scenario (IEA, 2011).

Studies have also examined the potential offset of emissions from further integration of sugarcane bioelectricity in the Brazilian grid (ESMAP, 2010; PNUD, 2005; Rosa and Ribeiro 1998; Souza and Macedo, 2010; Veiga, 2009). Again, the results are divergent in several factors, due to unlike methods of assessing harvests, assumptions on technology penetration, base lines considered and time frames. The same ESMAP (2010) compares a business-as-usual scenario against a low-carbon scenario, in which the full bioelectricity potential is achieved based on realistic technological improvements. A progressive adoption of best available technology is assumed to happen in a limited number of sugarcane mills, especially beyond 2018, following the same three technological shifts proposed above. Results show that in this low-carbon scenario, sugarcane bioelectricity would offset 12 megatonnes of carbon dioxide ($MtCO_2$) per year from the power sector emissions, beyond a business-as-usual scenario by 2030. This would be equivalent to 12% of projected Brazilian power sector emissions in 2030 in the World Energy Outlook Current Policies Scenario (IEA, 2011).

More than USD 50 billion (including interconnection costs) is needed to scale up bioelectricity to its full potential between now and 2030 (Figure 4) (ESMAP, 2010). Whether or not its full potential should be targeted entails other questionings, mostly related to assessing advantages and disadvantages of supplying the country's power demand with bioelectricity or other options. The extent to which the investments are realized will largely depend on the risk perceived, or discount rate considered by investors. When compared to the average cost of the power grid expansion in the business-as-usual scenario, these costs

Figure 4

Projected excess power generation and investment required: low-carbon vs. business-as-usual scenario



Source: adapted from ESMAP, 2010.

– with a discount rate of 18% – make bioelectricity insertion costs higher than average expansion cost only from 2018 onwards. In fact, with this discount rate the average cost of power system expansion in the low-carbon scenario is only slightly higher: USD 58/MWh against USD 56.57/MWh (ESMAP, 2010). The co-generation option is, of course, much more attractive with a lower discount rate; as the technology becomes commercially proven and tested, a high discount rate would no longer be justified and sugarcane waste co-generation would become quite competitive.

Conclusions

Brazil has a consolidated sugar-ethanol industry for which considerable growth is projected in the medium term – 22% growth between 2012 and 2017 (IEA, 2012). Implementing policies to promote the most efficient use of this industry's residual biomass is a logical step forward, in line with the country's declared energy security and climate change policy objectives. However, prior to this it is important to perform thorough comparative assessments on the economic, environmental and societal benefits of supplying the country's rising power demands along with other renewable resources (*e.g.* wind).

If a governmental decision would be taken to maximize bioelectricity deployment, a policy framework that is co-ordinated across federal and state levels – and involving key industry stakeholders – would be necessary to accelerate the realisation of this potential. In this hypothetical case, the government may take a lead role in bridging the gaps that currently hinder the development of this energy source.

To stimulate the three technological improvements proposed above, policies should seek to:

- extend the law for phasing out pre-harvest burning to a national level;
- prompt the adoption of efficient cane processing and efficient power generation units;
- facilitate the installation of transmission lines between sugarcane mills and the public power grid.

Policy measures will likely be required in order to support the achievement of the latter two aims. The environmental and energy security benefits of increased bioelectricity deployment provide adequate justification for such action, but again should be thoroughly compared to the advantages of acting to deploy other renewable alternatives in parallel.

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Bioenergy with carbon capture and storage: the negative emission concept

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The combination of bioenergy with carbon capture and storage (BECCS) can, in theory, produce heat, electricity or hydrogen with net negative emissions to the atmosphere. Recent modelling studies indicate that BECCS may be a crucial mitigation option if greenhouse-gas (GHG) concentrations are to be stabilised at low levels (lower than 450 parts per million [ppm] CO_2). BECCS is currently at the demonstration stage, but its large-scale development raises a number of issues. The potentials of large-scale bioenergy production and large-scale CCS remain controversial, and the sustainability of basic biomass sources is a major concern. Strict standards governing the reporting and accounting of negative emissions are needed to reinforce policies encouraging BECCS development.

What is BECCS?

Bioenergy is the energy which is generated from the processing or combustion of biomass – *i.e.*, recently living organisms or their metabolic by-products. Like all carbon-based fuels used to generate energy, biomass emits carbon dioxide (CO_2) during combustion. Because the carbon found in biomass was recently extracted from atmospheric carbon dioxide by growing plants, however, the combustion of biofuels does not result in a net increase of atmospheric CO_2 concentrations. During their growth, plants absorb CO_2 from the atmosphere; this "ecosystem service" offsets the CO_2 emitted during the combustion of biomass (Figure 1, bottom left panel). Carbon capture and storage (CCS) is a technological means of collecting CO_2 emissions at the power generation source and transporting them into underground storage sites where the CO_2 may be contained for thousands of years. At present, the development of CCS is applied primarily to fossil fuels because of the urgent need to reduce their high combustion emissions (Figure 1, upper right panel).

Bioenergy in combination with carbon capture and storage (BECCS) can result in the net removal of carbon dioxide from the atmosphere. Applying CCS to bioenergy production (using the same technologies as for fossil fuels) can actually produce "negative emissions" (Figure 1, bottom right panel). This prospect was first pointed out by Obersteiner *et al.* (2001), and was further substantiated in work by Möllersten, Yan and Moreira (2003) and Rhodes and Keith (2005 and 2008).

The potential for negative emissions with the BECCS system is attractive for two reasons. Firstly, it could compensate for emissions from a variety of sources and sectors, even those that are technically difficult and expensive to abate, such as from air transportation or fugitive emissions.[1]

1. Fugitive emissions are emissions of gases or vapours from pressurised equipment due to leaks and various other unintended or irregular releases of gases, mostly from industrial activities.

Secondly, BECCS can mitigate emissions that have occurred in the past. "Time profiles" of emission reductions for given concentration targets could make allowance for higher emissions in the short term to be compensated for by negative emissions in the longer term. As long as storage capacity is available and BECCS is widely applied, it could be used to remove CO_2 emissions from the atmosphere on a continuous basis. It could therefore be a crucial tool in "overshoot" strategies, *i.e.*, climate-change mitigation strategies that reach greenhouse-gas (GHG) concentration targets only after an above-target peak period.

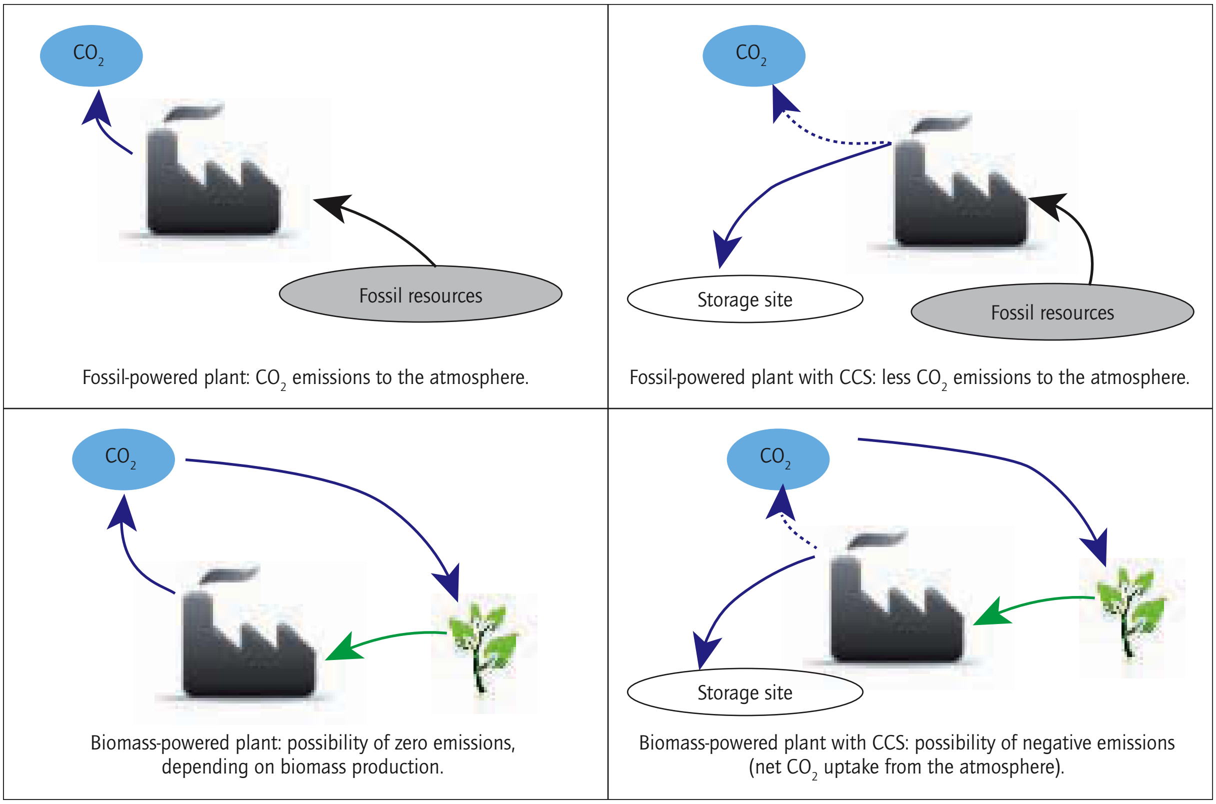
Negative emissions, however, can only be achieved if the production of bioenergy itself is carbon neutral, *i.e.*, that direct emissions (from fertiliser use, for example) and indirect emissions (from land-use changes, etc.) from bioenergy production do not outweigh the CO_2 emissions captured and stored.

What role for BECCS in low stabilisation strategies?

Recent modelling studies of low GHG stabilisation scenarios for the 21st century with integrated assessment models (IAMs) indicate that BECCS may be a crucial mitigation option. Several studies show that the large-scale availability of BECCS influences the cost and the technical feasibility of low concentration targets. Most modelling exercises conclude that without BECCS, very low targets (lower than 400 parts per million [ppm] of CO_2) are out of reach (Blanford *et al.*, 2009; Clarke *et al.*, 2009). When BECCS does not determine the technical feasibility of achieving a target, it still significantly influences its costs, and hence its economic feasibility and social and political acceptability (Edenhofer *et al.*, 2010; Azar *et al.*, 2010). For instance, Azar *et al.* (2010) report that existing evaluations estimate BECCS reduces the cost of reaching a 400 ppm CO_2 target by 20% to 70%. In contrast, for less ambitious targets

Figure 1

Carbon fluxes implied by fossil fuel-powered and biomass-powered plants, with and without CCS



(between 450 ppm and 550 ppm of CO_2), including BECCS in the technology portfolio has little or even no influence on cost, because less-costly mitigation options suffice to reach the target.

BECCS plays an important role in modelling low stabilisation scenarios for two main reasons. First, cost evaluations assess that BECCS will be less costly than some other mitigation options such as solar hydrogen, where hydrogen is produced

Integrated assessment models (IAMs)

IAMs are simulation tools for exploring long-term and global evolutions of technical systems and their interactions with the economy and the environment. They are widely used to assess GHG stabilisation scenarios. IAM teams develop their models to explore different assumptions and aim to improve the level of detail (e.g. energy conversion technologies, etc.) and to integrate more systems (e.g. the land-use system). The IAMs mentioned in this paper include:

- *GET (www.chalmers.se/ee/getonline);*
- *MESSAGE (www.iiasa.ac.at/Research/ENE/model/message);*
- *IMAGE-TIMER (http://131.224.244.83//en/themasites/image);*
- *MERGE (www.stanford.edu/group/MERGE/);*
- *REMIND (www.pik-potsdam.de/research/sustainable-solutions/models/remind);*
- *POLES (http://web.upmf-grenoble.fr/iepe/textes/poles-0506.pdf);*
- *GCAM (http://wiki.umd.edu/gcam).*

These IAMs differ in the level of detail of their representation of certain technical systems (e.g. power generation plants), their assumptions on costs and potentials of mitigation options, and their representations of energy demand, reaction to price changes, etc.

from water using the renewable energy of sunlight, or other negative emissions options such as direct air capture, a system which uses a chemical sorbent to remove CO_2 from air. For instance, Keith, Ha-Duong and Stolaroff (2006) evaluate BECCS would cost roughly USD 44 per tonne of CO_2 (tCO_2) removed from the atmosphere at current electricity prices, while direct air capture would cost around USD 136/tCO_2. Similarly, Azar *et al.* (2006) find that BECCS becomes competitive for heat, electricity and hydrogen production at a carbon price in the range of USD 27–54/tCO_2.[2]

Second, assuming negative emissions in the long term opens up the possibility of higher emissions in the near term. Deferring emission reduction actions reduces the overall discounted cost of mitigation by shifting costs into the future. This approach would lead to a higher peak atmospheric concentration than a strategy without the possibility of negative emissions in the long term. It is obviously a very risky strategy if the potential of BECCS turns out to be lower than expected.

In most low stabilisation scenarios BECCS is responsible for a significant share of total CO_2 reductions. For example, in the ADAM project (Edenhofer *et al.*, 2010), for a 400 ppm target, BECCS is responsible for 10% to 25% of total CO_2 reductions in the 21st century, depending on the model.[3] In the central assumption case of this project, BECCS reaches 200 exajoules per year (EJ/yr) of primary energy supply in 2100, with the entry date of the technology varying between 2020 and 2040. Table 1a outlines the focal points of recent modelling studies with respect to BECCS development in low stabilisation scenarios.

Table 1a

Focus of recent BECCS modelling studies

Study	Model/Aim
Azar *et al.*, 2006	Using the GET 5.0 model, examines a 350 ppm CO_2 scenario.
Calvin *et al.*, 2009	Using the GCAM model, this study analyses a 2.6 watts per square metre (W/m^2) scenario with an "overshoot" of the target at 3.4 W/m^2 in 2050.
Azar *et al.*, 2010	This study reports the results of three models (GET, MESSAGE and IMAGE-TIMER) for a 350 ppm CO_2 scenario.
Edenhofer *et al.*, 2010	This study reports the results of four models (MERGE, REMIND, POLES and TIMER) for a 400 ppm CO_2-equivalent scenario.

2. These evaluations of BECCS cost assume that the BECCS plant owners are paid for the capture and storage of the carbon, a price equal to the carbon tax per tonne of carbon captured and stored.

3. Four models are included (MERGE, REMIND, POLES, TIMER); one outlier was excluded (E3MG, which reaches the 400ppm target with almost no use of CCS).

Meeting the BECCS challenges

The large-scale development of BECCS as envisioned by some of the low stabilisation scenarios presented above depends on overcoming three challenges: ensuring the sustainability of large-scale biomass production; enabling large-scale CCS; and finding ways to combine the benefits of each into BECCS systems.

