

International Energy Agency

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Energy Policies of IEA Countries

The United States

2014 Review

International Energy Agency

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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 29 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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International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France
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1. EXECUTIVE SUMMARY AND KEY RECOMMENDATIONS

EXECUTIVE SUMMARY

The energy policy framework in the United States has undergone significant change over the six-year period since the last in-depth review was completed. In many aspects there have been significant improvements and the country is well placed to continue to deliver a reliable, affordable and environmentally sustainable energy system. The most obvious trend to have emerged is the resurgence of oil and gas production where output had previously been assumed to be in decline. The growth in unconventional gas production has been a game-changing development in North American markets, and is making a substantial additional contribution to economic activity and employment, both within the energy industry and elsewhere by, for example, lowering energy and input costs for other industrial sectors.

Together with strong energy efficiency measures, notably in the transport sector, that are set to curb fossil fuel consumption, alongside regulations for new and existing power plants and other actions, this energy revolution is having far-reaching consequences for energy markets, greenhouse gas emissions (GHG), economic competitiveness and, potentially, for energy security, geopolitics and the global economy. Energy security has been strengthened over the past six years and rising domestic production of oil, shale gas and bioenergy alongside demand-side measures such as policies to support energy efficiency and reduce consumption in the transport sector could result in the United States becoming all but self-sufficient in net terms by 2035 (IEA, 2013a).

THE OIL AND GAS BOOM

Oil continues to be the most significant energy source, accounting for 36% of total primary energy supply (TPES) in 2013. The country produces just under half of its domestic demand for crude oil, including conventional oil sources, field condensates and other hydrocarbons such as shale oil. In 2012, the United States was the third-largest producer of crude oil in the world, behind Saudi Arabia and the Russian Federation. Domestic production was 13% higher in 2013 than in 2012, which was the second consecutive year of strong growth. Compared to 2003, production was 30% higher. An important factor is increased production of light tight oil, a turnaround that has had a dramatic impact for the North American oil industry. Furthermore, productivity of oil and natural gas wells is increasing in many basins as a result of the increasing precision and efficiency of horizontal drilling and hydraulic fracturing in oil and natural gas extraction.

Improvements in advanced crude oil production technologies, such as hydraulic fracturing, are widely expected to continue to lift domestic supply into the medium term. The renaissance that the oil industry is undergoing is largely the result of growth in light tight oil (LTO) production, a boom that is expected to continue until 2020 at least. The International Energy Agency (IEA) projects that production will level off from 2020 and then to start a gradual decline, as it becomes less economically attractive, compared with other sources (IEA, 2014c).

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Another defining feature of the energy landscape in the United States has been the unexpected rise in shale gas production and the new-found abundance of inexpensive natural gas. Though shale gas (alongside other unconventional sources of tight gas and coalbed methane) has been produced for several decades, its production only started to expand after 2005, reversing the previous decline in gas production. Proved gas reserves have increased by almost three-quarters since 2000, up to 9.1 trillion cubic metres (or 323 trillion cubic feet) by end 2012, or the equivalent of more than 100 years of production at 2012 consumption rates. Natural gas production is projected to continue to increase over the period to 2040. Almost all of this increase is the result of the projected growth in shale gas production and two of the largest shale plays that have been identified, the Marcellus and Haynesville formations, which are among the largest known gas fields of any type in the world. With the advent of substantial shale gas production, the United States has moved quickly from two decades of increased dependence on imported gas to being a possible significant liquefied natural gas (LNG) exporter. With the approval of the Department of Energy for the export of LNG to countries with which the United States does not have a free trade agreement (FTA) forthcoming, the country has overcome an obstacle on the way to becoming one of the world's largest LNG suppliers.

A NEW ENERGY POLICY FRAMEWORK

Previously, many external and internal critics argued that the United States lacked a coherent national-level energy policy. Nonetheless, a number of strategic energy policy documents have been published over the past six years which go some way towards addressing such criticisms and guide the US economy away from its reliance on fossil fuels and towards a sustainable energy system with greater energy independence. The most notable among these policy documents are the "President's Blueprint for a Secure Energy Future" and the "All-of-the-Above Energy Strategy". The enactment of the American Recovery and Reinvestment Act of 2009 (ARRA) has also had significant impact on the sector by scaling up investment in energy infrastructure, clean energy projects and energy efficiency. By means of the ARRA, the Department of Energy (DOE) invested more than USD 31 billion to support a wide range of clean energy projects and technologies.

The President's Blueprint for a Secure Energy Future of 2011 provided a clear signal to policy makers and industry stakeholders, as well as to the public, as to the medium-term direction of federal energy policy: doubling of electricity generation from wind, solar and geothermal sources by 2020, halving net oil imports by the end of the decade and doubling energy productivity by 2030 as well as providing international leadership in clean energy. The "All-of-the-Above" strategy, announced in 2012, established three clear goals: support for economic growth and job creation, enhanced energy security, and deployment of low-carbon energy technologies, all supported by a series of defined policy actions.

The previous in-depth review also highlighted the absence of a clear link at the federal policy level between energy, environmental and security policies, and recommended that the United States pursue closer co-ordination among Congress, the Administration, and state governments, as well as between executive and legislative branches of the federal government. It also emphasised the need for greater co-ordination in order to ensure that energy policy challenges facing the country were addressed in a consistent manner. In this respect, the IEA welcomes the establishment of a quadrennial energy review (QER). The first-ever QER will focus on energy infrastructure and will identify the threats, risks and opportunities for US energy and climate security.

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Many executive departments and agencies play an important role alongside the DOE in developing and implementing policies, such as those governing energy resources and their associated environmental impacts. Many non-federal actors, such as the private sector, the states and academia also make a significant contribution to energy policies. There are also many regional, state and local policies and initiatives that complement federal efforts. The President established an interagency Quadrennial Energy Review Task Force, to develop an integrated review of energy policy that integrates all of these perspectives. The IEA welcomes this review of energy policy, which is expected to build on the Blueprint for a Secure Energy Future and the President's Climate Action Plan.

BUILDING A SUSTAINABLE ENERGY SYSTEM

Climate and greenhouse (GHG) gas policy remains an unsettled and disputed area of energy policy between the executive and legislative branches of government. In 2009, at the negotiations of the United Nations Framework Convention on Climate Change (UNFCCC) in Copenhagen, the President committed the United States to the goal of reducing GHG emissions in the range of 17% from 2005 levels by 2020 in conformity with any legislation.[1] More recently, at a speech in Georgetown University on June 2013, the President confirmed his willingness to work with Congress towards enacting a bipartisan, market-based scheme to reduce GHG emissions. He also highlighted the need to take executive branch actions in the absence of congressional support (Leggett, 2014). The Climate Action Plan (CAP), released in June 2013, sets forth a series of executive branch actions that, with Congress unlikely to enact major climate legislation, uses executive powers under existing laws to reduce emissions. The most significant reduction under the plan is likely to come from the Environmental Protection Agency (EPA) which is called on to develop regulations to control CO_2 emissions from power plants, similar to existing federal limits on emissions of arsenic, lead and mercury (Leggett, 2014).

In June 2014, the EPA proposed the Clean Power Plan to cut carbon pollution from existing power plants. The EPA has put forward state-specific, rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. This rule, to be in place by 30 June 2016, builds on existing measures to reduce CO_2 emissions similar to existing federal limits on emissions of arsenic, lead and mercury. EPA rules to introduce standards, regulations or guidelines for CO_2 emissions in existing power plants must be finalised by June 2015 and in place by 30 June 2016.

Energy efficiency policies have the potential to boost economic growth while reducing energy demand. In this regard, the United States has made good progress, and improvements are expected to continue over the medium term, as energy performance standards for appliances and equipment and for new buildings are implemented. The ARRA provided USD 12 billion for investment in energy efficiency programmes, notably in favour of low-income households, public buildings and research activities. Energy efficiency standards for new buildings have been progressively tightened over the past decade, culminating in the recent introduction of two new model building energy codes covering both residential and commercial buildings. These codes are projected to produce a 30% improvement in the energy efficiency of new buildings compared to buildings constructed to comply with

1. On 11 November 2014, the United States and China made a joint announcement on climate change and clean energy co-operation. As part of this co-operation, President Obama announced a new target to cut net GHG emissions 26% to 28% below 2005 levels by 2025.The possible impact of this announcement is not included in our analysis.

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the 2006 model code (IEA, 2013b). Since 2008, over one million low-income homes have been weatherised to improve energy efficiency. Furthermore, minimum energy performance standards (MEPS) for household appliances and commercial equipment have been strengthened and approximately 20 new standards have been completed since 2009, with more expected over the medium term.

In the transport sector, which is the largest oil consumer, new regulations have been introduced to reduce energy consumption. In 2012, federal agencies finalised a programme to improve the fuel economy of cars and trucks sold in the United States. More stringent fuel economy standards for light-duty vehicles model years 2012-16 (phase one) and model years 2017-25 (phase two) have been established alongside standards for heavy-duty vehicles for model years 2014-18. These fuel economy standards for vehicles are projected to save about 6.3 billion barrels of oil over the life of light-duty vehicles built from 2012-24 model years and heavy-duty vehicles built from 2014-18 model years, which is equivalent to almost one-half of US oil imports in 2012 (IEA, 2013a).[2] The country is also investing in electric vehicle technologies and by 2015 will be able to produce enough batteries and components to support the manufacture of one million plug-in hybrid and electric vehicles.

Smart grids have developed significantly over the past five years. Approximately 33 million households are equipped with advanced meters, and the number of measurement points on the transmission and distribution networks has increased by several orders of magnitude. Funding for research and development from both the public and private sectors of the technology has been strong although declining in the latter case. Despite the advantages offered by investment in smart grids – for example demand response – integration of renewables and resilience, market take-up has been slow. Market frameworks and regulations should encourage private-sector investment in these advanced technologies and practices. Recent developments regarding demand response are encouraging and the deployment of smart grids, smart meters and smart devices should drive down costs. Demand response also includes the development of time-of-use retail prices for electricity, which remain underdeveloped. Greater co-ordination between federal and state policies can benefit all stakeholders and create a larger market for demand response technologies. In particular, state retail demand-response programmes and policies can be better co-ordinated with organised wholesale market programmes.

The United States has set a goal to double renewable energy production from wind, geothermal and solar sources by 2020 compared to 2012, but there is no explicit national policy mechanism to ensure the country reaches this target, although many states have put in place renewable portfolio standards (RPS). In the absence of explicit national obligations or a binding national target, one of the key tools the federal government has at its disposal to support renewable energy is fiscal mechanisms. The durability of existing federal tax incentives for some forms of renewable energy, however, remains a persistent uncertainty. In early 2013, the federal government extended for one year its renewable energy production tax credit (PTC) for wind. With a one-year federal PTC extension granted in early 2013, a more robust outlook for onshore wind projects has emerged, at least during 2014 and 2015. Yet, there is uncertainty over whether there may be another renewal of the PTC. Such uncertainty continues to undermine investor confidence and contributes to the volatile pattern of annual wind deployment.

2. EPA and NHTSA are developing, in collaboration with the California Air Resources Board, plans to extend the Heavy-Duty National Program beyond model year 2018.

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Alternatively, extending the PTC for a fixed period of time while gradually reducing its level to zero on a permanent basis would provide greater investor certainty and spur continued reductions in wind costs. Similar uncertainties exist for solar energy incentives. Furthermore, proposals to amend the US renewable fuels standard have created difficulty in the market for renewable transport fuels. Lack of long-term durability associated with federal incentives represents a challenge for investment in new projects that must be addressed.

The federal government remains one the largest funding entities for energy technology research, development and demonstration (RD&D) in the world, and energy RD&D has historically played a critical role in achieving advances in all fields of energy, including nuclear, fossil fuels, renewables, and end-use technologies. The DOE's 2014 Strategic Plan provides a path to achieving national energy goals and demonstrates the government's firm commitment to basic research, development, demonstration and deployment of priority clean energy technologies. The quadrennial technology review (QTR) is providing a platform to help align energy technology and programme priorities to achieve national energy goals and guide the Department's priority-setting over a five-year horizon. The government should continue to develop approaches to secure a stable, long-term funding environment which would help meet energy technology goals and avoid negative impacts on programme stability.

The push to develop unconventional sources of gas in the United States using hydraulic fracturing techniques has attracted a great deal of criticism on environmental grounds. For example, greater volumes of associated gas as a by-product of oil production are being flared as there is little incentive to market the associated gas or build and upgrade the necessary infrastructure needed to transport it. The publication in March 2014 of Strategy to Reduce Methane Emissions is a welcome step. Water use also presents a problem as shale gas production may consume large volumes of water. Wastewater, if not properly treated, can threaten supplies of drinking water. As more and more areas of the United States are opened up to exploration and production, public concern about the environmental effects on water resources as well as road use/degradation, local traffic, ecosystems and urban disruption is likely to grow. The environmental consequences of hydraulic fracturing are not only of interest in the United States but worldwide as new areas of rich shale gas plays are being explored. The United States has a significant leadership opportunity to develop and showcase best practice at a time when other countries seek to benefit from this resource.

The boom in oil production has also given rise to new environmental and safety concerns. One example is the lack of pipeline infrastructure or where existing pipelines lack sufficient available capacity, which in some regions has forced unprecedented amounts of oil to be transported by rail. The exponential growth in the amount of crude oil having to be moved by rail has given rise to safety and environmental unease and a number of serious accidents have occurred across North America, some of which involved oil being moved from the Bakken Shale (which tends to be more volatile and flammable than crude produced elsewhere). United States rail infrastructure was not built to manage large volumes of crude oil and has a limited amount of specially designed rail trucks. If large movements of oil by rail are to continue, major investments in infrastructure need to be made alongside significant strengthening of safety regulations such as those proposed by the Department of Transport in July 2014.

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SECURING THE LONG-TERM STABILITY OF THE ELECTRICITY SECTOR

Since the last in-depth review, the electricity sector in the United States has experienced considerable changes. The arrival of inexpensive domestically produced natural gas has resulted in stable wholesale electricity prices and delivered other benefits such as lower GHG emissions when replacing coal and greater system flexibility. Nonetheless, if natural gas is to continue to play a key role in the electricity sector, there is a need to improve consistency between the operation of the gas pipeline system and the high and extra-high voltage power transmission system. While both systems are regulated by the Federal Energy Regulatory Commission (FERC), and in fact there is a series of gas-electricity co-ordination initiatives that FERC has put in place, the two systems' different regulatory and business models mean there is a need to better co-ordinate operations, as well as market and planning rules, in order to address increasing interdependence of the two systems.

The New Policies Scenario described in IEA *World Energy Investment Outlook 2014* projects that the US power sector will require USD 2.1 trillion of new investments between 2014 and 2035. This cumulative investment includes 579 gigawatt (GW) of new generating capacity, 260 000 km of new transmission lines, 1.3 million km of new distribution lines and extensive refurbishment of both the transmission and distribution networks (IEA, 2014b). The Energy Independence and Security Act of 2007 made it "the policy of the United States to support the modernization" of the electrical grid. The Edison Electric Institute (EEI) highlighted over 170 planned projects totalling approximately USD 60.6 billion in transmission investments through to 2024 that are required to modernise the transmission system (EEI, 2014). Three-quarters of this investment relates to projects supporting the integration of renewable resources and 43% to interstate transmission projects (projects may fall into more than one transmission investment category). The EEI highlighted the need for effective policies for planning and siting, cost allocation and cost recovery in order to achieve the levels of transmission investments required for a reliable and cost-effective service to electricity customers. The decision of President Obama in June 2013 to sign a Presidential Memorandum that directed federal agencies to streamline the siting, permitting and review process for transmission projects across federal, state and tribal governments represents good progress in this regard but more is needed.

System resilience, especially in the aftermath of Hurricane Sandy and other recent weather-related reliability events, remains a concern. The response to Hurricane Sandy by the federal government, led by DOE and the Federal Emergency Management Agency (FEMA), can be considered a model for future federal-state-local disaster relief and co-ordination of service restoration. Lessons learned will be carried forward in managing a future emergency response.

The existing electricity system delivers relatively inexpensive electricity to consumers across the country, and over time several regional transmission organisations (RTOs) and independent system operators (ISOs) have emerged. These entities have developed operating rules and protocols that allow generation dispatch and transmission co-ordination over increasingly wide geographic areas and that bring many benefits in terms of efficient use of existing assets and minimisation of electricity costs to consumers. Conversely, even between well-integrated RTOs in the Northeast, there are inefficiencies in the interregional co-ordination between the various system operators such as mid-continent independent system operator (MISO), PJM interconnection, New York independent system operator (ISO) and ISO New England.

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Achieving the right balance between consolidation of system operators and co-ordination between these systems is important for the efficient regional integration of electricity markets (IEA, 2014a). While all RTOs have adopted locational marginal pricing, there remains a considerable degree of diversity in the design of capacity markets and the lack of harmonisation between RTOs is a concern. To the extent that these capacity markets are justified by federal regulation (there is a cap on electricity bids in these markets), FERC should seek to achieve greater harmonisation and co-ordination of capacity markets.

Owners and operators of critical energy infrastructure have long had the operational duty to maintain their system security and reliability against threats from physical damage, weather and other hazards. However, over the previous two decades, the threats to energy delivery systems have expanded as a result of the increased use of automation, information technology (IT), telecommunications and other electronic communication-enabling devices. DOE, in collaboration with industry and other partners in the federal government, has released a Roadmap to Achieve Energy Delivery Systems Cybersecurity, which features a strategy and related milestones for addressing cybersecurity in the energy sector. The roadmap is used to collaborate with industry on specific research and development (R&D) projects, as well as operational guidance documents for energy stakeholders, including recent efforts with the Administration, the Department of Homeland Security (DHS), the National Institute for Standards and Technology (NIST) and FERC. With the modernisation of the grid, there are many cybersecurity challenges. The new technology is both advanced and complex and will contain vulnerabilities that may be exploited. It is important, therefore, to ensure the reliability and resilience of the sector regardless of cybersecurity events. Industry, with collaboration and leadership from DOE, is continuing to advance its cybersecurity and resilience capabilities to meet the growing cybersecurity risks in the energy sector.

There is a concern that competitive electricity markets may not trigger investments in large, high fixed-cost investments with long lead time such as nuclear, carbon capture and storage (CCS) and large renewable portfolio projects. This could result in a lack of diversity in the generation portfolio, exposing consumers to the risk of rising gas prices in future. The federal government should continue its efforts to create a better and consistent national regulatory framework to ensure resource adequacy over wider geographic areas and make the most of existing infrastructure.

The United States has long been a leader in nuclear technology and has a mature industry with high availabilities and low stable costs alongside an established regulatory environment. In the recent past, however, the retirement of four reactors has led to the first significant decline in nuclear capacity for many years. This has happened as many other reactors are moving into extended lifetime operation and in a period when only four new reactors are under construction. The economic basis of nuclear power has been severely challenged by competition from shale gas developments as well as weak power prices and slow growth in electricity demand. The domestic nuclear industry is therefore at a critical juncture as a consequence of its declining economic competitiveness, and existing market mechanisms do not favour investment in high capital-intensive nuclear technology. There is a need, therefore, to develop and articulate a clear strategy for nuclear power, including a statement of how the federal government will provide long-term support. Given the long lead times for construction and the declining share of nuclear power in the energy mix, these considerations should be concluded quickly.

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KEY RECOMMENDATIONS

The government of the United States should:

- *Complete the process leading to the quadrennial energy review (QER) and utilise its outcomes to re-establish a stable and co-ordinated strategic outlook for the energy sector.*
- *Maintain its path towards a secure sustainable energy system by:*
  - *Supporting the development and implementation of demand-side measures and energy efficiency policies with an emphasis on the transport and building sectors.*
  - *Offer greater durability and predictability of fiscal incentives for renewable energy in order to maintain investor confidence.*
- *Enhance the long-term sustainability of the electricity sector by:*
  - *Developing effective, co-ordinated national policies to reduce the uncertainties which impede investments in secure electricity infrastructure, including transmission, distribution, smart grids, renewable energy integration and climate resilience.*
  - *Introducing measures to deliver greater co-ordination between different grid operators in order to facilitate the integration of greater shares of variable renewables and to optimise regional transmission investments.*
  - *Articulating a clear strategy for the future diversity of the power sector, including a statement of how the federal government will provide long-term support for nuclear power.*

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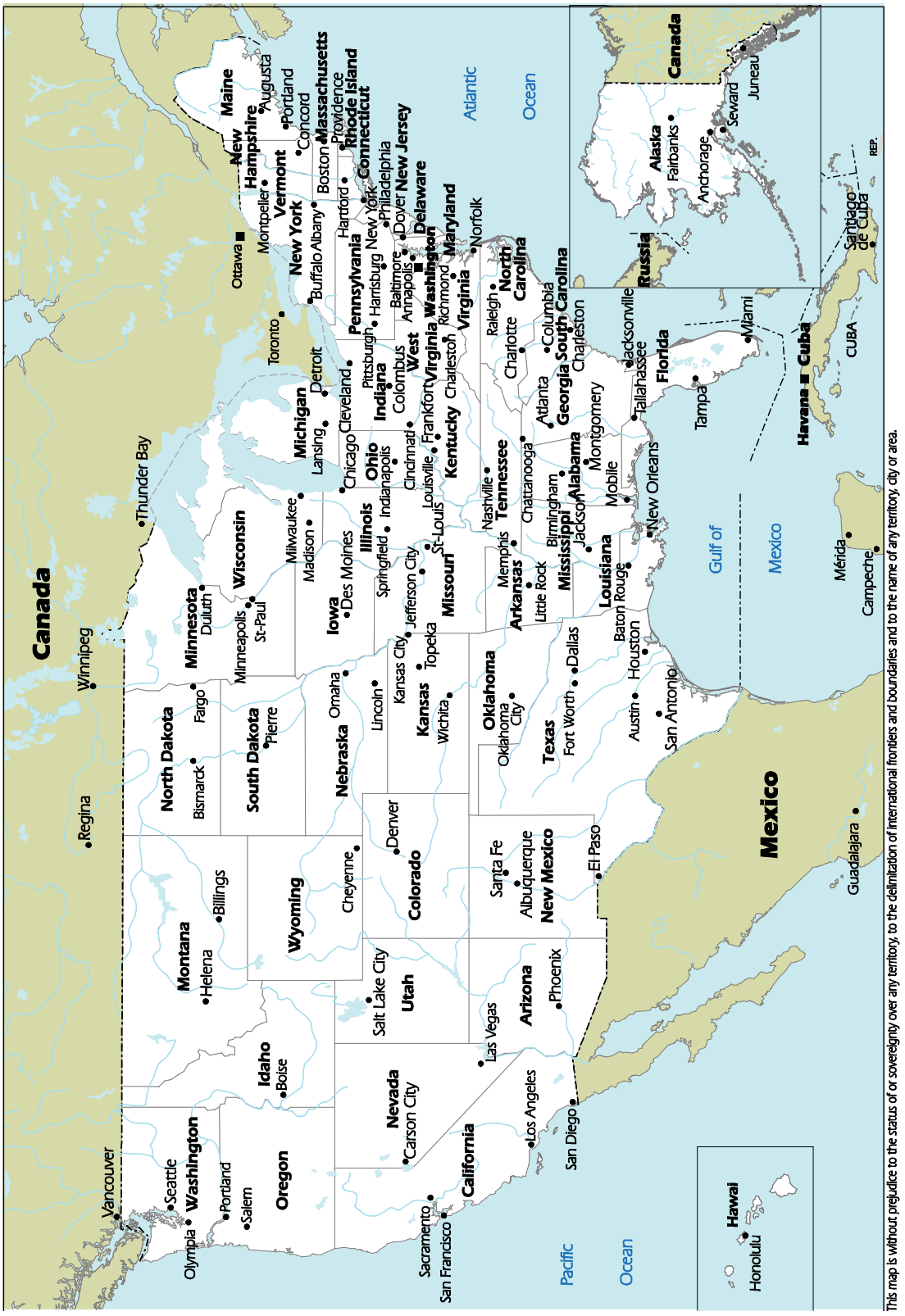
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PART I
POLICY AND SECTOR ANALYSIS

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Figure 2.1 Map of the United States



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2. GENERAL ENERGY POLICY

Key data (2013 estimated)

Energy production: 1 859.3 Mtoe (natural gas 30.4%, coal 25.8%, oil 24.8%, nuclear 11.5%, biofuels and waste 4.9%, hydro 1.3%, wind 0.8%, geothermal 0.5%, solar 0.1%), +13.8% since 2003

TPES: 2 186.7 Mtoe (oil 35.9%, natural gas 27.8%, coal 19.9%, nuclear 9.8%, biofuels and waste 4.2%, hydro 1.1%, wind 0.7%, geothermal 0.4%, solar 0.1%), -3.3% since 2003

TPES per capita: 6.9 toe (IEA average: 4.5 toe)

TPES per GDP: 0.15 toe/USD 1 000 PPP (IEA average: 0.13 toe/USD 1 000 PPP)

Electricity generation: 4 274.5 TWh (coal 40.2%, natural gas 26.9%, nuclear 19.2%, hydro 6.3%, wind 4%, biofuels and waste 1.7%, oil 0.8%, geothermal 0.4%, solar 0.4%), +5.4% since 2003

Electricity and heat generation per capita: 13.9 MWh (IEA average: 10 MWh)

COUNTRY OVERVIEW

The United States remains the largest economy in the world, with a gross domestic product (GDP) in current prices (2013) of USD 16 800 trillion or USD 51.7 thousand per capita. It covers an area of 9 826 million square kilometres, with a population of 318.9 million (estimated) in 2014, 13% of whom were born elsewhere. The major population areas are New York City and northern New Jersey with 20.4 million inhabitants on the east coast; Los Angeles, Long Beach and Santa Ana with 13.4 million on the west coast; and the Chicago area with 9.7 million in the eastern centre of the country. The civilian labour force stood at 155.4 million in 2013, 7.3% of which were unemployed. The population density of the United States is relatively low, with 31.9 inhabitants per square kilometre.

The country is a union of 50 states and one federal district, the District of Columbia. Government is based on a strong division of power, with three main branches. The executive branch is headed by a strong, indirectly elected president, assisted by Cabinet secretaries, departments and agencies. Congress, the legislative branch, consists of two directly elected chambers: the Senate, representing the states equally, each of which elects two senators regardless of its population; and the House, representing electoral districts in each state based on its population.

The United States has experienced strong economic performance in recent years, compared to other OECD member countries. Six years after the onset of the financial crisis, the US economic recovery is regaining momentum. Real GDP is about 6% above its pre-crisis level, the housing sector is beginning to recover, banks have returned to health, corporate profitability is high and equity prices have reached new peaks. Economic growth is expected to gain speed through 2014 and 2015 (OECD, 2014).

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ENERGY SUPPLY AND DEMAND

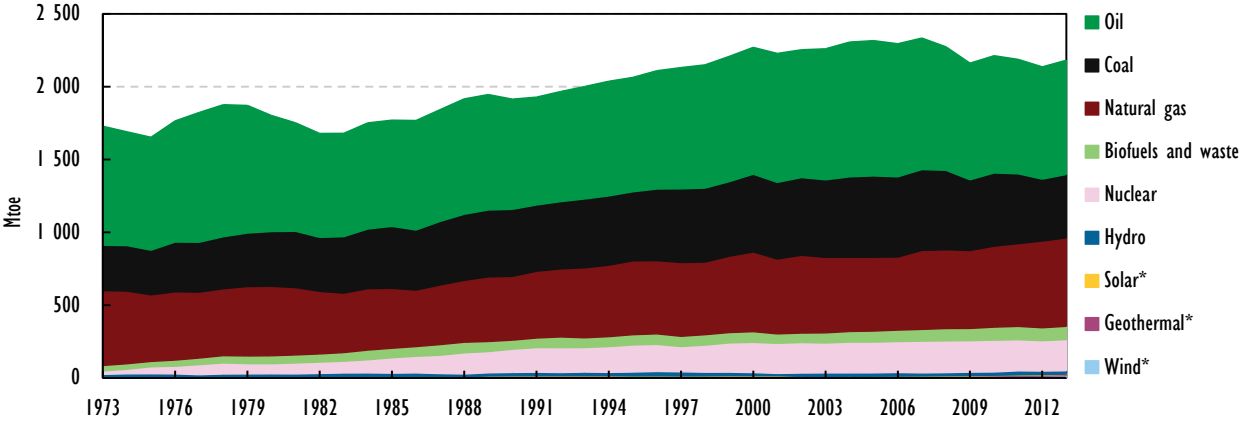
SUPPLY

Total primary energy supply (TPES) in the United States was 2 186.7 million tonnes of oil-equivalent (Mtoe) in 2013.[1] The most significant fuel in TPES is oil with a share of 35.9%, followed by natural gas (27.8%) and coal (19.9%). Nuclear power accounts for 9.8% of TPES, while renewables include biofuels and waste (4.2%), hydro (1.1%), wind (0.7%), geothermal (0.4%) and solar (0.1%).

The United States' TPES has declined over the past decade despite an increase in energy production as a result of falling demand and lower imports. TPES was 3.3% lower in 2013 than in 2003 and 4% lower than in 2008. The supply of coal and oil has experienced the sharpest decline over this period. Coal supply has contracted by 20% over the past five years while the supply of oil was 7.5% lower. The share of coal and oil in TPES has fallen from 24.1% and 40.1% respectively in 2005 when supply of these fuels was at peak.

The share of other sources in TPES has increased, particularly from natural gas (up by 12.3% since 2008 and up by 17.1% since 2003) and from robust growth in renewables. The share of natural gas is up from 23.8% in 2008 to 27.8% in 2013. Over the past five years, energy supply from wind has tripled while solar power increased by 60.4%.

Figure 2.2 TPES, 1973-2013



Note: data are estimated for 2013.

* Negligible.

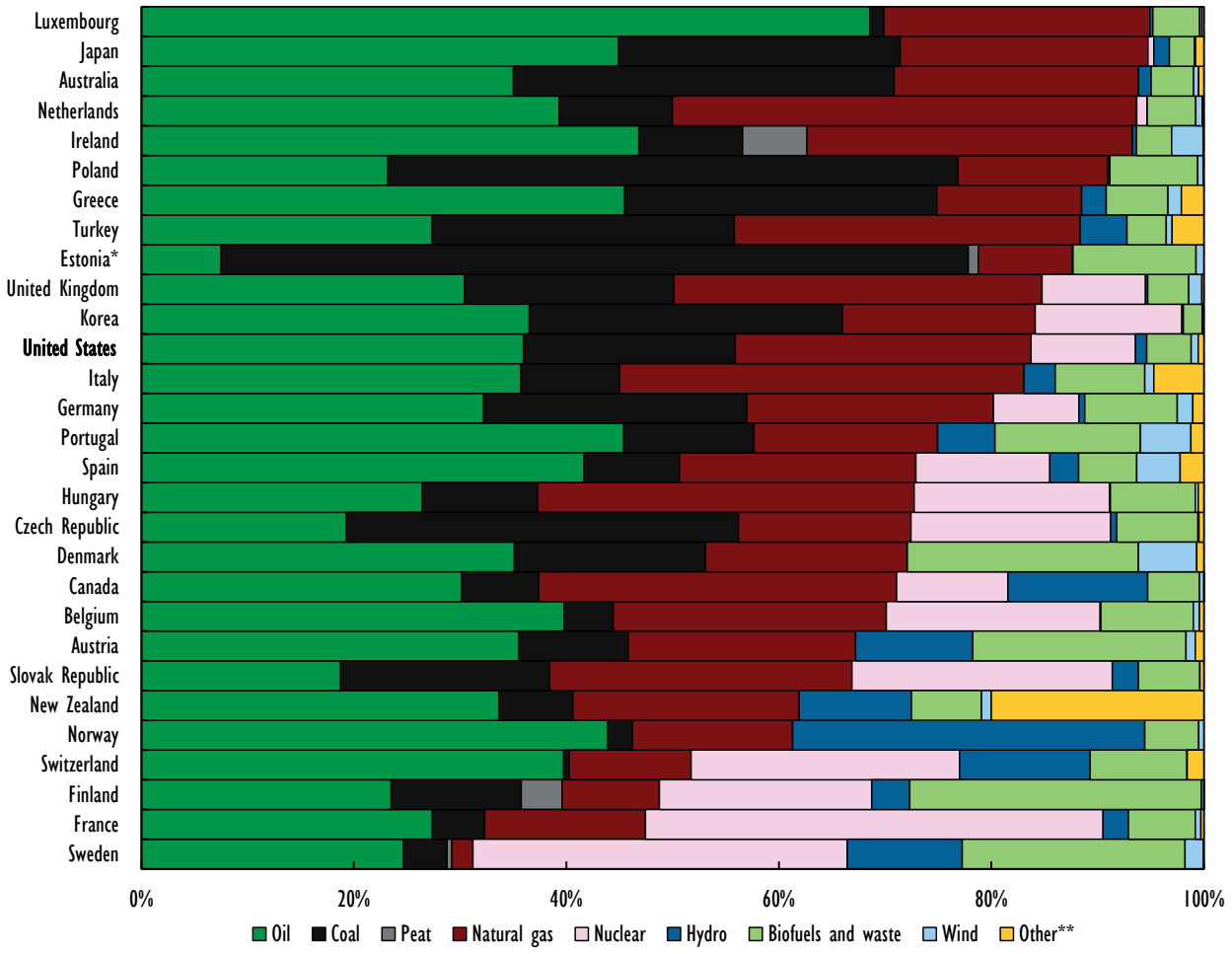
Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

Domestic production accounts for approximately 85% of TPES. However, the United States produces a mix of fossil fuels that is different from what it consumes and the geographical disparity prevents all domestic fuels from being consumed in the country. As such, the United States is reliant on imports for 27% of its energy needs. It is a net importer of oil and natural gas, and a net exporter of coal. Exports represent approximately 12% of energy produced. The United States ranks twelfth-highest among IEA member countries with regard to the share of fossil fuels in TPES.