Large-scale biomass production

The large-scale development of biomass production, as envisioned in the low stabilisation scenarios presented above, raises three areas of concern: technical potential for biomass production; competition for use of land and water resources; and biomass sourcing.

The **technical potential of biomass production** remains controversial and difficult to characterise (IPCC, 2011) due to uncertainty on a range of issues, including growth yield, the production potential of degraded land, and climate-change feedbacks. It is therefore unsure that biomass production will be able to reach the levels modelled in the scenarios above shown in Table 1b .

Large-scale biomass production would increasingly **compete for use of land and water resources** with food, timber, conservation or other uses. This increased competition would imply trade-offs for water availability, food security, soil quality, biodiversity and subsistence farming. The benefits of bioenergy must thus be weighed against the potential undesirable effects of this increased competition for land and water.

The **sustainability of underlying biomass sources** is critical, as in all bioenergy systems. At the moment, a gap exists between life-cycle analysis of biomass impact on GHG emissions and the assumptions used in the models assessing low stabilisation scenarios (Creutzig *et al.*, 2012). Most models do not account for the GHG emissions from land-use change (indirect emissions) and increased land-use intensification, and assume that bioenergy production is carbon-neutral (Table 1a). Life-cycle analyses demonstrate that in some situations the overall impact of biomass on GHG emissions can be higher than the direct emissions of conventional fuels, depending on the use of fertilisers, the input of fossil fuels in the production, transport and conversion of biomass, as well as on how land use is affected by biomass production (Leemans *et al.*, 1996; Searchinger *et al.*, 2008). For example, if large-scale expansion of bioenergy required plantations that provoked deforestation or indirectly pushed the agricultural frontier into forested areas, large quantities of CO_2 emissions would be produced through the loss of the ecosystem service formerly provided by the forests. Searchinger *et al.* (2008) evaluated that corn-based ethanol, instead of producing a 20% savings of CO_2 emissions, nearly doubles GHG emissions.

Table 1b

Potential of BECCS according to modelling studies

Study[a]	Total biomass		Total CCS		BECCS	
	Development	Assumption	Development	Assumption	Energy supply	Capture and storage[c]
Azar *et al.*, 2006	Potential of 200 EJ/yr saturated from 2060 on	Bioenergy is assumed to be carbon neutral	2 200 $GtCO_2$ stored over the 21st century	90% capture rate, 0% leakage of storage	150 EJ/yr in 2100, with a start in 2040	Around 14.7 $GtCO_2$/yr in 2100
Calvin *et al.*, 2009	135 EJ/yr in 2050; 200 EJ/yr in 2100	Crop residue (90 EJ/yr in 2100), municipal solid waste (30 EJ), purpose grown (80x EJ)	35 $GtCO_2$/yr (9.5 GtC/yr) stored by 2050, 70 $GtCO_2$/yr (19 GtC/yr) by 2100; total stored around 3 500 $GtCO_2$		Around 140 EJ in 2100	Around 13.9$GtCO_2$/yr in 2100
Azar *et al.*, 2010	200-400 EJ/yr 2050-2100, representing 20%-40% of energy supply		Between 1 200 and 1 800 $GtCO_2$ stored over the 21st century		Between 150 EJ/yr and 300 EJ/yr in 2100, with start dates between 2020 and 2040	Between 14.7 and 29.3 $GtCO_2$/yr in 2100
Edenhofer *et al.*, 2010	Approximately 200 EJ/yr in 2100	Zero emissions attributed to bioenergy use[b]	From 1 000 to 1 900 $GtCO_2$ stored over the 21st century		In 2100, most of the 200 EJ of bioenergy is for BECCS	Approximately 19.8 $GtCO_2$/yr in 2100

a. The four publications often study more scenarios than the selection considered in this table, and often propose sensitivity analysis of the results to the main assumptions. For the sake of clarity, this table retains only the central case assumptions and a selection of the low stabilisation scenarios.

b. Emissions from direct and indirect land-use changes and from biomass production itself are neglected.

c. These data are not given in the publications. They result from the author's own calculations, taking the total primary energy supply from BECCS with the assumptions of a 90% capture rate and a biomass carbon content of 109.6 tonnes of CO_2 per terrajoule (tCO_2/TJ).

These concerns point to the risk of the negative effects of large-scale biomass production outweighing the benefits of negative CO_2 emissions, which may limit the potential for BECCS. Overall, if BECCS is to make a significant contribution to CO_2 concentration stabilisation, policies will need to be implemented to avoid large-scale biomass production hindering food security and other environmental goals.

Large-scale CCS

Another critical issue for large-scale deployment of BECCS is the potential to store carbon from both fossil fuels and bioenergy. An IPCC assessment (2005) reports global storage capacity in geological formations that is likely at least 2 000 $GtCO_2$, This is a technical resource estimates that evaluates storage potential irrespective of cost. Cost considerations may reduce the potential that can be economically exploited.

Currently, only a few million tonnes of CO_2 are being stored in geologic repositories each year; an increase in storage of three orders of magnitude is necessary to reach the low stabilisation scenarios presented above. Realising this potential requires identification of appropriate storage sites and a significant expansion of CO_2 transport infrastructure. Detailed regional assessments of storage capacity will be necessary, given that the information regarding the distribution and size of storage capacity is currently limited.

The combining challenge

Compared to the two separate challenges of developing large-scale sustainable biomass production and enabling large-scale capture and storage, combining both into BECCS appears less daunting. A few issues would have to be solved, however. To avoid excessive transportation needs and the associated emissions, facilities for biomass production, power generation and CCS would have to be located in close proximity; hence, BECCS applicability may vary across countries according to local conditions. Moreover, CCS is more suitable and less costly for large plants, whereas biomass-fired plants are typically smaller than fossil fuel-fired plants. CCS may therefore be more costly for biomass-fired than for fossil fuel-fired plants.

Conclusion: current status and questions for policy makers

Existing BECCS projects are currently at the demonstration stage.[4] Fourteen projects were identified (Biorecro, 2011), out of which five are in mature phases and represent in total around 1 $MtCO_2$/yr captured and stored. This amount would have to increase by four orders of magnitude by 2050 to reach the large-scale development envisioned in the scenarios presented above. The time scale necessary for development, deployment and diffusion of the technology makes it imperative that policy issues be addressed today. Two important concerns are the accounting for greenhouse gases in activities involved with BECCS, and incentives for BECCS development and deployment.

An IEA review (2011) of how international GHG accounting frameworks calculate negative emissions finds that current frameworks provide limited guidance. Recently proposed and revised guidelines, under the UNFCCC and the Kyoto Protocol, offer an environmentally sound reporting framework for BECCS. But, as currently written, the new UNFCCC guidelines do not tackle a critical issue that has implications for all bioenergy systems: the overall carbon footprint of biomass production and use. Emissions from bioenergy may currently be under-reported in Annex I countries – not due to a lack of scientific expertise, but due to ineffective accounting policy. Processing and other life-cycle emissions are accounted for in the LULUCF (land use, land-use changes and forestry) category, and are not attributed to combustion. In the first commitment period of the Kyoto Protocol, however, accounting for emissions and removals from land management activities in the LULUCF category is voluntary for Annex I countries. Where LULUCF emissions are incompletely reported or not reported at all, bioenergy can erroneously appear to cause zero emissions over its life cycle.

The IEA (2011) recommends that, to the greatest extent possible, all carbon impacts of BECCS be fully reflected in carbon reporting and accounting systems under the UNFCCC. A solid understanding and reporting of the life-cycle emissions savings that BECCS achieves is a prerequisite for supporting and incentivising BECCS as a carbon reduction technology.

Although it may use different technologies, CO_2 capture equipment fulfils the same function for all fuels: preventing emissions from reaching the atmosphere. Within a framework aimed at reducing emissions, this may be reflected in a single set of incentives for capture and storage technology – independent of the fuel on which the equipment ultimately operates. For this reason BECCS should be eligible for all incentives that apply to conventional CCS.

To better reflect the environmental benefits of the negative life-cycle emissions that BECCS can achieve, additional incentives could be developed. Thus, if a carbon tax was used to put a price on CO_2 emissions, BECCS plants could be paid a sum per tonne of carbon stored equal to the carbon tax. This could be seen as a payment for the environmental service provided by the "negative emitter". If a cap-and-trade system were chosen, BECCS plants could be allocated free emission permits in proportion to the amount of carbon captured and stored. This extra incentive could be applied to biological sequestration, to capture or to storage.

Each point of application has advantages and disadvantages (IEA, 2012). Applied to biological sequestration, the incentive would encourage innovation in the production of biomass and not discriminate among different downstream uses of biomass. But the implementation may be costly if covering all producers of biomass. Applying the incentive to the capture of CO_2 would be made easier by using the same administrative infrastructure as other, existing CCS incentives. Finally, applying the incentive to storage would encourage the delivery of captured carbon all the way to the storage site. However, the last two options imply larger risks of supporting unsustainable biomass.

4. In addition to the BECCS projects, many plants worldwide are co-firing biomass with coal in existing large power-station boilers. This approach makes use of the existing infrastructure of the coal plant and thus requires only relatively minor investment in biomass pre-treatment and feed-in systems. This option provides an opportunity for direct carbon savings by directly reducing the volumes of coal used, and may be seen as a bridge technology towards BECCS. Since efficiencies in old coal-fired plants are considerably lower than in state-of-the-art installations, new dedicated biomass plants will increasingly be needed.

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PART 2

DATA

World

OECD Americas

OECD Asia Oceania

OECD Europe

Africa

Non OECD America

Middle East

Non OECD Europe and Eurasia

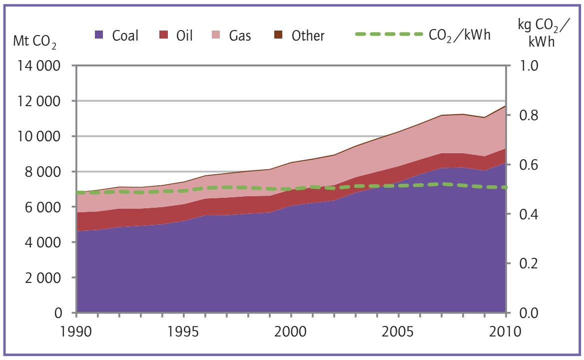
Asia (excluding China and India)

China

India

World*

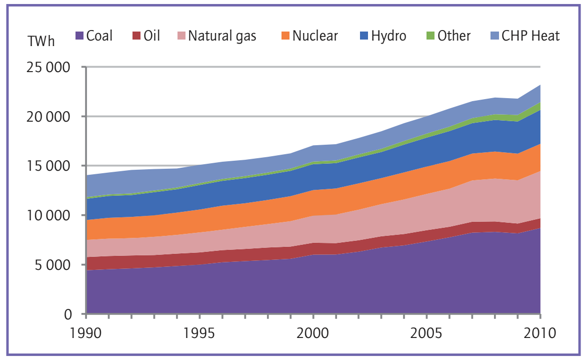
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 72.3% (Coal)
- Fastest growth over the last decade 57.7% (Gas)
- Emissions (annual rate): 2000-10 3.3%

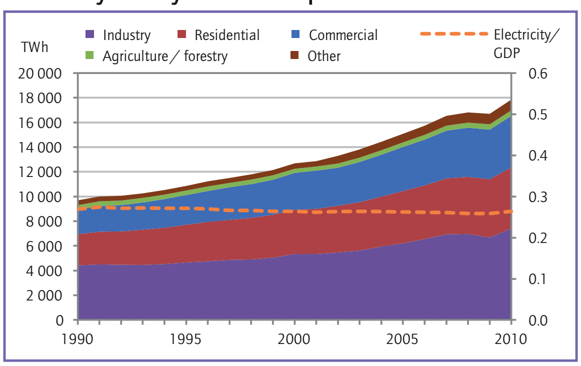
Figure 2
Generation mix of electricity and heat from CHP



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 40.6% (Coal)
- Fastest growth over the last decade 204.9% (Other)
- Electricity and CHP heat growth (annual rate): 2000-10 3.1%

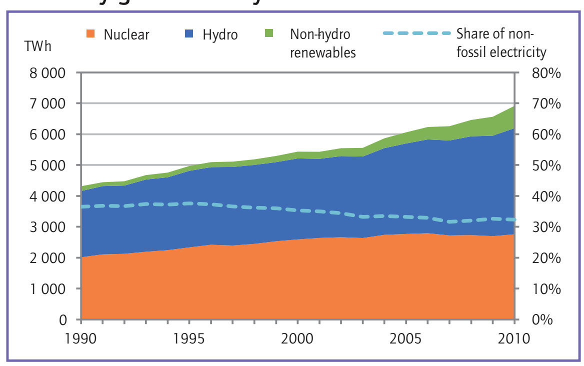
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 41.5% (Industry)
- Fastest growth over the last decade 97.5% (Other)
- Final electricity intensity (annual rate): 2000-10 0%

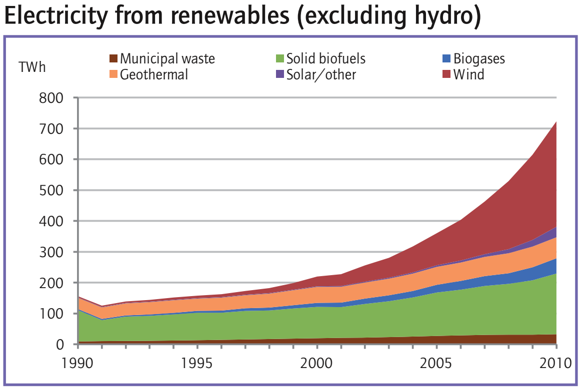
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 32.3%
- Largest source (2010) 49.7% (Hydro)
- TWh growth (annual rate): 2000-10 3.8%

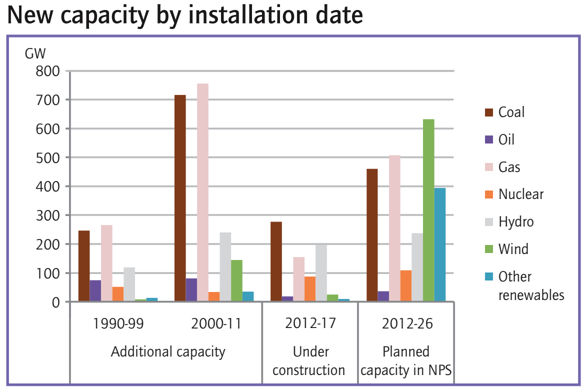
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 47.3% (Wind)
- Largest growth over the last decade 310.4 TWh (Wind)
- Growth (annual rate): 2000-10 12.6%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 27.2% (Gas)
- Largest additions under construction 26.5% (Coal)
- Largest additions planned between 2012-25 26.6% (Wind)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: World

▶ Total electricity and heat[1] output grew by 65% between 1990 and 2010, at an average annual rate of 3.1% in the past decade. The global economic recession caused the first decline in the period in 2009, affecting mostly North America and Europe, in contrast to consistent output growth in China and India. According to the Chinese press, China may now be the world's largest power producer, with an electricity output of 4 700 terawatt-hours (TWh) in 2011 (China Energy Weekly, 2012a).

▶ Global CO_2 emissions from combined electricity and heat production grew by 72% between 1990 and 2010, at an average rate of 3.3% per year in the last decade. Power sector emissions reached their highest level in 2010, exceeding 11.7 gigatonnes of carbon dioxide ($GtCO_2$) or 39% of global energy-related CO_2 emissions. The highest CO_2-emitting regions in the electricity sector were China (27% of the world total), OECD Americas (22%) and OECD Europe (11%). Global average power sector emissions per capita were 1.7 tonnes of CO_2 per capita in 2010. The OECD Americas region had the highest power sector emissions per capita, at 5.4 tonnes, while China approached OECD Europe's level of 2.4 tonnes per capita in 2010.

▶ Non-hydro renewables were the fastest growing source of electricity throughout this period, but coal still supplied 40% of global electricity and heat output in 2010. Gas gained market share over oil, with its share of electricity output growing from 17% to 20% between 2000 and 2010, against a decline from 8% to less than 2.6% in the same period for oil.

▶ CO_2 emission intensity of electricity and heat generation rose by 4.3% in the two-decade period, despite two consecutive years of reduction since 2008. OECD Europe witnessed the most important reduction in intensity (-27% between 1990 and 2010), an effort largely offset by increases in India (12%), Asia (7%), and Non-OECD Americas (7%). India and China had the highest CO_2 intensities, 80% and 49% above global averages in 2010.

▶ Industry still accounted for more than 41% of final electricity use in 2010, although its share declined over the past decade in all the regions, except for slight increases in India and China.

▶ Wind power generation is the largest renewable source of electricity outside hydro. Recent statistics show that over 79 gigawatts (GW) were installed in 2010 and 2011, bringing global installed capacity to 238 GW at the end of 2011 (GWEC, 2012).

▶ Global investment in renewable energy rose by 32% from 2009 to 2010, to a record USD 211 billion (UNEP, 2011). This figure reflects the effectiveness of policies to promote renewables, mostly feed-in tariffs, which were in effect in at least 60 countries by 2010 (IEA, 2012b). Total renewable energy subsidies worldwide were estimated at USD 66 billion in 2010, with USD 44 billion in electricity (IEA, 2011a). In comparison, more than USD 400 billion were spent to subsidise various uses of fossil fuels (IEA, 2011a).

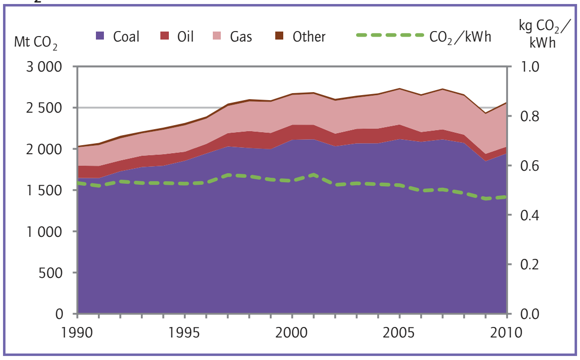
▶ The Fukushima Daiichi accident raised concerns about the safety of nuclear power, resulting in a deceleration of earlier plans, and decisions to phase out nuclear in Germany, Belgium and Switzerland. Nevertheless, significant growth in new capacity is envisioned, with 65 reactors under construction – of which 26 are in China, 10 in Russia, and 7 in India. Another 158 are on order or planned: 51 in China, 17 in Russia and 18 in India (WNA, 2012).

▶ Under the IEA World Energy Outlook New Policies Scenario (2011), capacity additions would amount to 3.1 TW globally by 2025. While coal (23%) and gas (21%) would dominate, wind and hydro would account for 21% and 13% respectively, which indicates a moderate decarbonisation of the sector in the next 15 years.

1. In this report heat refers to the output of combined electricity and heat plants.

OECD Americas*

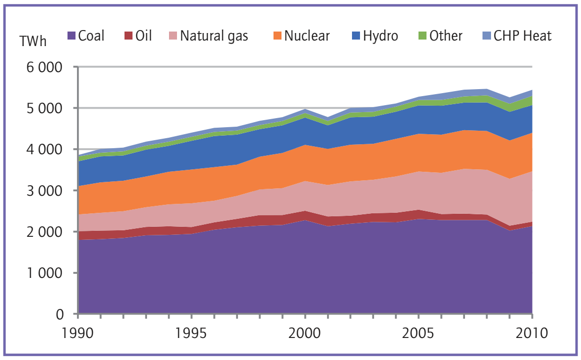
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 75.7% (Coal)
- Fastest growth over the last decade 44.7% (Gas)
- Emissions (annual rate): 2000-10 -0.4%

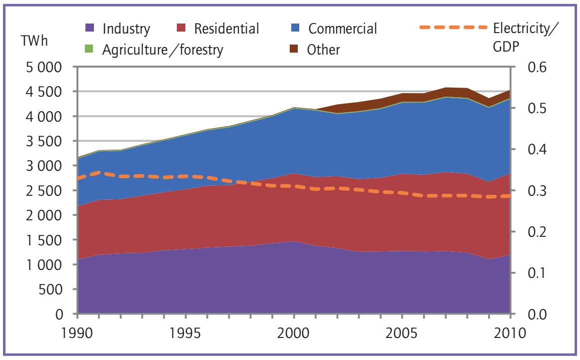
Figure 2
Generation mix of electricity and heat from CHP



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 40.3% (Coal)
- Fastest growth over the last decade 104.7% (Other)
- Electricity and CHP heat growth (annual rate): 2000-10 0.8%

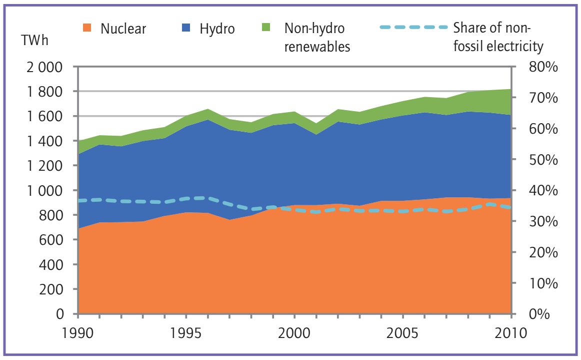
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 36.4% (Residential)
- Fastest growth over the last decade 1436.1% (Other)
- Final electricity intensity (annual rate): 2000-10 -0.8%

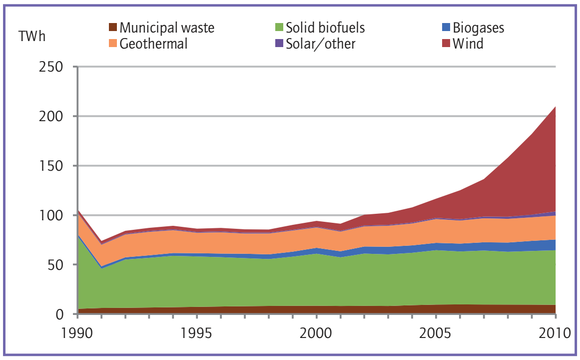
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 34.3%
- Largest source (2010) 51.5% (Nuclear)
- TWh growth (annual rate): 2000-10 1.5%

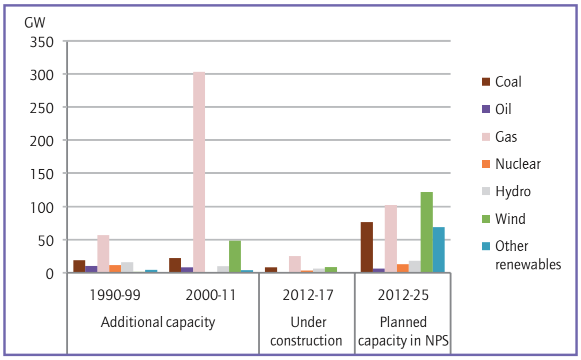
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 50.6% (Wind)
- Largest growth over the last decade 100.3 TWh (Wind)
- Growth (annual rate): 2000-10 8.3%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 64.5% (Gas)
- Largest additions under construction 38.8% (Gas)
- Largest additions planned 36.9% (Wind)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: OECD Americas

▶ Electricity and its associated heat output in the OECD Americas have returned to pre-recession levels, with a 3.4% growth in 2010. Power sector-related emissions rose by 5.3% after a sharp decline in 2009, but at 2.57 $GtCO_2$, they remained close to the region's emission level in 1999.

▶ Coal continued to supply the largest share of the region's electrical power generation in 2010, (39%), but gas-based power generation and non-hydro renewable energies grew most rapidly over the last decade, reaching 23% and 4.2% of the total respectively in 2010. The CO_2 intensity of power generation has been decreasing accordingly, on average by 1.3% annually over the past decade. The region reached 2010 the region emitting 0.47 tonnes of carbon dioxide per megawatt-hour (tCO_2/MWh), 7% below the world average.

▶ Electricity intensity of GDP decreased on average by 0.8% per year in the past decade, as power output outpaced gross domestic product (GDP) growth in the same period. The decrease indicates enhanced end-use electricity efficiency, as well as a tendency for energy-intensive manufacturing and industry sectors to lose shares of GDP of Canada, Chile and the United States (World Bank, 2012a).

▶ Renewables accounted for over 17% of total electricity output in OECD Americas in 2010 as a result of targeted policy support. Policies in support of renewable power include the Federal Renewable Electricity Production Tax Credit (PTC) in the United States, renewable portfolio standards in several Canadian provinces and US states, and renewable energy quotas in Chile (IEA, 2012b). The effectiveness of such policies is evident in recent data which show that 47 GW of wind power capacity had been added in the United States and Canada by mid-2011 (DOE, 2011; CANWEA, 2011).

▶ New power capacity additions planned in the region are expected to add 464 GW by 2025, out of which 27% will be gas-based and 28% wind-based. Gas currently dominates construction plans, with 25 GW of its expected capacity additions already under construction. Responding mostly to policy incentives and further decrease in cost, wind power capacity additions are expected to pick up late into this decade, exceeding gas capacity additions between now and 2025.

Emission standards for new power plants in the United States

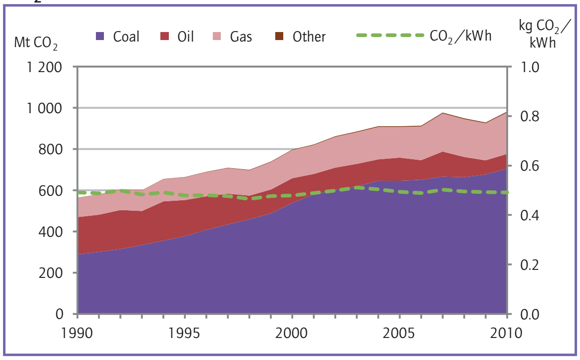
In March 2012, the US Environmental Protection Agency (EPA) defined its New Source Performance Standards, which limit emission rates for new plants in the power sector to 0.82 tCO_2/MWh for their first 10 operational years and 0.27 tCO_2/MWh thereafter, leading to an average of 0.45 tCO_2/MWh over 30 years. The average standard is in line with emissions from combined cycle natural gas plants, and 55% below the average emissions intensity of coal-fired power plants – unless they are fitted with carbon capture and storage. The standards pave the way for gas-fired or lower-emission power production technologies for future generations. In the near term, the extent to which gas will increase its share depends largely on relative fuel prices (gas v. coal). If gas prices are above a certain range, coal-fired generation is cheaper and will be dispatched more. Current reports show that recent spikes in natural gas prices, and expected fluctuations in 2013, may increase coal-fired power generation by 9.3% in 2013, which would drive up coal-power emissions by 8.5% (EIA, 2012).

In June 2012, a court decision upheld the EPA's actions in four elements of its greenhouse-gas (GHG) regulations, reinforcing the Agency's authority in regulating GHG emissions (Environmental Finance, 2012).

OECD Asia Oceania*

Figure 1

CO_2 emissions by fuel in electricity generation

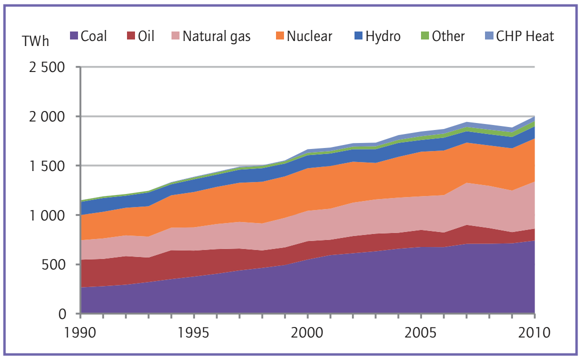


Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 71.8% (Coal)
- Fastest growth over the last decade 84.9% (Gas)
- Emissions (annual rate): 2000-10 2.1%

Figure 2

Generation mix of electricity and heat from CHP

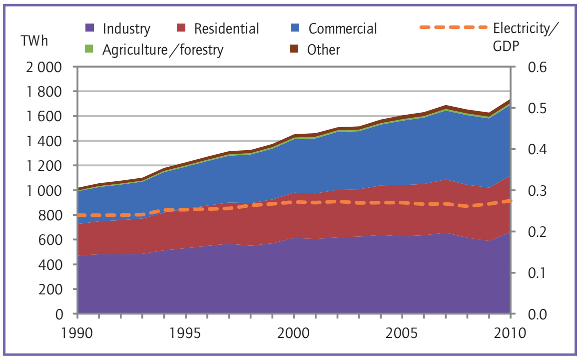


Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 37.9% (Coal)
- Fastest growth over the last decade 125.3% (Other)
- Electricity and CHP heat growth (annual rate): 2000-10 1.8%

Figure 3

Electricity use by sector and per unit of GDP

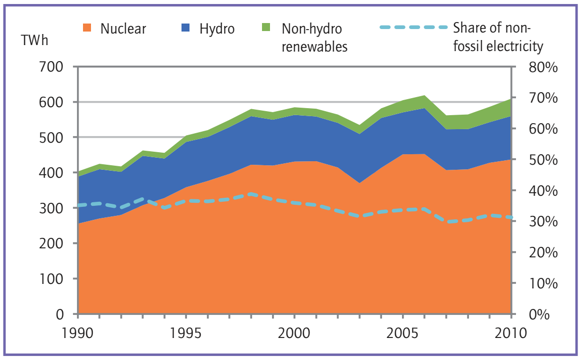


Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 38.1% (Industry)
- Fastest growth over the last decade 32.5% (Commercial)
- Final electricity intensity (annual rate): 2000-10 0.1%