1. TPES is made up of production + imports - exports - international marine bunkers - international aviation bunkers ± stock changes. This equals the total supply of energy that is consumed domestically, either in transformation (for example refining) or in final use.

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Figure 2.3 Breakdown of TPES in IEA member countries, 2013



Note: data are estimated.

* Estonia's coal represents mostly oil shale.

** *Other* includes geothermal, solar, wind, and ambient heat production.

Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

Production

The United States is one of the largest energy producers in the world, second only to the People's Republic of China. In 2013, energy produced in the United States amounted to 1 859.3 million tonnes of oil-equivalent (Mtoe) which represents approximately 13% of the world total. Energy production has been on the rise over the past decade and was 13.8% higher in 2013 than in 2003. During the 2009 economic recession, production contracted by a marginal 0.9% in that year.

Around 30% of energy production comes from natural gas in 2013, closely followed by coal (25.8%) and oil (24.8%). The total share of fossil fuels has remained relatively constant over the past decade, shifting away from coal towards more oil and gas. Much of the increase in oil and gas production comes from discoveries of unconventional sources.

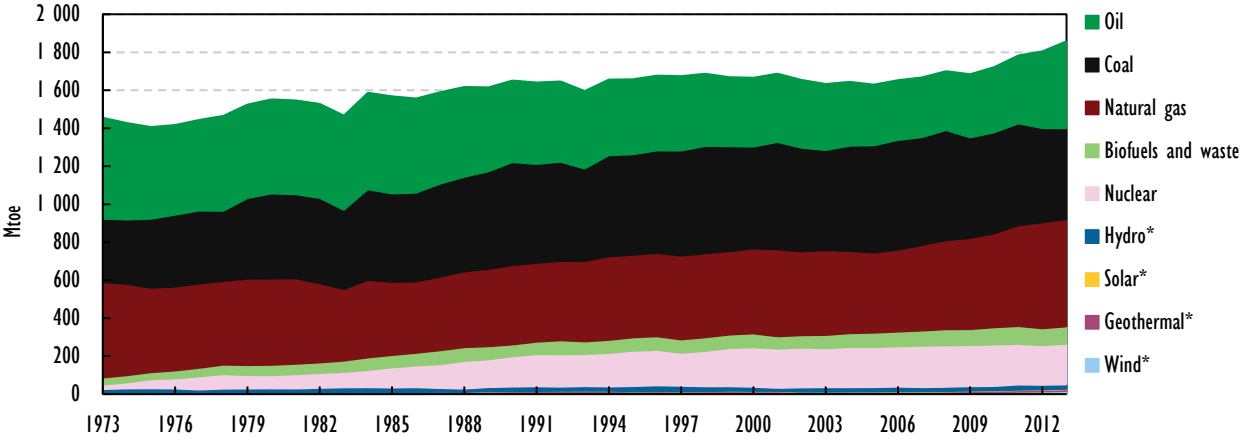
Nuclear power represents 11.5% of total production and has experienced a slow decline since the start of the century, down by 1.9% from 2008 to 2013.

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Conversely, renewable energy has boomed over the same period. Wind power has increased fifteen-fold from 2003 to 2013 (tripling over the past five years) while solar power has nearly doubled. Energy from biofuels and waste was 31.1% higher in 2013 than ten years earlier and 7.4% higher than in 2008. Geothermal and hydropower were 9.9% and 5.7% higher compared to 2008, respectively.

Government projections submitted to the IEA indicate that the United States will continue to expand energy production over the next 25 to 30 years, reaching 2 461.9 Mtoe in 2040. Oil production is expected to decline owing to depleting resources, while all other energy sources will maintain growth. Fossil fuels are projected to account for 76.9% of total energy production in 2040, down from 80.9% in 2013.

Figure 2.4 Energy production by source, 1973-2013



Note: data are estimated for 2013.

* Negligible.

Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

DEMAND

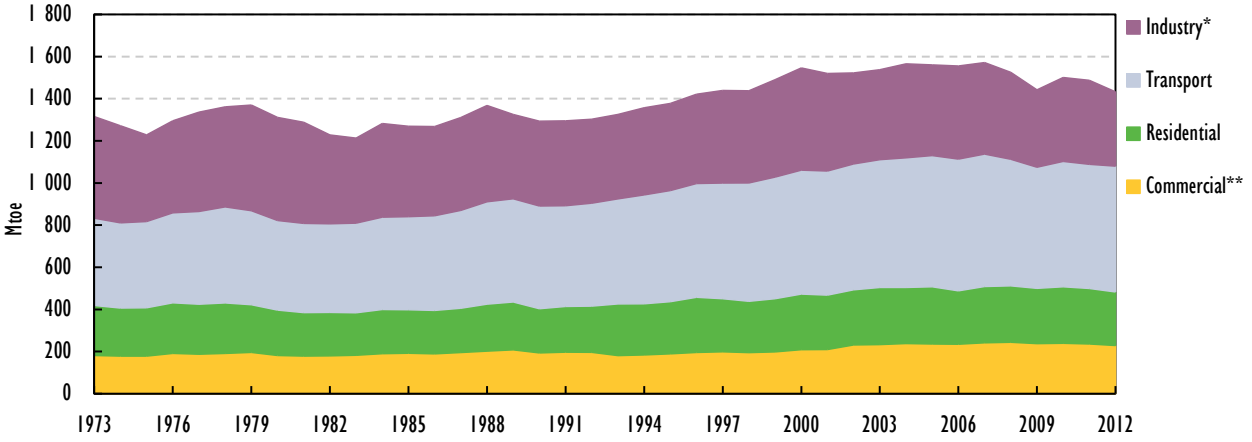
Total final consumption (TFC) in the United States amounted to 1 432.7 Mtoe in 2012 (the latest data available per sector).[2] Final consumption represents 66% of TPES, with the remainder used in power generation and other transformations.

Transport is the largest consuming sector with 41.7% of TFC. Industry represents 24.6%, followed by the residential sector (17.7%) and the commercial sector (15.9%). Over the decade to 2012, energy demand has fallen by 5.9%, decreasing in each sector except in transport where it has remained unchanged. Demand in the residential sector contracted by 2.9% over the ten years with demand in the commercial sector down by 1.2%. Demand in industry experienced the most significant decline and was 18.4% lower in 2002 than in 2012. The long-term trend since the early 1970s has been a slight shift away from energy consumption in *industry* in favour of the commercial sector. However, government projections submitted to the IEA indicate that by 2040, the strongest growth in demand will be in industry, with the least growth expected in the commercial sector.

2. TFC is the final consumption by end-users, i.e. in the form of electricity, heat, gas, oil products, etc. TFC excludes fuels used in electricity and heat generation and other energy industries (transformations) such as refining.

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Figure 2.5 TFC by sector, 1973-2012



* *Industry* includes non-energy use.

** *Commercial* includes commercial and public services, agriculture, fishing and forestry.

Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

INSTITUTIONS

THE WHITE HOUSE

Under Article II of the United States Constitution, the President is responsible for the execution and enforcement of the laws promulgated by Congress. Fifteen executive departments – each led by an appointed member of the President's Cabinet – carry out the day-to-day administration of the federal government. They are joined in this by other executive agencies such as the Environmental Protection Agency (EPA), the heads of which are not part of the Cabinet, but are under the full authority of the President.

The President also appoints the heads of more than 50 independent federal commissions, such as the Federal Energy Regulatory Commission (FERC), as well as federal judges, ambassadors, and other federal officers. The President has the power either to sign legislation into law or to veto bills enacted by Congress, although Congress may override a veto with a two-thirds vote of both houses. The executive branch conducts diplomacy with other nations, and the President has the power to negotiate and sign treaties, which also must be ratified by two-thirds of the Senate. The President can issue executive orders, which direct executive officers or further clarify existing laws. The President also has unlimited power to extend pardons and clemencies for federal crimes, except in cases of impeachment.

Congress established the **Office of Science and Technology Policy** (OSTP) in 1976 with a broad mandate to advise the President and others within the Executive Office of the President on the effects of science and technology on domestic and international affairs. The 1976 Act also authorises OSTP, which has an Energy and Environment Division, to lead interagency efforts to develop and implement sound science and technology policies and budgets, and to work with the private sector, state and local governments, the science and higher education communities, and other countries towards this end.

The **Council on Environmental Quality** (CEQ) is responsible for co-ordinating a number of federal environmental efforts. It works closely with other agencies and White House offices to develop new environmental policies and initiatives. These initiatives include

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retrofitting programmes for private dwellings, measures to improve the overall quality and timeliness of electricity transmission infrastructure permits, and leadership of this Interagency Task Force. The CEQ was established within the Executive Office of the President by Congress as part of the National Environmental Policy Act of 1969 (NEPA) and additional responsibilities were provided by the Environmental Quality Improvement Act of 1970.

THE DEPARTMENT OF ENERGY

The mission of the Department of Energy (DOE) is to advance the national, economic and energy security of the United States. The Department is comprised of approximately 14 000 federal employees and over 90 000 management and operating contractor and other contractor employees at the Department's headquarters in Washington, D.C., and at 85 field locations.

The DOE promotes energy security by encouraging the development of reliable, clean and affordable energy. It administers federal funding for scientific research to further the goal of discovery and innovation, thereby ensuring economic competitiveness and improving quality of life. The DOE is also tasked with ensuring nuclear security, and with protecting the environment by providing a responsible resolution to the legacy of nuclear weapons production. The United States Secretary of Energy oversees a budget of approximately USD 23 billion and more than 100 000 federal and contract employees. The Department's work is carried out by ten distinct programme offices described in greater detail below. Furthermore, the DOE also has an advisory board known as the **Secretary of Energy Advisory Board** (SEAB). The purpose of SEAB is to provide advice and recommendations to the Secretary of Energy on the DOE's basic and applied research and development activities, economic and national security policy, educational issues, operational issues and any other activities and operations of the DOE as the Secretary may direct. SEAB has four standing sub-committees that provide advice and recommendations to the Secretary on the DOE's main areas of activity.

The **Office of Electricity Delivery and Energy Reliability** (OE) supports reliable electricity supply through programmes which are described in more detail in Chapter 3. It provides direction on policies to support a secure, resilient and reliable energy delivery system. It supports the development of new technologies to improve electricity infrastructure, and the federal and state electricity policies and programmes related to electricity system planning and market operations. It also works to strengthen the resilience of the electric networks and assists with restoration efforts when major energy supply interruptions occur.

The **Office of Energy Efficiency and Renewable Energy** (EERE) supports programmes that accelerate development, and facilitate deployment, of energy efficiency and renewable energy technologies and market-based solutions. It leads DOE efforts to develop and deliver market-driven solutions for energy-saving homes, buildings, and manufacturing; sustainable transportation; and renewable electricity generation. Some of its programmes are described in greater detail in Chapter 5 on renewable energy, Chapter 7 on energy efficiency, and Chapter 11 on R&D.

The **Office of Fossil Energy** (FE) is responsible for a number of high-priority initiatives, including implementation of the Clean Coal Power Initiative to develop a new generation of environmentally sound and clean coal technologies, carbon capture and storage, the fossil energy elements of the American Recovery and Reinvestment Act (ARRA) of 2009, and the Strategic Petroleum Reserve and Northeast Home Heating Oil Reserve. It also has regulatory responsibilities with regard to international natural gas sales.

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The **Office of Nuclear Energy's** (NE) primary mission is to advance nuclear power as a resource capable of making major contributions in meeting energy supply, environmental and energy security needs. It examines and seeks to resolve technical, cost, safety, security and regulatory issues through research, development and demonstration (RD&D). By focusing on the development of advanced nuclear technologies, NE supports the goals of providing domestic sources of secure energy, reducing GHG emissions, and enhancing national security. NE's work programme is guided by the four research objectives set out in its Nuclear Energy Research and Development Roadmap (see Chapter 4).

The **Office of International Affairs** (IA) has primary responsibility in the DOE for international energy co-operation in energy, science and technology. The Assistant Secretary for International Affairs (IA) advises the Secretary, Deputy Secretary and other relevant DOE leadership on strategic implementation of the United States' international energy policy. IA leads and develops the department's bilateral and multilateral R&D co-operation, including investment and trade activities, and represents the department and the United States government in interagency processes, intergovernmental forums, and bilateral and multilateral proceedings that address the development and implementation of energy policies, strategies and objectives.

The role of the **Office of Energy Policy and Systems Analysis** (EPSA) is to deliver unbiased energy analysis on existing and prospective energy-related policies, focusing in part on integrative analysis of energy systems. The director of EPSA is the primary energy policy advisor to the Secretary and Deputy Secretary on domestic energy policy development and implementation, as well as on DOE's policy analysis and activities. EPSA is the Secretariat of the Quadrennial Energy Review with primary responsibility for supporting the White House interagency process and providing it with data, analysis, stakeholder engagement, and data synthesis.

The **Advanced Research Projects Agency for Energy** (ARPA-E) is responsible for the advancement of high-potential, high-impact energy technologies that are too early for private-sector investment. It focuses on transformational energy projects that can be meaningfully advanced with a small investment over a defined period of time. It also supports energy researchers with funding, technical assistance and market readiness.

The **Loan Programs Office** (LPO) enables DOE to work with private companies and lenders to mitigate the financial risks associated with clean energy projects. This encourages their development on a much-needed broader scale. It consists of three separate programmes managed by two offices, the Loan Guarantee Program Office (LGP) and the Advanced Technology Vehicles Manufacturing Loan Program Office. LPO originates, guarantees, and monitors loans to support clean energy projects through these programmes.

The role of the **Office of Environmental Management** (EM) is to address the Cold War environmental legacy resulting from five decades of nuclear weapons production and government-sponsored nuclear energy research. This legacy includes dangerous radioactive sites with large amounts of radioactive wastes, spent nuclear fuel, excess plutonium and uranium, thousands of contaminated facilities, and contaminated soil and groundwater. Created in 1989, EM has the responsibility for completing the clean-up of the Cold War legacy and managing the remaining nuclear materials.

The **Office of Indian Energy Policy and Programs**, or Office of Indian Energy, is charged by Congress to direct, foster, co-ordinate and implement energy planning, education, management, and programmes that assist tribes with energy development, capacity building, energy infrastructure, energy costs, and electrification of Indian lands and homes.

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The **Office of Legacy Management** is responsible for managing the historical legacy of World War II and the Cold War and includes radioactive and chemical waste, environmental contamination, and hazardous material stored at over 100 sites across the country. It ensures that DOE's post-closure responsibilities are met and provides programmes for long-term surveillance and maintenance, records management, workforce restructuring and benefits continuity, property management, land-use planning, and community assistance.

The **Office of Science** is the lead federal agency supporting fundamental scientific research for energy and the nation's largest supporter of basic research in the physical sciences. Its portfolio has two principal thrusts: direct support of scientific research and direct support of the development, construction and operation of unique, open-access scientific-user facilities. The Office of Science supports research in all 50 states and the District of Columbia, at DOE's laboratories and more than 300 universities and institutions of higher learning across the United States.

OTHER FEDERAL DEPARTMENTS

The United States **Department of Transportation** (DOT) is responsible for transportation policy, including planning and oversight of highways, railroads and waterways including maritime administration. The DOT oversees the National Highway Traffic Safety Administration (NHTSA), which is responsible for regulation of vehicle safety and the setting of Corporate Average Fuel Economy (CAFE) standards. The Federal Aviation Administration (FAA), which also falls under the DOT, is an independent agency responsible for air traffic regulation and security. It participates in projects to increase the energy efficiency of air traffic. Other relevant offices with transport-related functions in DOT include the Pipeline and Hazardous Materials Safety Administration, the Maritime Administration, the Surface Transportation Board and the Federal Railroad Administration.

The United States **Department of Interior** (DOI) is responsible for the protection of natural resources and heritage. Its role includes management of royalties from oil and gas, and the environmental impact assessment of the development of new resources, such as oil shale. Other energy-related offices include the Bureau of Safety and Environmental Enforcement, the Bureau of Ocean Management, the US Geological Survey and the Office of Surface Mining.

The **Department of State** manages relationships with foreign governments, international organisations, and the people of other countries. The **Bureau of Energy Resources** (ENR), which was established as a direct result of the Quadrennial Diplomacy and Development Review, works to ensure that US diplomatic relationships advance its interests in having access to secure, reliable and ever-cleaner sources of energy. The ENR has three core objectives:

- *Energy diplomacy*: To manage the geopolitics of the energy economy through reinvigorated energy diplomacy with major producers and consumers.
- *Energy transformation*: To stimulate the market forces that will sustain transformational energy policies in terms of alternative energy, electricity, development, and reconstruction.
- *Energy transparency and access*: To expand good governance, increase transparency, and improve commercially viable and environmentally sustainable access to the 1.3 billion people without energy services.

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AGENCIES AND OTHER BODIES

The **Energy Information Administration** (EIA) is an independent statistical and analytical agency within DOE. It maintains a comprehensive data and information programme relevant to energy supplies and reserves, energy production, energy demand, energy technologies, and related financial and statistical information. The EIA's mission is to provide high-quality, policy-independent energy information to meet the requirements of government, industry and the public in a manner that promotes sound policy making, efficient markets, and public understanding.

The **Federal Energy Regulatory Commission** (FERC) is an independent commission which has regulatory powers in electricity, hydropower, and natural gas and oil markets. It regulates interstate gas and electricity markets (i.e. pipelines and transmission services) and is nominally part of DOE but operates independently, with appointed commissioners and professional staff. The **North American Electric Reliability Corporation** (NERC) is the body responsible for the reliability of the electricity transmission network in the United States and Canada. On 20 July 2006, it was certified as the "Electric Reliability Organisation" by the Federal Energy Regulatory Commission. NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organisation that relies on the diverse and collective expertise of industry participants. As the electric reliability organisation, NERC is subject to audit by the United States Federal Energy Regulatory Commission and governmental authorities in Canada.

The **Environmental Protection Agency** (EPA) is an independent agency responsible for the development and enforcement of environmental regulations based on laws enacted by Congress. It carries out research, offers financial assistance, and publishes information for the public.

The 50 **federal states**, the **District of Columbia**, and **United States territories** are responsible for many environmental and energy-related policies within their borders. Many have regulatory commissions, either elected or appointed by the governor or the state legislature, and which have the responsibility to regulate energy undertakings within the jurisdiction. States regulate all retail electricity rates and services, as well as decisions on siting and construction of electricity generation and transmission.

ENERGY POLICY

The federal government retains a strong preference for market-based regulations in energy and environment policy. Following the election of President Obama in 2008, the country appeared to be making progress in developing a new long-term energy agenda by means of stimulus funding and energy and climate legislation. For example, the **American Recovery and Reinvestment Act** (ARRA or Recovery Act) of 2009 provided significant impetus for energy-related projects, including the provision of more than USD 30 billion for clean energy investments. On 13 February 2009, as a direct response to the economic crisis at that time and with the support of President Obama, Congress passed the Recovery Act, more generally known as the "stimulus package". Four days later, the President signed the Recovery Act into law. The three immediate goals of the Recovery Act were:

- Create new jobs and save existing ones
- Spur economic activity and invest in long-term growth
- Foster unprecedented levels of accountability and transparency in government spending

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The Recovery Act intended to achieve those goals by providing funding for:

- Tax cuts and benefits for millions of working families and businesses
- Funding for entitlement programmes, such as unemployment benefits
- Funding for federal contracts, grants and loans

Table 2.1 American Recovery and Reinvestment Act of 2009, Department of Energy Accounts

Budget account	Bureau	Budget function	Funds awarded (USD billion)	Funds paid out (USD billion)
Energy Efficiency and Renewable Energy	Energy Programs	Energy	16.5	15.5
Defense Environmental Cleanup	Environmental and Other Defense Activities	National defence	5.1	5.1
Electricity Delivery and Energy Reliability	Energy Programs	Multiple functions	4.4	3.9
Fossil Energy Research and Development	Energy Programs	Energy	3.2	1.2
Science	Energy Programs	General science, space and technology	1.8	1.7
Title 17 Innovative Technology Loan Guarantee Program	Energy Programs	Energy	1.5	1.3
Bonneville Power Administration Fund	Power Marketing Administration	Energy	1.4	1.4
Non-defense Environmental Cleanup	Energy Programs	Energy	0.4	0.4
Uranium Enrichment Decontamination and Decommissioning Fund	Energy Programs	Energy	0.4	0.04
Energy Transformation Acceleration Fund, Recovery Act	Energy Programs	Energy	0.4	0.3
Departmental Administration	Departmental Administration	Energy	0.1	0.1
Weapons Activities	National Nuclear Security Administration	National defence	0.016	0.016
Isotope Production and Distribution Program Fund	Energy Programs	Energy	0.014	0.014
Construction, Rehabilitation, Operation and Maintenance, Western	Power Marketing Administration	Energy	0.01	0.01
Advanced Technology Vehicles Manufacturing Loan Program Account	Energy Programs	Energy	0.009	0.009
Energy Information Administration	Energy Programs	Energy	0.007	0.007
Title 17 Innovative Technology Guaranteed Loan Financing Account	Energy Programs	Energy	0.006	0.006
Operation and Maintenance, Southwestern Power Administration	Power Marketing Administration	Energy	0.0003	0.0003
Other Defense Activities	Environmental and Other Defense Activities	Multiple functions	0.0002	0.0002

Source: Department of Energy Financial and Activity Reports.

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Two years later, the original overall expenditure estimate of USD 787 billion across all sectors of the economy was increased to USD 840 billion so as to be consistent with the President's 2012 budget and also with changes made by the Congressional Budget Office since the enactment of the Recovery Act. By means of the Recovery Act, the federal government financed more than USD 90 billion in investments and tax incentives to support a vision of a clean energy economy of the future. Of the USD 90 billion, DOE received USD 35.2 billion (USD 32.7 billion in contracts and grants; USD 2.5 billion in credit subsidy) to support nearly USD 80 billion in clean energy projects. Congress also established a temporary grant programme pursuant to Section 1603 of the Recovery Act, which offered cash payments in lieu of previously existing investment tax credit. The section 1603 Program awarded USD 11.6 billion to almost 38 000 projects. Assuming the award equalled 30% of total project costs, the programme was estimated to support almost USD 39 billion in total investments (Harper and Mendelsohn, 2012).

In March 2011, President Obama published a **Blueprint for a Secure Energy Future**, which outlined a three-part strategy for US energy policy. The three parts can be summarised as follows:

- Develop and secure domestic energy supplies: capital, innovation, and technology will be deployed to safely and responsibly develop more domestic energy and move to the fore of the global energy economy.
- Provide consumers with choices to reduce costs and save energy: Volatile petrol prices send a clear signal to consumers that greater innovation is needed. It will become more affordable to buy more advanced and fuel-efficient vehicles, use public transport, insulate homes and workplaces and, by doing so, save money and protect the environment. Support for such measures will help reduce dependence on fossil fuels and help create employment.
- Innovate the way to a clean energy future: the United States wants to become a world leader in clean energy and will work to create markets for innovative clean technologies that are ready to deploy, and fund research to produce the next generation of technologies.

ALL-OF-THE-ABOVE ENERGY STRATEGY

In his January 2012 State of the Union address, President Obama said that the United States needs an "all-out, all-of-the-above strategy that develops every available source of American energy – a strategy that is cleaner, cheaper, and full of new jobs." This has been called his Blueprint to Make the Most of America's Energy Resources, also known as the **All-of-the-Above Energy Strategy**.

As part of the Obama Administration's "all-of-the above" energy strategy to expand safe and responsible domestic energy production, the Department of the Interior and the Bureau of Ocean Energy Management (BOEM) finalised a five-year offshore oil and gas leasing programme for 2012-17 that makes all areas with the highest-known resource potential available for offshore oil and gas leasing. The programme focused on the areas with the most likely recoverable oil and gas resources that the US Outer Continental Shelf is estimated to hold, and scheduled 15 potential offshore lease sales for the five-year period, including 12 in the Gulf of Mexico and three off the coast of Alaska. Six lease sales have already been held under the programme in the Gulf of Mexico.

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PRESIDENT OBAMA'S PLAN TO FIGHT CLIMATE CHANGE

In 2009, President Obama made a pledge that by 2020, America would reduce its GHG emissions in the range of 17% below 2005 levels if all other major economies agreed to limit their emissions as well.[3] While efforts to introduce broader energy and climate change legislation made little progress in the Senate, the United States made strong progress in reducing GHG emissions between 2009 and 2014. Notably, measures to increase the share of renewables in final energy supply and to establish more stringent fuel economy standards for motor vehicles succeeded.

Nonetheless, on 25 June 2013, President Obama announced a comprehensive Climate Action Plan for tackling climate change. The plan, which was divided into three sections, outlined steps to cut carbon pollution, including standards for both new and existing power plants, actions to prepare for the impacts of climate change, and plans to lead international efforts to address global climate change. The plan, which consists of a wide variety of executive actions, has three key pillars:

- Reduce domestic emissions reductions, by:
  - regulating emissions from new and existing power plants using the Clean Air Act
  - increasing clean energy, by developing renewable energy on federal lands, government purchasing, and support for clean energy innovation for biofuels, batteries, and carbon capture and storage
  - wasting less energy, by strengthening energy efficiency policies, including in buildings, appliances and heavy vehicles
  - focusing on highly potent GHGs: hydrofluorocarbon and methane emissions.
- Preparing for the impacts of climate change, by
  - working with local agencies to make communities' infrastructure more resilient, including piloting coastal flooding resilience in the areas affected by Hurricane Sandy
  - providing climate preparedness data and tools
  - maintaining agricultural productivity by helping farmers adapt to drought.
- Leading international efforts to combat climate change, through:
  - bilateral and multilateral (UNFCCC) climate processes
  - ending US support for financing coal plants in developing countries
  - using sound science to manage climate impacts.

The United States is working to build on the actions that it is taking domestically to achieve significant global GHG emissions reductions and enhance climate preparedness through major international initiatives focused on spurring concrete action, including bilateral initiatives with China, India and other major emitting countries.

The plan also urges the United States to prepare for the impacts of climate change, including through identifying vulnerabilities of the energy sector as well as potential opportunities to make the energy infrastructure more resilient to these risks.

3. On 11 November 2014, the United States and China made a joint announcement on climate change and clean energy co-operation including a new US target to cut net GHG emissions 26% to 28% below 2005 levels by 2025.

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The plan also asks for leading international efforts to address global climate change through bilateral initiatives with other major emitting countries; calling for the end of US public-sector financing of new coal-fired powers plants overseas (except if with CCS or efficient coal-fired power in the world's poorest countries); and strengthening global resilience to climate change.

QUADRENNIAL ENERGY REVIEW

In January 2014, President Obama issued a Presidential Memorandum directing the Administration to conduct a Quadrennial Energy Review (QER). In announcing the QER, the President acknowledged that meeting US energy goals will require a comprehensive and integrated energy strategy resulting from interagency dialogue and active engagement of external stakeholders. Accordingly, the President directed the establishment of an interagency QER Task Force, which will include members from all relevant executive departments and agencies. This task force, the SEAB QER Task Force, which is intended to serve as an independent group of experts to assist SEAB in providing DOE support for the QER. The Task Force will offer recommendations on what additional actions it believes would be appropriate. These may include recommendations on additional executive or legislative actions needed.

The Task Force is co-chaired by the Director of the Office of Science and Technology Policy and the Special Assistant to the President for Energy and Climate Change. The Department of Energy will help co-ordinate interagency activities and provide policy analysis and modelling, and stakeholder engagement. The SEAB QER Task Force will prepare a QER Report that:

- Provides an integrated view of, and recommendations for, federal energy policy in the context of economic, environmental, occupational, security, and health and safety priorities, with attention in the first report given to the challenges facing US energy infrastructures.
- Reviews the adequacy, with respect to energy policy, of existing executive and legislative actions, and recommends additional executive and legislative actions as appropriate.
- Assesses and recommends priorities for research, development and demonstration programmes to support key energy innovation goals.
- Identifies analytical tools and data needed to support further policy development and implementation.

The purpose of the first review (energy infrastructure) is to help identify the threats, risks, and opportunities for US energy and climate security and to enable the federal government to translate policy goals into a set of integrated actions. The DOE is hosting stakeholder engagement meetings across the United States throughout 2014 to gather public input.

ENERGY DATA

The US Energy Information Administration (EIA) is the statistical and analytical agency within the US Department of Energy. It collects, analyses, and disseminates independent and impartial energy information to promote sound policy making, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

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The Department of Energy Organization Act of 1977 established EIA as the primary federal government authority on energy statistics and analysis, building upon systems and organisations first established in 1974 following the oil market disruption of 1973. Located in Washington, D.C., EIA is an organisation of about 370 federal employees, with an annual budget in Fiscal Year (FY) 2014 of USD 117 million.

Each year, EIA produces projections of energy supply and demand in the *Annual Energy Outlook* (*AEO*). The *AEO* presents long-term annual projections of energy supply, demand, and prices, based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make projections under alternative, internally consistent sets of assumptions, the results of which are presented as cases. The analysis presented in the *2014 AEO* focused on five primary cases: a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases were also presented highlighting uncertainties associated with the Reference case projections (EIA, 2014a).

The projections in the *AEO* are not statements of what will happen but of what could happen, given the assumptions and methodologies used. The projections are business-as-usual trend projections, given known policy, technology and demographic trends. While the analyses in the *AEO* focus primarily on a reference case, low and high economic growth cases, and low and high energy price cases, more than 30 alternative cases are generally included. EIA also publishes a *Short-Term Energy Outlook* that is updated each month. Monthly forecasts for up to 18 months are provided.

As in previous editions of the *AEO*, the reference case assumes that current laws and regulations affecting the energy sector generally remain unchanged throughout the projection period. Some possible policy changes – notably the adoption of policies to limit or reduce GHG emissions – could change the reference case projections significantly. The degree of uncertainty increases in the out years of the projections because of a variety of factors.

ENERGY PRICING AND TAXATION

Energy prices are determined by the market or by regulation where specific conditions apply, e.g. where there are natural monopolies, or certain privately owned energy suppliers. Electricity prices can be regulated either by FERC (wholesale) or by state regulatory commissions (retail).

Compared to other IEA member countries, energy is taxed at a relatively low rate in the United States. Taxes can be raised independently by states, and/or the federal government, and they are cumulative. The most pervasive energy tax is the federal gasoline tax, which on 1 January 2013 was at USD 0.184 per gallon of gasoline, equivalent to USD 0.049 per litre of gasoline (EIA, 2014b). Diesel was taxed at a rate of USD 0.244 per gallon. The average state gasoline tax is USD 0.2417 per gallon (USD 0.2470 per gallon of diesel). As a result of the additional taxes being imposed in each of the states, the average gasoline tax was USD 0.4247 per gallon (USD 0.491 per gallon of diesel). The highest rate of state gasoline tax is applied in the state of Pennsylvania with USD 0.418 per gallon (USD 0.521 per gallon of diesel), while the lowest state taxes are applied in Alaska and Georgia, which both apply a rate of USD 0.08 per gallon for both gasoline and diesel. These levels of gasoline and diesel taxes are among the lowest in the IEA, and gasoline is considerably cheaper in the United States than in any other member country.

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Income is also raised from mineral rights for the production of coal, oil or natural gas on federal lands. In FY 2012, companies received over USD 66 billion from the sale of oil and gas produced from federal lands and waters, and they paid USD 9.7 billion to the federal government for developing these resources according to the Department of the Interior (GAO, 2013). Under the US fiscal system, companies pay royalties, rents, and other payments − payments generally specified in lease terms − and taxes on profits from the sale of oil and gas produced from federal leases. The revenues collected by the federal government on oil and gas development are shared with states, as directed by statute, and the remaining funds are deposited in the US Treasury.

In addition to the collection of these payments by the Department of Interior (DOI), the federal government assesses taxes on the profits companies earn on the sale of oil and gas produced from federal leases. Under the oil and gas fiscal system, companies bid on leases that DOI makes available. DOI awards the lease to the highest bidder generally on the basis of a lump-sum payment called a bonus bid that is due when the lease is issued. The lease is a contract and conveys the rights to explore for and produce the oil and gas in a specified area to a company that holds the lease. The company is then subject to the payment of rental rates until production begins and then to payment of royalties on any oil and gas that is eventually produced on the lease. The royalty rate is a percentage of the value of production, and the royalty owed is the volume of production times the unit value of production times the royalty rate. The federal government receives royalty payments once production starts.

Following an audit conducted in 2012 and 2013, the US Government Accountability Office recommended that the Secretary of the Interior take a number of actions to better ensure that the government receives a fair return on its oil and gas resources. These recommendations focused in the need for greater transparency and flexibility when adjusting leases.

The tax system is also used as a means to subsidise some forms of clean energy and energy efficiency investments. Businesses can, for example, avail of tax credits and deductions for alternative motor vehicles, the purchase of energy-efficient appliances, plug-in electric drive motor vehicles and research activities. Householders can avail of tax credits and deductions related to energy efficiency investments (credit expired on 31 December 2013) and residential investments in renewable energy (solar-electric systems, solar water-heating systems, fuel cells, small wind energy systems and geothermal heat pumps). Investors in large-scale renewable energy projects can avail of the Renewable Electricity Production Tax Credit (PTC), which provides a tax credit of USD 0.023 per kilowatt hour (kWh) for wind, geothermal, closed-loop biomass and USD 0.011 per kWh for other eligible technologies. The PTC generally applies to the first ten years of operation.

Individual states and cities also offer a wide range of tax credits and rebates. For example, the District of Columbia's Sustainable Energy Utility administers the Business Energy Rebate Program which offers tax rebates to businesses and institutions for the installation of energy-efficient equipment. The state of New York Assisted Home Performance Program provides grants to low-income home-owners in family buildings for up to 50% of costs for energy-efficient improvements. The Alabama Department of Economic and Community Affairs offers an energy efficiency and renewable energy revolving loan fund (AlabamaSAVES) which supports the installation of renewable energy systems on property owned and/or operated by an eligible business. Texas offers a number of fiscal incentives such as property tax exemptions and franchise tax deductions. In California, householders can benefit from a 7.5% state income tax credit on the purchase and installation costs of solar or wind energy systems.

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ASSESSMENT

The energy system and policy environment in the United States has undergone significant change over the six-year period since the last in-depth review was completed. In many aspects, there have been significant improvements and, overall the United States is well placed to continue to deliver a reliable, affordable and environmentally sustainable energy system to meet its policy goals. The most obvious trend to emerge since the last review in 2008 is the resurgence of oil and gas production where output had previously been widely assumed to be in inevitable decline. Together with strong energy efficiency measures, notably in the transport sector, that are set to curb oil consumption, this energy resurgence is having far-reaching consequences for energy markets, trade and, potentially, even for energy security, geopolitics and the global economy. The growth in unconventional gas production has been a game-changing development in North American markets, and is making a substantial additional contribution to economic activity and employment, both within the energy industry and elsewhere, for example by lowering energy and input costs for other energy-intensive industrial sectors.

The previous US in-depth review highlighted the absence of a clear link at the federal policy level between energy, environmental and security policies, and many external and internal critics continued to argue that the United States lacks a coherent national-level energy policy. Remarkably, however, a number of strategic energy policy documents have been written over the past six years which go a large way towards addressing such criticism and steer the US economy away from reliance on fossil fuels and towards even greater energy independence. The most notable among these are the President's Blueprint for a Secure Energy Future, the All-of-the-Above Energy Strategy, and the President's Climate Action Plan. In addition, the American Recovery and Reinvestment Act of 2009 financed more than USD 90 billion in investments and tax incentives to support the federal government's vision of a clean energy economy of the future and to give further impetus to new policies. The forthcoming Quadrennial Energy Review will recommend a range of energy policy options, while establishing a framework for future policy co-ordination across agencies.

The President's Blueprint provided a clear signal to both policy makers and industry stakeholders, and to the public, as to the medium-term direction of federal energy policy: doubling of electricity generation from wind, solar and geothermal sources by 2020 relative to 2012 levels; reducing net oil imports by half by the end of the decade, doubling energy productivity by 2030, and providing international leadership in clean energy. The All-of-the-Above Strategy established three clear goals: support for economic growth and job creation; enhanced energy security; and deployment of low-carbon energy technologies – all supported by a series of defined policy actions.

Although climate and GHG continue to remain the most unsettled and disputed areas of policy, the announcement in June 2013 of President Obama's Climate Action Plan (CAP) represents a major step forward. With Congress unlikely to enact major climate legislation, the CAP relies almost entirely on executive powers under existing laws. It contains a mandate to the EPA to develop regulations to control CO_2 emissions from power plants, similar to existing federal limits on emissions of arsenic, lead and mercury. The President affirmed his 2009 pledge to reduce US GHG emissions by 17% below 2005 levels by 2020 if all other major economies agreed to limit their emissions as well. Among other things, the CAP confirmed the willingness of the President to work with Congress towards enacting a bipartisan, market-based scheme to reduce GHG emissions, and the need to

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take executive branch actions in the absence of congressional support (Leggett, 2014). EPA rules introducing standards, regulations or guidelines for CO_2 emissions to existing power plants must be finalised by June 2015 and in place by 30 June 2016. Nonetheless, there remains a danger that the success of any new regulations depends on the courts and how congressional leaders receive them.

The policies set out in the CAP should not damage economic growth or jobs and will contribute to the continued recovery of the US economy while strengthening energy security. The 2013 publication, *Redrawing the Energy-Climate Map* (IEA, 2013), demonstrated that a package of policies very similar to those proposed by the United States – increasing energy efficiency, targeting methane emissions, phasing down fossil fuel subsidies and reducing reliance on highly polluting coal plants – can be delivered at zero GDP cost between now and 2020. Conversely, this approach to emissions abatement, which also gives states flexibility in how to implement policy, may prove to be more costly than a market-based mechanism.

Although the significant resilience and innovation that arise from such a decentralised and varied system as the United States are sometimes underplayed, the IEA supports proposals for a Quadrennial Energy Review (QER). This will introduce a more formalised and regular federal-level policy review mechanism including a detailed scenario and sensitivity analysis. The federal government will conduct a QER, which will be led by the White House Domestic Policy Council and by the Office of Science and Technology Policy, supported by a Secretariat established at the Department of Energy. This process will involve robust engagement with a broad sweep of federal agencies and industry stakeholders. The IEA Secretariat understands that the first-ever review, which has been under way since January 2014, will focus on energy transmission, storage and distribution (TS&D) infrastructure and will identify the threats, risks and opportunities for US energy and climate security. The QER should enable the federal government to translate its policy goals into a set of analytically based, clearly articulated, sequenced and integrated actions, and into proposed investments over a four-year planning horizon. The IEA welcomes the introduction of this mechanism.

In the electricity sector, the arrival of inexpensive domestic natural gas has resulted in stable wholesale electricity prices and allowed the integration of large volumes of electricity produced from renewable sources without increasing end-user rates. The impact of the domestic shale gas boom has also resulted in notable changes in electricity production: in 2005, coal-fired power plants accounted for 49.6% of electricity production, and by 2012, this had fallen to 37.4% while the share of natural gas in the electricity mix increased from 18.8% to 30.4% over the same period. In 2013, coal accounted for 40% of output compared to 27% for natural gas. This shift in electricity generation has had an impact on CO_2 emissions from the power sector, which have declined by 10% since 2005. Nonetheless, the coal-fired power fleet is likely to remain a major GHG emitter for some time despite these trends and forthcoming environmental regulations.

Since the last in-depth review in 2008, the use of renewable energy in the United States has continued to increase, boosted by policies to support electricity at the state level and by a nationwide policy that mandated significant increases in the use of biofuels. President Obama has set a goal to double renewable energy production from wind, solar and geothermal sources by 2020 and has supported a number of policies to facilitate this goal, such as more efficient permitting of clean energy on federal lands and upgrading the electricity grid. The CAP has sought to promote the deployment of solar, wind and geothermal energy on federal lands through prioritised permitting and environmental

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review processes. However, proposals to amend the renewable fuels standard have created difficulty in the market for renewable transport fuels, and the durability of federal tax incentives for some forms of renewable energy remains a persistent uncertainty for investors. These concerns need to be addressed.

Distributed generation, particularly photovoltaic (PV), creates challenges for tariff structures and investment on distribution networks in the end-user sector, where fixed network costs are recovered by means of variable energy charges. As the penetration of PV on residential and commercial premises increases, regressive cross-subsidies and financial pressure on utilities can result. Although primarily a matter for state regulators, this issue could act as a significant barrier to further renewable energy penetration, and the IEA encourages the federal government to take leadership in initiating the analysis and public debate necessary to lead to new tariffing strategies.

Among OECD member countries, the United States has achieved the biggest improvement in energy intensity in recent decades, albeit from relatively high levels. Its energy intensity declined at an average rate of 2% per year from 1980 to 2010. In recent years, policy efforts to further improve energy efficiency have been reinforced. The 2009 economic stimulus package included new energy efficiency initiatives and substantial additional funding for existing programmes. While the country does not have an economy-wide energy efficiency target, it is focusing increasingly on improving energy efficiency in road transport. New standards adopted in 2011 will increase fuel economy to 54.5 miles per gallon (compared with less than 35 mpg today) for cars and light-duty trucks of model year 2025. In 2013, it was further announced that standards for heavy-duty vehicles that currently target the model year 2018 will be extended and further tightened. Together, the standards represent one of the largest steps taken by the federal government directed at climate change. Furthermore, the country is in the process of revising its minimum energy performance standards (MEPS) for appliances and equipment, a sector in which the country has been very active since 1978. Twenty-four states have adopted long-term energy savings targets, which are driving utility investments in energy efficiency.

The absolute strength of the energy system is its deep public- and private-sector investment in energy-related RD&D activities. The ability for applied technology to solve problems and reduce costs is crucial to addressing many of the challenges in domestic and global energy systems. A policy of investment across the board in "All-of-the-Above Energy Strategy" is appropriate given the breadth and depth of capability in the United States.

RECOMMENDATIONS

The government of the United States should:

- *Complete the process leading to the Quadrennial Energy Review and utilise its outcomes to re-establish a stable and co-ordinated framework for energy policy, including greater certainty for investors in renewable energy.*
- *Constructively finalise the US climate change policy framework, ideally by the introduction of a broad-based price on carbon, but if not, by supporting the Environmental Protection Agency's efforts to implement carbon pollution regulations for both new and existing power plants.*
- *Develop the array of policies and measures capable of improving the efficiency of utilisation of existing infrastructure; mobilise the investment required to renovate, modernise and expand gas and electricity infrastructure.*

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3. ELECTRICITY

Key data (2013 estimated)

Electricity generation: 4 274.5 TWh, +5.4% since 2003

Electricity generation mix: coal 40.2%, natural gas 26.9%, nuclear 19.2%, hydro 6.3%, wind 4%, biofuels and waste 1.7%, oil 0.8%, geothermal 0.4%, solar 0.4%

Installed capacity (2012): 1 067.9 GW, +18% since 2002

Peak demand (2012): 782.5 GW

Inland consumption (2012): 320.5 Mtoe (commercial and other services 40.2%, residential 36.9%, industry 22.7%, transport 0.2%)

OVERVIEW

Since the last in-depth review, the United States has experienced significant growth in the use of natural gas for electric generation, primarily as a result of the increased availability and affordability of domestic natural gas, but also thanks to its relative environmental advantages and its role in balancing the growing fleet of variable renewable resources. A second factor driving changes in US power supply is the considerable growth of renewable energy supply, energy efficiency and demand response programmes, fostered by developments in technology and by policy initiatives at both the state and federal levels. Finally, new environmental regulations are contributing to changes in power supply. Furthermore, the steady growth in natural gas-fired generation is leading to greater interdependence between the natural gas and electricity markets and their associated infrastructures. Changes in power supply require a more robust transmission grid to serve customers reliably and at reasonable cost.

SUPPLY AND DEMAND

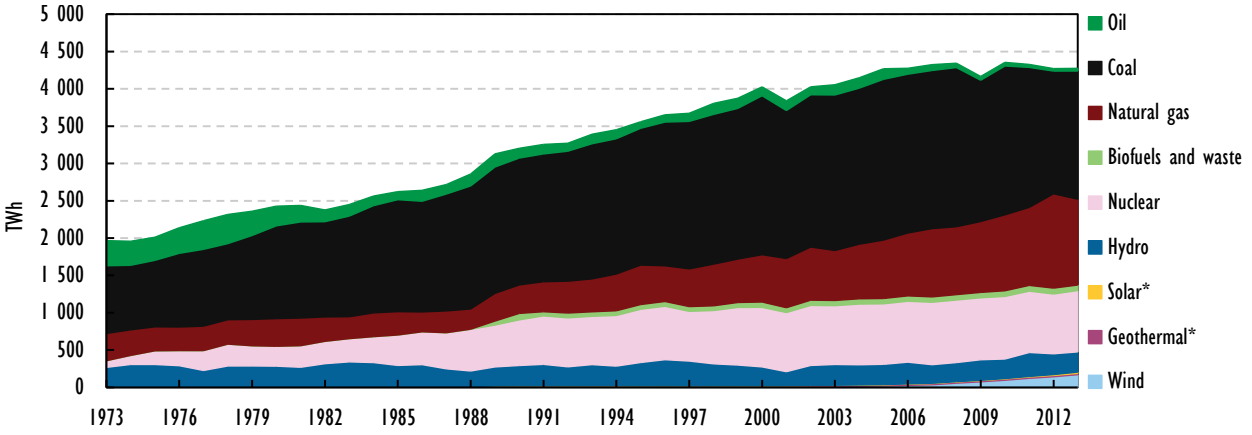
ELECTRICITY GENERATION

Electricity generation in the United States was 4 274.5 terawatt-hours (TWh) in 2013, relatively unchanged compared to the previous year. Over the ten years since 2003, generation output has increased by 5.4% (including a 4.1% decline in 2009).

Coal and natural gas are the major sources of electricity, accounting for 67% of production. During 2013, 40.2% of electricity was generated from coal while 26.9% came from natural gas. A decade ago, coal represented 51.4% and natural gas was 16.5% of generation. While the use of both coal and natural gas has increased over the past three decades, electricity production from coal peaked at 2 154 TWh in 2005 and has declined since. Conversely, electricity from natural gas has continued to grow, reaching a record 1 264.6 TWh in 2012.

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Figure 3.1 Electricity generation by source, 1973-2013

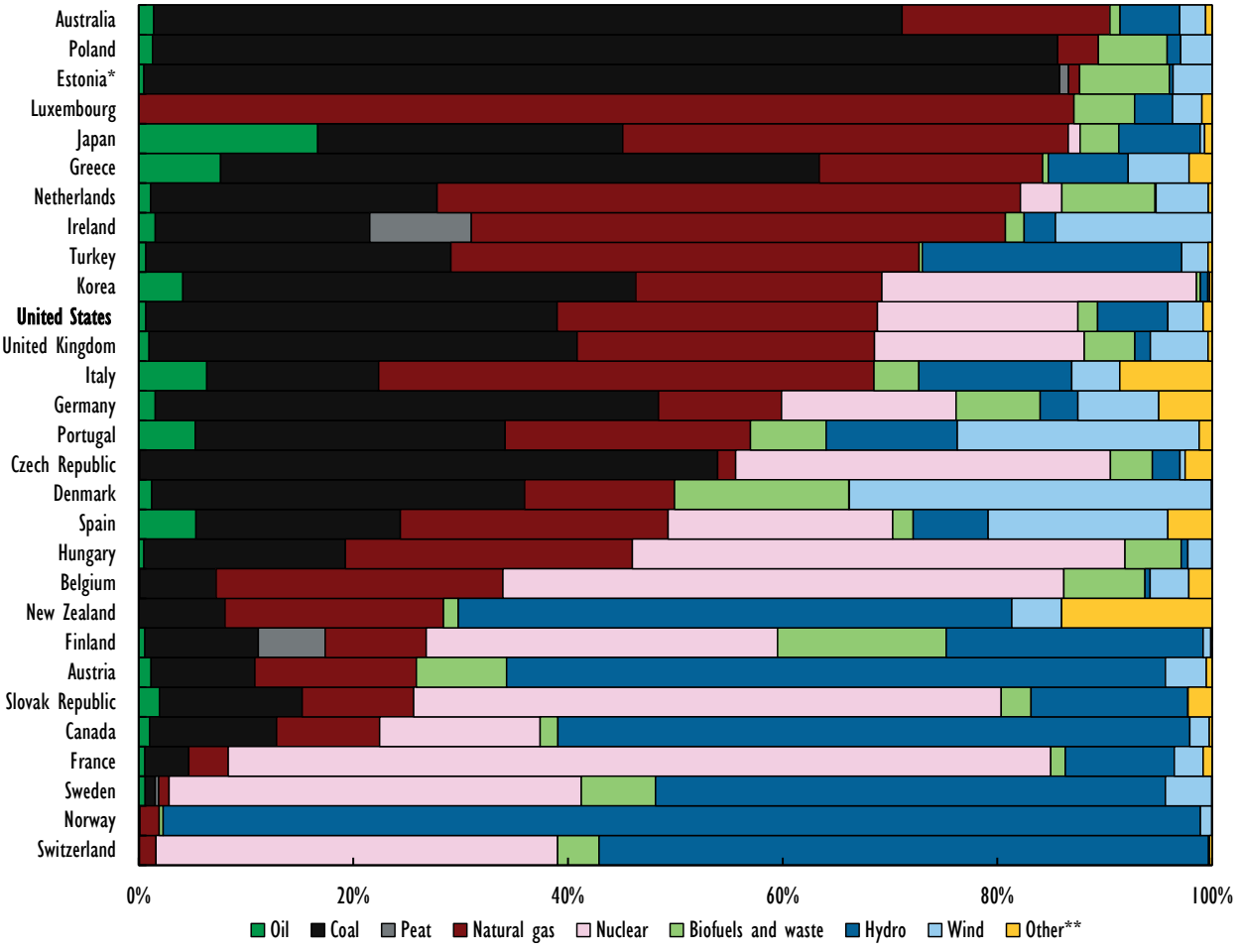


Note: data are estimated for 2013.

* Negligible.

Source: (IEA 2014c), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

Figure 3.2 Breakdown of electricity generation by source in IEA member countries, 2013



Note: data are estimated.

* Estonia's coal represents oil shale.

** *Other* includes geothermal and solar.

Source: (IEA 2014c), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

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Oil accounts for less than 1% of electricity output, down from 3.4% in 2003. In comparison to other IEA member countries, the share of fossil fuels in electricity generation in the United States is the eleventh-highest at 67.9%, behind Australia, Poland, Estonia, Luxembourg, Japan, Greece, the Netherlands, Ireland, Turkey and Korea. The federal government projects that fossil fuels will remain the major source of electricity in 2040, with coal at 35.5% of generation, natural gas at 30.5% and oil at 0.6%.

Nuclear energy is the third-largest source of electricity in the United States, accounting for 19.2% of generation in 2013. Over the decade since 2003, electricity from nuclear energy has increased by 4.3% although it was 1.9% lower in 2013 than in 2008.

Renewable energy sources accounted for 12.9% of electricity generation output in 2013, made up of hydro (6.3%), wind (4%), biofuels and waste (1.7%), geothermal (0.4%) and solar (0.4%). Wind and solar energy have experienced a boom, rising from negligible levels at the start of the century. Electricity from geothermal has grown by 22.3% from 2003 to 2013, while growth from biofuels and waste was more subdued, at 6.3%. Hydropower generation was 2.6% lower in 2013 than a decade ago, owing to high annual variations in production. The federal government expects that renewable energy will account for 16% of generation by 2040, with an expansion of all sources apart from hydro.

RECENT TRENDS IN POWER GENERATION

The generation mix is undergoing a period of change and adjustment as a result of the availability of inexpensive natural gas, tighter environmental restrictions and the growth in renewable energy supply.

In 2005, when the first commercial natural shale gas wells were fractured, coal produced almost three times as much power in the United States as gas; by 2017, their shares will be almost the same (IEA, 2012). Over the shorter term, it is likely that gas-fired power plants will suffer from higher gas prices. In the medium term, it is expected that gas-fired generation will fall from the levels reached in 2012 and will not be reached again until 2015. Conversely, coal-fired generation will recover over 2013/14, before resuming a slightly declining trend from 2014 onward. As power demand continues to increase over 2015-18, gas-fired generation and renewable energies fill this gap, a pattern seen previously over the past decade (IEA, 2013a).

Historically, coal-fired power supply provided half of all electricity consumed in the United States. Since 2008, however, natural gas has eaten into this share as its share of supply increased by 8.6%, from 21% in 2008 to 30.4% in 2012, while electricity prices remained relatively subdued, at least until mid-2013.

The impact of this has been two-old: first, a decline in the amount of coal-fired output and an increase in natural gas (and renewable) output; and secondly, an increase in coal exports as coal producers look to new markets. At the same time, the power sector was facing the imposition of tighter emissions rules from the Environmental Protection Agency (EPA). This has resulted in growth in the number of retirements in the coal-fired power sector and greater concentration of gas-fired generation in the gas-producing regions.

Instead of new capacity builds, much of the recent shift in power generation has happened as a result of gas-fired generators operating at higher capacity factors while capacity factors of coal-fired producers have fallen.[1] For example, between 2008 and

1. The capacity factor of a power plant in the ratio of its actual output over a period of time to its potential output if it were possible for it to operate at full nameplate capacity.

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2012, the average capacity factor of a gas-fired plant in the United States increased from 40.1% to 51.1% or by a quarter. Conversely, the average capacity factor in the coal-fired sector fell from 73.4% to 56.7%. Preliminary data for 2013 suggest that coal is making a recovery of sorts (EIA, 2013b). Should natural gas prices continue to rise – and by late 2013 they were USD 4.71 per million British thermal units (MBtu) compared to prices as low as USD 1.95/MBtu in April 2012 – it is likely that the generators will begin to run existing coal-fired plants at higher capacity levels alongside higher levels of renewable output.

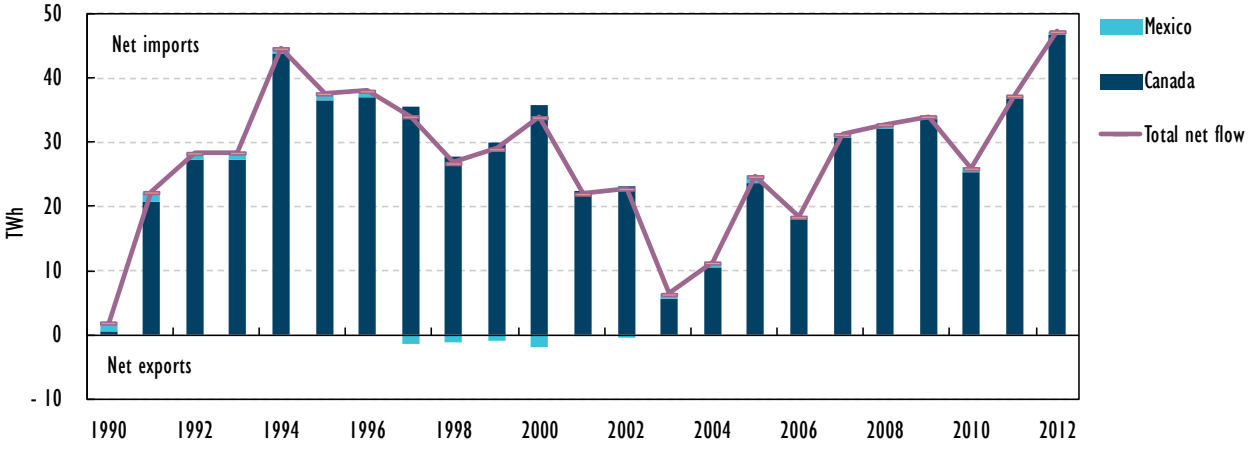
Combined heat and power

Interest in combined heat and power (CHP) production in the United States is rising as a result of low natural gas prices, the return of manufacturing to US shores, and growing awareness of the value of energy resilience. Section 2 of Presidential Executive Order No. 13624, Accelerating Investment in Industrial Energy Efficiency, contains a set of measures to co-ordinate and encourages efforts to achieve a goal of deploying 40 GW of new, cost-effective industrial CHP by the end of 2020. While combined heat and power (CHP) represents 8% of US electricity-generating capacity, it represents over 12% of annual US power generation, reflecting the longer operating hours of CHP plants as compared to conventional forms of generation. CHP is used in a broad range of applications, primarily the provision of power and steam to large industries such as chemicals, paper, refining, food processing and metals. CHP in commercial and institutional applications is currently limited (14% of existing CHP capacity), but growing in use to provide power, heating and, in many cases, cooling, to hospitals, schools, university campuses, nursing homes, hotels, and office and apartment complexes. Commercial and institutional applications also include the use of CHP for district heating and cooling, which currently makes up 23% of the installed CHP capacity in the commercial/institutional sector (IEA, 2014a).

IMPORTS AND EXPORTS

Imports totalled 63.6 TWh in 2013 while exports amounted to 11.3 TWh. Since 2003, the volume of imports has grown by 109%, while exports have declined by 53%.

Figure 3.3 Net electricity imports to and exports from the United States, by country, 1990-2012



Source: (IEA 2014b), *Electricity Information*, OECD/IEA, Paris.

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Electricity trade in the United States is at a marginal level, with net imports accounting for approximately 1% of domestic demand. The country has two trading partners, Canada in the north and Mexico in the south. Over 95% of both import and export volumes are traded with Canada, where the United States is a net importer. Trade with Mexico is more volatile and switches between net imports and net exports. Greater trade with Canada is likely; for example, in August 2014, the DOE completed an environmental review of a proposed 330-mile transmission line to bring Canadian hydroelectric power to New York City. This approval cleared the way for final permitting of the 1 000 megawatts (MW) Champlain Hudson Power Express transmission line, which has been in development since 2008. During 2014, DOE is reviewing four other permits that would also add extra capacity, if approved.

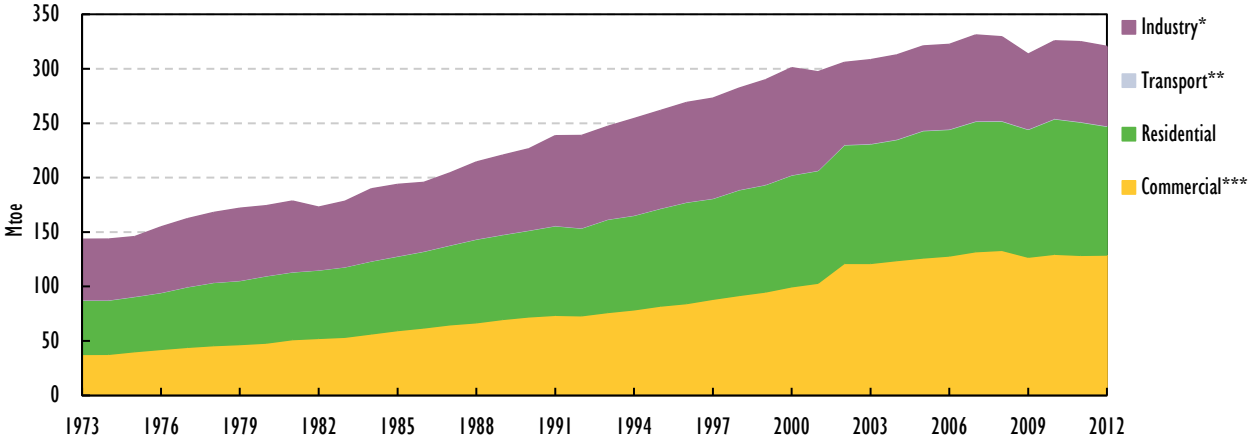
ELECTRICITY CONSUMPTION

The services and residential sectors are the largest consumers of electricity in the United States. In 2012 (the latest available data for consumption by sector), 40.2% of total demand was from commercial and public services while 36.9% came from households. Industry accounted for 22.7% of total demand while 0.2% was consumed by the transport sector. The demand for electricity in the transport sector has increased by 13.6% since 2002, up from 0.1% of consumption.

Electricity consumption totalled 320.5 million tonnes of oil-equivalent (Mtoe) in 2012, increasing by 4.8% since 2002. Demand in the commercial and residential sectors has grown at a faster rate, namely by 6.3% and 8.6% respectively. As such, the share of consumption by these sectors has increased from 39.7% for commercial and from 35.6% for households in 2002.

Conversely, consumption in the industry sector has experienced a downward trend since the late 1990s, with total demand decreasing by 3.3% since 2002. The share of industry in electricity consumption has fallen from 24.6% in 2002 to 22.7% in 2012.

Figure 3.4 Electricity consumption by sector, 1973-2012



* *Industry* includes non-energy use.

** Negligible.

*** *Commercial* includes commercial, public service, agricultural, fishing and other non-specified sectors.

Source: (IEA 2014c), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

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REGULATORY OVERSIGHT

OVERVIEW

The electricity industry is subject to a complex series of regulatory regimes at municipal, state and federal levels, with some exemptions. The Constitution allows federal regulation of utilities only where interstate commerce is involved. Accordingly, intrastate activities are subject to regulation by state regulatory commissions, which approve the construction of generating plants and transmission lines, while all states approve retail prices for their jurisdictional electric utilities.

The DOE may also exercise regulatory oversight. In 1977, Executive Order 12038 transferred the authority for the construction or operation of electric transmission facilities at the US international borders to the Secretary of Energy.

The Federal Energy Regulatory Commission (FERC) enjoys exclusive jurisdiction over the transmission of electricity in interstate commerce, over the sale of electric energy at wholesale in interstate commerce, and over all facilities for such transmission or sale of electric energy. FERC also has jurisdiction over wholesale transactions where there is no crossing of state boundaries. Other matters such as hydropower, regulation of intrastate transmission lines and gas pipelines, and nuclear plant permitting issues, are under federal regulation. At end-user level, some activities, such as customer billing, are treated as monopoly services in many jurisdictions, but are treated as competitive in others and are regulated by state regulatory commissions.

In addition to the 1978 Federal Energy Act and the Public Utility Regulatory Policies Act (PURPA), which introduced the first steps towards competition, the Energy Policy Act of 1992 was an important driver for competition in electricity markets. It gave FERC the authority to order open access for wholesale transactions between utilities.

Federal Power Act

The Federal Power Act (FPA), the purpose of which was to more effectively co-ordinate the development of hydroelectric projects in the United States, was first enacted as the Federal Water Power Act in 1920, and amended a number of times since, most recently by the Energy Policy Acts of 1992 and 2005. The legal authority of FERC comes from the Federal Power Act and major amendments made to it by the US Congress.