Figure 4

Electricity generation by non-fossil fuels

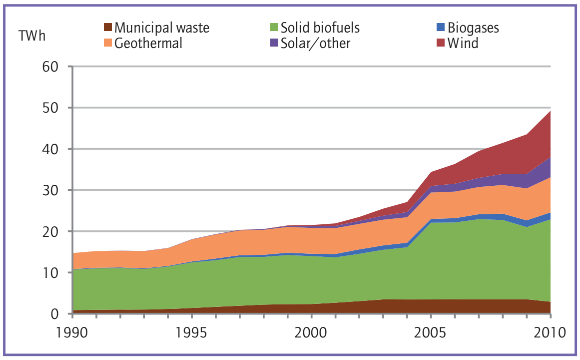


Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 31.2%
- Largest source (2010) 71.7% (Nuclear)
- TWh growth (annual rate): 2000-10 0.7%

Figure 5

Electricity from renewables (excluding hydro)

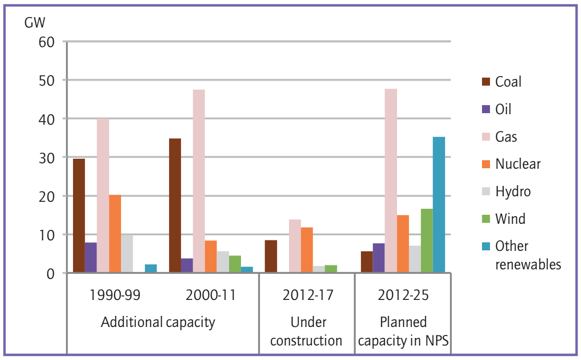


Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 40.5% (Solid biofuels)
- Largest growth over the last decade 10.9 TWh (Wind)
- Growth (annual rate): 2000-10 8.6%

Figure 6

New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 31.2% (Gas)
- Largest additions under construction 29.8% (Gas)
- Largest additions planned 35.4% (Gas)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: OECD Asia Oceania

▶ Electricity and heat output in the OECD Asia Oceania region rose on average by 2.8% annually between 1990 and 2010. The region's power and heat output in 2010 represents around 8.6% of that year's global output, and the region contains 3% of the world's population (UNDESA, 2011).

▶ Total CO_2 emissions from electricity increased by 2.1% per year on average over the last decade, amounting to 8.3% of the global power sector emissions in 2010. The CO_2 emission intensity of power generation remained stable throughout the period, mainly because of natural gas-fired power plants offsetting oil-fuelled generation in all the countries.

▶ The relatively balanced fuel mix in power generation in 2010 hides marked country differences, apart from a general dependence on coal. In 2010, Australia relied on coal to supply 76% of its electricity demand; Japan relied on nuclear power, coal and gas to supply roughly 27% each, reflecting its resource constraints; Korea relied mostly on coal (44%) and nuclear (31%); Israel depended almost exclusively on coal and natural gas; and hydro provided 55% of New Zealand's electricity needs.

▶ In March 2011 the Great East Japan Earthquake and tsunami forced several large nuclear and thermal power stations out of service. Anticipating shortfalls in electricity generation throughout the summer months, the government announced electricity-saving targets of 15% for most sectors (IEA, 2011b). Exacerbating the shortfall, several nuclear power plants were not allowed to go back online after routine maintenance checks in 2011. It was projected that increased reliance on fossil-fuelled plants and ensuing liquefied natural gas imports could increase electricity bills by 18% for an average household, and by 35% for industry (Yamashita, 2012).

▶ Among OECD regions, the growth in non-hydro renewable power generation was the slowest in OECD Asia Oceania; coupled with a decrease in hydropower output, this resulted in a declining share of renewable electricity from 13% in 1990 to 9% in 2010. Wind nonetheless recorded the fastest growth in the 2000-10 decade, mainly due to Japan's and Australia's capacity additions, and recent accelerated deployment in New Zealand and Korea.

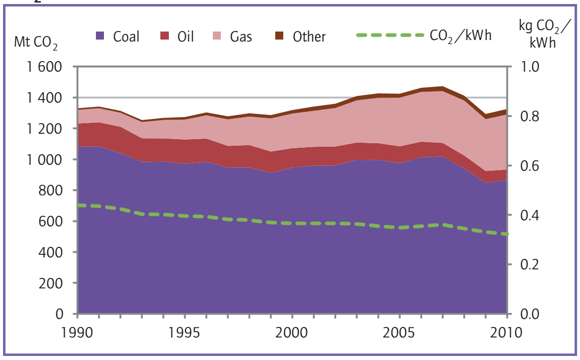
▶ New power-related emission reduction efforts were initiated in 2012. Australia's Clean Energy Legislative Package imposed a tax of AUD 23 per tonne of carbon dioxide equivalent (tCO_2e) on its 293 top emitters from 1 July 2012, aiming to reduce emissions from 2000 levels by 5% in 2020 and 80% in 2050 (DCCEE, 2011). Japan leads the East Asia Low-Carbon Growth Partnership Dialogue, supported by 18 Asia-Pacific countries which agreed to establish a new carbon offset market outside the Clean Development Mechanism. Israel intends to decrease its baseline electricity consumption by 20% by 2020 through its National Energy Efficiency Programme and feed-in tariffs for wind and solar technologies (MNI, 2012).

Japanese electricity-saving strategy

The Japanese government aims for a peak power demand reduction of 15% in relation to its baseline projected consumption. Mandatory restrictions are applied to large businesses, while small businesses are encouraged to make voluntary savings. In the public sector, lights were removed, dimmed or switched off, air-conditioning temperatures were raised and trains and metros ran less frequently in peak demand months. As a result, peak power demand was cut by over 15% in the summer of 2011. In June 2012, two nuclear reactors were back on line, but major power utilities saw decreased sales in July 2012 compared to the same month in 2011, despite record high temperatures (Hongo, 2012).

OECD Europe*

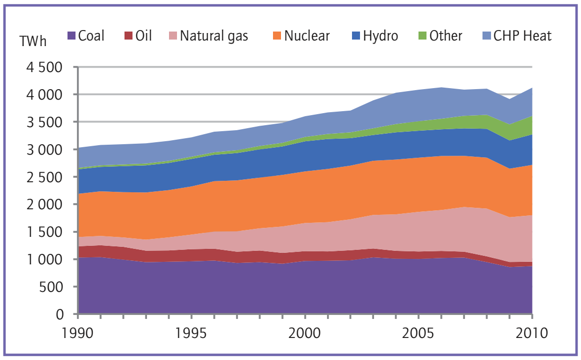
Figure 1
CO_2 emissions by fuel in electricity generation



Note: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 65.4% (Coal)
- Fastest growth over the last decade 59.3% (Gas)
- Emissions (annual rate): 2000-10 0.1%

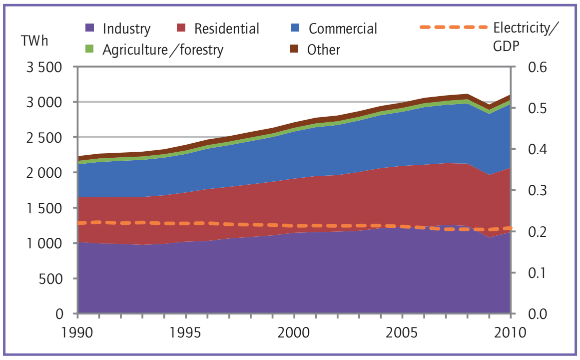
Figure 2
Generation mix of electricity and heat from CHP



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 25.4% (Nuclear)
- Fastest growth over the last decade 323.3% (Other)
- Electricity and CHP heat growth (annual rate): 2000-10 1.4%

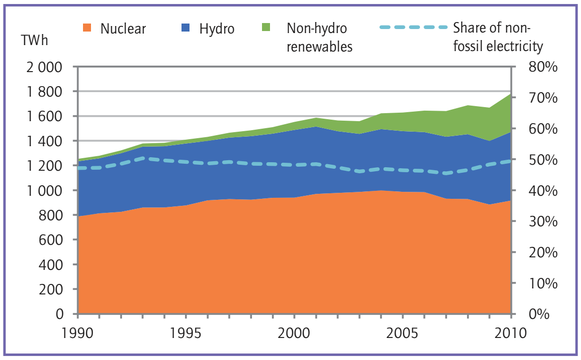
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 37.2% (Industry)
- Fastest growth over the last decade 35.4% (Commercial)
- Final electricity intensity (annual rate): 2000-10 -0.2%

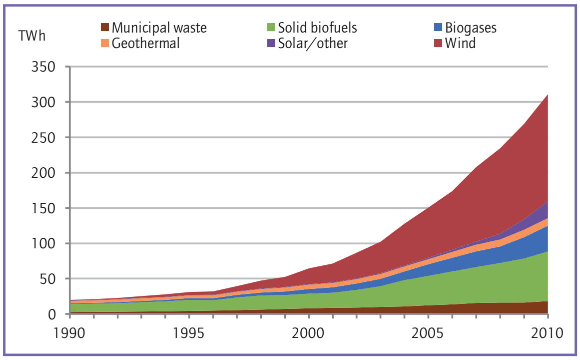
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 49.4%
- Largest source (2010) 51.4% (Nuclear)
- TWh growth (annual rate): 2000-10 3.3%

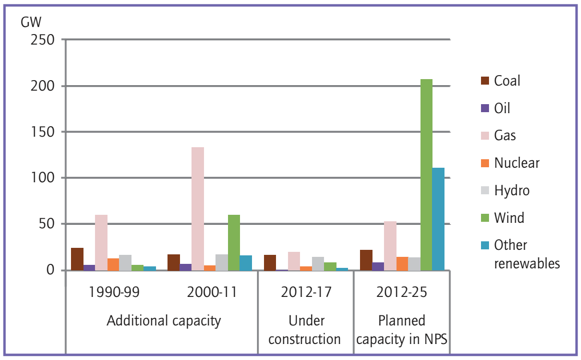
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 48.8% (Wind)
- Largest growth over the last decade 129.3 TWh (Wind)
- Growth (annual rate): 2000-10 17%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 45.1% (Gas)
- Largest additions under construction 23.4% (Gas)
- Largest additions planned between 2012-25 48.2% (Wind)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: OECD Europe

▶ Total electricity and its associated heat generation in OECD Europe exceeded 4 100 TWh in 2010, recovering pre-recession levels. The region's electricity sector CO_2 emissions dropped below 1990 levels in 2009 but were again higher in 2010.

▶ Slow growth in demand, and the prioritisation of renewable power generation dispatch over that of fossil fuels, resulted in emissions intensity reductions for the third consecutive year, maintaining the region 37% below the global average in 2010. Coal and oil electricity outputs decreased significantly from 2000 to 2010, by 8% and 47% respectively, but the emissions avoided were almost equally compensated by the 59% increase in gas output since 2000.

▶ Germany, the UK, Poland and Italy accounted for 60% of the CO_2 emitted by the electricity sector in OECD Europe in 2010. The power sector is by far the largest source of CO_2 emissions in the European Union Emissions Trading Scheme (EU ETS), despite a net increase of the share of renewables. Power generation emitted above its allocated CO_2 cap between 2005 and 2011 despite its decreased output in 2009 (EEA, 2012).

▶ The European Union's Action Plan for Energy Efficiency (EC, 2006), within the EU 2020 policy, has set targets for member states to achieve a 20% reduction in primary energy consumption by 2020. The global economic recession slowed primary energy usage, lowering projected consumption for 2020 and diminishing the gap to be closed in reaching the initial 20% objective. Even so, 2010 estimates of savings to be reached by 2020 with current and planned policies show a 9% gap, leaving half of the original target to be met. To close this gap, the new Energy Efficiency Directive agreed by the European Council and Parliament (EC, 2011) is meant to build up commitment towards further energy efficiency areas across all sectors, prompting the development of an energy savings business. Critics point out that the new Directive leaves a 6% gap in the original 20% reduction goal, mostly due to weak enforcement in the building sector.

▶ The effectiveness of renewable energy deployment policies in the region is demonstrated by the impressive average annual growth of 17% of non-hydro renewable output over the past decade. Feed-in tariffs promoted a sharp rise in the installed capacity of solar photovoltaic panels (PV), as did the fact that PV system costs were more than halved in the past few years. Several European countries adjusted their policies accordingly, reducing or eliminating incentives for new PV installations. Despite several market factors, these cuts are a sign that some renewable energy technologies are evolving towards the stage where public support will no longer be necessary.

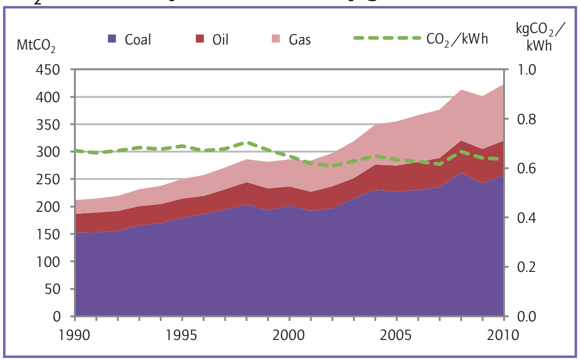
▶ Wind power installed capacity rose from 76 GW in 2009 to 94 GW by the end of 2011 (EWEA, 2012). Germany (29 GW) and Spain (22 GW) represented 31% and 23% of the EU's wind-power capacity by the end of 2011 (EWEA, 2012). Denmark had 3.87 GW of wind capacity installed by the end of 2011, which amounts to approximately one-quarter of the country's power generation.

Doubts on shale gas

The prospects of shale gas in Europe weakened when Bulgaria became the second EU state after France to set a moratorium on hydraulic fracturing technology. Hydraulic fracturing activities are currently ongoing in Poland, Austria, Germany, the Netherlands, Sweden and the UK, despite some public opposition to the technology's possible effects on groundwater contamination and emissions of CO_2 and methane (European Parliament, 2012). The high population density on many of the prospective areas for European shale gas development increases the likelihood of opposition from local communities, and will likely impede rapid growth of unconventional gas production (IEA, 2012c).

Africa*

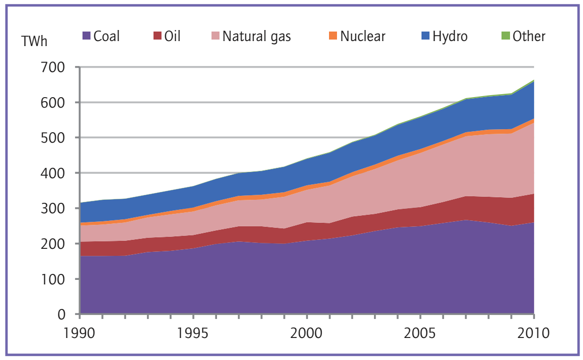
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 60.8% (Coal)
- Fastest growth over the last decade 108.3% (Gas)
- Emissions (annual rate): 2000-10 4%

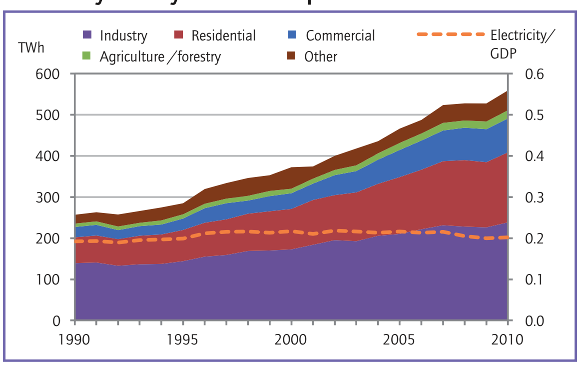
Figure 2
Generation mix of electricity



Note: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 39.1% (Coal)
- Fastest growth over the last decade 230.3% (Other)
- Electricity growth (annual rate): 2000-10 4.2%

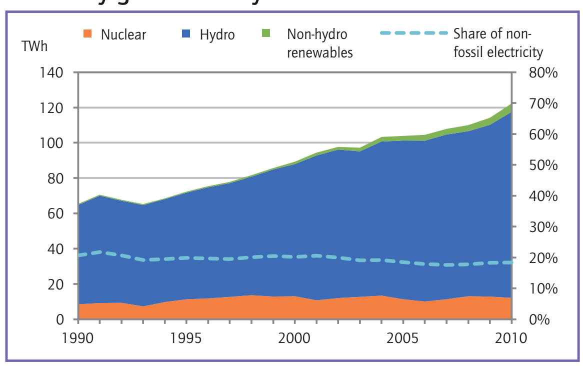
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 42.6% (Industry)
- Fastest growth over the last decade 115.8% (Commercial)
- Final electricity intensity (annual rate): 2000-10 -0.7%

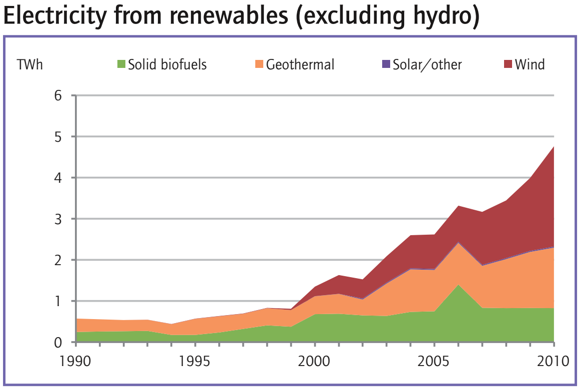
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 18.4%
- Largest source (2010) 86.2% (Hydro)
- TWh growth (annual rate): 2000-10 2.9%

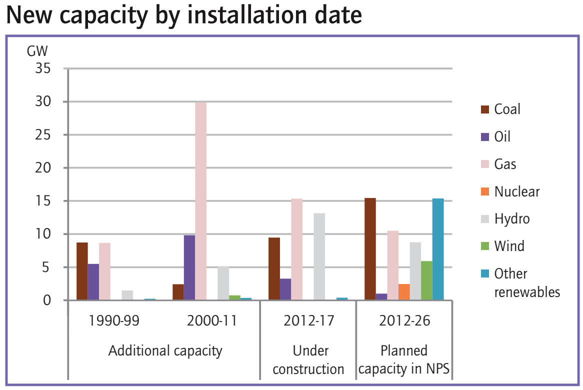
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 51.2% (Wind)
- Largest growth over the last decade 2.2 TWh (Wind)
- Growth (annual rate): 2000-10 13.4%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 45.8% (Gas)
- Largest additions under construction 30% (Gas)
- Largest additions planned between 2012-25 26% (Coal)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: Africa

▶ Total electricity and its associated heat output in Africa increased by over 50% between 2000 and 2010, leading to a 48% increase in CO_2 emissions over the same period. South Africa alone emitted 56% of Africa's power sector CO_2 emissions in 2010, while Egypt, Libya, Algeria and Morocco combined emitted another 32%. Although home to 10.5% of the global population (UNDESA, 2011), Africa's power output in 2010 represented only 2.9% of total global output.

▶ Africa's CO_2 intensity of power generation decreased by 5% throughout the two-decade period, but remains 25% above world averages. Intensity reductions were pushed predominantly by the two-fold increase in the share of gas power, which displaced mostly coal generation. Although South Africa's reliance on coal to supply 94% of its electricity remains unchanged since 1990, gas-fuelled power capacity was constructed in Algeria and Egypt.

▶ Electricity demand in Africa is predominantly directed to the industrial sector, but the sector's share in demand generally diminished in the two-decade period, mostly within the continent's five major economies.[1] The commercial and residential sectors' share of electricity demand grew the quickest between 2000 and 2010, from 10% to 15% and 26% to 30%, respectively. Following demographic growth, household final expenditures more than doubled in the past decade (World Bank, 2012b), leading to a higher number of appliances in homes and businesses.

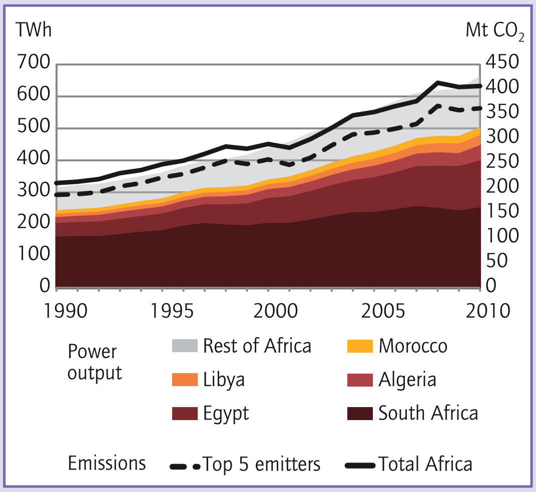
▶ Hydropower output rose by 40% in the past decade, to supply 16% of African electricity in 2010. Non-hydro renewable output more than doubled in the same period, led by wind and geothermal energies, but their share remains minor. Several policies were implemented to enhance renewable energy's share in the power mix: Egypt's New National Renewable Energy Strategy, aiming to have 20% of the country's power supply come from renewables by 2020 (NREA, 2007); Algeria's law on renewable energy promotion; incentives for solar technologies in Botswana (IEA, 2012b); incentives and subsidies for renewables through the Energy Development and Access Project in Ghana (GEF, 2007); feed-in tariffs for renewable energy in South Africa, Uganda and Kenya; and the Integrated Resource Plan for Electricity in South Africa, which aims to supply 20% of the country's energy demand by wind and solar PV by 2030 (ZA, 2012).

▶ South Africa recently announced a plan for the region's first emission caps on the country's most polluting sectors, including power, but emission ceilings are yet to be set within the next two years (Roelf, 2011).

▶ The majority of planned power generation capacity additions remain fossil-fuel based, with coal and gas accounting for a quarter each, followed by hydro, with 22% of total additions.

Electricity and CO_2: Africa's top 5

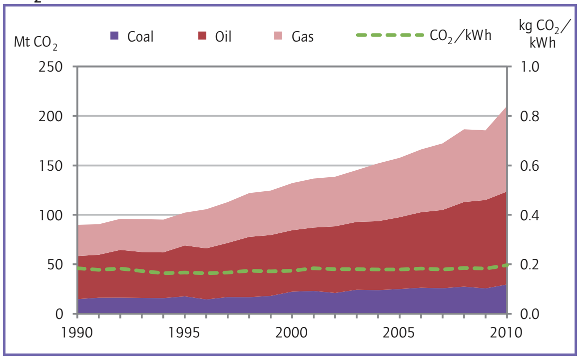
South Africa, Egypt, Algeria, Libya and Morocco were responsible for 76% of the continent's power generation and 89% of its emissions in 2010, with only 20% of the continent's population. Coal supplied over 50% of these countries' electricity, while gas supplied 31% in 2010.



1. South africa, Egypt, Nigeria, Algeria and Morocco (World Bank, 2012c).

Non-OECD America*

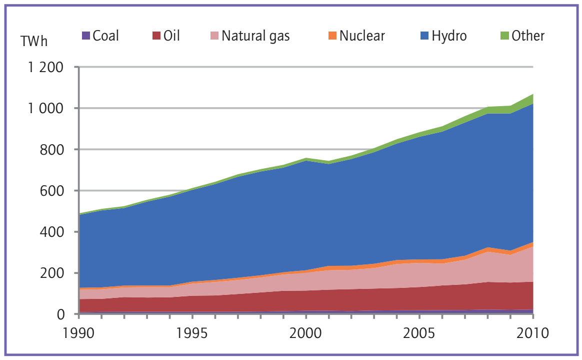
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 44.7% (Oil)
- Fastest growth over the last decade 81.5% (Gas)
- Emissions (annual rate): 2000-10 4.7%

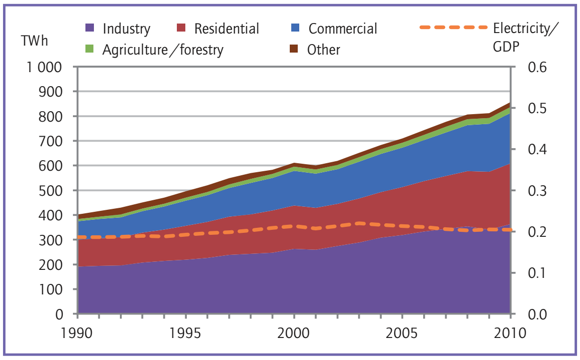
Figure 2
Generation mix of electricity



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 62.9% (Hydro)
- Fastest growth over the last decade 241.8% (Other)
- Electricity growth (annual rate): 2000-10 3.5%

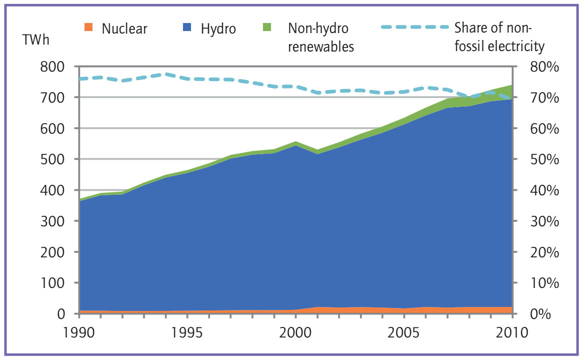
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 42.4% (Industry)
- Fastest growth over the last decade 45.5% (Commercial)
- Final electricity intensity (annual rate): 2000-10 -0.4%

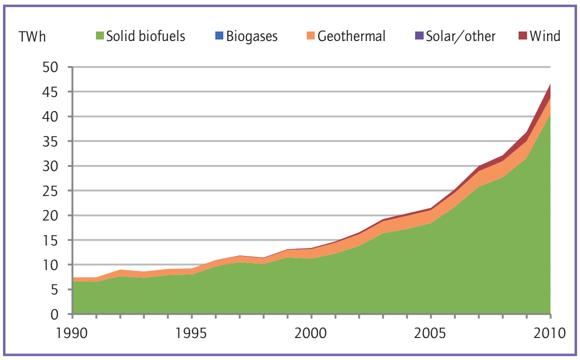
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 69.3%
- Largest source (2010) 90.8% (Hydro)
- TWh growth (annual rate): 2000-10 2.4%

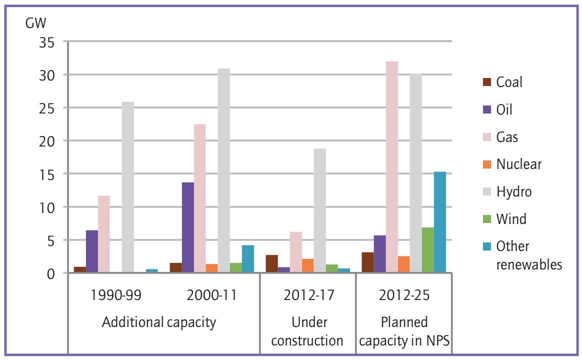
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 86.8% (Solid biofuels)
- Largest growth over the last decade 29.2 TWh (Solid biofuels)
- Growth (annual rate): 2000-10 13.3%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 45.8% (Hydro)
- Largest additions under construction 53.1% (Hydro)
- Largest additions planned between 2012-25 33.4% (Gas)

* *Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: non-OECD America

▶ Non-OECD America continues to have the lowest CO_2 intensity of electricity among all regions considered in this report, thanks to hydropower accounting for 63% of its electricity generation in 2010. The region's power and heat sector emitted 1.7% of global electricity-related CO_2 emissions, although it is home to 8.4% of the world's population (UNDESA, 2011).

▶ Nevertheless, the region's power sector emissions rose by 4.7% per year on average in the past decade, outpacing electricity output growth of 3.5% per year. This resulted in a 1.2% average annual increase in emissions intensity in the past decade, compared to an average 0.5% yearly decrease between 1990 and 2000. Although hydroelectricity maintained steady absolute growth in the two-decade period, its share diminished from 70% in 2000 to 62% in 2010, mainly losing ground to natural gas power generation. Non-hydro renewables represented 4.3% of total power generation in 2010, with a tripling over the last decade, largely thanks to solid biofuels (87% of the total), with wind and geothermal power accounting for the rest.

▶ Despite its small share in power generation, oil is the largest source of CO_2 emissions from the region's electricity sector, accounting for 94 $MtCO_2$ from a 135-TWh output in 2010, followed by gas-fired power plants emitting 86 $MtCO_2$ from 170 TWh.

▶ Latin America's GDP growth outpaced the growth in electricity demand only in the last decade. The electricity intensity of GDP remained slightly higher in 2010 than in 1990.

▶ The region's great diversity of available primary energy sources is not reflected in its generation mix. Solid biofuels, biogas, solar and wind shares in electricity output fall short of their estimated potential, according to recent studies (ANEEL, 2012; Secretaria de Energia, 2008; SIAC, 2012). Their future development contributes to lowering dependency on hydro power and rain seasonality, but will largely depend on how easily the new variable sources can be accommodated by the grid.

▶ The main policies in force to deploy wind and biomass power have goals set above projections from the IEA World Energy Outlook 450 Scenario, under which all regions act to limit global temperature increase to below two degrees centigrade (IEA, 2011a). Examples include Argentina's Renewable Energy Generation Programme, which aims for 8% renewable power generation by 2016, Brazil's Alternative Source Incentive Programme (PROINFA), and targeted renewable power incentives in Peru. Brazil alone added 587 MW of wind capacity in 2011, bringing the region's total to more than 1 200 MW.