DOE's authority to regulate the export of electric energy is based on the statutory authority contained in section 202(e) of the FPA. This power has been exercised on a number of occasions, for example in December 2000 when an emergency order was issued in response to the California energy crisis, and in September 2008 in response to Hurricane Ike. Furthermore, section 216(h) to the Federal Power Act stated that the DOE is to co-ordinate all federal authorisations and related environmental reviews needed for siting interstate electric transmission projects, including National Environmental Policy Act of 1969 (NEPA) reviews. The purpose of this co-ordination is to streamline agencies' review processes and avoid duplication among federal agencies.

Energy Policy Acts of 1992 and 2005

Passed by Congress in 1992, this landmark legislation promoted competition in the wholesale electricity market. One of the Act's provisions amended the Federal Power Act, giving FERC authority to order utilities to provide transmission services to requesting wholesale

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generators. The Act also promoted the use of solar and renewable energy, overhauled nuclear plant licensing procedures and established programmes to increase energy efficiency.

FERC tried to promote further development of liberalised markets with this authority but achieving fully liberalised and competitive markets required additional state legislation. In the northeastern states, in California and in Texas, liberalisation was brought forward through state legislation, which ordered partial or full retail access for consumers to switch supplier. The Energy Policy Act of 2005 established a number of energy management goals for federal facilities and fleets; for example it mandated advanced meters for collecting data (at least daily) and measuring the consumption of electricity (at least hourly).

FERC Orders 888 and 889

Issued in 1996, these companion orders established the rules regarding opening the nation's wholesale bulk electric system to competition.[2] These orders required the establishment of an electronic bulletin board called open access same-time information system (OASIS), which allows users to receive data on current operating status and transmission capacity of any transmission provider.

FERC Order 2000

Order 2000 encouraged all FERC jurisdictional utilities that own, operate or control transmission lines (those that carry power from generating plants to distribution substations) to turn operational control of those lines over to an independent agency (independent system operator or regional transmission organisation).

A large part of the framework for operating the electricity sector is decided by the state Public Utility Commissions and FERC. For example, within the PJM interconnection area, it is PJM that decides on the market rules and design features that, in the end, direct the electricity flow; but always within the framework of rules and regulations set by regional and federal regulators. FERC also approves various entities to act as Regional Transmission Organisations (RTOs), one of whose roles is to provide non-discriminatory wholesale electric transmission service under one tariff for a large geographic area.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

FERC is an independent agency that regulates the interstate transmission of electricity, natural gas and oil. A primary function of FERC is to "assist consumers in obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means" (FERC, 2013a). One of the FERC's fundamental statutory responsibilities is to ensure that rates, terms and conditions for wholesale sales and transmission of electric energy are just and reasonable and not unduly discriminatory or preferential. The Commission uses a combination of regulatory and market means to achieve this goal, consistent with national policy and priorities. FERC's Order Nos. 888 and 889 established non-discriminatory open access transmission services and stranded cost recovery rules for the transition to competitive markets. These rules established a sound foundation for competitive bulk power markets in the United States.

2. Order 888: Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (24 April 1996) and Order 889: Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct (24 April 1996).

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In summary, in the electricity sector, FERC carries out the following activities:

- regulation of the transmission and the wholesale sales of electricity in interstate commerce
- oversight of certain mergers and acquisitions, and corporate transactions by electricity companies
- oversight of siting applications for electricity transmission projects under limited circumstances
- licensing and inspection of private, municipal, and state hydroelectric projects
- protection of the reliability of the high-voltage interstate transmission system through mandatory reliability standards
- monitoring and investigation of energy markets
- regulation of natural gas transportation, and natural gas pipelines, storage and liquefied natural gas siting
- oversight of North American Electric Reliability Corporation (NERC).

In recent years, the focus of FERC in the electricity supply sector has been on a number of strategic priorities such as:

- smart grids
- demand response
- integration of renewables
- Order no. 1 000, transmission planning and cost allocation.

RELIABILITY ENTITIES

The North American Electric Reliability Corporation (NERC) is responsible for the reliability of the bulk power system in North America. NERC develops and enforces reliability standards; annually assesses seasonal and long-term reliability; and monitors the bulk power system through system awareness. NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States, Canada and a portion of Baja California in Mexico.[3]

STATE PUBLIC UTILITY COMMISSIONS

Regulatory activities that fall outside FERC's jurisdictional responsibility are dealt with by State Public Utility Commissions. These activities include:

- regulation of retail electricity sales to consumers
- approval for the construction of electricity-generating facilities
- regulation of activities of the municipal power systems, federal power marketing agencies such as the Tennessee Valley Authority, and most rural electric co-operatives
- reliability problems related to failures of local distribution facilities.

3. Florida Reliability Co-ordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Co-ordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool, RE (SPP), Texas Reliability Entity (TRE) and Western Electricity Co-ordinating Council (WECC).

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STRUCTURE OF THE POWER GENERATION SECTOR

The electricity industry in the United States is made up of over 3 000 public, private and co-operative utilities, including more than 1 000 independent power producers (IPPs), three regional synchronised power grids, eight electricity reliability councils, some 150 control-area operators, and thousands of separate engineering, economic, environmental, and land-use regulatory authorities (RAP, 2011).

Ownership is divided among a variety of structures: investor-owned utilities, publicly owned utilities (largely municipal), federal, co-operative (largely rural) utilities, other providers (state-owned public utility districts and irrigational districts or power marketers and energy service providers (ESP), independent non-utility power producers (IPP), combined heat and power (CHP) independent power producers, and commercial and industrial combined heat and power generators.

Investor-owned utilities (IOUs) tend to be large privately owned companies, subject to state regulation, which generally maintain multi-fuel or multi-state operations. Approximately 75% of the population, or 54% of demand, is served by IOUs. **Consumer-owned utilities** (COUs) serve the remaining 25% of the population, or 46% of demand, in both cities and large rural areas. COUs may include city-owned or municipal utilities, public utility districts and co-operatives. They may also include other ownership categories such as Native American tribes and quasi-public entities.

INTERACTION BETWEEN ELECTRICITY AND NATURAL GAS

IMPACT OF LOW NATURAL GAS PRICES ON INVESTMENT

Since 1991, more than three-quarters of all capacity additions in the United States have been natural gas-fired (EIA, 2013a) initially driven by market deregulation rather than price developments. In the five-year period from 1998 to 2003 alone, the United States added 175 GW of natural gas capacity. Since 2003, the growth of natural gas generation has continued at a slower, though fairly steady pace. Planned natural gas additions through 2015 make it clear that this trend will continue at least into the near term.

Coal capacity over the same timeframe has remained relatively constant. In 2012, however, nearly 10 GW of coal capacity was retired, the largest single-year decline in at least two decades. Over the period to 2015, planned coal retirements will continue at pace, more than offsetting all of the planned natural gas additions. Taken together, natural gas is on its way to becoming the primary source of generation in the United States. The EIA projects that natural gas generation will exceed coal generation by around 2035 (EIA, 2014a).

This trend is at least partially being driven by existing and forthcoming environmental regulations covering coal plant emissions and waste. These regulations include: the Mercury and Air Toxics Standards (MATS), which requires both existing and new coal-fired plants to install controls to reduce mercury, sulphur (SO_2), and particulate matter ($PM_{2.5}$); the Clean Air Interstate Rule (CAIR), which introduced a cap-and-trade system to reduce emissions of sulphur dioxide (SO_2)and nitrous oxide (NO_x) in the eastern portion of the United States;[4] regulation of solid waste, including limits on the amount of

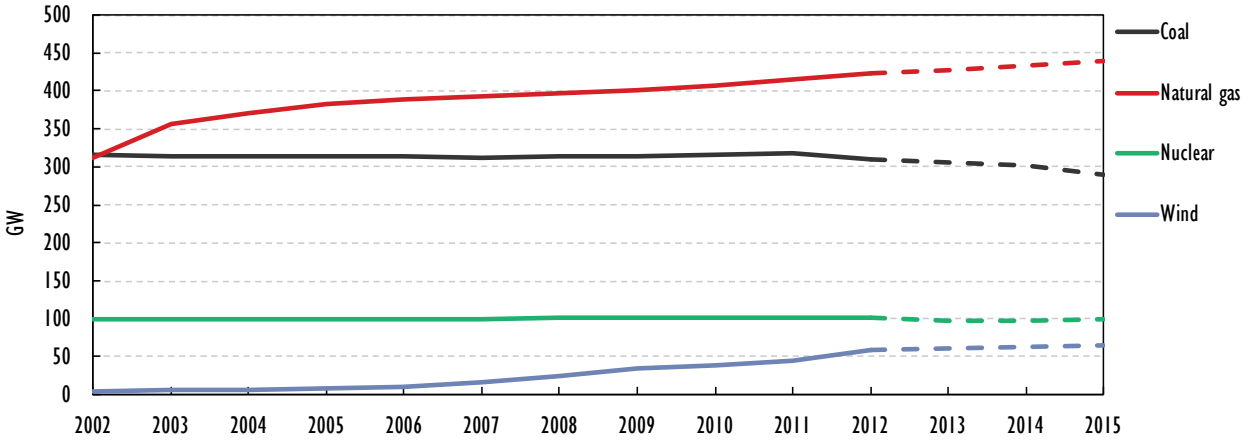
4. The EPA has proposed the Cross-State Air Pollution Rule (CSAPR) as a replacement for CAIR. CSAPR will cover a slightly different set of states and will include more stringent regulation of SO_2 emissions. The proposed rule, however, is being challenged in court, and so it is unclear what the implemented regulation will look like.

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pollutants that can be discharged into rivers and lakes; and, perhaps most significantly, limitations on CO_2 emissions both on new and existing plants. The EPA has proposed the New Source Performance Standard (NSPS), which would limit emissions from new coal plants to 1 000 pounds (0.45 tonnes) of CO_2 per megawatt-hour (MWh). Rules limiting CO_2 emissions for existing plants are still being developed.

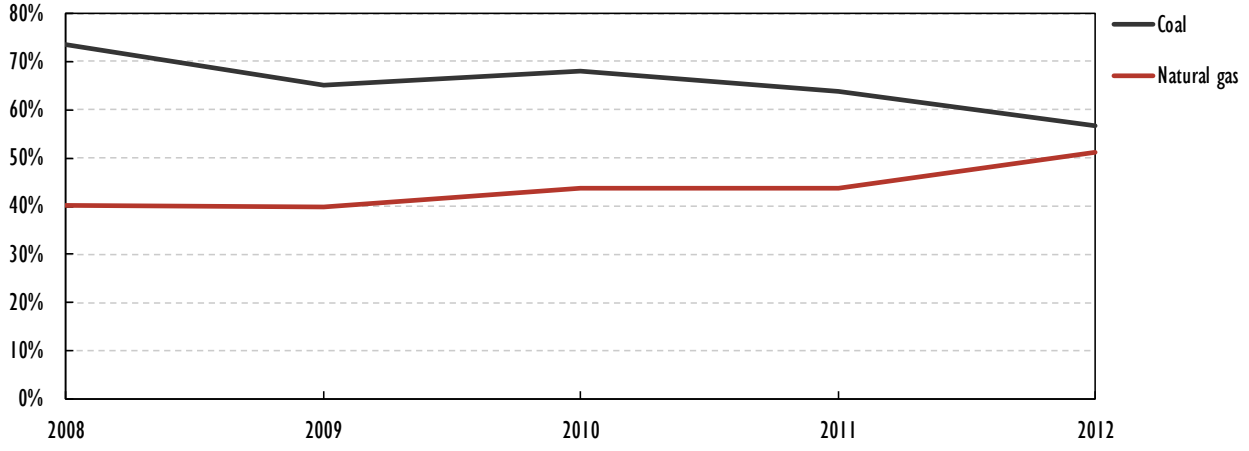
In addition to these rules, however, low natural gas prices have significantly changed the economics of both natural gas and coal generation.

Figure 3.5 Net summer generating capacity, 2002-15



Source: EIA (2013a), *Annual Energy Outlook 2013 with Projections to 2040*, EIA, Washington, D.C., April, www.eia.gov/forecasts/aeo/pdf/0383.pdf.

Figure 3.6 Capacity utilisation rates, coal versus natural gas, 2008-12



Source: EIA (2014b), *Electric Power Monthly with Data for December 2013*, EIA, www.eia.gov/electricity/monthly/current_year/february2014.pdf.

The most immediate impact has been operational. Low natural gas prices have made it possible to run natural gas plants for more hours a day. Whereas natural gas plants have traditionally been used as mid-merit and peaking generation, more and more often natural gas has been the marginal price setter in off-peak hours, displacing coal plants from the merit order. As a result, average coal plant capacity factors declined from 73% in 2008 to 60% in 2012, while natural gas capacity factors increased from 40% to 51% over that same time frame (EIA, 2014b). This is particularly the case in regions such as PJM

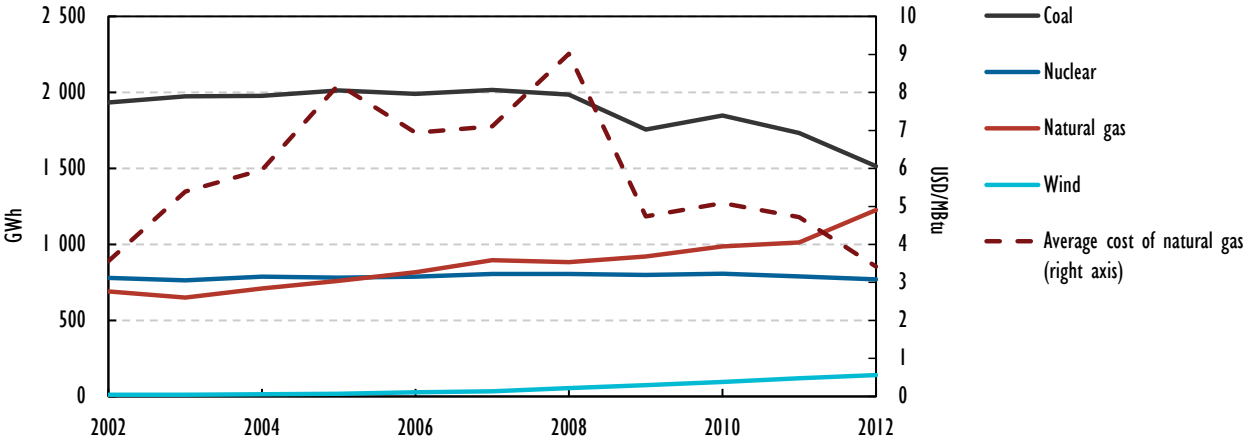
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and the southeast, which have significant amounts of both coal and natural gas capacity (FERC, 2012b). Looking at net generation over the past decade, it is clear that this recent trend is mainly the result of the significant and sustained decrease in natural gas prices.

Less clear is the degree to which low natural gas prices are driving decisions to invest in new natural gas capacity over the long term. As noted earlier, the trend towards natural gas generation is not new. While developers will certainly take into account fuel price trends when making investment decisions, natural gas-fired generation has been popular in large part because of the relatively low capital intensity of the projects and their operational flexibility.

Near-term fuel price trends, however, can have an impact on long-term investment decisions. Low natural gas prices are making it more difficult for coal generators to recover their costs in the wholesale electricity market. This is on top of the fact that coal generators are facing the potential for additional investment needs required to comply with forthcoming environmental regulations. As a result, more coal generation is expected to retire over the next few decades. While slowing demand growth in parts of the United States may reduce the need for capacity additions, it is reasonable to assume that some of these retirements will have to be offset by additional capacity investments.

Figure 3.7 Net generation by fuel source versus cost of natural gas (2002-12)



Source: EIA (2014c), *Annual Energy Review*, interactive tool, www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf, accessed 10 December 2014.

While a significant portion of this new capacity will certainly come in the form of renewable generation, natural gas will continue to play a strong role. Operational flexibility provides natural gas capacity a clear advantage over coal and nuclear. Combined-cycle gas turbines (CCGT) built to supply mid-merit or even peak loads can take on more of a base-load role if it becomes economic to do so, and in many cases can even completely replace retiring coal plants. The same cannot be said in reverse: coal and nuclear capacity cannot as easily replace natural gas during peaking hours to offset the loss of natural gas generation.

The changing economics of natural gas generation has also had an impact on planned investments in the nuclear fleet. The relatively high capital cost of nuclear power means that, in an environment with low natural gas prices and, by extension, low wholesale electricity prices, it is hard or impossible to recover fixed costs in the competitive wholesale market alone. Out of 29 planned nuclear reactors, only two are moving forward with development (Smith, 2012). Decisions to invest in uprates or other capacity additions in nuclear plants may be delayed or shelved indefinitely for economic reasons. It is worth

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noting, however, that the closure of the Kewaunee nuclear power station, which was announced in 2014, was largely attributed to low wholesale electricity prices. The EIA predicts that there will be a net decline in nuclear capacity by 2020 and that capacity additions will not completely offset this loss of generation until 2040 (EIA, 2014a).

One factor that may constrain the growth in natural gas-fired generation in the future is gas pipeline capacity. Parts of the country that have seen significant increases in natural gas-fired generating capacity have not seen commensurate development of natural gas pipelines. The reasons for this will be discussed in more detail in the next section. Long-term investments in natural gas, however, will depend on sufficient supply being available when and where it is needed, and it is almost certain that this will require additional investments in pipelines throughout the country.

CO-ORDINATION BETWEEN NATURAL GAS AND ELECTRICITY

As a result of the boom in natural gas-fired generation, the power sector has become the single largest consumer of natural gas in the United States and in regions such as the Northeast. Natural gas demand may double by 2025 (Kruse, 2012).

Misalignments between the natural gas and electricity sectors, however, are creating the potential for shortages (and, in some cases, have resulted in actual outages), increasing costs throughout the system, and reducing the flexibility of both the natural gas and the power systems.

The particular nature of gas-fired generation leads to consumption patterns very different from other, more traditional natural gas consumers. Generators are relatively large single users that require higher-pressure delivery than other consumers. Consumption of natural gas by generators is also highly variable, with needs differing from other sectors both by season (power generation tends to peak in summer, while heating, for example, peaks in winter) and intra-day. Pipelines were built under the assumption of steady rates of consumption and therefore do not handle large swings well. Moreover, the demand for higher pressure and more variable delivery is likely to increase as CCGT technologies improve and as increasing penetrations of variable renewable energy require gas to play a larger balancing role over shorter-time horizons.

Given the significant regional diversity in the generation mix, concerns related to natural gas-fired generation can vary between regions. In regions that rely on significant portions of natural gas generation, increased demand has resulted in problems related to pipeline capacity availability and congestion. This in turn has led to large price spikes and even outages. In New England, for example, average day-ahead prices in January 2014 reached nearly USD 80/MBtu as a result of a combination of lower than typical LNG imports, congested natural gas pipelines, and extreme cold (EIA, 2014d). These high natural gas prices drove day-ahead electricity prices as high as USD 437/MWh.

FERC has specifically highlighted New England as a region that is at risk for future outages because of lack of pipeline capacity and rising demand (FERC, 2012b). In Texas, capacity shortages of approximately 4 000 MW led to rolling blackouts affecting 3.2 million customers in February 2011. In Texas, however, the primary cause of the capacity problems during the relevant event was the cold weather. Hundreds of thousands of customers in neighbouring New Mexico and Arizona were also affected (FERC/NERC, 2011).

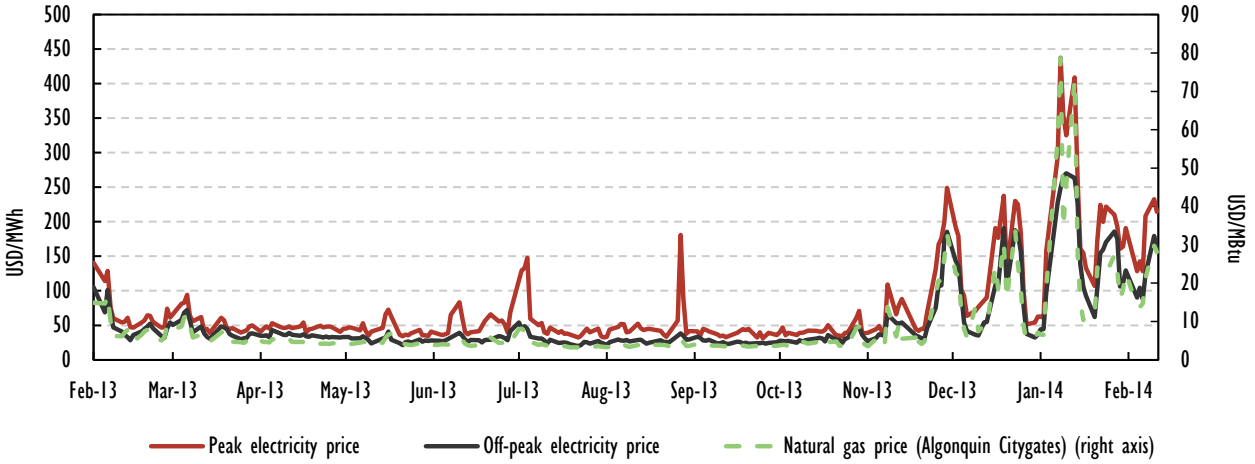
Potential electricity-gas industry concerns could include gas supply/transport capacity and the co-ordination of the respective markets, but such issues and their associated impacts can vary between regions. In New England, low natural gas prices have reduced the

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competitiveness of LNG imports from Canada, increasing overall reliance on gas from the Marcellus Shale. A lack of pipeline capacity means that spikes in demand or unexpected supply shortages can quickly lead to shortages without a ready alternative supply to fill in the gaps. Conversely, gas-fired generators in gas-constrained areas such as Nebraska and Florida have dual fuel capabilities.

The misalignments between the natural gas and electricity markets stem from differences in the way the markets have developed historically, as well as from differences in how they are regulated. In terms of natural gas regulation, FERC has authority over the wholesale gas market, gas pipeline siting, and gas quality. For electricity, FERC has authority over the wholesale power market, but does not oversee siting of generation or transmission.

Figure 3.8 Day-ahead electricity prices versus day-ahead natural gas prices



Source: EIA (2014e), "Wholesale electricity and natural gas market data", interactive tool, accessed 10 December 2014, www.eia.gov/electricity/wholesale/index.cfm; Intercontinental Exchange.

The larger problem, though, derives from temporal disconnects between the two markets, both long term and short term. Over the long term, pipeline development tends to be driven by firmly contracted demand. While local distribution companies (LDCs) will generally enter into long-term contracts for natural gas capacity, independent generators in some regions will often prefer to enter into interruptible contracts for natural gas supply, and then to rely on the capacity release market to make up the difference while generators elsewhere will contract firm capacity.

Utilities procure firm transportation contracts in regions of the country where cost recovery is available. Given the way organised markets are currently structured, it does not always make economic sense for a utility to line up firm gas transportation. This is a regional issue and in regions where these costs cannot be passed on to consumers, and so generators that run infrequently (in particular, peaking plants) will generally prefer to avoid this cost.

Under capacity release, the holder of a firm capacity contract from the contracted party can reallocate his rights to a third party (in this case, a generator) on a temporary or permanent basis. Relying on capacity release, though, is a risky strategy, as it depends on firmly contracted natural gas being under-utilised at times when the generators demand is high. In times of high overall system demand (for example, extreme weather events), there may not be enough slack capacity to make up the difference.

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Over the short term, disconnects in the planning and scheduling calendars for the natural gas and electricity markets can lead to significant system inefficiencies in some regions. The natural gas and electricity schedule days do not match up, with time gaps of eight hours or more between the natural gas and electricity commitment windows in some parts of the country (NERC, 2011b). Generators must commit to buying natural gas before they are scheduled by the system operator, and so must either choose to self-schedule or develop their own estimates for when they may be called to run. Under some capacity contracts, generators have faced significant penalties in the case of both over- and under-consumption, and face penalties in the electricity wholesale market if they are unable to deliver power when called upon. Those that choose to self-schedule risk either running when it is not economic to do so, or not running when it would be economic to do so (Tabors, Englander and Russo, 2012).

These problems are compounded by the fact that the natural gas pipeline system is not as flexible as the power transmission system. Large, rapid draw-downs of natural gas can reduce pressure throughout the system, which can in turn force natural gas generators to de-rate or even shut down. A loss of generating capacity can impact the natural gas system, which relies on electricity to run compressor pumps in order to maintain system pressure.

The situation has improved somewhat, with more recent contracts allowing for large swings in consumption and utilities creating different structured contracts for different generation types (for example, fixed quantity contracts for base-load generation, limited swing contracts for mid-merit plants, and large swing contracts for peakers) (NERC, 2011b). There remain, however, communication issues between gas suppliers and reliability co-ordinators, as well as other relevant parties such as large users. Real-time communication between the electricity and natural gas markets should become even more important as intermittent variable generation becomes a larger part of the power system, and natural gas generators are required more and more often to ramp production up or down to compensate for their variability.

RESOURCE ADEQUACY/CAPACITY MARKETS

The Energy Policy Act of 2005 contains reliability provisions that authorise the creation of a regulatory electricity reliability organisation that spans North America. This led to the creation of the North American Electric Reliability Corporation (NERC), taking over the previous institution with the same acronym, the National Electricity Reliability Council. NERC has a regulatory authority for reliability of the bulk power system across the borders between different jurisdictions, with FERC oversight in the United States.

Among its activities, NERC annually assesses adequacy via a ten-year forecast and winter and summer forecasts. The historical NERC regions (eight in all) are no longer relevant in this context; instead NERC assesses reliability for areas corresponding to the footprints of independent system operators/regional transmission organisations (ISOs/RTOs). NERC provides independent assessments using a consistent methodology across North America, and detailed data provided by regional entities.

In its assessments, NERC uses a 15% reference for its planning reserve margin.[5] Another widely used reliability metric is the one event in ten years loss of load standard ("one-in-

5. The planning reserve margin equals the difference in deliverable or prospective resources and net internal demand, divided by net internal demand.

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ten LOLE"). This reliability criterion translates into a planning reserve margin that depends on systems (Pfeifenberger et al., 2013).

Neither NERC nor FERC, however, have the authority to establish reliability standards for resource adequacy (e.g. reserve margin criteria) or to order the construction of resources or transmission. This falls under the responsibility of RTOs/ISOs, balancing authorities or the public utility regulatory commissions of individual states. In practice, therefore, resource adequacy is primarily assessed at the boundaries of these jurisdictions. When these jurisdictions perceive a threat to resource adequacy, they can initiate policy actions and implement measures to attract new investments.

Since the emergence of liberalisation, most markets have enjoyed comfortable reserve margins inherited from the wave of investment in new combined-cycle gas turbines (CCGTs) in the 1990s (the dash for gas). While this is still the case in many areas, resource adequacy, and in particular generation adequacy, is becoming a concern in some regions of the United States.

In the next five to 20 years, resource adequacy will be heavily impacted by the retirement of ageing coal capacity driven by EPA regulations, the deployment of wind and solar power, and the shift to natural gas. Of course, there are safeguards. For instance, if a retirement creates a reliability issue, FERC can accept "reliability must-run" (RMR) contracts to allow power plants to operate. Such agreements, however, are limited to a certain period of time and new investments are needed to ensure generation adequacy. These agreements can also run afoul of federal and state air quality regulations and the federal government needs to provide clarity on which legal mandate is to be followed or provide immunity from penalties associated with violations.

The challenge to maintaining resource adequacy depends on whether the electricity industry remains regulated or is market-based. In states where public utility commissions determine rates rather than the wholesale market, which represents 40% of electricity consumption, integrated resource planning identifies investment needs and resource adequacy is achieved through rate recovery of approved investments in networks and generation.

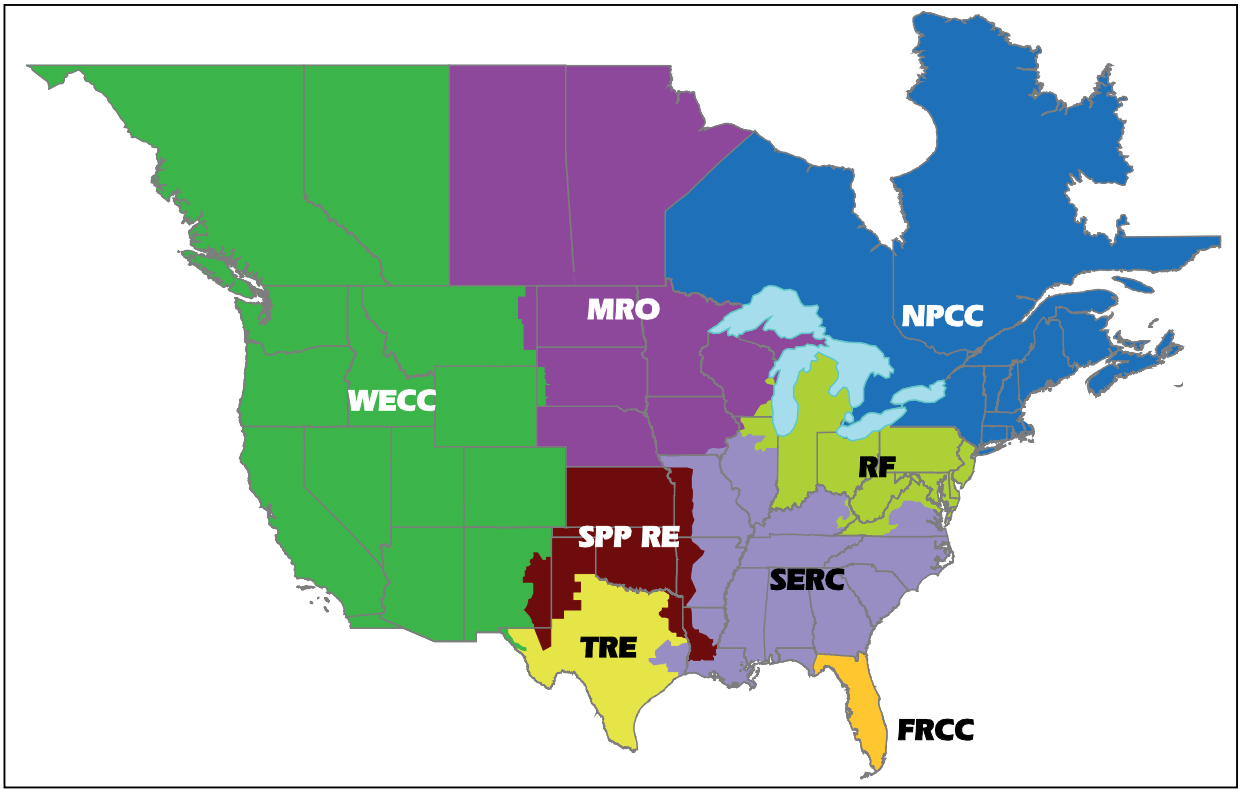
In market-based environments, investments can be attracted if market revenues are high enough, on average, to cover costs and provide a sufficient return on investments. The need to replace ageing capacity and accommodate renewables constitutes a "stress-test" for market and regulatory arrangements.

In some markets such as the Electric Reliability Council of Texas (ERCOT), power plant revenues come from the sale of energy and ancillary services. This mechanism triggered sufficient investment during the first years of the market. In 2011 and 2012, however, Texas experienced heat waves that pushed peak electricity demand for air conditioning. Anticipating falling reserve margins (see Figure 3.9), ERCOT took several measures including an increase in the cap on electricity price during tight market conditions and programmes to procure capability to reduce load and contribute to resource adequacy.

Allowing high prices during tight market conditions should, in principle, lead prices to reflect the value of electricity and yield an efficient reliability level. The actual outcome, however, remains uncertain. Furthermore, this might not be sufficient to reach the planning reserve margin that regulators wish to maintain. Accordingly, all relevant parties in the ERCOT region are reviewing the resource adequacy issue in the region.

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Figure 3.9 Map of balancing entities/control areas

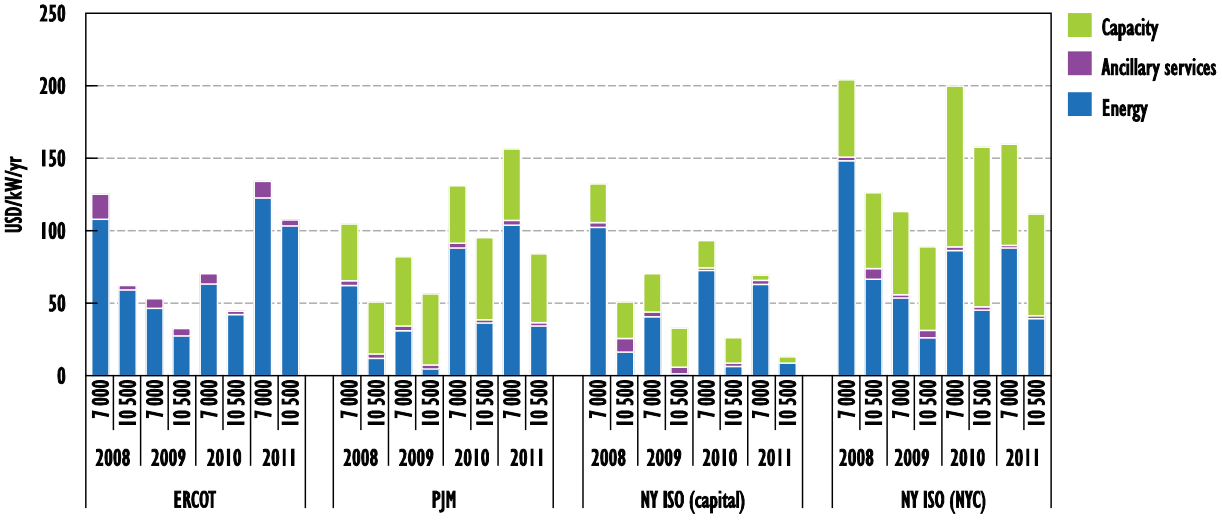


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: FRCC = Florida Reliability Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RF = eliabilityFirst; SERC = SERC Reliability Corporation; SPP = Southwest Power Pool; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

Source: NERC (North American Electric Reliability Corporation) (2014), "Regional entities", website, www.nerc.com/aboutnerc/keyplayers/pages/regional-entities.aspx, accessed 10 December 2014.

Figure 3.10 Comparison of net revenues of gas-fired generation between markets



Source: Potomac Economics, Independent Market Monitor for the ERCOT Wholesale Market (2012), *2011 State of the Market Report for the ERCOT Wholesale Electricity Markets,* Potomac Economics, Texas.

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In all other market-based environments in the United States, power plant revenues also depend on their generating capacity, in addition to energy and ancillary services. Capacity markets exist PJM, ISO-NE, NY ISO (see Figure 3.10) and, albeit in different form, in MISO and CAISO. To date such capacity markets were successful in ensuring resource adequacy. For instance, for the 2015/16 delivery period, PJM reliability pricing model (RPM, capacity markets) attracted sufficient investments in new gas power plants and demand response capability to replace retiring coal capacity.

Capacity markets can be effective in creating a safety net and maintain the reserve margin required to ensure reliability. But many parameters have to be defined by regulators and system operators, including the definition of capacity products, the horizon and duration of the delivery, the overall capacity requirements, the definition of locational capacity requirements to cope with network constraints, the demand curve for capacity products, the determination and treatment of energy revenues, the control of capacity availability, and the penalties.

After ten years of efforts, the eastern ISO/RTOs are still refining the design of capacity and energy markets. One important evolution is the recent decision to increase the energy price caps (see Table 3.1). This decision should improve the efficiency of the price signal during scarcity, increase the economic demand response (as opposed to emergency demand response), increase energy revenues and therefore decrease the capacity payments required. Ultimately, capacity markets could become a residual revenue stream, creating a safety net so as to be certain to meet the reserve margin that regulators wish to maintain.

Table 3.1 Comparison of different US electricity market arrangements

		MISO	PJM	NY ISO	ISO-NE	ERCOT
Market for energy and system services	Price cap	USD 3 500/MWh	USD 1 000/MWh increasing to USD 2 700/MWh by 2015	USD 1 850/MWh to USD 2 750/MWh by location	USD 2 000/MWh to USD 2 250/MWh by location	None – if congestion is present: adders if up to USD 5 000 per constraint
	Offer cap	USD 1 000/MWh or lower with mitigation	USD 1 000/MWh or lower with mitigation	USD 1 000/MWh or lower with mitigation	USD 1 000/MWh or lower with mitigation	USD 7 000 until June 2015 and USD 9 000 thereafter
	Reserve shortage	Additive penalty factors Additive USD 850 penalty factor	Additive USD 850 penalty factor	Additive USD 20 to USD 500 demand curve	Additive USD 20 to USD 850 penalty factor	Operating reserve demand curve
Capacity construct	Capacity construct	Reliability requirement and planning	Forward capacity market	Forward capacity market	Forward capacity market	None – energy-only market
	Forward period for capacity construct	One year	Three year	One year	Three year	None – energy-only market

Source: Brattle Group.

With capacity markets, a further complication comes from possible intervention of individual states. Some of them wish to have generating capacity located in their jurisdiction. For instance, New Jersey procured and subsidised the construction of new generating capacity in New Jersey, while at the same time being part of the footprint of an ISO/RTO organisation (PJM in the case of New Jersey). Such subsidised plants have lower revenue requirements and there is a concern that their bids have the potential to distort capacity

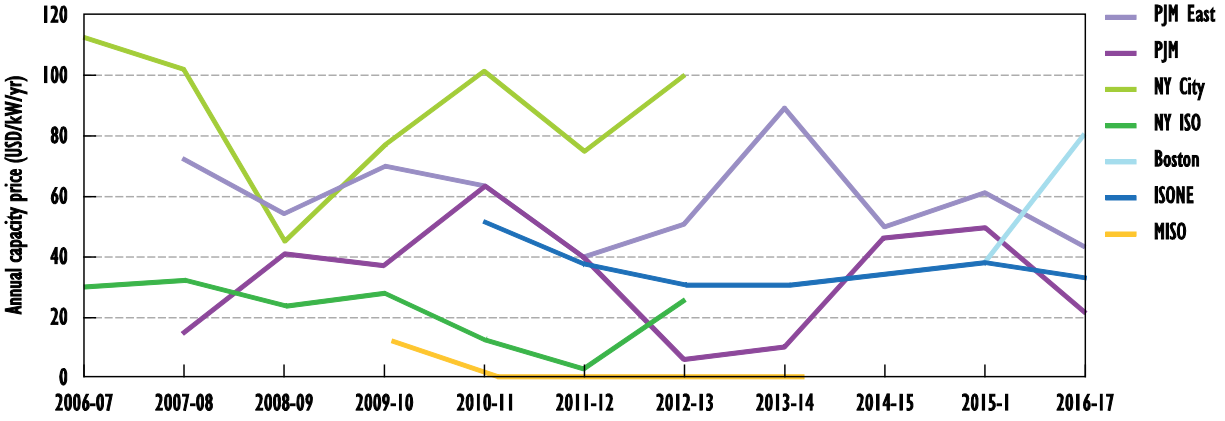
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markets clearing prices. In order to prevent this, FERC imposes a minimum offer price rule (MOPR) for such capacities, further increasing regulatory intervention on these markets.

Co-ordination of generation adequacy across ISO/RTOs is also becoming a concern: the capacity prices can be very different for adjacent areas. While this is not a problem *per se* to the extent this would reflect different market conditions and the existence of transmission bottlenecks, there may be other reasons such as: the complexity of capacity markets, each capacity market developed over time, and each time FERC approved separate design proposals, often with compromises.

Cross-border trade of capacity is feasible but remains limited. A power plant physically linked to MISO or ISO NY can participate in the PJM capacity market. There remain many barriers to such trades. One of the key concerns relates to the degree of reliability of such external capacity: when exported, they do not respond to dispatch instruction of the system operator procuring them, and they are subject to curtailments. This raises the question of co-ordination of adjacent balancing areas controlled by distinct system operators.

Figure 3.11 Divergent capacity prices in FERC



Source: FERC (2013b), *Centralized Capacity Market Design Elements, Commission Staff Report, AD13-7-000*, FERC, Washington, D.C.

TRANSMISSION NETWORKS

The transmission grid consists of eight regions and is overseen by the North American Electric Reliability Corporation (NERC). The system in the United States is primarily comprised of three interconnections (Eastern, Western and Texas interconnection). The three interconnections are linked by direct current (DC) transmission lines which limit and control the amount of electricity transferred between them. Within each interconnection, electricity travels through a network of alternating current (AC) transmission lines.

NATIONAL INTEREST ELECTRICITY TRANSMISSION CORRIDORS

Section 216(a) of the Federal Power Act, as amended by the Energy Policy Act of 2005, directed the Department of Energy (DOE) to conduct a study every three years on electricity transmission congestion and constraints within the Eastern and Western Interconnections.[6] On the basis of this study and comments from states and other

6. On 1 February 2011, the 9th Circuit Court made a ruling which eliminated the Mid-Atlantic and Southwest national interest electric transmission corridors (NIETC) designations. The Court ruled on the basis that DOE failed to conduct an environmental review as required by the National Environmental Policy Act and failed to consult with affected states.

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stakeholders, the Secretary of Energy had the authority to designate any geographic area experiencing electricity transmission capacity constraints or congestion as a national interest electricity transmission corridor (National Corridor). This authority was reversed in a federal court in 2009. Designation as a national corridor allowed FERC to approve transmission lines within the corridor if the state agency involved has "withheld approval" for more than a year (only two corridors have been designed since 2007). The American Reinvestment and Recovery Act of 2009 (Recovery Act) further directed the Secretary to include in the 2009 Congestion Study an analysis of significant potential sources of renewable energy that are constrained by lack of adequate transmission capacity.

THE INTERCONNECTED NETWORKS

The American power system has evolved into three major interconnected systems (power grids) within which regional transmission organisations and independent system operators (in some geographic regions) exist to operate transmission systems in a non-discriminatory manner. They also manage organised competitive markets for the purchase and sale of wholesale electricity. The major networks consist of extra-high voltage connections between individual utilities designed to permit the transfer of electricity from one part of the network to another. These transfers are restricted, on occasion, because of a lack of contractual arrangements or because of limited transmission capability. The three networks are:

- the Eastern Interconnected System
- the Western Interconnected System
- the Texas Interconnected System.

The Texas Interconnected System is not interconnected with the other two networks (except by certain direct current lines). The other two networks have limited interconnections to each other. Both the Western and the Texas Interconnects are linked with different parts of Mexico. The Eastern and Western Interconnects are completely integrated with most of Canada or have links to the Quebec power grid. Most utilities are interconnected with at least one other utility by these three major grids. The exceptions are in Alaska and Hawaii. The bulk power system makes it possible for utilities to engage in wholesale (sales for resale) electricity trade. Wholesale trade has historically played an important role, allowing utilities to reduce power costs, increase power supply options, and improve reliability. Historically, most wholesale trade was between interconnected utilities within the continental United States. With open access and deregulation of wholesale markets, cross-border trade has become more prominent in meeting domestic electricity requirements.

US CROSS-BORDER TRANSMISSION PROJECT APPLICATIONS

Executive Order 12038 states that DOE has the authority to issue Presidential permits for the construction, operation, maintenance and interconnection of transmission facilities crossing the US border. DOE must determine if issuance of the permit is consistent with the public interest. The two criteria used by DOE to determine if a proposed project is consistent with the public interest are *i)* the impact on electric reliability of the US grid and *ii)* the review of environmental impacts consistent with the National Environmental Policy Act (NEPA). DOE must obtain concurrence from the US Department of State and the Department of Defense before issuing a Presidential permit. Currently, DOE is reviewing five Presidential permit applications for projects crossing the United States-Canada border. Below is a summary and status update for each of these projects:

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Champlain Hudson Power Express: On 25 January 2010, Transmission Developers, Incorporated (TDI) submitted an application on behalf of Champlain Hudson Power Express, Inc. to the Department for a Presidential permit to construct, operate, maintain and connect a 1 000 MW high-voltage direct current, voltage source converter (VSC) controllable transmission system from the Canadian Province of Quebec to New York City. The DOE received concurrence from both the State and Defense Departments to issue the Presidential permit in February 2014 and June 2014, respectively.

Northern Pass Transmission: Northern Pass Transmission, LLC, filed its original Presidential permit application on 14 October 2010, seeking to construct, operate, maintain, and connect a high-voltage direct current (HVDC) transmission line crossing the United States-Canada border. The proposed HVDC transmission line would be capable of transmitting up to 1 200 MW of power and would extend south from the United States-Canada international border approximately 140 miles to a HVDC converter terminal that would be constructed in Franklin, New Hampshire. From there, a 345 kilovolts (kV) alternating current transmission line will interconnect to the independent system operator of New England (ISO-NE) grid at a substation in Deerfield, NH. The total project length is approximately 187 miles. The application has been amended on a number of occasions and awaits approval.

Great Northern Transmission Line: Minnesota Power proposes the construction of a new 500-kV, approximately 270-mile, AC transmission line from Winnipeg, Manitoba, Canada to the Mesabi Iron Range in Minnesota. The proposed Great Northern Line will provide delivery and access to power generated by Manitoba Hydro's existing hydroelectric stations in Manitoba, Canada, as well as reinvigorating the mining industry and supporting job growth in the Mesabi Iron Range. The Office of Electricity Delivery (OE) received Minnesota Power's application on 15 April 2014.

New England Clean Power Link: On 20 May 2014, TDI-New England (TDI-NE) applied for a Presidential permit. TDI-NE proposes to construct, operate and maintain the New England Clean Power Link Project (NECPL), a high-voltage direct current (HVDC) electric transmission line with an operating voltage of more or less 300 to 320 kV. The project would be constructed in both aquatic (underwater) and terrestrial (underground) environments from the Canadian border to Ludlow, Vermont. The total project length is approximately 154 miles.

Soule Hydro: Applied for Presidential permit on 18 March 2013. Soule Hydro proposes to construct and operate a HVAC hydroelectric transmission line (approximately 8 miles in Alaska) that is to originate at the Soule River, on Portland Canal in Southeast Alaska, and continue to the BC Hydro Stewart Substation on the north side of Stewart, British Columbia. The hydroelectric facility would occupy federal land administered by the Ketchikan-Misty Fjords Ranger District of the US Forest Service and would be capable of generating and transmitting up to 77.4 MW of power. Soule Hydro applied to both the Federal Energy Regulatory Commission (FERC) and the US Forest Service for the required licences and special use permits seven years ago. DOE is currently a co-operating agency with FERC to prepare the EIS.

In addition to the projects currently under review, DOE expects to receiving applications for two more projects: the Northern Maine Reliability Solution and the Lake Erie CleanPower Connector.

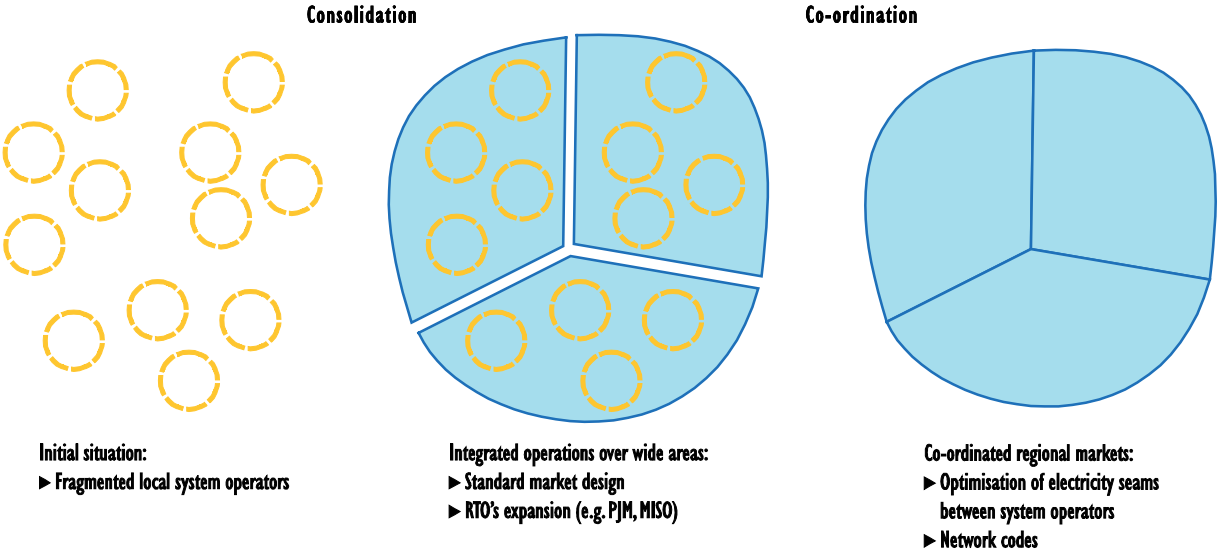
REGIONAL TRANSMISSION ORGANISATIONS

Independent system operators (ISOs) emerged from FERC Orders No. 888 and No. 889. These orders first proposed the concept of an independent system operator as a means for existing power pools to satisfy the requirement of providing non-discriminatory

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access to transmission services. On 20 December 1999, FERC issued Order 2000, its final rule on regional transmission organisations (RTOs), which encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America (including Canada). FERC regulates the RTOs and approves all tariff provisions. Order No. 2000 set out 12 characteristics and functions that an entity must satisfy in order to become an RTO.

Figure 3.12 Approaches to consolidation and co-ordination towards regional market integration



Source: IEA (2013c), *Secure and Efficient Electricity Supply during the Transition to Low Carbon Power Systems*, OECD/IEA, Paris.

Today, ten RTOs operate bulk electric power systems across a large portion of the United States (and Canada). RTOs are independent, membership-based, non-profit organisations that ensure reliability and optimise supply and demand bids for wholesale electricity. In regions not served by the RTOs, electricity systems are operated by utilities or utility holding companies.

In the Northeast, the RTOs evolved from power pools that had co-ordinated utility operations for many decades. Elsewhere (the Midwest, California and Texas), RTOs evolved to meet both state and federal policies on competitive generation and open transmission access. Membership of RTOs includes generators, transmission companies and load-serving entities, vertically integrated utilities and other market participants such as power marketers and energy traders.

The seven RTOs in the United States are:

California ISO (CAISO), which was established in 1996, covers 80% of the state of California plus a small part of the state of Nevada. CAISO is the largest of about 38 balancing authorities in the western interconnection, handling an estimated 35% of the electric load in the West. It serves 30 million customers and contains approximately

760 power plants, which offer 60 gigawatts (GW) of capacity connected to 26 000 miles of transmission lines. CAISO carried 242 TWh of electricity in 2012. Gas is CAISO's marginal fuel source.

Established in 2001, the **Mid-continent (MISO)** covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, and Michigan, and parts of

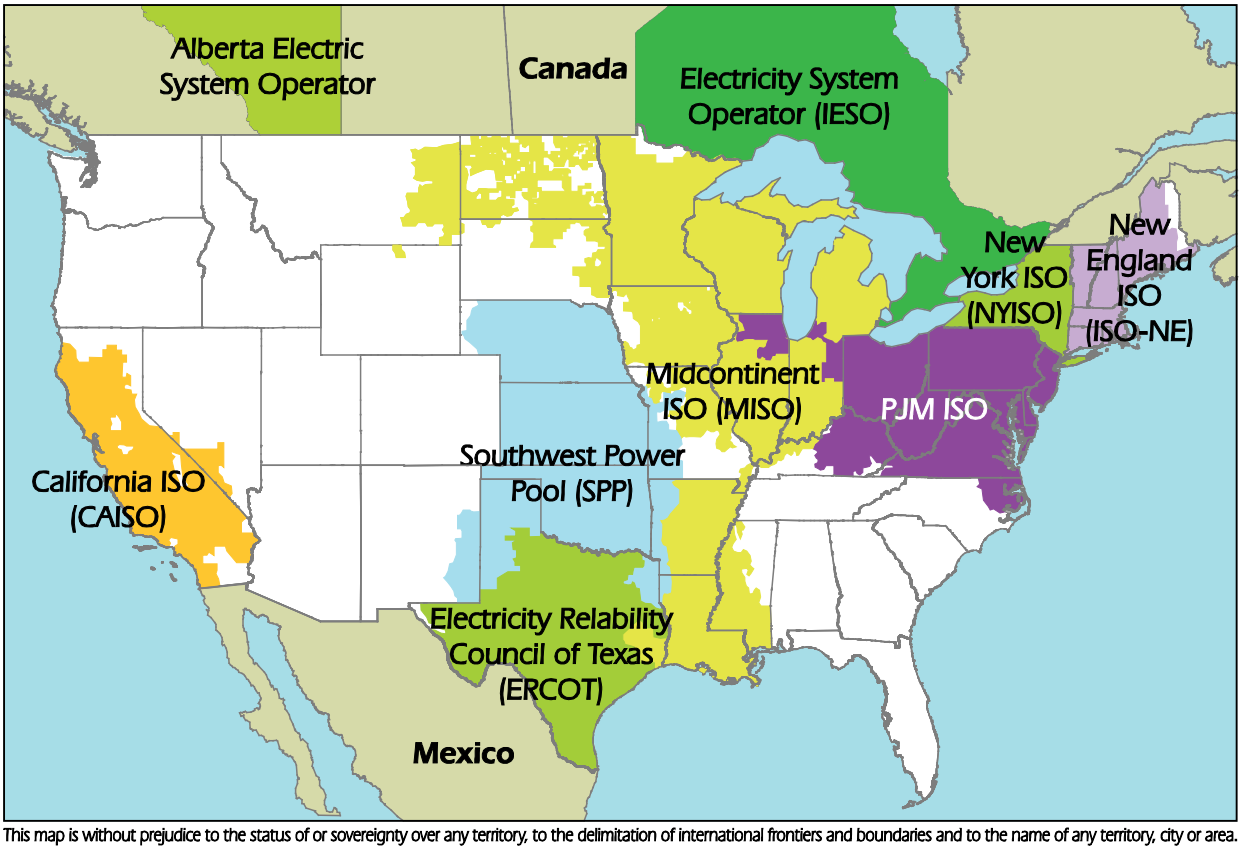
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Montana, Missouri, Kentucky, Manitoba (Canada) and Ohio. MISO has 176 GW of generating capacity and 67 000 miles of transmission lines. The market served 42 million customers and carried 526 TWh of electricity in 2012. The MISO-administered grid interconnects with the Independent Electricity System Operator of Ontario, the Mid-Continent Area Power Pool, PJM, Southwest Power Pool and the Tennessee Valley Authority. Coal is the marginal fuel source in MISO.

The **PJM Interconnection** covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM controls the operation of about 183 GW of generating capacity and 62 500 miles of transmission lines in its territory. The PJM interconnects with MISO, the Southeast and New York ISO. The marginal fuel source in PJM is generally coal.

The **New York ISO** (NYISO) covers the state of New York. The NYISO is responsible for the operation of nearly 11 000 miles of transmission lines, 38 GW of generating capacity. Total electricity usage in 2012 was 163 000 GWh. NYISO interconnects with PJM and the New England ISO. Gas is the marginal fuel source in NYISO.

Figure 3.13 Regional transmission organisations/independent system operators



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: FERC (2014c), "Regional transmission organizations", www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf, accessed 10 December 2014.

The **New England ISO** (ISO-NE) covers the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO-NE serves approximately 6.5 million customers, has 32 GW of generating capacity and over 8 000 miles of transmission lines. There are 13 interconnections with the NYISO and Canada. Gas is the marginal fuel source in ISO-NE.

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The **Electric Reliability Council of Texas** (ERCOT) covers most of the state of Texas and has an installed capacity of 86 GW, about 43 000 miles of transmission lines and approximately 24 million customers.

The **Southwest Power Pool** (Southwest) covers nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. It has approximately 59 GW of generating capacity, 50 600 miles of transmission lines and approximately 5 million customers.

Box 3.1 Failure of the Standard Market Design model proposal

In July 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) for a standard market design (SMD), which proposed to address remaining undue discrimination and establish a standardised transmission service and wholesale electricity market design. The purpose of this NOPR was to provide a level playing field for all parties wishing to participate in wholesale electricity markets, while acknowledging certain regional variations (FERC, 2005). FERC proposed a flexible transmission service and an open and transparent spot market design that, it argued, could provide accurate pricing signals for investment in transmission and generation facilities. Market monitoring and market power mitigation also formed part of the proposal.

In April 2003, following extensive consultation with market participants, FERC issued a new document, the Wholesale Power Market Platform White Paper, which set out a revised proposal for building a wholesale electricity market. While the original proposal was deemed by many to lack clarity, to infringe on state jurisdiction, to be over-prescriptive and to provide insufficient protection for existing customers, the revised proposal contained a more flexible approach to regional needs and expressed intent to focus on the formation of regional transmission organisations (RTOs).While the revised proposal received some support from the market, concerns about the practicality of a one-size-fits-all solution and the mandatory approach to RTOs remained. At the same time, there were a number of changes in the market, such as progress in the development of voluntary RTOs and independent system operators (ISOs) such as the Midwest Independent Transmission System Operator and Southwest Power Pool. FERC acknowledged that these changes were reflecting the needs of each particular region and concluded that the standard market design NOPR has been overtaken by events and, on this basis, terminated the SMD process.

FOCUS ON SELECTED REGIONS

TEXAS

The transmission grid administered by the Electric Reliability Council of Texas (ERCOT) is located solely within the state of Texas. Notably, the transmission of electricity occurring wholly within ERCOT is not subject to FERC jurisdiction under sections 203, 205 or 206 of the Federal Power Act. The system is not synchronously interconnected to the rest of the United States, but it can exchange about 1 106 MW with the Southwest Power Pool and Mexico through DC links.[7] ERCOT is unique among RTOs in that it is generally not subject to the plenary jurisdiction of FERC and thus to the set of federal regulations that includes, for example, the power to set rates for transmission service and wholesale power. The Texas Legislature and the Public Utility Commission (PUC) of Texas have primary jurisdiction over ERCOT.

7. When the new Sharyland (New Railroad Tie) 150 MW tie is placed in service, the DC tie transfer capability will be 1 256 MW.

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ERCOT, as an intrastate electricity interconnection, traces its roots to the response of some Texas utilities to the passage of the Federal Power Act. In August 1935, "solely because of the passage of the Federal Power Act, and solely to avoid becoming subject to Federal Power Commission (FPC) jurisdiction", these select utilities "elected to isolate their properties from interstate commerce" so as to place themselves beyond the reach of the FPC, "whose jurisdiction was limited to utilities operating in interstate commerce". During World War II, these and other intrastate utilities interconnected their grids to meet wartime imperatives, forming what was then known as the Texas Interconnected System (TIS). In 1970, members of TIS as well as "various municipalities and rural electric co-operatives", all operating on an exclusively intrastate basis, formed the ERCOT (Fleisher, 2008). Nonetheless, two asynchronous interconnections link ERCOT to the Southwest Power Pool (SPP) outside Texas; therefore, the system is not wholly intrastate in nature.

Created in 1970, ERCOT was the successor to the Texas Interconnected System (TIS), which was established at the beginning of World War II to provide power for aluminium-smelting companies located along the Gulf Coast. In 1981, ERCOT became the central operating co-ordinator for Texas electricity, and in 1996, it became the first electric utility industry ISO in the United States.

In September 2003, the Texas state legislature and Public Utilities Commission (PUC) ordered ERCOT to change from a wholesale electricity market with four large regions to a marketplace made up of more than 4 000 nodes throughout the state. The purpose of this undertaking, the Nodal Project, was to strengthen the efficiency of the grid by gathering specific information for different locations throughout the state.

In 2006, Texas surpassed California in wind power production and became the top wind energy-producing state in the United States. In March 2014, ERCOT's wind output reached 29% of its load (10 296 MW), a record high. This accomplishment exceeded the state legislature's goal, as stated in Senate Bill 20, for Texas to receive at least 10% of its energy from renewable sources by 2025.

MISO

In 1998, several transmission owners recognised the benefits of FERC's vision to form an independently operated regional transmission system and voluntarily came together to establish MISO, the Mid-Continent ISO. FERC accepted MISO's organisational plan and initial transmission tariff in September 1998 and approved MISO as the first RTO in December 2001. On 15 December 2001, MISO began reliability co-ordination and regional planning services, and initiated procedures for regional planning, generation interconnection, maintenance co-ordination, market monitoring and dispute resolution.

In February 2002, FERC accepted MISO's open access transmission tariff (OATT), allowing it to also provide regional transmission services and eliminate pancaking rates, when a transmission customer is charged separate access charges for each service in each territory crossed by the customer's power transaction. In April 2005, MISO launched its energy markets and began centrally dispatching generating units throughout much of the central United States on the basis of bids and offers cleared in the market. MISO also began administering a market for tradable financial transmission rights. In January 2009, MISO launched its ancillary services market (ASM) and also became the region's balancing authority, instructing local balancing authorities on operation of resources. Integration of ASM into market operations made possible the central dispatch of regulated reserves, spinning reserves and supplemental reserves based on bids and offers cleared.

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CALIFORNIA

In the late 1990s, California emerged as a leader in the movement towards greater reliance on markets to deliver efficient outcome: a wholesale market began operation in 1998 and competing retailers were allowed to enter in the same year. During 2000 and 2001, however, the wholesale market experienced dramatic price increases and blackouts. The crisis was attributed to a variety of causes, including a flawed market design, unusual shortage conditions in the western grid, illegal market manipulation on the part of some market participants, and inappropriate regulatory responses to emerging problems. The state is no longer a leader in retail competition.

Box 3.2 Power marketing administrations and the Bonneville power administration

In 1937, the United States Congress established power marketing administrations (PMAs) to distribute and sell electricity from a network of more than 130 federally built hydroelectric dams, including the Hoover dam, the Columbia River dams, and others throughout the United States. The four PMAs, Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA) do not own or manage the dams, but instead they market the electricity and in many cases maintain the transmission infrastructure to distribute the low-cost, carbon-free electricity.

The Bonneville Power Administration is based in the Pacific Northwest. Although BPA is part of the Department of Energy, it is self-funding and covers its costs by selling its products and services. BPA markets wholesale electricity from 31 federal hydro projects (22 458 MW) in the Columbia River basin, one non-federal nuclear plant (1 030 MW) and several small non-federal power plants (519 MW). The dams are operated by the United States Army Corps of Engineers and the Bureau of Reclamation. About a third of the electricity used in the Northwest comes from BPA.

BPA also operates and maintains about three-quarters of the high-voltage transmission lines in its service territory. BPA's service territory covers an area of 300 000 square miles (777 000 square kilometres) and includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

As part of its responsibilities, BPA promotes energy efficiency, renewable resources and new technologies. The administration also funds regional efforts to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin.

Sources: Department of Energy; Bonneville Power Administration.

THE REGIONAL INTERFACE

The electricity sector in the United States remains extremely fragmented. NERC has registered 124 balancing entities responsible for maintaining the balance of load and generation over a series of defined geographic areas (NERC, 2011a).[8] This fragmentation is not well adapted to meet the challenges associated with the deployment of renewables and to ensure the efficient co-ordination of gas and power infrastructure. Furthermore, such fragmentation does not allow reaping the full benefits or increasing computing power

8. Similarly, publicly owned utilities and co-operatives account for 88% of the electricity providers but serve only 27% of the energy. www.publicpower.org/files/PDFs/USElectricUtilityIndustryStatistics.pdf.

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and new communication technologies. Accordingly, modernising electricity infrastructure calls for a reorganisation.

The development of RTOs and ISOs triggered the consolidation of balancing areas. PJM, the largest ISO with a peak demand of 157 GW in July 2013, expanded its footprint over the last decade: Allegheny Power joined PJM in 2002, AEP Energy in 2004, and others in 2004, 2005, 2011 and 2013. The Midwest ISO (MISO) recently consolidated the operation of 27 balancing authorities. It is widely acknowledged that centralised least-cost dispatch and transmission planning has brought benefits. A higher degree of consolidation of system operations and markets has the potential to further reduce costs.

Besides consolidation, co-operation at the interface between adjacent areas will become more critical than ever, as wind and solar power continue to grow. Because interconnected and electricity flows do not follow commercial transactions but the laws of physics, maintaining the real-time balance of load and generation needs to be ensured over the entire interconnection, not only within each balancing area.

Wind power and solar energy increase the volatility and reduce the predictability of energy flows over the West and East interconnections, crossing the border of balancing areas. This vision, however, requires a high degree of integration of balancing authorities and energy trade across states.