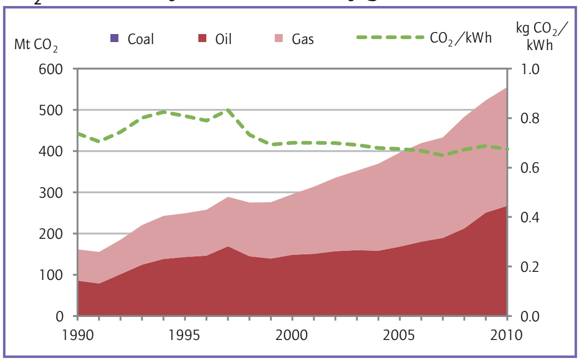
▶ Power capacity under construction and planned includes considerable fossil fuel additions to the current mix. From a total of 128 GW under construction or planned until 2025, 30% is expected to come from gas, 4.5% from coal and 5% from oil. Hydropower expected to account for 38% of new additions.

Hydroelectric expansion into northern basins

Brazil intends to increase its hydropower installed capacity from its current 83 GW to 115 GW by 2020 (EPE, 2011). More than 20 GW of new capacity is already contracted or under construction. With over 70% of new contracted capacity under construction in the Amazon region, original plans for large-scale dams such as Belo Monte were reshaped into run-of-river plants. This will reduce reservoir areas and environmental impacts, as well as average projected power generation from these plants. Due to the marked seasonality of rain periods in the region, it is expected that Belo Monte's 11 GW installed capacity will in fact operate at 4.5 GW on average.

Middle East*

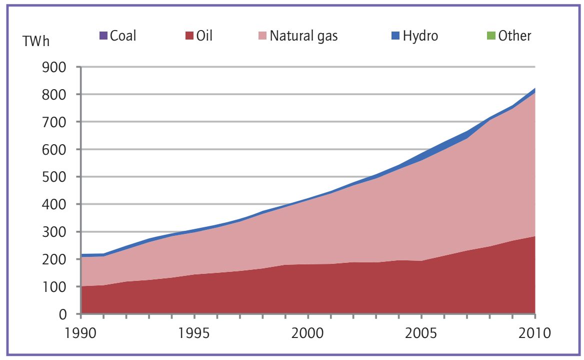
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 51.9% (Gas)
- Fastest growth over the last decade 95.8% (Gas)
- Emissions (annual rate): 2000-10 6.5%

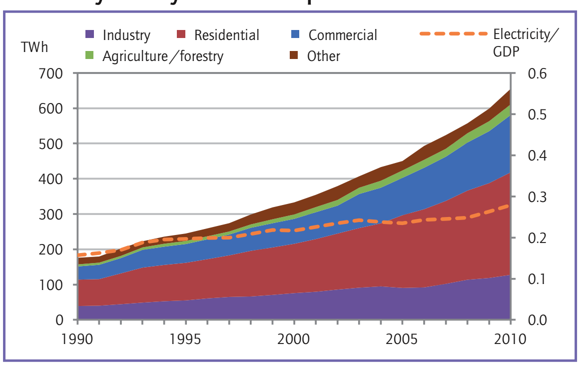
Figure 2
Generation mix of electricity



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 63.4% (Gas)
- Fastest growth over the last decade 347.5% (Other)
- Electricity growth (annual rate): 2000-10 6.9%

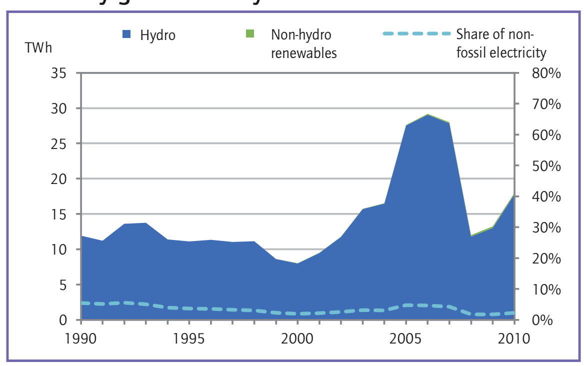
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 44.4% (Residential)
- Fastest growth over the last decade 141.6% (Agriculture/forestry)
- Final electricity intensity (annual rate): 2000-10 2.5%

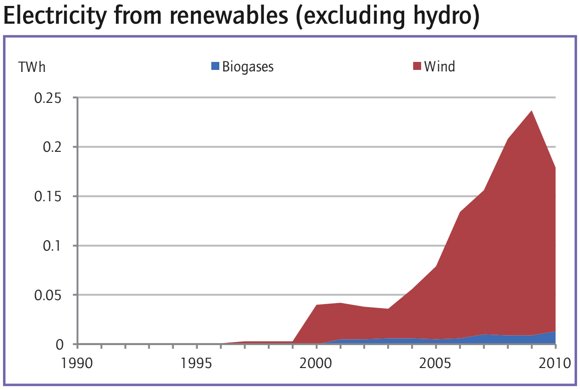
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 2.2%
- Largest source (2010) 99% (Hydro)
- TWh growth (annual rate): 2000-10 7.4%

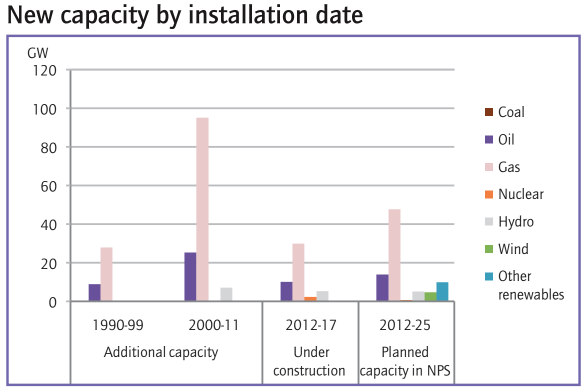
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 92.7% (Wind)
- Largest growth over the last decade 0.1 TWh (Wind)
- Growth (annual rate): 2000-10 16.2%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 74.5% (Gas)
- Largest additions under construction 62.6% (Gas)
- Largest additions planned between 2012-25 57.8% (Gas)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: Middle East

▶ Within regions considered in this report, the Middle East had the second largest growth in power generation (95%) and CO_2 emissions (87%) in the last decade. The increase in the share of gas in total output has nonetheless led CO_2 intensity of electricity generation to decrease annually by 0.4% on average over the past decade. The region accounts for over 28% of the world's oil-fired electricity generation, but gas generation is gaining ground quickly, mostly over the oil share.

▶ Power generation CO_2 emissions in this region are concentrated in Saudi Arabia and Iran. These two countries contributed more than 53% of the region's emissions in 2010, emitting 141 $MtCO_2$ (Saudi Arabia) and 126 $MtCO_2$ (Iran). Regional installed capacity is 63% gas-based and 34% oil-based; Saudi Arabia, Iran and the United Arab Emirates (UAE) collectively possess 21% of regional installed oil capacity and 44% of installed gas capacity.

▶ The Middle East's residential sector accounted for 44% of final electricity use in 2010 – the highest among all regions – while industry accounted for a mere 20%. The low industrial power demand is partly explained by the region's recent economic development, and the tendency for industry in this region to rely on oil and gas rather than electricity for its energy needs. The growth in the commercial and residential sectors' shares of electricity consumption reflects the increased use of electrical equipment and appliances in the region: household final consumption expenditures more than doubled between 2002 and 2009 (World Bank, 2012b).

▶ The abundant availability of low-cost fossil fuels has not encouraged energy efficiency or renewable energy development in the region during the past decade. However, measures enacted by countries in the region, such as energy efficiency programmes in Saudi Arabia (UNDP, 2012) and Jordan's aim for 10% renewable power generation by 2020 (IEA, 2012b), indicate a shift in policy.

▶ More than 2% of the region's electricity output was supplied by hydropower in 2010, mostly in Iran, Iraq and Syria. A recent decline in hydropower generation in the region occurred due to drought conditions in Iran, which hosts two-thirds of the region's hydro capacity.

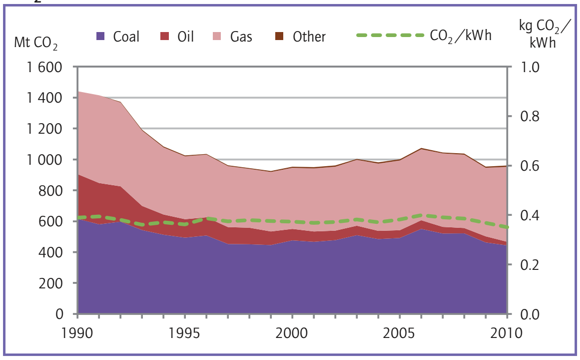
▶ More than 125 GW of new power capacity is under construction or planned to be connected by 2025, in order to meet rapidly rising power demands. Oil and gas account for 15% and 62% of expected capacity additions, and renewables gain ground mostly with another 10 GW of hydro. Wind and solar power together are expected to add another 11 GW by 2025. Nuclear energy may play a larger role in this and the next decade than shown in Figure 6, but there are still considerable uncertainties regarding the time frame of such additions.

Nuclear power to satisfy growing demand

The Gulf Cooperation Council (GCC) countries – Kuwait, Saudi Arabia, Bahrain, the United Arab Emirates (UAE), Qatar and Oman – intend to rely on nuclear power to reduce their use of oil and gas in electricity generation. The United Arab Emirates plans to build four reactors (5 600 MW) between 2017 and 2020 to meet 25% of its projected power demand (ENEC, 2012). Saudi Arabia, the main electricity producer and consumer in the Gulf States, plans to construct 16 nuclear power reactors by 2030 at an estimated cost of more USD 100 billion (WPR, 2011). It has signed nuclear agreements with China, France, Argentina and South Korea (Shamseddine, 2011), and expects to have its first two reactors on line in ten years, with the ambition of adding two more per year until 2030.

Non-OECD Europe and Eurasia*

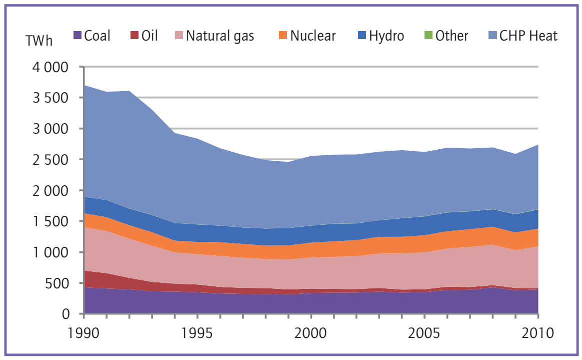
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 50.5% (Gas)
- Fastest growth over the last decade 22.7% (Gas)
- Emissions (annual rate): 2000-10 0.1%

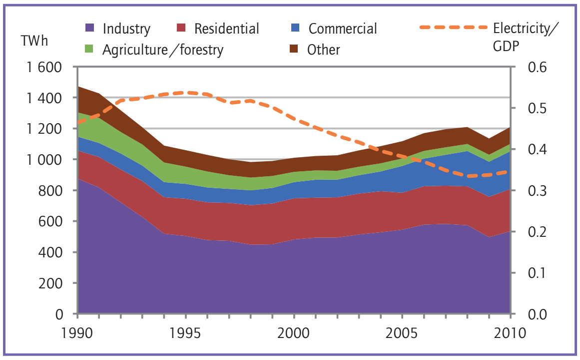
Figure 2
Generation mix of electricity and heat from CHP



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 39.7% (Gas)
- Fastest growth over the last decade 129.5% (Other)
- Electricity and CHP heat growth (annual rate): 2000-10 0.7%

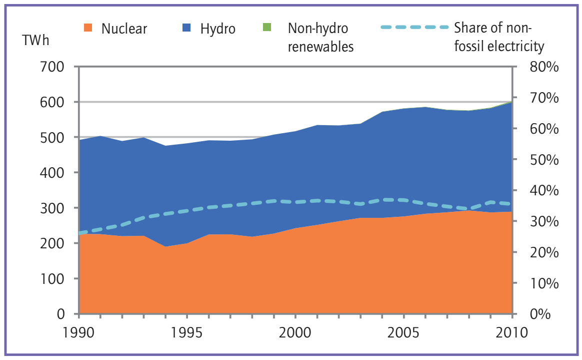
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 44.2% (Industry)
- Fastest growth over the last decade 135% (Commercial)
- Final electricity intensity (annual rate): 2000-10 -3.1%

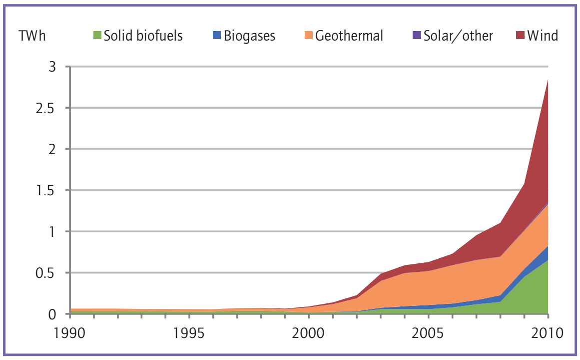
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 35.5%
- Largest source (2010) 51.5% (Hydro)
- TWh growth (annual rate): 2000-10 1.1%

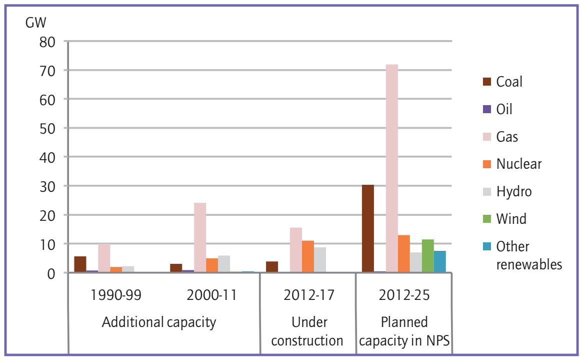
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 52.5% (Wind)
- Largest growth over the last decade 1.5 TWh (Wind)
- Growth (annual rate): 2000-10 41%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 48.8% (Gas)
- Largest additions under construction 35.7% (Gas)
- Largest additions planned between 2012-25 50.8% (Gas)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: non-OECD Europe and Eurasia

▶ Electricity and its associated heat generation fell by 4% in 2009 as a result of the recession and rose by 5.8% in 2010. On average, the region's output rose by 0.7% per year over the last decade. CO_2 emissions followed a similar yet lower trend, rising by only 0.1% per year on average. In 2010, CO_2 emissions from electricity and associated heat remained 33% below their 1990 levels.

▶ The CO_2 emission intensity of power generation reached its lowest point since 1990 in 2010, at 0.35 tCO_2/MWh, 30% below world average. This is due to the region's large share of gas-based electricity (39% or 672 TWh in 2010), and the important share of combined heat and power (CHP) plants that are more efficient than electricity-only plants.