The co-ordination of gas and power infrastructures is another important dimension. The relative costs to transport gas to power stations or transmit electricity should determine the efficient location of new gas power plants. While the gas market is already well integrated and fully liberalised across the country, this is far from being the case at the moment for electricity. Such an asymmetry can distort investment decisions, the technology choice and location of pipelines and new gas capacity, and the overall cost of the gas and electricity infrastructure.

As a result of the institutional and organisational fragmentation of the electricity system, transactions on the day-ahead and real-time markets tend to remain limited in a number of areas. Compared to Europe, cross-border trade of electricity remains relatively limited with the exception of California (Figure 3.14). The increase of exports within PJM after AEP joined the PJM, suggests that inter-ISO trade could be much more developed and could lower the total cost of electricity. A major cause of uplift payments during the polar vortex in December 2013 and early 2014 was a consequence of the fact that regions did not know how much imports they were going to receive. The RTOs are working on putting notice and other requirements around this.

Given the existing organisation, proper co-ordination of operations in adjacent balancing areas is difficult. Several issues are the following:

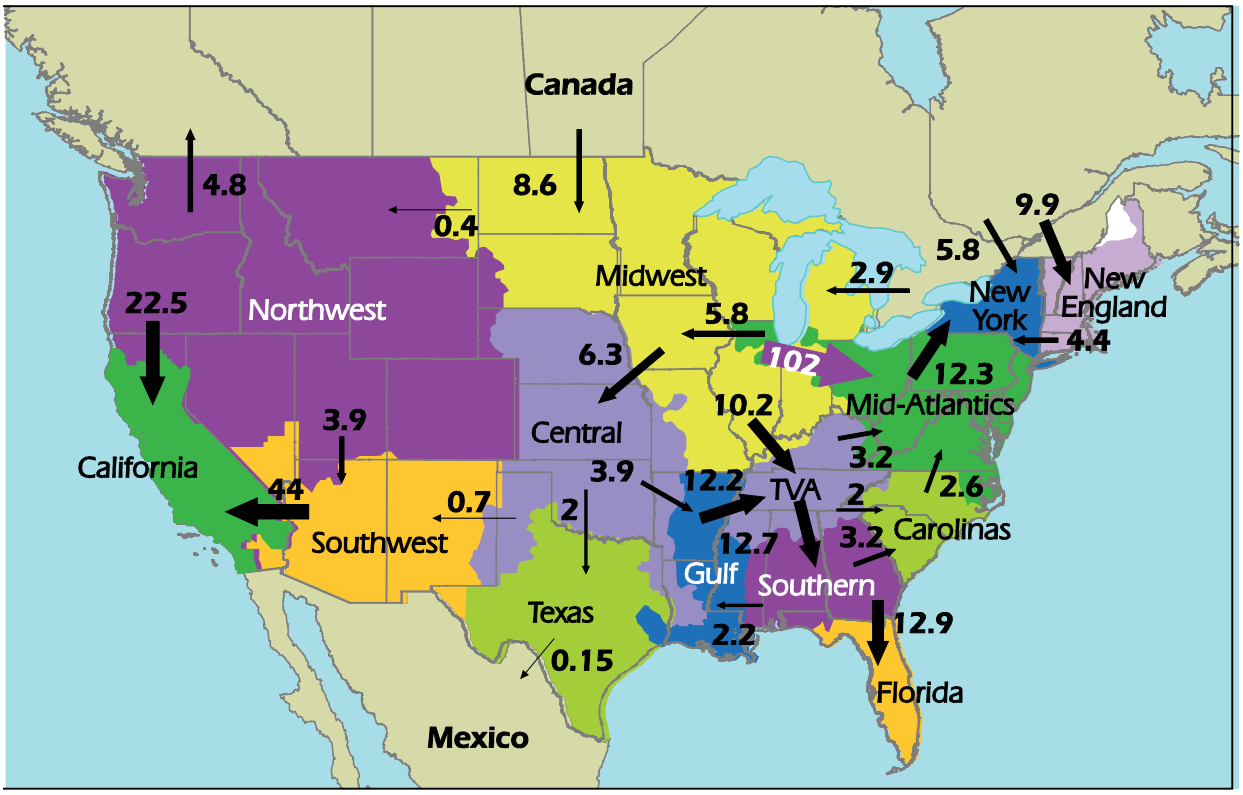
First, reliability criteria used in different areas can differ substantially (Pfeifenberger et al., 2013). The one-in-ten resource adequacy standard is interpreted differently and leads to enforcement of different planning reserve margins. Variations also exist in the operation of the electricity systems during scarcity events and emergency procedures. In particular, reliability procedures such as transmission loading relief (TLR) procedures imply that trade with neighbouring entities can be curtailed, which reduces the certainty of cross-border trades.

Second, integrated resource planning mechanisms are poorly co-ordinated across borders. Transmission planning requirements and generation adequacy assessment fall under the responsibility of the balancing authority, which ensures that investment needed within

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the footprint of one ISO can be identified but does not necessarily lead to the system-wide minimum-cost solution. Joint planning studies, for instance between MISO and PJM, seek to improve this situation. The costs of transmission lines have also to be allocated between jurisdictions, which raises methodological difficulties and remains a contentious topic (FERC Order 1 000).

Figure 3.14 Electricity trade in North America



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: DOE.

Third, allocation of cross-border transmission capacity presents inefficiencies. The approach consisting of the identification of a source and a sink for cross-border trades does not reflect the physical reality of power flows. The "flow gate" approach could be substantially improved. In addition, access to cross-border transmission infrastructure requires several transmission reservations: some of them are charged by system operators (so-called pancaking). For instance, "if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, the lowest-cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (Monitoring Analytics, 2013). Moving to a postage stamp approach for network charging and a more efficient allocation of cross-border capacity thanks to a single entity (similar to the Capacity Allocating Service Company, CASC), the central auction office for cross-border transmission capacity for Central-Western Europe) can ensure a better use of existing network infrastructure. It is worth noting, however, that the Court of Appeals rejected PJM's proposed postage stamp proposal and the majority found that there needed to be some demonstration of benefits.

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Fourthly, unscheduled energy flows (loop flows) across borders remain a significant concern for system operators. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing. Such unscheduled flows will be more frequent as a result of the deployment of wind power in some regions.

Fifthly, energy flows at the border seem to be in the right direction only by chance, with a probability close to 50%. Locational marginal prices calculated by adjacent system operators are often different for the same node of a seam. When there are differences, the power should flow from the area with low prices to the area with the higher prices. At the interface of PJM with bordering areas, the real-time hourly price difference was consistent with the direction of the average hourly flows only around half of the hours. This means that electricity flows are inefficient.

System operators are taking actions to address these "seam issues". Joint operating and reliability agreements have been developed.[9] These bilateral operating agreements include provisions for congestion management and mechanisms to address price issues at the seam. For instance, one RTO/ISO can ask another RTO/ISO to re-dispatch a power plant in order to manage network congestion; FERC's implication in these agreements remains limited. The federal regulator recently started to monitor progress in this regard (RTO Insider, 2013).

In other regions, new projects seek to develop electricity trade and improve operational co-ordination across larger geographic areas.

- In February 2013, the California ISO and PacifiCorp, a west coast utility, entered into a memorandum of understanding to create a regional real-time energy imbalance market (EIM). NV Energy, a public utility in the state of Nevada, joined the EIM in November 2013. The ISO market system will automatically balance electricity every five minutes. It is expected that this initiative will assist in the greater integration of renewables and enhanced reliability.
- Several projects seek to remove transmission bottlenecks between the three major interconnections (Eastern and Western Electricity Coordinating Council, and ERCOT). These long-term projects are motivated by the objective to deliver renewable energy to load centres. Some of them face institutional barriers; however, Texas, among others, wants to get confirmation from the Federal Energy Regulatory Commission that these projects would not trigger federal oversight of the ERCOT grid.

In addition to existing initiatives, there is a need to further reinforce co-ordination between neighbouring balancing authorities. Several states are reluctant to adopt the ISO/RTO approach in their jurisdiction, as this leads to transferring the final authority over the dispatch of power plants in real time to an entity that may be located in another state. This could be considered a radical change compared to the present situation and is often considered as over centralisation.

Recognising these institutional barriers, experience in other IEA member countries suggests that better co-ordination is still possible while maintaining a decentralised decision making. This is the case, for instance, in the ongoing so-called price-coupling of 15 different European day-ahead markets. Similarly, cross-border integration of balancing markets in

9. Examples of such agreements include Joint Operating agreements and the Reliability Co-ordination Agreement between PJM and its neighbours.

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Europe is under construction and does not require the consolidation of system operations but relies on the co-ordination of system operators (IEA, 2014e).

DEMAND RESPONSE

Development of demand response in the United States is a recent trend in the industry. The Recovery Act of 2009 funded the deployment of smart infrastructure and smart technologies to increase the potential of economical and efficient demand response.

According to FERC, the potential demand response resource contribution in the United States is estimated to be nearly 72 000 MW, or about 9.2% of peak demand.[10] With an actual peak reduction from demand response resources representing only around 30% of the potential, however, the actual demand response is much more limited.

The Energy Policy Act of 2005 requires FERC to assess demand response resource (FERC, 2012a).[11] To fulfil this requirement, FERC conducts comprehensive nationwide surveys and publishes a yearly *Commission Staff Report* which indicates significant progress. Since 2009, demand response potential increased by more than 4.1% in organised markets (i.e. ISO and RTO regions).

Aggregators of demand response resources have successfully developed over the past few years. For instance, EnerNOC manages a demand response portfolio of more than 9 000 MW. Many other companies developed similar activities.

FERC surveys provide a detailed review of legislative and regulatory activities that contribute to the expansion of demand response programmes.[12] For instance, the California Public Utility Commission is currently establishing public policies needed to expand the amount of demand response resources available to CAISO. ERCOT also expanded access to its demand response programmes aimed at improving the reserve margin during summer peak events and when operating margins fall below a certain level.

In 2011, FERC issued Order No. 7545, which requires demand reduction to be compensated at the same market clearing price as generation, rather than as a bid to reduce demand. This order is highly controversial and many economists criticised the FERC rule: not only do customers save on their bills when they reduce demand, but in addition they receive the wholesale market price for the same demand reduction (known as the double payment issue).

In practice, however, such economic demand response remains limited. Demand response resources, in particular emergency demand response, made significant contributions to balancing supply and demand during system emergencies for several RTOs and ISOs in the summer of 2013. Demand response often benefits from forward contracting such as on capacity markets, as illustrated by the rapid growth of demand response in the PJM footprint.

Emergency demand response, however, presents some complications. The first is the double payment issue just mentioned. The second, the impact on wholesale electricity prices, happens when ISOs anticipating tight system conditions call a demand response that results in reduced real-time peak prices. This so-called price suppression effect during

10. According to FERC, Demand Response is defined as: "Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."

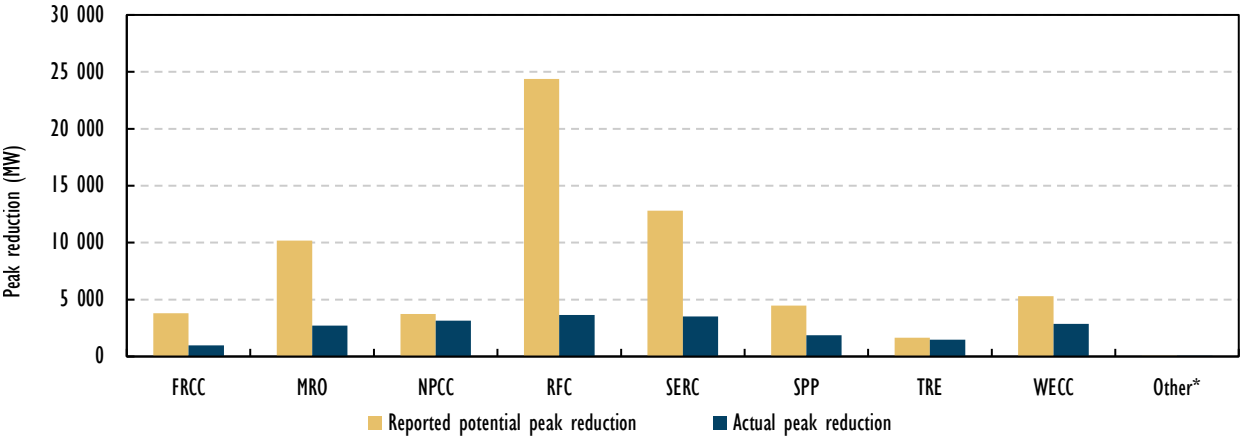
11. The Energy Independence and Security Act of 2007 also required FERC to develop plans to encourage demand response.

12. www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf.

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scarcity conditions can distort investment incentives, leading to underinvestment in peaking capacity. To address this, measures are being taken in order to define a portfolio of demand response products to better reflect resource characteristics and system needs.

Figure 3.15 Potential and actual peak demand response reductions by North American Electric Reliability Corporation (NERC) Regions in 2012

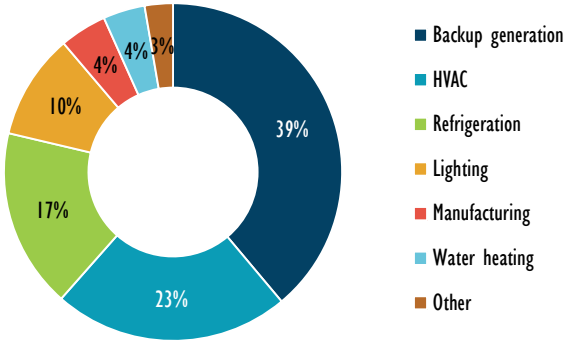


Note: FRCC = Florida Reliability Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = SERC Reliability Corporation; SPP = Southwest Power Pool; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

* *Other* is negligible.

Source: FERC (2012a), *Assessment of Demand Response and Advanced Metering*, Staff Report, FERC, Washington, D.C., December.

Figure 3.16 Sources for confirmed emergency demand response registration for delivery years 2013-14 (% of nominated capacity)



Source: PJM.

Recent developments regarding demand response are encouraging and the deployment of smart grids, smart meters and smart devices should further drive down costs of demand response. In addition to reducing load during system emergencies, demand response is expected to become a provider of operating reserves, helping to balance the deviations in wind and solar generation.

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The United States' experience in terms of demand response suggests that creating a level playing field for demand response remains a difficult task for market design. The lack of demand response has long been recognised as a unique characteristic of the power industry. The straightforward solution, at least in principle, is to expose customers to peak wholesale electricity prices that reflect tight system conditions. Other measures can also be introduced to promote demand response, for example, using capacity markets that encourage demand response develops where it is more efficient than adding new generating capacity.

Demand response also includes the development of time-of-use electricity retail prices. This includes real-time pricing of electricity and critical peak pricing. These forms of demand response remain underdeveloped in the United States. It is worth mentioning, however, that retail rates are under the jurisdiction of the state public utility regulators rather than the federal mandate.

MARKET POWER

COMPETITION POLICY

In terms of competition, there is no federal electricity policy mandating the restructuring and liberalisation of electricity markets all over the country. The Energy Policy Act of 2005 represents the most significant change in United States energy policy since the Federal Power Act of 1935, but it does not order unbundling. This contrasts with the federal policy for other network industries such as gas, railroads or telecoms. Some states never engaged in liberalisation while others suspended their liberalisation process after the collapse of the California electricity market in 2001, with the exception of Texas.

As a result, the electricity sector is a patchwork of regulated and unregulated markets. Regulated utilities can export power or bid in neighbouring competitive markets at a subsidised price, which exposes interregional trades to distortions of competition. Similarly, several large investor-owned utilities operate in both regulated and competitive environments. As a result, when setting retail rates, the Public Utility Regulatory Commission has to monitor the presence or otherwise of cross-subsidies between regulated and non-regulated activities.

FERC implemented an open access policy since 1998, but there is no vertical unbundling of network and generation activities. Many utilities continue to own both generation and network assets. Where they exist, ISOs and RTOs can ensure that available network infrastructure is used without discrimination between competitors, although it is not clear to what extent transmission owners can influence the availability and capacity of transmission assets.

Paradoxically, the federally owned utilities also all operate under a regulated framework, while federal policy promotes competitive electricity markets. Tennessee Valley Authority (TVA) and Bonneville Power Administration (BPA), own and operate assets built decades ago which are largely depreciated.

"The electricity sector is stuck somewhere between the policy framework of 1935 and the vision for restructuring, competition and regulatory reform that emerged in the late 1990s" (Joskow, 2008). The context of the electricity sector is changing rapidly and this reinforces the need for national policy for the sector. As already mentioned, the abundance and low price of gas has led to a convergence of electricity prices between regulated and competitive states and this calls for a better co-ordination of the

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electricity and gas infrastructure, the latter having been already successfully restructured on a national basis. Moreover, continued deployment of wind and solar power is likely to increase interstate trade of electricity, most notably between sunny and windy locations to load centres on the coasts. A comprehensive national framework would help to control the costs of reducing carbon emissions.

REGULATION OF COMPETITION

Various competition authorities intervene, depending on the area controlled. There is, in practice, a set of competition laws in different jurisdictions, and different bodies in charge of competition policies. In general, mergers and acquisitions remain within the hands of competition authorities, the Federal Trade Commission and the Department of Justice. FERC grants the right to sell electricity at market-based rates to generators if these can demonstrate that the lack of price responsive have mitigated market power. The manipulation of physical electricity markets can be monitored by FERC, in co-operation with independent market monitors and RTOs. In the financial products market, the Dodd-Franck Act confers regulatory authority to the Commodity Futures Trading Commission (CFTC).

The determination of anti-competitive practices in wholesale electricity markets takes into account the unique characteristic of wholesale electricity markets. Real-time electricity markets are prone to the exercise of market power during scarcity conditions, as a result of the lack of price responsive demand that enables generators to bid very high prices, far above the generation costs. Specific metrics were developed to capture this (see Box 3.3).

In addition, generators can enjoy local market power when a plant is needed to solve local congestion on a specific transmission line. Market power mitigation techniques commonly used include setting a cap on the electricity price (usually USD 1 000/MWh or more) and offer caps based on the costs of specific units.

Market power mitigation practices, however, have led to further complications in the design of electricity markets. A price cap, if too low, does not provide adequate revenues to invest in the capacity needed to meet the reliability standards. This “missing money problem” is usually mentioned as one of the key justifications of the capacity markets. Considering the high complexity added by capacity markets to the overall market design, one could ask whether these price caps are the most reasonable instrument to mitigate market power. Proposals to increase price caps in several wholesale markets are rightly addressing this issue.

Conversely, some power plants benefit from explicit or implicit subsidies, as a consequence of the coexistence of regulated and competitive power plants in the same electricity system. This has led FERC and system operators to use minimum offer price rules (MOPR) for certain power plants. The objective is to prevent too low bids on capacity markets that would artificially suppress prices below the competitive level needed to encourage efficient investments.

Given the inherent complexity of monitoring market power in wholesale electricity markets, RTOs and ISOs usually hire independent market monitors (IMM). They process the huge amount of data available on hourly and sub-hourly day-ahead and real-time locational markets. Market monitors are responsible for identifying attempts to exercise market power and issue periodic reports providing an independent assessment of the competitive performance and operational efficiency of the markets (Potomac Economics, 2012). Anti-competitive behaviour can be referred to FERC.

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FERC's jurisdiction and penalty authority is increasingly important. Under the Energy Policy Act of 2005, Congress directed FERC to detect, prevent and appropriately sanction the gaming of energy markets. The Office of Enforcement of the Commission settled many cases in 2013. For instance, in July 2013, FERC ordered a USD 453 million in penalties for western power market manipulation and JP Morgan agreed a penalty of USD 410 million to resolve an investigation on bidding practices.

Box 3.3 Market concentration metrics: Herfindahl-Hirschman Index and the three pivotal supplier test

In the United States, independent market monitors for different regional transmission organisations (RTOs) also analyse market concentration according to the calculations for hourly HHI (Herfindahl-Hirschman Index) for the control area of each RTO.

- For PJM, the HHI indicates that by FERC standards, the PJM Energy Market during 2012 was moderately concentrated. Using the hourly energy market measure, average HHI was 1240 with a minimum of 931 and a maximum of 1657 in 2012 (Monitoring Analytics, 2013).
- For MISO, the HHI is low. However, it is considerably higher in the individual regions – it is nearly 2 500 in the eastern region (i.e. "highly concentrated"). The regional HHIs are higher than those in the comparable zones of other RTOs because vertically integrated utilities in MISO that have not divested generation and tend to have a substantial market (Potomac Economics, 2012).

However, the HHI metric has some limitations as an indicator of overall competitiveness. In particular, it does not capture the unique characteristics of electricity and the local market power issues due to the existence of network constraints. Another indicator of potential market power used in the United States is the notion of pivotal supplier. A supplier is pivotal when its power plants are necessary to satisfy load or to manage a network constraint.

According to some independent market monitors, the three pivotal supplier (TPS) test is considered to be the most relevant measure of market structure when demand is totally inelastic. This test uses actual market conditions reflecting both temporal and geographic granularity and indicates the existence of market power in local markets created by transmission constraints. According to Monitoring Analytics, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

INFRASTRUCTURE RESILIENCE

The global energy system is not immune from the physical impacts of climate change, notably of extreme weather events, and must adapt. Sudden and destructive climate impacts pose risks to power plants and grids, oil and gas installations, wind farms and other infrastructure. Other impacts are more gradual, such as changes to heating and cooling demand, sea level rise on coastal infrastructure, shifting weather patterns on hydropower and water scarcity on power plants (IEA, 2013b).

To improve the climate resilience of the energy system, all governments need to design and implement frameworks that encourage prudent adaptation, while the private sector must assess the risks and impacts as part of its investment decisions.

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According to the federal government, severe weather is the leading cause of power outages in the United States. Between 2003 and 2012, the government estimated 679 widespread power outages occurred as a result of severe weather. A Congressional Research Service study estimated the inflation-adjusted cost of weather-related outages at between USD 25 billion and USD 70 billion annually (Campbell, 2012). Strengthening the resilience of the electricity grid is a priority for government and for the network operators.

A White House paper published in 2013 estimated the annual cost of weather-related power outages and set out various strategies for modernising the grid and increasing grid resilience (Executive Office of the President, 2013). In 2012, for example, the United States experienced 11 more-than-one-billion-dollar weather disasters, the second-largest number for any year on record, behind only 2011. The White House report concluded that preparing for the challenges posed by climate change will require investment in 21st century technology, which will increase the resilience and reliability of the grid. The report identified a series of priorities for a multi-dimensional strategy needed to prepare the United States for climate change and the increasing incidence of severe weather. A key step is the development of a smarter, more resilient electricity grid.

Previously, in 2012, to help the electricity industry better understand these low probability risks, NERC and DOE published a report titled, "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System". Subsequently, NERC approved a Co-ordinated Action Plan under the leadership of the NERC Technical Committees to establish four task forces to address this matter. One of those task forces, the Severe Impact Resilience Task Force (SIRTF), published a short report in 2012, which provided guidance to network asset owners and operators in the form of recommendations to enhance the resilience of the bulk power system.

THE ROLE OF NERC AND THE DEVELOPMENT OF PHYSICAL SECURITY STANDARDS

In March 2014, FERC directed NERC to develop reliability standards requiring owners and operators of the Bulk Power System to address the risks imposed by physical security threats and vulnerabilities (FERC, 2014a). The strengthened reliability standards will require owners and operators of the Bulk Power System to take at least three steps to protect physical security.

i) Owners and operators must perform a risk assessment of their system to identify facilities that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation, or cascading failures of the Bulk Power System. *ii)* Owners and operators of critical facilities must evaluate potential threats to and vulnerabilities of those facilities. *iii)* Owners and operators must develop and implement a security plan to address potential threats and vulnerabilities.

SMART GRIDS AND METERING

Smart grids are networks that monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. They are, and will continue to be deployed at different rates in a variety of settings around the world, depending on local commercial attractiveness, compatibility with existing technologies, regulatory developments and investment frameworks.

Smart grid efforts involve a broad range of government agencies, at both the federal and state levels. The federal agencies include primarily the Department of Energy (DOE), the

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National Institute of Standards and Technology (NIST) and FERC. DOE's tasks include awarding grants for smart grid projects and developing a smart grid information clearinghouse. NIST has primary responsibility for co-ordinating the development of an "interoperability framework" allowing smart grid technologies to communicate and work together. FERC is then responsible for promulgating interoperability standards, once FERC is satisfied that NIST's work has led to sufficient consensus.

The Energy Independence and Security Act of 2007 made it "the policy of the United States to support the modernization" of the electrical grid (US Congress, 2007). The Recovery Act of 2009 made USD 4.5 billion available for investment in electricity delivery and energy reliability activities related to the modernisation the electricity grid. These funds are in turn being matched by more than USD 5.5 billion from public and private stakeholders to fund 141 smart grid grants and co-operative agreements for smart grid and energy storage technologies across the country, with additional funding going towards workforce training (Executive Office of the President, 2011). In addition, the Rural Utilities Service provided USD 7.1 billion in loans in 2010 to support the modernisation of electricity infrastructure serving rural America, including more than USD 152 million for smart meter deployments alone.

ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

The Energy Independence and Security Act of 2007 (EISA) (US Congress, 2007) made it the policy of the United States to modernise the nation's electricity transmission and distribution system with the intention of moving the United States towards greater energy independence and security. In Title XIII of the EISA, Congress called for the modernisation of the electricity grid to address some of the electricity grid's systemic problems.

This modernisation of the transmission system is referred to as the Smart Grid. Title XIII also established a Smart Grid Task Force, which is authorised to co-ordinate implementation of the Smart Grid. The Smart Grid Task Force is required to report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment.

Box 3.4 Examples of smart grid activities

Vermont Transco is using Recovery Act funding to institute a state-wide meter data management system and modernise the technology used in the state's electricity distribution system (Smart Grid, 2014). Similarly, in Texas, following legislation to encourage deployment of smart meters, all major transmission and distribution (T&D) providers have to have their plans approved by public utility commissions (PUC) to deploy Advanced Metering Infrastructure (AMI) in their service areas.

These T&D service providers have already deployed 2.5 million meters and will have more than 6 million in place by 2015 (PUCT, 2013). The new smart meters being deployed in Texas enable consumers to access their timely energy usage data online through a web portal, www.smartmetertexas.com. Consequently, Texans can use the data with third-party devices and services of their choosing to find ways to save money and energy.

Furthermore, and to ensure that reliability is not ignored, the EISA creates two programmes that support the development of reliability technology. First, section 1304 charges the Secretary of the DOE and the FERC to develop a programme that would test

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new reliability technologies. Second, section 1306 establishes a federal matching fund that compensates companies for the cost of the technology used to improve the reliability of the transmission system.

AMERICAN RECOVERY AND REINVESTMENT ACT OF 2009

The Recovery Act of 2009 (US Congress, 2009) accelerated the development of smart grid technologies, investing USD 4.5 billion for electricity delivery and energy reliability activities to modernise the electric grid and implement demonstration and deployment programmes (as authorised under Title XIII of EISA).

The Recovery Act included approximately USD 4.0 billion in federal funding for the Smart Grid Investment Grant Program (SGIG) and the Smart Grid Demonstration Program (SGDP). The SGIG focused on the deployment of existing smart grid technologies, tools and techniques while SGDP is focused on demonstrating advanced concepts and innovative applications in regional smart grid and energy storage demonstrations.

In early 2010, the DOE announced competitive awards for 99 SGIG projects and 32 SGDP projects following an open solicitation process. One of DOE's goals for both SGIG and SGDP is the assessment of metrics, impacts, costs and benefits for the full spectrum of smart grid programmes and applications, including those for electric transmission systems, electric distribution systems, advanced metering infrastructure, and customer systems. The aim is to provide fact-based information from actual projects and assist public and private decision makers in identifying the most cost-effective smart grid technologies, tools and techniques (Smart Grid, 2014).

A POLICY FRAMEWORK FOR THE 21ST CENTURY GRID: ENABLING OUR SECURE ENERGY FUTURE (JUNE 2011)

The federal government, building on the policy direction set out in the EISA and the investments supported by the Recovery Act, presented a policy framework to support the modernisation of the grid in order to take advantage of opportunities made possible by modern information, energy and communications technologies. This framework is based upon on four pillars:

- enabling cost-effective smart grid investments
- unlocking the potential for innovation in the electricity sector
- empowering consumers and enabling them to take informed decisions
- securing the grid.

FERC and the Smart Grid

FERC, according to the authority granted to it by the Federal Power Act, may "provide rate incentives for appropriate Smart Grid projects, and can provide guidance on cost recovery for such projects."

FERC's interest and responsibilities in this area derive from its authority over rates; terms and conditions of transmission and wholesale sales in interstate commerce and its responsibility for approving and enforcing mandatory reliability standards for the bulk power system. FERC is required to adopt interoperability standards and protocols necessary

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to ensure smart grid functionality and interoperability in the interstate transmission of electricity and in regional and wholesale electricity markets.

In 2008, FERC and the National Association of Regulatory Utility Commissioners (NARUC) formed a Smart Grid Collaborative to serve as a forum for federal and state energy regulators to discuss technological and other issues that would facilitate the transition to a smart grid. Since then, the Smart Grid Collaborative (SGC) merged with another NARUC/FERC collaborative focusing on demand response, because many of the topics overlap. The SGC provides an opportunity for state and federal energy regulators to discuss emerging issues and to better understand the range of issues that cut across both wholesale and retail energy markets.

Furthermore, in July 2009, FERC issued a Smart Grid Policy Statement that, among other things, discussed smart grid functions and characteristics that could help address challenges to the reliable operation of the transmission system. In response to the need for action on these challenges, the Commission identified areas that deserved high priority in the smart grid standards development process. These areas include two cross-cutting issues, system security and inter-system communication, and four key grid functionalities: wide-area situational awareness, demand response, electric storage, and electric vehicles.[13]

CYBER- AND GRID SECURITY

Modern grid management networks based on computers, intelligent electronic devices, software, and communication technologies are widely understood to present greater infrastructure protection challenges than those of the traditional electricity network infrastructure, and expose the networks to new risks related to intrusions, error-caused disruptions, malicious attacks, destruction, and other threats.

Cybersecurity practices are needed to address not only the threats and vulnerabilities of traditional information systems, such as the lengthy life expectancy of energy control systems, low-latency communications needed for real-time control, and differing requirements and regulatory frameworks among grid stakeholders, but also a variety of other matters unique to electricity grid technology. The US National Infrastructure Advisory Council has advised that updated cybersecurity legislation is required.

Homeland Security Presidential Directive 798 and the National Infrastructure Protection Plan established the initial framework for public-private partnerships for 18 critical infrastructure sectors and designated DOE as the sector-specific agency to work collaboratively with all

stakeholders in the energy sector. The strategy to ensure the overall security of the electricity sector is outlined in the Energy Sector-Specific Plan, initially published in 2007 and updated in 2010.

Since 2006, more than 65 initiatives have been launched by DOE, universities and private-sector entities to develop and commercialise advanced cybersecurity solutions to improve cybersecurity across the energy sector. In 2010, DOE worked in partnership with industry stakeholders to update the 2006 Roadmap so as to specifically address new threats and challenges introduced by smart grid technologies. A public-private working group, the Energy Sector Control Systems Working Group, has been established to track progress towards the Roadmap goals.

13. Testimony of Mason W. Emnett, Associate Director, Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, before the Technology and Innovation Subcommittee of the Committee on Science and Technology, United States House of Representatives, 1 July 2010.

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The roles of FERC and NERC

The Energy Policy Act gave FERC the authority to oversee the reliability of the bulk power system, including the authority to approve mandatory cybersecurity reliability standards. NERC, which was certified by FERC as the Electric Reliability Organization, developed cybersecurity reliability standards for the critical infrastructure protection (CIP) programme. In January 2008, FERC issued Order No. 706, the Final Rule approving the CIP reliability standards, while concurrently directing NERC to develop significant modifications to address specific concerns. The CIP reliability standards require certain users, owners and operators of the bulk power system to comply with specific requirements to safeguard critical cyber-assets.

Furthermore, the Energy Independence and Security Act of 2007 (EISA) gave FERC and the National Institute of Standards and Technology (NIST) responsibilities related to co-ordinating the development and adoption of smart grid guidelines and standards.

FERC was mandated by the President to work with NERC to determine whether a mandatory reliability standard under Section 215 of the Federal Power Act is needed to protect against physical attacks on our electrical infrastructure (FERC, 2014b).