▶ The non-OECD Europe and Eurasia region still possesses the highest electricity intensity of GDP among all the regions analysed in this report. Large state infrastructure investments in the former Soviet Union provided abundant and inexpensive power, leading to high electricity consumption in the 1980s. After the fall of the Soviet Union, the region experienced a sharp recession while electricity consumption remained high, thereby increasing the ratio of electricity usage to GDP. GDP growth outpaced electricity and heat consumption growth rates in the last decade, resulting in a 26% reduction in the electricity intensity of GDP.

▶ Industry is still the region's largest electricity user, consuming 44% of the region's electricity in 2010. The sector regained importance as its participation in the GDP rose within three of the region's six largest economies (World Bank, 2012a).[1] Even so, the region's industry remains inefficient in comparison with OECD countries, the result of decades of virtually free energy in the former Soviet Union. In spite of industry's dominant share of electricity, the commercial sector has grown 135% in the last decade.

▶ The share of non-fossil electricity generation rose from 26% to 35% between 1990 and 2010, as nuclear and hydro power outputs increased by 28% and 17%, while fossil-based generation declined across the board. The contribution of non-hydro renewables remains negligible, even though their output grew 16% per year on average over the last two decades. Existing policies to foster renewable power include tax exemptions in the Slovak Republic, and incentives and subsidies for renewables in Russia, Belarus, Bulgaria, and Slovenia (IEA, 2012b).

▶ More than 194 GW of new power capacity is expected to come on line in the region by 2025, of which 50% is expected to come from gas, 19% from oil and 13% from nuclear. Plans for new nuclear power plants are quickly being realised, as almost all the anticipated new nuclear capacity is already under construction. Another 15 GW of the expected gas-fired capacity and 8 GW of hydropower are also under construction.

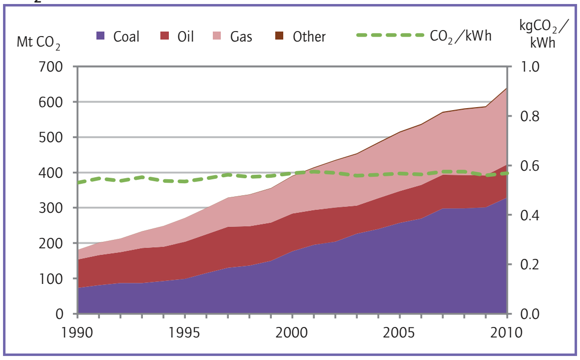
Potential for energy efficiency in Russia

High shares of outdated technologies in energy-intensive sectors represent an equally large potential for energy savings in Russia. Conservative estimates indicate that Russia could reduce the fuel consumed in its electricity plants by 43.4 million tonnes of oil equivalent (Mtoe), or 22% of its 2005 consumption (CENEf, 2008). Potential efficiency gains lie mostly in the upgrade of gas-fired condensing plants and CHP plants, but their economic and financial viability depends on fuel prices.

1. Russian Federation, Ukraine, Romania, Croatia, Azerbaijan, Kazakhstan (World Bank, 2012c).

Asia (excluding China and India)*

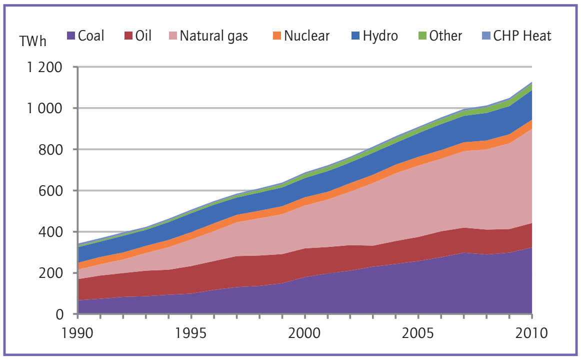
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 51.3% (Coal)
- Fastest growth over the last decade 136.9% (Other)
- Emissions (annual rate): 2000-10 5.1%

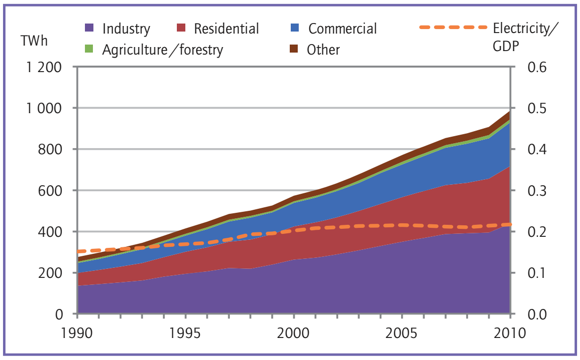
Figure 2
Generation mix of electricity



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 40.9% (Gas)
- Fastest growth over the last decade 120% (Gas)
- Electricity and CHP heat growth (annual rate): 2000-10 5.1%

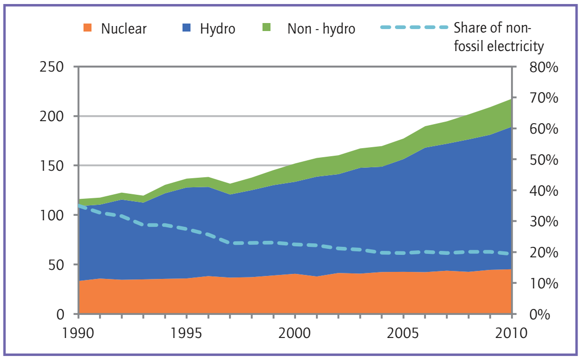
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 44.4% (Industry)
- Fastest growth over the last decade 95.7% (Agriculture/forestry)
- Final electricity intensity (annual rate): 2000-10 0.7%

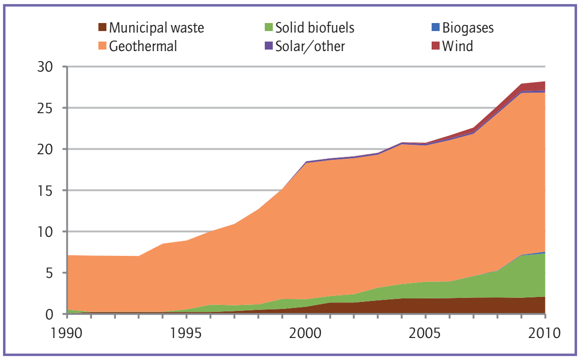
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 19.4%
- Largest source (2010) 66.3% (Hydro)
- TWh growth (annual rate): 2000-10 3.7%

Figure 5
Electricity from renewables (excluding hydro)

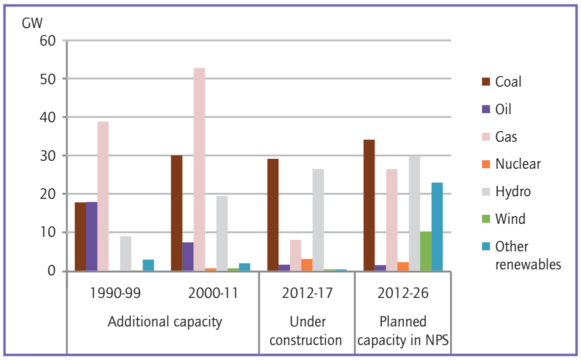


Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 68.4% (Geothermal)
- Largest growth over the last decade 4.3 TWh (Solid biofuels)
- Growth (annual rate): 2000-10 4.3%

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 36.9% (Gas)
- Largest additions under construction 29.7% (Coal)
- Largest additions planned between 2012-25 26.8% (Coal)

Key features in electricity and CO_2: Asia (excluding China and India)

▶ Electricity and its associated heat generation more than tripled in this region between 1990 and 2010, reaching 1 127 TWh in 2010, or 5% of the world output. While electricity generation rose steadily throughout the period, associated heat production decreased in absolute terms. Gas accounted for most of the growth, and reached 41% of the region's total power output in 2010. Coal-based generation also doubled in the last decade, reaching 29% of the total in 2010.

▶ Power sector CO_2 emissions rose accordingly, by 64% in the last decade. Emissions intensity in the region remains relatively stable, above the world average, yet below neighbouring China and India due to more efficient gas-based generation.

▶ Despite the region's industry increasing its electricity and heat demand by 62% in the last decade, industrial electricity end-use was outpaced by the residential, commercial and agricultural sectors, where demand rose by 74%, 86% and 96% in the same period.

▶ The region's non-fossil electricity generation is historically dominated by hydropower, which represented 12% of total output in 2010, with nuclear contributing 4% in 2010. The shares of both sources have been continuously decreasing as coal and gas provided a staggering 90% of the generation growth between 2000 and 2010.

▶ Non-hydro renewables remain marginal but witnessed significantly rising shares thanks to a series of policy incentives. Incentives and subsidies for renewable energies currently in place in Indonesia are expected to result in significant local renewable capacity addition. The country uses less than 2 GW out of an estimated 28-GW potential. The Philippines provides a legal and institutional framework for harmonising policies on the development of renewable energy through its Renewable Energy Act of 2008. Thailand's energy conservation programme provides incentives to renewables in several sectors, as does Vietnam's National Power Development Plan with specific deployment goals for renewable technologies into the next decades (IEA, 2012b).

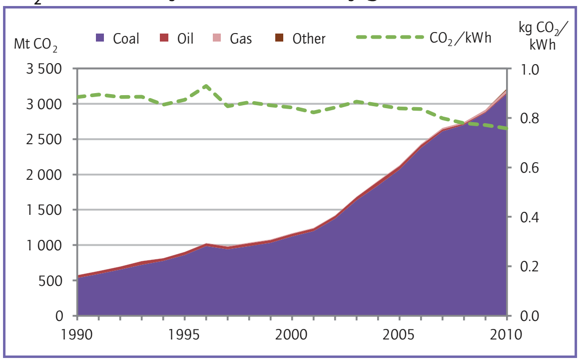
▶ Asia (excluding China and India) is expected to bring more than 196 GW of new power capacity on line by 2025. Coal dominates the projected additions (32%), followed by hydropower (29%) and gas (18%). More than 29 GW of coal-fired power generation capacity is currently under construction, as well as 28 GW of hydropower capacity mostly in Vietnam, Laos and Nepal. Striving to meet a fast-rising demand, several countries have shown interest in building nuclear power plants. Still, a limited number of new nuclear power plants are expected to be in operation before 2020, as construction may last more than a decade. Under current policy efforts, renewable energy sources are expected to maintain low shares in the region's energy mix.

Coal to increase its share in supply

Demand for electricity is growing in Southeast Asia. As Singapore, Malaysia and Thailand have switched from coal- and oil-burning plants to gas, other countries go the opposite direction. Indonesia, which had 40 GW of installed power-generating capacity by 2010, plans to add 10 GW of new capacity by 2014, largely coal, with 3 GW now under construction (Patel, 2012a). Vietnam, with 19.5 GW of installed capacity in 2010 and a fifth of its generation from coal, plans to add 67 GW of capacity by 2020, with more than half to be based on coal (IEVN, 2011).

China*

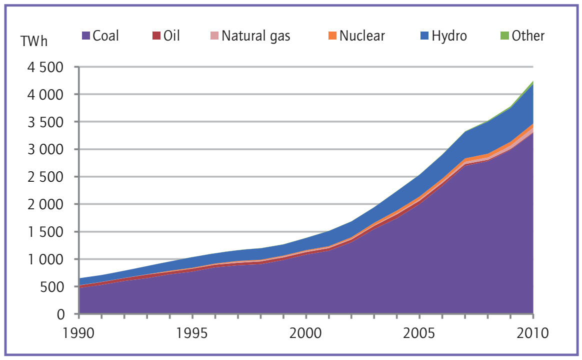
Figure 1
CO_2 emissions by fuel in electricity generation



Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 97.7% (Coal)
- Fastest growth over the last decade 384.8% (Gas)
- Emissions (annual rate): 2000-10 10.7%

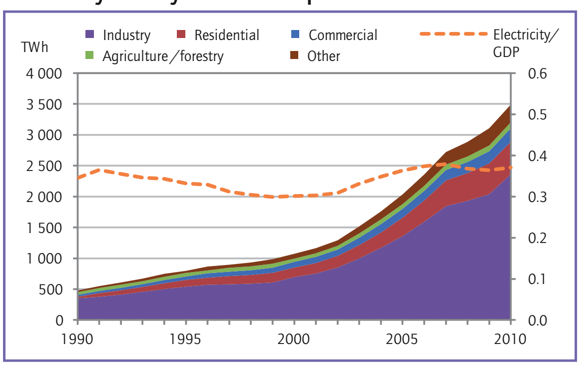
Figure 2
Generation mix of electricity



Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 77.6% (Coal)
- Fastest growth over the last decade 1769.4% (Other)
- Electricity growth (annual rate): 2000-10 11.8%

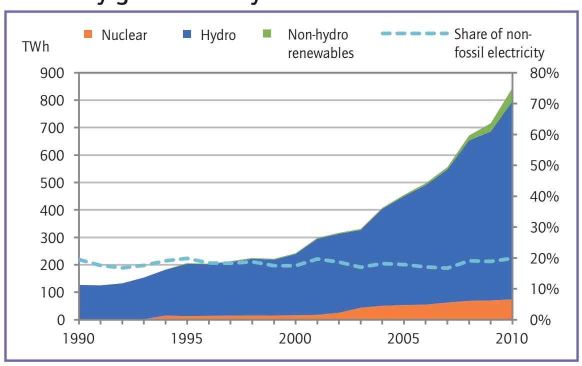
Figure 3
Electricity use by sector and per unit of GDP



Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 67.7% (Industry)
- Fastest growth over the last decade 267.4% (Other)
- Final electricity intensity (annual rate): 2000-10 2.1%

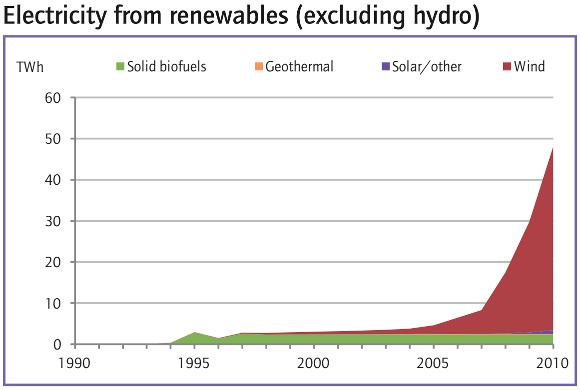
Figure 4
Electricity generation by non-fossil fuels



Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 19.9%
- Largest source (2010) 85.6% (Hydro)
- TWh growth (annual rate): 2000-10 12.5%

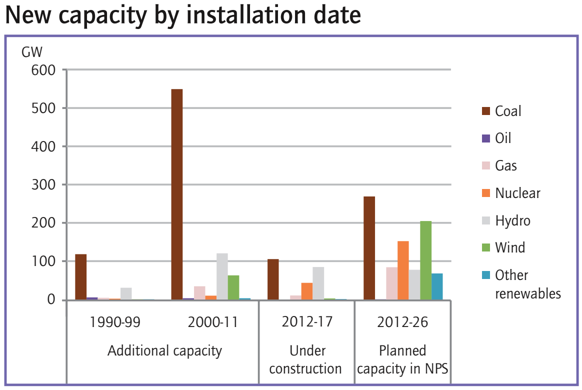
Figure 5
Electricity from renewables (excluding hydro)



Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 92.8% (Wind)
- Largest growth over the last decade 44 TWh (Wind)
- Growth (annual rate): 2000-10 31.7%

Figure 6
New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 41.4% (Coal)
- Largest additions under construction 29.9% (Coal)
- Largest additions planned between 2012-25 31.4% (Coal)

** Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: China

▶ China's impressive growth in electricity output regained momentum after a two-year slowdown during the global recession. The country witnessed 12% power output growth in 2010, and an 11.7% increase in 2011 (*China Energy Weekly*, 2012a). GDP is expected to keep rising, but recent reports indicate a long-awaited deceleration in 2012 (*World Bank*, 2012d).

▶ Electricity-related emission intensity in China is the second largest among all regions, and 49% above world average. It nonetheless decreased considerably in the last two decades, thanks mainly to improved performance of the huge fleet of coal-fired plants, both through construction of large, efficient, modern power plants and accelerated retirement of older, less-efficient plants.

▶ China indicated in its 12th Five-Year Plan its objective to cut the country's energy consumption and its CO_2 emissions per unit of GDP by 16% and 17%, between 2010 and 2015. Although official data show that energy intensity decreased by 2% in 2011, falling short of the required 3.5% annual improvement (Point Carbon, 2012a), early indications for 2012 are more promising. Moreover, with the largest additions in the world to renewable and nuclear power generation capacity and progress in its goal to more than double natural gas use over the 12th Five-Year Plan, the country is making strides on the supply side to bring down carbon intensity.

▶ Industry still accounts for the lion's share of electricity demand, 68% of the total in 2010; its consumption rose on average by 13% per year in the last decade. Residential demand, although much smaller (14% share in 2010), rose at the same rate, following rising household incomes and a corresponding penetration of electrical appliances and equipment (World Bank, 2012b).

▶ Seasonal imbalances between supply and demand have persisted for years. Insufficient coal supplies and inadequate rainfall, for instance, were blamed for power outages in 2011 that forced rationing in several regions. The China Electricity Council, which represents the power industry, warned that installed power capacity in 2012 was expected to be 30 GW to 40 GW below peak demand (China Energy Weekly, 2012b).

▶ Government policies enabled wind capacity to rise more than tenfold between 2007 and 2011, making China the world leader in installed wind capacity by the end of 2011 with 62.7 GW (GWEC, 2012). Projections show that China will reach 173 GW of wind capacity and 35 GW of solar capacity by 2017 (IEA, 2012d), pending the transmission system's capability of integrating their intermittent output (GWEC, 2011). Renewable power's growth is supported by feed-in-tariffs for wind and solar and other policy packages that remove import duties and value-added taxes on key renewable energy equipment (IEA, 2012). Thanks to these, of the 988 GW of the new power generation capacity expected to be built between 2012 and 2025, 38% is expected to come from coal, 21% from wind and 17% from hydro power.

▶ Pilot carbon markets are currently being developed in two provinces and five cities. The central government has given city and provincial governments the freedom to set caps, choose sectors, and use not-yet-approved CDM projects to supply low-cost offsets to the emitters covered (Point Carbon, 2012b). A nationwide system could follow based on this experience, contributing in the longer term to emissions reductions.

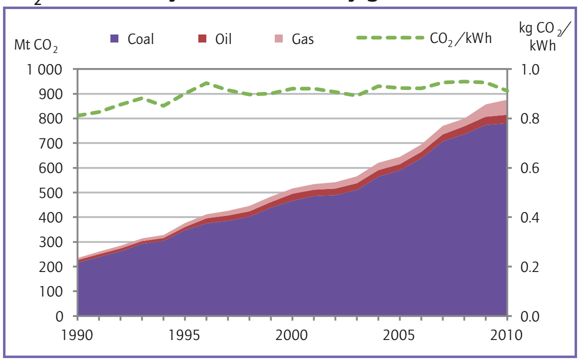
China's cap on electricity consumption

*China's National Energy Administration has set regional ceilings for total primary energy supply and electricity output by 2015. At the national level, the ceilings are 4.1 billion tonnes of coal equivalent (tce) and 6 400 TWh by 2015 (*China Energy Weekly*, 2012a). Electricity output in 2011 was 4 700 TWh in 2011 (*China Energy Weekly*, 2012a), so meeting the ceiling would limit average annual growth to 8% until 2015, against 11.8% observed between 2000 and 2010. As for total primary energy supply, the ceiling implies an average annual growth of 4% between 2009 and 2015, considerably below the average of 7.5% of the ten previous years.*

India*

Figure 1

CO_2 emissions by fuel in electricity generation

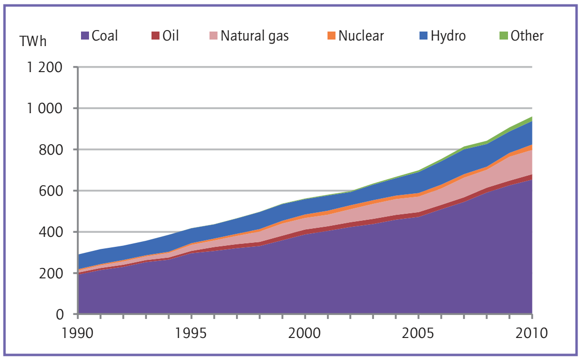


Notes: emissions from electricity only and CHP plants. Coal includes peat. Other includes non-renewable waste.

- Largest source of emissions (2010) 89.1% (Coal)
- Fastest growth over the last decade 181.4% (Gas)
- Emissions (annual rate): 2000-10 5.4%

Figure 2

Generation mix of electricity

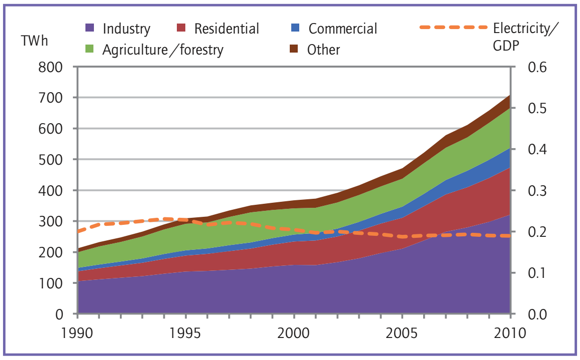


Notes: coal includes peat. Other includes geothermal, solar, wind, biofuels and waste, etc.

- Largest source of electricity (2010) 68% (Coal)
- Fastest growth over the last decade 623.9% (Other)
- Electricity growth (annual rate): 2000-10 5.5%

Figure 3

Electricity use by sector and per unit of GDP

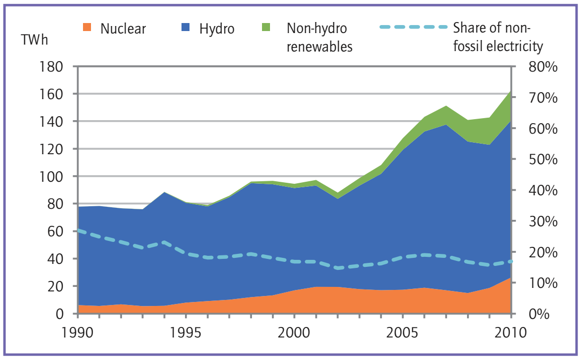


Note: electricity/GDP measured in kWh per 2005 USD PPP.

- Largest sector of consumption (2010) 45.2% (Industry)
- Fastest growth over the last decade 182.5% (Commercial)
- Final electricity intensity (annual rate): 2000-10 -0.8%

Figure 4

Electricity generation by non-fossil fuels

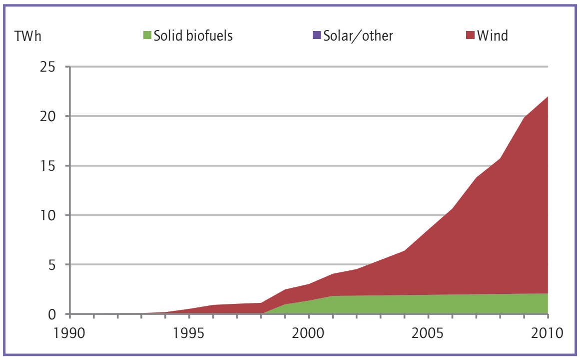


Note: non-hydro renewables includes geothermal, solar, wind, biofuels and renewable municipal waste.

- Share of non-fossil sources in total electricity (2010) 16.9%
- Largest source (2010) 70.3% (Hydro)
- TWh growth (annual rate): 2000-10 5%

Figure 5

Electricity from renewables (excluding hydro)

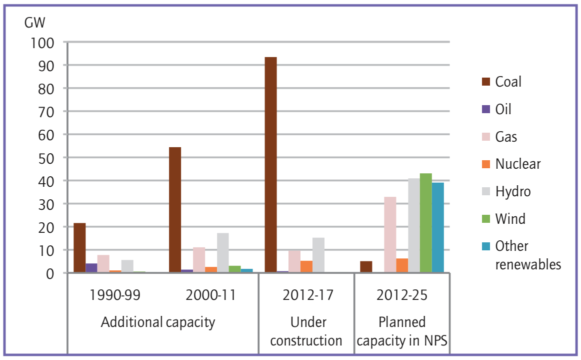


Notes: biogases includes small quantities of liquid biofuels. Municipal waste only includes the renewable portion of waste.

- Largest source excluding hydro (2010) 90.5% (Wind)
- Largest growth over the last decade 18.2 TWh (Wind)
- Growth (annual rate): 2000-10 21.9%

Figure 6

New capacity by installation date



Source: Platts, 2010. Note: planned capacity for new policies scenario (IEA, 2011a), other renewables include: bioenergy, biogas, geothermal, solar photovoltaic, solar thermal and renewable municipal waste.

- Largest additions in 1990-2010 36.3% (Coal)
- Largest additions under construction 42.8% (Coal)
- Largest additions planned between 2012-25 25.7% (Wind)

* *Unless otherwise indicated, all material for figures derives from IEA, 2012a.*

Key features in electricity and CO_2: India

▶ India's electricity output grew more than threefold between 1990 and 2010, averaging 6.2% growth per year. India's electricity system recently became the fifth-largest in the world, with an installed capacity of around 180 GW in 2011. However, more than 400 million Indians have no access to electricity, and by 2035 India's power generation is expected to more than triple (IEA, 2011a), providing a prodigious challenge for the country. Due to its heavy reliance on coal, India's CO_2 emissions in the power sector have increased in tandem with its growth in output.

▶ The CO_2 intensity of electricity in India is the highest of all regions included here (80% above world average); although it rose over the last two decades, it fell by 3% in 2010 thanks to a 40% growth in nuclear output and 10% in renewables that year alone. Coal still dominates India's power mix, providing 68% of the country's electricity output in 2010, with gas providing another 12%.

▶ Industry accounted for 45% of India's electricity demand in 2010, although its share has generally decreased, being outpaced by the residential and commercial sectors. Policy measures such as the mandatory market-based mechanism "Perform, Achieve and Trade", may reduce industry's share in total demand in the next decade through enhanced energy efficiency. Due to large irrigation needs, India has the largest share of electricity demand in agriculture within all regions (18% in 2010), comparable to its residential demand. Residential demand more than doubled over the last decade, pushed by strong demographic growth and the emergence of a large middle class.

▶ The National Action Plan on Climate Change of 2008 has paved the way for more renewable power, making non-hydro renewables the fastest growing source of electricity. Installed wind capacity rose from 11 GW in 2009 to beyond 16 GW by the end of 2011, with plans for an additional 5 GW by 2015 (GWEC, 2012). India's National Solar Mission aims to install 20 GW of solar capacity by 2022, which exceeds projections of the IEA 450ppm Scenario (IEA, 2011a). Solar capacity rose from 17.8 MW in early 2010 to 506.9 MW as of March 2012 (NRDC, 2012). India's renewable energy obligation targets are supported by subsidy incentives for multiple renewable energy sources, and tradable renewable energy certificates to facilitate compliance, encourage competition and reduce near-term generation costs (IEA, 2012b).

▶ More than 293 GW of new power generation capacity is expected to be on line in India by 2025 under the IEA *World Energy Outlook* New Policies Scenario (2011). Coal-fired power plants are expected to remain dominant, adding 99 GW (34%) of this new capacity. Another 19 GW of hydropower and 14 GW of natural gas power capacity are expected to be on line by 2025. Non-hydro renewables complete the figure and are expected to significantly increase their shares, adding 14 GW of wind and 10 GW of solar power capacity by 2025.

Chronic coal shortages in a coal dependent system

Although India has very ambitious targets for the penetration of renewable energy in electricity, new capacity developments are largely based on coal-fired capacity. India has to rely on all available energy sources to allow economic and social development; in light of its plentiful coal resources, and the prospect of rising CO_2 emissions, carbon capture and storage (CCS) should be considered. At this stage, the loss of thermal efficiency brought by CCS implies higher coal use per unit of generated electricity, an unattractive proposition as coal supply in India is under pressure.

Coal shortages repeatedly occurred in the past years, on the order of 17 million tonnes in 2012 (Patel, 2012b), with expensive coal imports as a result. The near monopoly of two public enterprises of coal supply is stalling productivity improvements, and increasingly pointing to the need for a reform of the Indian coal sector. If successful, the reform will enhance coal supply in India and soon raise the question of policies required to avoid sky-rocketing CO_2 emissions from electricity.

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1. Estonia and Slovenia are included starting in 1990. Prior to 1990, data for Estonia are included in Former Soviet Union and data for Slovenia in Former Yugoslavia in the publication Energy Balances of Non-OECD Countries.

2. Oil statistics as well as coal trade statistics for Puerto Rico are included under the United States.

*3. **Note by Turkey**:*
The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognizes the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus" issue.
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4. Serbia includes Montenegro until 2004 and Kosovo until 1999.

Acronyms and abbreviations, units of measure

CO_2	carbon dioxide
Gt	gigatonne
$GtCO_2$	gigatonnes of carbon dioxide
GW	gigawatt
$MtCO_2$	megatonnes of carbon dioxide
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWh	megawatt-hours
tce	tonnes of coal equivalent
tCO_2	tonnes of carbon dioxide
tCO_2e	tonnes of carbon dioxide equivalent
TW	terawatt
TWh	terawatt-hours

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