Box 3.5 Pacific Northwest National Laboratory: Future Power Grid Initiative

Located in Richland, Washington (state), the Pacific Northwest National Laboratory (PNNL) is one of ten DOE national laboratories managed by DOE's Office of Science. PNNL supports research for not only DOE, but also for the US Department of Homeland Security, the National Nuclear Security Administration, other government agencies, universities and industry.

The PNNL Future Power Grid Initiative (FPGI) aims to clarify the look ahead through the integration of communication and computational technologies with new grid sensor technologies. This research in data management, simulation and visualisation is laying the foundations for a new power grid, giving operators, planners and policy makers the tools to fully comprehend and utilise the power grid of the 21st century.

The purpose of the FPGI is to deliver next-generation concepts and tools for grid operation and planning. It will also help ensure a more secure, efficient and reliable future grid. Building on the Electricity Infrastructure Operations Center (EIOC), the PNNL national electric grid research facility, FPGI will advance the science and develop the technologies necessary to meet expectations for a reliable and efficient electric grid and reduce carbon emissions. To tackle these issues, the FPGI is concentrating on what it sees as three of the most pressing areas of research: large-scale real-time simulation, stochastic and uncertainty modelling, and data-driven decision support.

Cybersecurity Capability Maturity Model

The Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) was established as a result of the federal government's efforts to improve the electricity subsector cybersecurity capabilities, and to understand the cybersecurity position of the energy sector. In February 2014, DOE announced the release of new versions of the model, which help organisations assess their own cybersecurity capabilities and identify steps to help strengthen their defences; these include a version that can be used by industries outside the energy sector. The C2M2 model, designed to be used by any organisation to strengthen its cybersecurity capabilities, is publicly available on the DOE website.

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Guidelines for smart grid cybersecurity

Guidelines for smart grid cybersecurity were developed by the Department of Commerce's National Institute for Standards and Technology (NIST). The standards support the development of effective cybersecurity strategies tailored to a combination of smart grid-related characteristics, risks and vulnerabilities. Smart grid stakeholders, from utilities to providers of energy management services and to manufacturers of electric vehicles and charging stations, can use the methods and supporting information presented by NIST as guidance for assessing risk and identifying and applying appropriate security requirements.

This initial version of the Guidelines was developed as a consensus document by the Cybersecurity Working Group (CSWG) of the Smart Grid Interoperability Panel (SGIP), a public-private partnership launched by the National Institute of Standards and Technology (NIST) in November 2009. The CSWG now numbers more than 475 participants from the private sector (including vendors and service providers), manufacturers, various standards organisations, academia, regulatory organisations and federal agencies. A number of these members are from outside the United States (SGIP, 2010).

DISTRIBUTION, RETAIL MARKETS AND END-USE PRICES

DISTRIBUTION

In the United States, transmission lines are high-voltage lines with kilovolt-ampere (kVA) ratings of 115 kVA and above. Distribution lines have lower voltage ratings, such as 69 kVA, 34 kVA and 13 kVA. The majority of electricity distribution-only utilities are smaller consumer-owned ones, but some are large investor-owned utilities. These distribution-only utilities either buy their power from one or more upstream wholesale providers, or, in the restructured states, consumers may obtain their power directly from suppliers, with the utility providing only the distribution service.

RETAIL MARKETS OVERVIEW

Although well established in most OECD economies, retail competition in the US electricity market is relatively limited and confined to a small number of states. End-users in fewer than 20 states benefit from retail energy competition, while the majority of consumers in the remaining states enjoy only one option, a monopoly utility provider, when it comes to purchasing electricity (and natural gas).

Residential electricity choice began in the late 1990s following the early phases of industry restructuring. Following problems with market liberalisation in California in 2000, liberalisation has been either suspended or decided against in a number of states. At the moment, retail competition is present for residential users in 17 states and the District of Columbia, and is available to approximately 17.2 million customers. The equivalent number for commercial and industrial consumers is 15 states plus the District of Colombia. In Texas, a leading exponent of retail competition, more than 80% of eligible residential customers have exercised choice in the market (PUCT, 2013).

The form of retail competition also varies widely. At the extreme is the fully separated European Union model, implemented through its Electricity Directive, in which the distribution utility is allowed to sell only distribution network services; energy and other services must be purchased from other enterprises. This is essentially the approach used in Texas, but retail competition associated with full unbundling constitutes the exception

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and not the rule in the United States. Without retail competition, innovation in retail electricity services depends on incumbent monopoly distribution companies. But rate regulation may impede the efficient development and introduction of new services. Innovation involves risk and regulated firms have little to gain from voluntarily assuming risks: if things go well, the benefits go mainly to customers; if things go badly, the pain is borne mainly by managers and shareholders.

In states where full retail competition (or retail choice) is provided, customers may choose between their incumbent utility supplier and a variety of competitive suppliers. In most states providing retail competition, customers who do not choose a supplier from the markets are served by their incumbent utility through "provider of last resort" service, which is required to secure its needed power on the wholesale market through a competitive bid process. Retail markets are regulated at the state level by commissions that approve any alternative competitive supplier before they can serve customers and oversee the activities of the last-resort provider. In states where retail competition is unavailable, the commissions regulate the expenditures of the monopoly utilities by allowing a rate of return on most costs. In these states, utilities are vertically integrated and may construct, own and operate power plants. To curb inefficiencies that occur under any monopoly system, all states with vertically integrated utilities require utility power resources to be acquired through a competitive bid process, similar to how government contracts are filled.

Retail competition is meant to create pressure among suppliers to develop new, innovative and higher-value products. Consumers value electricity supply services for different reasons, but will for the most part select a particular provider on the basis of some combination of price, customer service and social concerns (for example, environmental issues). Given that any kilowatt delivered is the same regardless of who is supplying it, in practice this means retailers compete by offering lower prices, differing pricing structures, particular generation mixes, and enhanced customer support (for example through the use of information technology services). For example, some retailers may offer volumetric charges in some hours of the day and allow for unlimited consumption in other hours. Others may offer a generation portfolio that is 100% renewables. Some retailers will offer products that tie energy delivery to other services, such as distributed generation (for example, rooftop solar) or home energy efficiency audits.

The implementation of retail competition requires additional administrative and technical infrastructure. For example, third-party providers must be given access to customer data. This requires developing rules for sharing data that ensure no single party has a particular advantage because it has access to data that others do not, while at the same time maintaining a sufficient level of customer privacy and security. Billing practices should be standardised, and consumers should be given the tools to make proper comparisons among different offers (for example a single clearinghouse for all retailers).

Improvements to technical infrastructure to support retail choice could also include the installation of interval or smart meters, to allow for remote data collection and real-time information on consumption, or some alternative. Retailers who are unable to differentiate between high- and low-consumption periods would have difficulty in developing products beyond a simple fixed rate. In cases where the metering infrastructure is not in place, providers will often develop models of consumption behaviour. While these models can be quite sophisticated, they lack real-time feedback, and so make it difficult or impossible to develop products that include demand response or net metered distributed generation.

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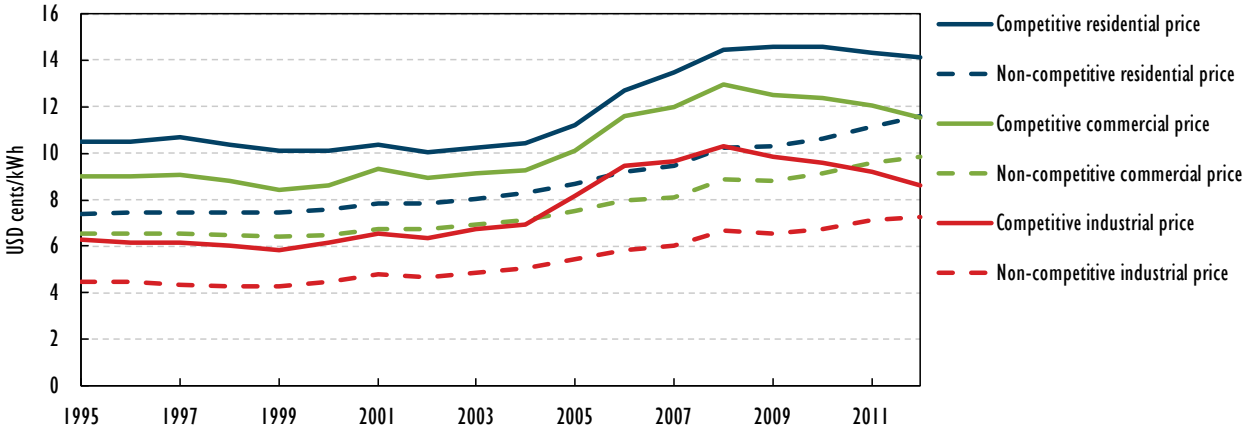
They can also create distorted incentives, where customers who fall outside typical consumption patterns may unfairly benefit or be penalised.

Most states that have introduced retail choice have a default service (sometimes referred to as standard offer or basic generation service) provider, which is often the incumbent distribution utility. This is to ensure consistency of service during the transition to retail competition, and to reassure consumers who are concerned about relying on third parties for the delivery of an essential service and hoping that there will also be some provider under any circumstance. Many who advocate on behalf of retail competition, however, point to the existence of default retail suppliers as an obstacle to competition, suggesting that the third parties should be allowed to bid to provide default service, or that the default service should be removed.

In total, 17 states plus the District of Columbia have some form of retail competition (EIA, 2012). Rates of participation vary significantly, however, depending on the state, and in general have been fairly low for residential customers. Of the approximately 48 million homes eligible, only 17 million, or 36%, have switched to a new retailer (DEFG, 2014). Retail competition has seen its largest success (in terms of the number of customers choosing to switch supplier) within the commercial and industrial sectors.

Price competition is at times introduced with the notion that it should, on the whole, lower prices for consumers. In fact, competition should simply bring prices more in line with underlying costs, and so prices would be expected to rise or fall depending on the degree and direction of underlying distortions under the regulated market system. Figure 3.17 compares retail prices for the different market segments (residential, commercial and industrial) in states that have introduced competition and in those that have not.

Figure 3.17 Average retail electricity price, 1995-2012



Sources: EIA (2014f), "Average retail price of electricity to ultimate customers by end-use sector, by state, June 2014 and 2013", *Electric Power Monthly*, EIA, August; DEFG (Distributed Energy Financial Group) (2014), *Annual Baseline Assessment of Choice in Canada and the United States*, DEFG, 22 January.

It should be read with a few caveats. In particular, different states have introduced competition to varying degrees and according to different time schedules, and so the averages displayed hide variations both within categories and over time. In addition, different states had different starting points. States that have introduced retail competition have tended to be higher-cost states (for example the industrialised states of the Northeast). As a result, higher prices under competition may reflect circumstances particular to this group of states, and not specific to the nature of retail competition itself.

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Despite the difficulty in making cross-state comparisons, certain trends are apparent. Competitive states have had historically higher prices in all sectors than in non-competitive states, but before the introduction of retail competition prices in all states had tended to move together. After the introduction of competition, prices began to diverge significantly, in particular starting in 2004 and 2005. Since 2008, prices have begun to converge, with prices in competitive states declining while prices in other states have continued to rise. This change coincides with a decline in natural gas prices, suggesting that wholesale prices are indeed more reflective of – or at least more responsive to – underlying costs. It may also suggest that average pricing performed in regulated markets mitigates fuel price risk more efficiently than marginal pricing.

While there are too many US experiences in this area to summarise in depth, it is worth examining particular states to gain a better sense of the impact of retail competition.

EXAMPLES OF RETAIL COMPETITION IN SELECTED STATES

Michigan

In Michigan, retail competition has existed in some form since 1999. Switching has been extremely limited, however, in part because of a market share cap instituted in 2007 that limits alternative suppliers to 10% of the sales of a given service. While removing this cap would almost certainly lead to an increase in participation in some parts of the state, there are a number of service territories with participation well below the limit.

In fact, only two service territories have active alternative suppliers. In areas with rural co-operatives that allow retail choice, there has been little retail competition (Michigan PSC, 2014). In general, participation has been limited to industrial and commercial customers. Retail rates, meanwhile, have continued to rise for all consumers. From 2005 to 2012, for example, residential rates increased by nearly 70%. Whether this price rise is a result of limits on retail competition or to other factors is not clear.

New York

New York is another example of a state considered to have successfully introduced retail competition. Interestingly, competition in New York was introduced through regulatory action on the part of the Public Service Commission, and not legislatively, as it has been in most other states. By default, consumers in New York receive service from their local distribution company, which continues to sell electricity at regulated rates. However, all customers can choose to switch to an alternative supplier. New York has introduced rules to allow for the sharing of information between suppliers and to protect consumer welfare, but has not, for example, created blanket rules about the deployment of smart meters (though these are allowed, there is no requirement that they be installed nor a specific mechanism for cost recovery). Switching rates follow the same trend as other states: residential customers have generally preferred to stay with their incumbent provider, while the majority of commercial and industrial customers have switched to some alternative. Retail rates since the introduction of competition have increased for all customer classes, though mainly for residential and commercial customers. Industrial rates are, on average, higher than before restructuring, but have declined significantly since 2008, alongside declines in natural gas prices.

As these examples show, there is a diversity of experiences even within states that have introduced retail competition. That there is no unifying factor behind them is in part a

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consequence of the fragmented nature of retail regulation within the United States. There are opportunities, however, for states to share lessons learned and collaborate to improve retail electricity markets throughout the country. For example, states that have not introduced retail competition may still potentially learn from billing practices or data protection standards from states that have. They may also draw upon some of the more innovative retail offerings to encourage regulated utilities to offer a greater diversity of products to consumers, in particular in states that also have specific energy efficiency and renewable energy goals. Finally, states that have experimented with retail competition but that have not seen great success (in terms of customer switching rates, for example, or in pricing) may be able to identify policy options or reforms by more closely examining the experiences of states whose programmes and results they wish to emulate.

Texas

Texas is widely considered to have most successfully implemented retail competition. All consumers in Texas are able to choose between a large number of suppliers, though how many are specifically available varies depending on where the customer is located. In 2007, consumers could collectively choose from 28 suppliers offering approximately 100 different retail products. By 2013, the number of active retail suppliers had increased to 52, offering a total of 322 products. Texas is also the only state to have completely eliminated default service.

Box 3.6 Public Utility Commission of Texas: Driving retail competition

In the state of Texas, about 60% of all consumers have access to retail electricity choice and most have enjoyed the benefits of choice in electricity providers and products for almost 15 years. Retail competition started in 2002, when all residential customers in the competitive areas of the Electricity Reliability Council of Texas (ERCOT) were moved from a fully regulated service to price-to-beat rates that were established at a discount of 6% below existing residential tariffs. Today, customers can choose from a variety of fixed, variable, prepaid or post-paid retail products and from around 60 renewable energy-based products (100% renewables content) from over 100 service providers. Prepaid energy, where customers have access to daily usage and account balance updates via text or email, is popular in Texas and the market offers 16 prepay plans from 12 retail electricity providers (REPs).

The number of REPs in Texas has grown steadily since 2002 and by August of 2012 there were 114 of them providing service to customers. A REP sells electricity to retail customers in the areas of Texas where the sale of electricity is open to retail competition. Such provider buys wholesale electricity, delivers service and related services, prices electricity for customers, and seeks customers to buy electricity at retail. Texas is often recognised as the most successful competitive retail market in North America and the state has been ranked the number-one state for retail choice in the Annual Baseline Assessment of Choice in Canada and the United States.

Since its inception in February 2001, the goal for the Public Utilities Commission of Texas's campaign "Texas Electric Choice" has been to educate Texans about the changes and choices in the retail electric market. The Commission actively tries to educate Texans about electricity choice, retail electricity providers, and plan options from using a variety of approaches, in both English and Spanish, to reach and inform the public.

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Box 3.6 Public Utility Commission of Texas: Driving retail competition (continued)

The Commission supports a range of activities to raise the profile and public visibility of retail choice, largely designed to inform electricity customers of the official electric choice website. The website allows customers to compare offers and to shop for electricity providers; learn more about digital smart meters, generating and selling renewable power, discover various incentives for energy efficiency and renewable energy, and read numerous publications including fact sheets and Texas Electric Choice brochures (PUCT, 2014).

Beginning on 1 March 2010, a call centre became available to answer "Texas Electric Choice" questions for the public. The Customer Protection Division (CPD) offers trained staff, both in English and Spanish, available to answer calls, along with assembling and mailing fulfilment packets requested by customers including brochures, a list of REPs in their area along with their contact phone numbers. The PUCT also publishes educational literature on the benefits of retail choice, administers low-income/elderly education outreach programmes and energy conservation awareness campaigns.

Texas laid the groundwork for retail competition with a series of legislative actions that, among other things, set certification procedures for the retail electric providers (REPs), required the installation of smart meters (with costs passed on to consumers in the form of a fixed surcharge), developed standards of information disclosure, introduced the possibility for prepaid services, and allowed for retail customer participation in demand response programmes (referred to as emergency response). Retail choice in Texas was phased in, with some regions allowing customers to switch provider earlier than others. In the first few years of the phase in process, rates in regions with retail choice rose faster than in regulated areas of the state, though this rise was tempered somewhat by the regulated "price to beat", which set a benchmark rate for service. "Price to beat" was fully eliminated in 2007, at the same time retail competition was extended to all customers.

In the years following the expiration of "price to beat", retail rates declined. While some point to the fully competitive market as the driving force behind the price declines, others note that these declines coincide with a period of lower natural gas prices. Theory suggests that, in an unregulated market, retail prices should more directly reflect the marginal wholesale price. In Texas, natural gas tends to be the marginal fuel in the electricity wholesale market.

Despite the relative success of the Texas programme, there is still significant market concentration. As of 2010, three retailers managed the accounts of approximately three-quarters of all residential customers, and the same three companies have nearly half of the commercial and industrial market (Sioshansi, 2013). Texas provides a clear picture of what is possible under retail competition in the absence of regulatory limits, but it is not typical of states.

PRICE LEVELS

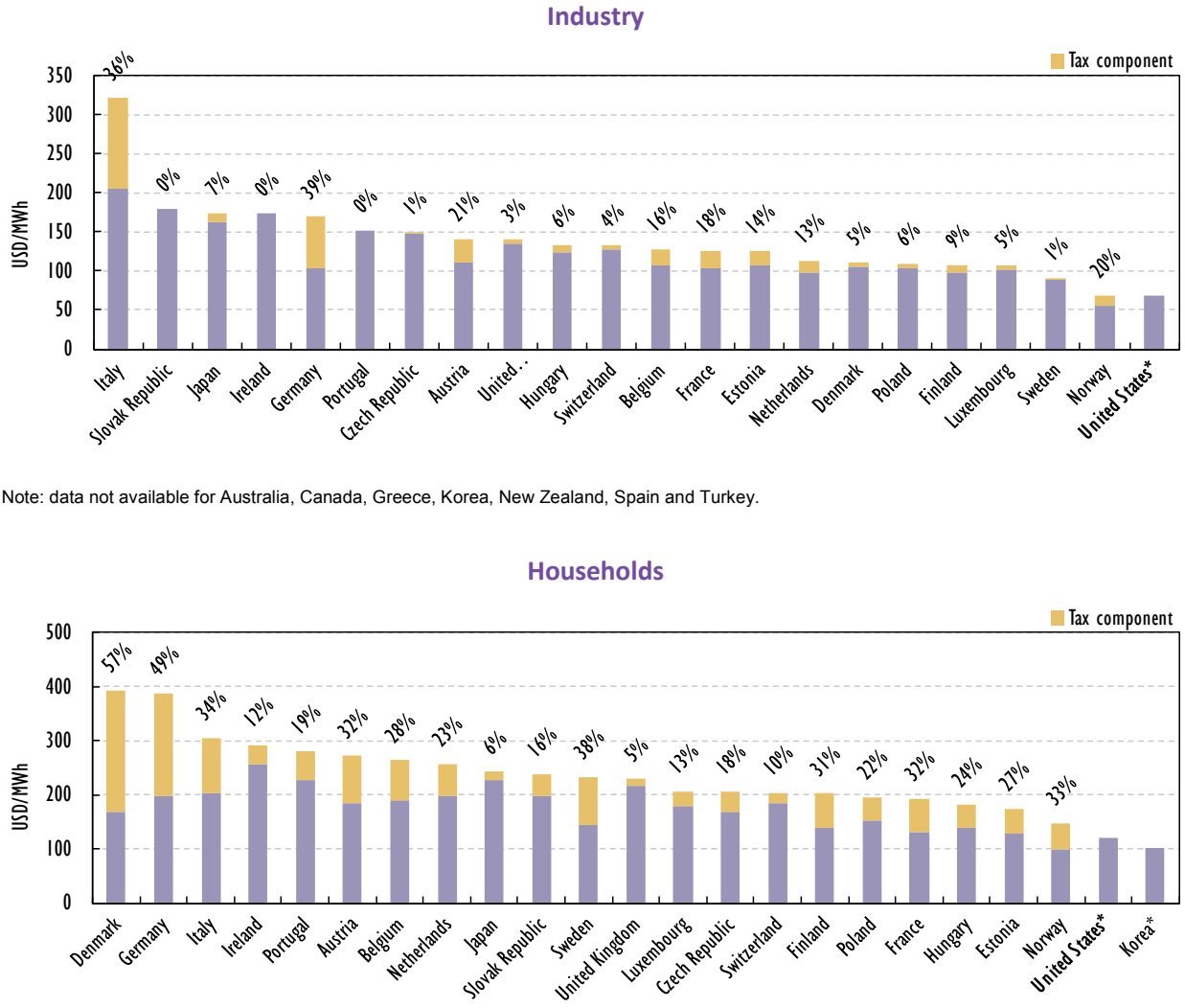
In 2012, and for the second consecutive year, the average monthly electricity bill for residential customers in the United States decreased relative to the previous year (EIA, 2013a). These declines are understood to have been driven by reductions in average consumption per customer rather than falling rates: tariffs increased in 2011 and 2012 while average consumption per customer fell over the same period. According to the IEA, the reduction in consumption per customer could be influenced by a number of factors such as weather trends and more efficient use of electricity. Interestingly, the number of heating degree days fell in both 2011 and 2011 while the number of cooling

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degree days increased but to a lesser extent. As always, these trends were not national: bills generally decreased in the eastern side of the country as far as Texas, while average bills generally increased in the Midwest and West.

At national level, average electricity prices in the United States tend to be among the very lowest in the OECD for both households and industry. Consumers also benefit from lower taxes on energy consumption. Nonetheless, climate variations across the United States can result in higher average consumption per household in some states relative to other OECD member countries leading to higher bills. According to EIA data, households' electricity bills are highest in the states of Alaska, Hawaii and northeastern states. Conversely, bills are lowest in Washington, West Virginia and Louisiana (EIA, 2014b).

Figure 3.18 Electricity prices in IEA member countries, 2013



Note: data not available for Australia, Canada, Greece, Korea, New Zealand, Spain and Turkey.

Note: data not available for Australia, Canada, Greece, New Zealand, Spain and Turkey.

* Tax information not available.

Source: IEA (2014d), *Energy Prices and Taxes*, OECD/IEA, Paris.

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ASSESSMENT

The United States bulk power system delivers relatively inexpensive electricity to consumers across the United States. Over time, several regional transmission organisations (RTOs) and independent system operators (ISOs) have developed operating rules and protocols that allow generation dispatch and transmission co-ordination over increasingly wide geographic areas. There is ample evidence to support the argument that regional integration of electricity systems or electricity markets bring important benefits in terms of efficient use of existing assets and minimisation of electricity cost.

The process of electricity reform, which commenced in 1978 with the Public Utilities Regulatory Policy Act and created a market for power from non-utility power producers, has stalled over the last decade, largely because of the California crisis of the early 2000s. Nonetheless, PJM is expanding its market footprint gradually and MISO now covers a large portion of the Midwest, a market area that also includes vertically integrated utilities. In zones without RTOs, the electricity system remains extremely fragmented, leading to less efficient use of existing assets. Many smaller vertically integrated regulated utilities continue to operate small balancing areas under an old regulatory framework.

Moreover, the trade of electricity across the borders of utilities remains difficult. Despite open access policies, a number of institutional barriers hinder efficient trade between control areas or across regions. Even between RTOs in the Northeast, there are inefficiencies in the interregional co-ordination between MISO, PJM, New York ISO and ISO New England.

THE GAS AND POWER INTERFACE

In the recent past, the arrival of cheap domestic natural gas has resulted in stable wholesale electricity prices and allowed the integration of large volumes of electricity generated from renewable sources without increasing end-user rates. Flexibility in terms of fuel use has been possible thanks to a large installed base of gas capacity inherited from the *dash for gas* 15 years ago. The greater role of gas in the power sector, while bringing some challenges and risks, also has had, and will continue to have, other benefits:

- It can result in lower GHG emissions. Although, to some extent, this advantage depends on more detailed analysis of the lifecycle-GHG assessment of shale gas.
- Gas-fired generation can be placed closer to load centres, which can reduce the need for (or at least postpone for a period) investment in new transmission investments.
- Gas-fired CCGTs offer the market greater flexibility and are more suitable for rapid start and shutdown than coal-fired power plants. CCGTs can respond to load variation needs quickly and also help in maintain the stability in the grid.
- The cost of deploying wind and solar power has been compensated, to some extent, by lower wholesale electricity. Conversely, it could also divert investment away from renewables in the longer term. A new wave of investments in CCGT is under way in some markets, which will help to compensate for the retirement of older coal-fired power plants.
- Finally, lower electricity costs can support economic recovery by contributing to reducing the cost base of the manufacturing sector compared to other competing economies.

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As gas is envisaged to play a key role, the need for greater co-ordination between gas and electricity infrastructure and their operation is becoming essential. For example, ISO New England and NERC have expressed concerns that the natural gas transmission system may not deliver enough gas during times of high demand to serve both residential gas heating and electricity generation. There is a need to improve consistency between the gas pipeline system and the high- and extra-high voltage power transmission system. While both systems are regulated by FERC, the two systems' different historical regulatory and business models have now resulted in a need to better co-ordinate operations, as well as market and planning rules, in order to address increasing interdependence of the two systems.

The federal government has an important role to play both in setting standards and in providing an effective avenue for communication between regions. FERC has demonstrated that this is a key concern by issuing a rule allowing for the sharing of non-public information between natural gas and electricity transmission operators with the explicit purpose of promoting system reliability (FERC Order 787). The problem of poorly aligned scheduling and dispatch is a key one, however, and it needs to be addressed to a greater degree. To some extent, regional markets have attempted to address this issue. However, these efforts have not been co-ordinated. Regional efforts run the risk of creating incompatible market rules, which could hinder, for example, the integration of renewable resources over long distances (e.g. Midwest wind connected to coastal load centres). The federal government can help by creating a core set of flexible standards to improve co-ordination and communication between the natural gas and electricity markets.

The power system seems to have adapted smoothly and robustly to major changes in the past five years: the shift from coal to gas and the rapid development of renewables. The shift to gas was mostly absorbed by existing infrastructure, as gas-fired power plants were already in place. Future evolution may however be more dramatic, as new gas-fired power plants come on line and variable renewables achieve higher levels of market penetration. An important concern is the level of co-ordination between gas infrastructures, that are already tight in some places, and electric infrastructures: will the power plants be built close to the wells or close to the load? A further concern relates to the design of market rules and contracting methods to ensure natural gas pipelines can raise the necessary finance.

Environmental policies and regulations also introduce greater uncertainty over the pace of retirement of ageing coal and nuclear generating capacity. The failure to introduce a carbon-pricing scheme has led the government to consider several other options to reduce GHG emissions from the power sector and this uncertainty has had an impact on the functioning of some electricity markets.

INTEGRATION OF RENEWABLES

With regard to the integration of wind and solar power, the best renewable energy resources are often located far from load centres, and their variability introduces new challenges to balancing the electricity system. The deployment of variable renewables such as wind and solar power tends to be concentrated in certain areas such as California, Texas and the Midwest. Continued deployment of renewables will take place all around the country and managing variability will require access to the balancing and flexibility resources available over wider geographic areas.

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DESIGNING CAPACITY MARKETS

While all RTOs have adopted locational marginal pricing, there remains a considerable degree of diversity in the design of capacity markets. Most of these capacity mechanisms are gradually being improved. Capacity located in the footprint of one RTO can clear in the capacity market of an adjacent RTO, but the lack of harmonisation between RTOs is a concern. To the extent that these capacity markets are justified by federal regulation (there is a cap on electricity bids in these markets), the FERC should seek to achieve greater harmonisation and co-ordination of capacity markets. In the case of ERCOT, however, it could be argued that average wholesale prices are generally very low and high prices for a few hours a year do not induce new investment.

Reserve margins in some markets may become tight over the medium term. While most of the control areas currently enjoy a comfortable level of reserve margins, demand could grow faster than expected, depending on economic growth and the results of energy efficiency programmes, and a lot of ageing capacity will be retired. New wind and gas capacity will also be added. A concern has been expressed that capacity markets may not provide the right incentives to ensure the right location of new investments and timely investments in markets operated by RTOs. There is a concern that competitive electricity markets may not trigger investments in large, high fixed-cost projects with long lead time such as nuclear, carbon capture and storage (CCS) and large renewable portfolio projects. There are other reasons that impede the development of such technologies in all markets, including the existence of excess capacity, low gas prices, the absence of a carbon price and the high upfront costs of Generation III nuclear reactors. Ultimately, this could result in a lack of diversity in the generation portfolio, exposing consumers to the risk of high gas prices in coming years.

Nuclear power illustrates the inefficiencies that can result from inconsistent regulatory and market arrangements across the country. On the one hand, five reactors are under construction, all of them in states with regulated electricity markets. Conversely, two reactors are being closed in competitive wholesale markets. The inefficiency comes from the fact that the closure of the two reactors is for economic reasons and not for any safety or technical reasons related to continued operation. According to some utilities, the market price of electricity is too low to justify the investments needed to extend their lifetime beyond 40 years, despite the fact that life extension is certainly a much cheaper source of low-carbon electricity than building new reactors.

Once again, a comprehensive national framework for nuclear power could be needed, should this technology remain part of the electricity mix. Such a framework should recognise the more challenging economics of nuclear generation in competitive market arrangements, as for other low-carbon and high capital cost technologies (see Chapter 4 on Nuclear Energy).

REGIONAL INTEGRATION OF ELECTRICITY MARKETS

Electricity systems are covering very large interconnections over which it is physically relevant to assess generation adequacy. Electricity flows and trade involve interstate transactions and could in principle fall under the jurisdiction of FERC. Despite the existence of NERC, however, the regulatory and market arrangements regarding resource adequacy remain extremely fragmented in the United States. These institutional barriers create co-ordination problems that prevent to reach the least-cost outcome. One option to resolve this problem is to promote and encourage consolidation of balancing areas by

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mobilising the authorities in charge of controlling the supply and demand balance over these areas. PJM and MISO have been successful in expanding their footprints and implemented locational marginal pricing over large areas and in reducing dispatching costs and generation investment requirements.

The federal government should continue its efforts to work with regions and states to create a better and consistent national regulatory framework to ensure resource adequacy over wider geographic areas and make the most of existing infrastructure. The last ten years have been an extraordinary period to experiment new market design arrangements. The understanding of how to design electricity markets considerably improved. Nonetheless, while most regions have adopted market arrangements with a locational marginal pricing framework, no capacity model seems to have emerged as a dominant solution.

NETWORK INFRASTRUCTURE

The power system in the United States is largely decentralised and the organisations dealing with electricity networks are very diverse. Transmission lines may be built and operated by federal organisations, sub-state organisations such as municipal utilities and co-ops or privately owned enterprises. The market and regulatory environments are also extremely diverse: some areas are served by vertically integrated utilities while others have regional transmission operators in open markets. The siting and permitting of intrastate transmission lines and generation facilities fall under state regulatory jurisdiction, but when transfers of power across states lines occur, FERC has oversight of transmission system planning and wholesale power transactions.

The stakeholders in this complex environment have developed forums, such as the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Officials (NASEO), the Edison Electric Institute (EEI) and the transmission industry (WIRES), to discuss and resolve their common network issues. At federal level, DOE and FERC have specific powers: DOE is the designated lead federal agency responsible for the co-ordination of transmission permitting when a project requires multiple federal authorisations and when a transmission project is to cross an international border.

FERC handles permitting of projects which fall into national interest electricity transmission corridors (NIETC) that DOE designates in the national interest based on a national congestion study and other factors. Relevant agencies are required to designate federal energy corridors on federal land under authority granted to them in Section 368 of the Energy Policy Act of 2005, and to perform environmental reviews in order to simplify a possible future permitting process.

Cost allocation and financing of transmission lines is system-dependent. FERC Order 1000 will be helpful in bringing together potentially different cost allocation rules on interstate projects, but its implementation needs to be carefully considered. Higher returns on equity (ROE) for transmission projects regulated by FERC reflect intrinsic risks related to permitting. In some areas, transmission projects can be awarded competitively, whereas in others they are conducted by the incumbent utility.

RELIABILITY

The North American Electric Reliability Corporation (NERC) develops and enforces reliability standards, under FERC oversight. NERC prepares long-term reliability assessments, season-ahead assessments twice a year, as well as strategic evaluation of reliability implications of scenarios. Section 215 of the Federal Power Act requires NERC to develop mandatory

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and enforceable reliability standards, which are subject to review and approval. NERC-approved reliability standards become mandatory and enforceable in the United States on a date established in the Orders approving the standards.

NERC works with registered entities, which are subject to reliability standards, as well as federal and state agencies in the United States (and provincial authorities in Canada) to address mandated reliability requirements. Application and consistency, however, differ from region to region. Not all regions and planners use the same definitions for measures such as loss of load expectation (LOLE) and loss of load probability (LOLP). For example, some refer to LOLP as the probability of having one or more hours of loss of load in any year while others refer to LOLE as an hourly metric. Recent changes to generation mixes such as higher penetrations of wind, solar, and demand response resources have contributed to even greater disparity between regions.

SMART GRIDS AND RESILIENCE

Smart grids have developed significantly over the past five years. Approximately 33 million households are equipped with advanced meters, and the number of measurement points on the transmission and distribution networks has increased by several orders of magnitude. Funding for research and development from both the public and private sectors of the technology has been strong although declining in the latter. Several pilot experiments have been conducted throughout the country. Demand response has grown in regions where market models have allowed it (PJM, MISO). In the wake of recent severe weather-related outages, all players have integrated resilience into their goals for smart grid development. Forensics analyses of outages are already possible. Despite the advantages offered by investment in smart grids – for example demand response, integration of renewables and resilience – market take-up has been slow. Market frameworks and regulations should encourage private-sector investment in these advanced technologies and practices.

System resilience is another concern, especially in the aftermath of Hurricane Sandy and other recent weather-related reliability events. The response to Hurricane Sandy by the federal government, led by DOE and the Federal Emergency Management Agency (FEMA), is considered a model for future federal-state-local disaster relief and co-ordination of service restoration. Lessons learned that will be carried forward in future emergency response planning include the need for refined product reserves, streamlining of permits for transport of heavy equipment, and prioritisation of critical loads. Events also highlighted the value of distributed generation to grid resilience, as several areas were able to keep the power on thanks to combined heat and power facilities or onsite renewable generation. Additional efforts are being planned to codify the design changes needed during reconstruction to increase future resilience (e.g. siting transformers well above grade and emergency generators on upper floors of structures).

Cybersecurity has become a serious concern in the context of power system operations. The devolved nature of the electricity system, with thousands of small and large generators and grid operators, has created potential vulnerabilities to various types of attack. Although cybersecurity may not be a priority issue for all investor-owned utilities, grid reliability is firmly within the federal realm of interest. DOE's Office of Electricity Delivery and Energy Reliability, in conjunction with NERC, FERC, the National Institute for Standards and Technology (NIST), alongside Congress and other institutional partners, has launched a major effort to identify and address cybersecurity concerns. This effort is systematically examining the cybersecurity maturity levels of the advanced grid control

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and communications technologies being installed across the grid, as well as the human factor issues which contribute to cybersecurity vulnerabilities.

For example, one of the biggest risk factors is chain-of-custody for the software for connected devices placed onto the grid. One of the outcomes of this effort will be minimal operational standards for regulated utilities to be developed jointly with FERC's Office of Energy infrastructure security, NARUC, and the standards community. These preventive and awareness-building activities should continue, along with increased research by national labs such as the Pacific Northwest Laboratory into cybersecurity vulnerabilities and defensive strategies. Initiatives such as the Cybersecurity Risk Information Sharing Project (CRISP), which allows pooling of confidential data on vulnerabilities and defensive measures is a good example of what can be done.

DEMAND RESPONSE

Development of demand response in the United States is a relatively new phenomenon. The Recovery Act of 2009 provided resources for the deployment of smart infrastructure and smart technologies to increase the potential of economical and efficient demand response. Recent developments regarding demand response are encouraging and the deployment of smart grids, smart meters and smart devices should further drive down costs of demand response.

The United States experience in terms of demand response suggests that creating a level playing field for demand response remains a difficult task for market design. The lack of demand response has long been recognised as a unique characteristic of the power industry. The straightforward solution, at least in principle, is to expose customers to peak wholesale electricity prices that reflect tight system conditions. Other measures can also be effective to promote demand response, in particular on capacity markets, and should ensure that the demand response develops when this is more efficient than adding new generating capacity.

Demand response also includes the development of time-of-use prices of electricity retail prices. This includes real-time pricing of electricity and critical peak pricing. These forms of demand response remain underdeveloped in the United States. It is worth mentioning, however, that retail rates are under the jurisdiction of the state public utility regulators rather than the federal mandate.

Greater co-ordination between federal and state policies can benefit all stakeholders and create a larger market for demand response technologies. In particular, state retail demand response programmes and policies can be better co-ordinated with organised wholesale market programmes.

RETAIL MARKETS AND COMPETITION

Retail choice programmes do not exist in all states but could bring benefits to consumers. The recent deployment of smart meters and demand response capability creates a more favourable competitive environment for innovative commercial offers and services. Where retail programmes exist, the market share of new entrants remains limited. Although the states have to decide whether or not to engage in customer choice programmes, lessons can be learned from the identification of best practices, including promoting transparency particularly around pricing and energy usage and the quantification of benefits of existing mechanisms. Retail choice programmes can benefit from increased visibility and understanding of pricing information to allow customers to make informed choices

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about their energy usage and supply options. Grid modernisation efforts can help to provide more information to customers.

Although the IEA recognises the need to articulate national and state electricity policies, maintaining an affordable electricity supply in the face of these new challenges call for greater federal co-ordination in terms of regulation of the electricity system. The introduction of competition in electricity markets remains a work-in-progress in many parts of the United States. The monitoring of anti-competitive practices shows recent significant progress. Still, market power remains an important issue in wholesale electricity markets, as suggested by the reliance on many market power mitigation instruments and recent penalties. Further increasing the transparency of markets, not only of prices but also of individual bids, and carefully designing price formation during scarcity circumstances could create the conditions for more efficient prices.

RECOMMENDATIONS

The government of the United States should:

- ☐ *Strengthen the interregional integration of electricity systems by:*
  - *Developing a regulatory mechanism to facilitate better co-ordination and communication between natural gas and electricity system operators, as well as market and planning rules, in order to address increasing interdependence of the two systems.*
  - *Ensuring that projects of federal interest are identified, planned and permitted in time to respond to possible needs emerging from the rapid shift to gas and the increase in renewables.*
  - *Where and if possible, supporting the creation of system operators over wider geographic areas and the consolidation of balancing areas. This will require proactive federal co-ordination of interchange optimisation effort.*
  - *Ensuring greater co-ordination and harmonisation of capacity markets to correct incentives to deliver new and timely investment at the most appropriate locations in markets operated by regional transmission organisations.*
  - *Ensuring that electricity markets can remunerate capacity during tight system conditions by, for example, adapting the design of existing wholesale electricity markets in order to deliver adequate generating capacity in a timely and efficient manner.*
  - *Encouraging harmonisation of the methodologies and technical definitions used for the regulation of reliability.*
- ☐ *Continue to support cybersecurity preventive and awareness-building activities, supported by increased national research into cybersecurity vulnerabilities and defensive strategies.*
- ☐ *Promote the development of demand response mechanisms to ensure that the response develops in the first instance rather than adding new generation or network capacity.*
- ☐ *Take steps to increase the transparency of electricity markets, not only price transparency but also individual bids, and ensure that price formation mechanisms during scarcity circumstances create the conditions for more efficient prices.*
- ☐ *Work with states regulators to promote the development of retail choice programmes, with transparent price visibility and energy usage information in order to empower*

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customer choice and take advantage of the deployment of advanced metering. This will allow customers to make informed choices about their energy usage and supply options.

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4. NUCLEAR ENERGY

Key data (2013)

Number of reactors in operation: 100

Installed capacity: 98 GW

Electricity generation: 822 TWh, +4.3% since 2003

Share of nuclear: 9.8% of TPES and 19.2% of electricity generation

OVERVIEW

The United States was a pioneer of nuclear power development. Westinghouse designed the first fully commercial pressurised water reactor (PWR) of 250 megawatts electrical capacity (MW_e), Yankee Rowe, which started up in 1960 and remained in operation until 1992. Meanwhile, the boiling water reactor (BWR) was developed by the Argonne National Laboratory, and the first commercial plant, Dresden 1 (250 MW_e), designed by General Electric, commenced power production in 1960. By the end of the 1960s, orders were being placed for PWR and BWR reactor units of more than 1 000 MW_e capacity, and a major construction programme began. These two models remain the only types in commercial operation in the United States. It is worth noting, however, there have been examples of non-light water reactor (LWR) that were built and operated commercially.[1]

The use of nuclear-generated electricity has grown substantially since then. Nuclear power as a percentage of total US electricity generation increased quickly from nearly 5% in 1973 to 9% in 1975 and then to the current level of about 19%, which is 8% of all energy consumed in the United States. Nuclear developments suffered a major setback after the 1979 Three Mile Island (TMI) accident and licensing actions were suspended until completion of the TMI Action Plan in 1982. The incident, a partial melt down and the most serious accident in US commercial nuclear power plant operating history, combined with economic pressures of high interest rates and low demand forecasts, which had already begun to force utilities to cancel projects, caused further pressures on the viability of new nuclear projects.

PRODUCTION

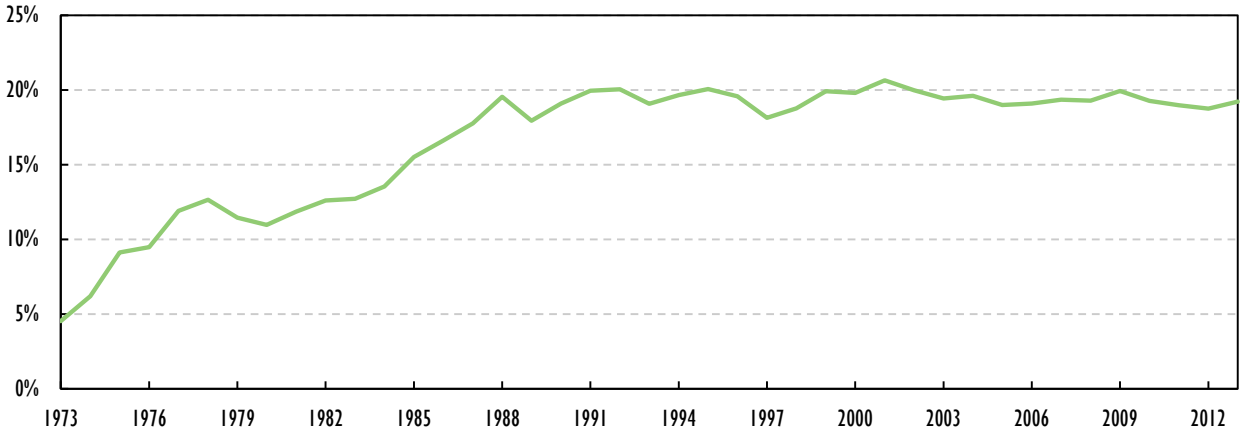
The US nuclear power industry is now the largest in the world. In 2013, the United States generated over 822 gigawatt-hours (GWh) of nuclear electricity from 100 reactors at 62 nuclear power plants (NPPs) located in 30 states and operated by 31 different power companies. Following the decisions to close Crystal River, Kewaunee and two reactors at San Onofre, 65 of these 100 reactors are PWRs with combined capacity of about 66 GW_e and 35 are BWRs, with combined capacity of about 32 GW_e, for a total nuclear capacity of 99 GW.

1. Peach Bottom Unit 1 and Fort St. Vrain were examples of high-temperature gas-cooled reactors that were operated commercially. Fermi Unit 1 was a sodium-cooled fast reactor that was taken out of service in 1972.

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Nuclear energy supply in the United States was 214.2 million tonnes of oil-equivalent (Mtoe) in 2013, accounting for 9.8% of TPES. Nuclear energy is used in electricity generation, with an output of 822 terawatt-hours (TWh) in 2013 (19.8% of the total). Since 2003, electricity generation from nuclear has increased by 4.3% while total electricity generation has increased at a slightly faster rate, up by 5.4% over the same period. Consequently, the share of nuclear has increased marginally from 19.4% in 2003. Of the 16 IEA member countries with nuclear energy in the electricity generation mix, the United States ranks 11th in terms of the nuclear share in the energy mix.

Figure 4.1 Share of nuclear power in electricity generation, 1973-2013



Note: data are estimated for 2013.

Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

In February 2013, Duke Energy's 860 MW_e Crystal River PWR in Florida was retired as a result of damage to the containment structure sustained when new steam generators were fitted in 2009-10, under its previous owner Progress Energy. Its 40-year operating licence was due to expire in 2016 and its application for a 20-year renewal had not been granted when the decision to close was taken. Some USD 835 million in insurance compensation was claimed. Dominion Energy's 566 MW_e Kewaunee PWR in Wisconsin was shut down for economic reasons in May 2013 after 39 years operation even though it had received a licence renewal to operate for 60 years. In June 2013, Edison International, the parent company of San Onofre and owner of Southern California Edison, announced that both reactors at the San Onofre NPP in California will be retired in response to the lengthy and uncertain regulation surrounding their return to service. In August 2013, Entergy announced that Vermont Yankee would be retired in 2014. The Oyster Creek reactor is scheduled for permanent shutdown in 2019.

The oldest plants in the United States are 42 years old, and the average age of the fleet is 31 years old. Before the implementation of lifetime extension programmes started (in 1998), 12 plants in the United States had been closed since 1987, most of them for economic reasons:

- La Crosse (1987)
- Shoreham (1989)[2]
- Rancho Seco (1989)
- Fort St. Vrain (1989)

2. The Shoreham NPP was closed before it went into commercial operation.

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- Yankee Rowe (1991)
- Trojan (1992)
- San Onofre 1 (1992)
- Millstone Unit 1 (1995)
- Connecticut Yankee (1996)
- Maine Yankee (1996)
- Big Rock Point (1997)
- Zion Units 1 and 2 (1998).

Overall, the United States is not as reliant on nuclear power as a share of total electricity generation as some other OECD member countries. France, the OECD's second-largest producer, generates about half that amount, but this provides nearly 80% of its electricity.

INSTITUTIONAL OVERSIGHT AND REGULATION

THE NUCLEAR REGULATORY COMMISSION (NRC)

The NRC is responsible for regulation of the nuclear industry, notably reactors, fuel cycle facilities, materials and wastes (as well as other civil uses of nuclear materials) and adjudicates legal matters. The NRC was established as an independent federal regulatory agency in 1974. Prior to this, nuclear regulation was performed by the Atomic Energy Commission, which also promoted nuclear technology development. The NRC is headed by five Commissioners appointed by the President and confirmed by the Senate for five-year terms.

The NRC licenses NPPs for a term of 40 years. Licences may be renewed for periods of up to 20 years with no limit on the number of renewals. The first licence renewal application was approved in March 2000. Seventy-three reactors have already received renewals and it is anticipated that almost all of the remaining operating reactors will seek a renewal. The subject of additional licence extensions beyond the initial 20 years remains an open issue that will be addressed during the coming years. It is anticipated that some reactor operators will seek additional licence extensions, but it is not certain how many will do so. The earliest year for which extensions could be needed is 2029.

Nearly 50 years of operational experience and steadily improving licensee performance have changed the way that the US regulates nuclear power to a more risk-informed and performance-based approach. To encourage a sustained level of high-safety performance in nuclear plants, important oversight processes have incorporated risk insights from quantitative risk analysis. Efforts also continue to revise regulations to focus requirements on plant programmes and activities that are most risk-significant.

Since March 2011, the NRC has been working to understand the events surrounding the Fukushima Daiichi nuclear accident in Japan and relaying important information for US nuclear power plants. In particular, the NRC established a task force made up of senior agency experts to determine lessons learned from the accident and to initiate a review of NRC regulations to determine whether additional measures needed to be taken to ensure the safety of US plants. The task force issued its report on 12 July 2011, which concluded that there was no imminent risk from continued operation and licensing activities. The task force also concluded that enhancements to safety and emergency preparedness were warranted and made a dozen recommendations for NRC consideration.

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The NRC subsequently prioritised, and expanded upon, the task force recommendations and continues to make additions and modifications, as appropriate. The task force recommendations were prioritised into three tiers.

The first tier consists of those actions that the staff determined should be started without unnecessary delay and for which there is sufficient resource flexibility, including availability of critical skill sets:

- seismic and flood hazard re-evaluations
- seismic and flood visual inspections
- station blackout regulatory actions
- mitigating strategies for beyond-design events
- reliable hardened vents for Mark I and Mark II containments
- spent fuel pool instrumentation
- strengthening and integrating emergency operating procedures, severe accident management guidelines, and extensive damage mitigation guidelines
- emergency preparedness regulatory actions (staffing and communications).

The second tier consists of those actions which could not be initiated in the near term because of factors such as the need for further technical assessment and alignment, dependence on Tier 1 issues, or availability of critical skill sets. These actions do not require long-term study and can be initiated when sufficient technical information and applicable resources become available.

- spent fuel pool make-up capability
- emergency preparedness regulatory actions
- other external hazards re-evaluation (tornadoes, hurricanes, drought, etc.).

The third tier consists of those actions that require further staff study to support a regulatory action, have an associated shorter-term action that needs to be completed to inform the longer-term action, are dependent on the availability of critical skill sets, or are dependent on resolving other issues. NRC has focused its initial efforts on developing the schedules, milestones and resources associated with Tier One and Tier Two activities. Once they have completed their evaluation of the resource impacts of Tier One and Two recommendations, they will be able to more accurately address Tier Three recommendations.

- ten-year confirmation of seismic and flooding hazards
- potential enhancements to the capability to prevent or mitigate seismically induced fires and floods
- reliable hardened vents for other containment designs
- hydrogen control and mitigation inside containment or in other buildings
- emergency preparedness enhancements for prolonged station blackout and multi-unit events
- emergency response data system capability
- additional emergency preparedness topics for prolonged station blackout and multi-unit events

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- emergency preparedness topics for decision making, radiation monitoring, and public education
- reactor oversight process modifications to reflect the recommended defence-in-depth framework
- staff training on severe accidents and resident inspector training on severe accident management guidelines
- basis of emergency planning zone size
- pre-staging of potassium iodide beyond ten miles
- transfer of spent fuel to dry cask storage.

On 12 March 2012, in compliance with the prioritised task force recommendations, the NRC issued the first regulatory requirements for the 100 operating US reactors, based on the lessons learned at Fukushima Daiichi. The NRC continues to evaluate and act on the lessons learned to ensure that appropriate safety enhancements are implemented. In accordance with Commission direction, the NRC's activities are being led by a steering committee comprised of senior NRC management. Furthermore, the NRC established the Japan Lessons Learned Project Directorate, a group of more than 20 full-time employees focused exclusively on implementing the lessons learned.

The Energy Policy Act of 1992 (EPACT1992) specified a new nuclear power plant licensing process. Under the new procedure, an applicant who seeks to build a new reactor can use standardised reactor designs that have been previously approved and certified by the NRC. After reviewing the application and holding public hearings, the NRC may issue a combined construction and operating licence (the previous process separated these licences, which were issued at different times). When the applicant uses an NRC-certified design, safety issues related to the design will have been resolved previously, and the main concern will be the quality of reactor construction.

Before authorising power operation at a reactor, the NRC performs comprehensive testing and acceptance procedures. The new licensing process is codified in part 52 of Title 10, Code of Federal Regulations and has been utilised for the past few years after certification of the new designs is completed. Westinghouse received a design certification for the AP1000 in December 2011. In 2012 the first combined construction and operating licences were issued for Vogtle 3 and 4 in Georgia and VC Summer 2 and 3 in South Carolina. The new licence procedure results in a more predictable process and less financial risk to the applicant.

DEPARTMENT OF ENERGY

The mission of the DOE Office of Nuclear Energy (NE) is to advance nuclear power as a resource capable of meeting the country's energy, environmental, and national security needs by resolving technical, cost, safety, proliferation resistance and security barriers through research, development, and demonstration as appropriate. The DOE-NE work programme is guided by the four research objectives detailed in its Nuclear Energy Research and Development Roadmap:

1. Develop technologies and other solutions that can improve the reliability, sustain the safety, and extend the life of current reactors.
2. Develop improvements in the affordability of new reactors to enable nuclear energy to help meet the Administration's energy security and climate change goals.

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3. Develop sustainable fuel cycles.
4. Understand and minimise the risks of nuclear proliferation and terrorism.

DOE-NE serves present and future energy needs by developing critical technologies for the future and helping to train tomorrow's workforce. The benefits of nuclear power as a safe, carbon-free, reliable and secure source of energy make it an essential element in the United States' energy and environmental future.

PLANT UPGRADING, PLANT LIFE MANAGEMENT AND LICENCE RENEWALS

The need for additional power in the United States, along with improved economic and safety performance, has resulted in most licensees seeking to extend their operating licences for an additional 20 years beyond their initial 40-year limits. Seventy-three reactors have had their operating licences extended. Licensees have also implemented power uprates throughout their history as a means to increase the output of their reactors. Power uprates are classified by the NRC in three groups:

1. Measurement uncertainty recapture uprates of less than 2% implement enhanced techniques for calculating reactor power.
2. Stretch power uprates are typically less than 7% and do not usually involve major plant modification.
3. Extended power uprates, larger than stretch power uprates, require significant modification to major balance-of-plant equipment. Extended uprates have been approved for increases of as much as 20%, though these may take place over several stages of plant modification.

As of 3 June 2013, the NRC had approved 148 power uprates adding about 6 862 MW_e to the generating capacity or the equivalent to more than six average-sized nuclear power plants (NRC, 2013).

COSTS OF NUCLEAR POWER

In Figure 4.2 and Figure 4.3, taken from NEA (2012), the estimates of levelised cost of electricity (LCOE) for existing NPPs in the United States with lifetime extension costs factored in, are compared to LCOE with alternative sources: gas, coal and new nuclear (NEA, 2012). The overnight capital costs, and operation and maintenance (O&M) costs were taken from (IEA/NEA, 2010), except for new build where increased overnight costs were used, based on more recent experiences. For a new NPP, an overnight investment of USD 4 500/kW_e was assumed. The price of coal is assumed to be USD 50 per metric tonne. Three cases of natural gas prices were considered: low costs (USD 2.0 per million British thermal units) average case (USD 5.0/MBtu) and high case scenario (USD 7.0/MBtu).[3]

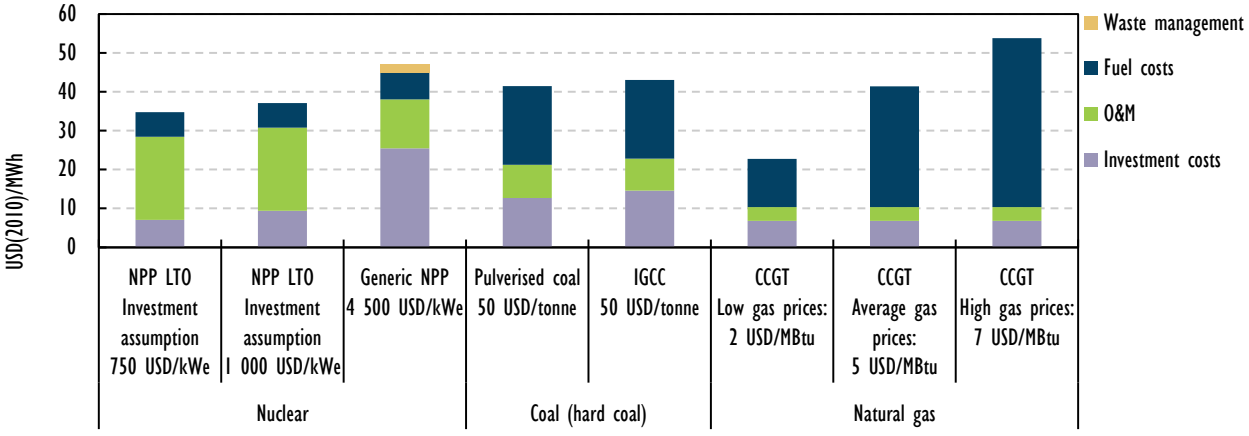
The extended operation of existing NPPs has the lowest levelised costs of electricity generation, even at 8% discount rates, unless gas prices were to remain low. This means that, in the current low gas price regime, some utilities will have some reticence about major investment, even for lifetime extension.

3. The IEA assumptions (Current Policies Scenario) for the natural gas import price in the United States in the *World Energy Outlook 2011* (IEA, 2011) is USD 6.1/MBtu in 2015, USD 7.0/MBtu in 2020, USD 7.7/MBtu in 2025 and USD 8.4/MBtu in 2030. All values are expressed in 2010 United States dollars (USD).

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With some exceptions, however, life extension remains a preferred route for many utilities, but this will eventually lead to a decline in NPPs, which will accelerate after 30 years (based on an average of 31 years for NPPs) unless there is significant new build. To delay this further, research is ongoing to consider whether some of these reactors can continue to 80 years, but this is not yet demonstrated and may prove to be challenging.

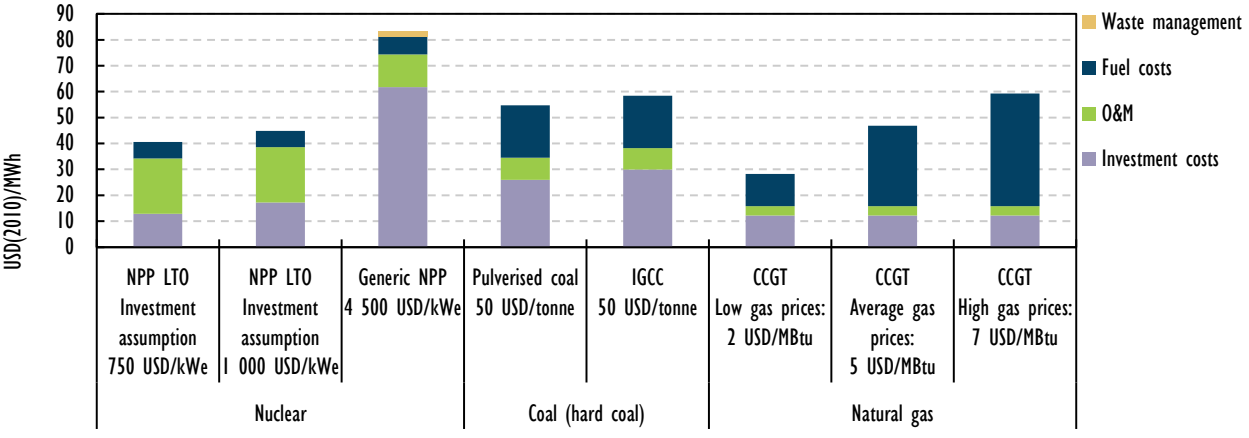
Figure 4.2 Projected costs of electricity generation with alternative sources in the United States, at 3% real discount rate



Notes: O&M = operation and maintenance; CCGT = Combined-cycle gas turbine; IGCC = Integrated gasification combined-cycle.

Source: this is an update of the LCOE calculation for the US, OECD/NEA (Nuclear Energy Agency) (2010), *Projected Costs of Generating Electricity*, 2010 edition, OECD Publishing, Paris.

Figure 4.3 Projected costs of electricity generation with alternative sources in the United States, at 8% real discount rate



Source: This is an update of the LCOE calculation for the US originally published in OECD/NEA (2010), *Projected Costs of Generating Electricity*, 2010 edition, OECD Publishing, Paris.

For a new nuclear power plant, it would only be economically justified if gas prices were high, if a carbon price was introduced for carbon-emitting sources or an incentive mechanism was available to encourage investment. In Figures 4.2 and 4.3, the capital cost is the largest element in the LCOE, and it could be even higher if the first-of-a-kind (FOAK) estimates from European plants of USD 6 000/kW_e were used. In contrast, however, if capital costs typical of the recent Korean and Chinese constructions were used, the

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competitiveness of nuclear improves significantly. This emphasises the challenges to the industry to learn lessons from new build that could lead to lower costs and better budget adherence in the future.

NUCLEAR POWER DEVELOPMENT STRATEGY

The future of nuclear power in the United States will depend on several factors including reduction of nuclear construction costs, greater regulatory certainty, development of favourable government policies, and the relative costs of other energy options as well as resolution of nuclear waste disposal issues. During 2013, the greatest commercial challenges to the continued operation of the nuclear power industry have included:

- the low price and relatively high availability of natural gas from shale deposits
- slow economic growth and weak national economy
- slow growth in overall electricity demand.

Nuclear energy remains an important element of the present government's "All-of-the-Above" strategy for energy – helping to advance a sustainable, clean energy future. Accordingly, the DOE-NE is pursuing five strategic goals:

1. Extend the useful life, improve the performance, and maintain the safety of the current fleet of NPPs. This is the objective of the Light Water Reactor Sustainability Program.
2. Enable new NPPs to be built for electricity production and improve the affordability of nuclear energy. The Nuclear Plant 2010 (NP2010) Program is a joint government/ industry cost-shared effort to identify sites for new NPPs, develop and bring to market advanced nuclear plant technologies, evaluate the business case for building new NPPs and demonstrate untested regulatory processes. Two project areas are active: GE Hitachi Nuclear Energy detailed design work, and Nustart construction and operating licences application development.
3. Reduce the carbon footprint of transportation and industry. The heat generated by nuclear energy can be harnessed for process heat, thus reducing or eliminating the need to burn fossil fuels for this purpose. Developing this capability is one objective of the Next Generation Nuclear Plant (NGNP) initiative.
4. Develop a sustainable fuel cycle. The Fuel Cycle Research and Development Program is developing ways to make used fuel less radiotoxic, recycle it, and create widely acceptable solutions to the challenges of nuclear waste.
5. Prevent proliferation. Developing techniques and materials to prevent proliferation are objectives of the Fuel Cycle Research and Development Program.

SMALL MODULAR REACTORS

The United States has shown particular interest in the development of small modular reactors (SMRs). The development of clean, affordable nuclear power options is a key element of the DOE-NE Nuclear Energy Research and Development Roadmap. The DOE-NE has placed a high priority on helping accelerate the timelines for the commercialisation and deployment of small modular reactor technologies through the SMR Licensing Technical Support programme.

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The mission of the SMR Licensing Technical Support programme is to promote the accelerated deployment of SMRs by supporting certification and licensing requirements for US-based SMR projects through co-operative agreements with industry partners, and by supporting the resolution of generic SMR issues. DOE anticipates continuing efforts towards a six-year USD 452 million programme.

In April 2013, the Department of Energy and mPower (Babcock & Wilcox, Tennessee Valley Authority, and Bechtel) agreed to work together in licensing and developing activities related to the possible construction of small reactors at Tennessee Valley Authority's Clinch River site by 2022. In December 2013, DOE chose NuScale as a second development partner with a deployment objective of 2025. It is anticipated that, if successful, SMR development could reshape the demand for and development of nuclear power in the United States.

FUEL CYCLE

The nuclear industry includes most phases of the fuel cycle, from uranium exploration and mining to nuclear waste disposal, but does not include reprocessing. Many services and supplies to the nuclear power industry are imported.

Spent fuel reprocessing for waste management in the United States has been discouraged by public policy, and the once-through fuel cycle is the present policy along with an active research and development (R&D) programme on advanced fuel cycle alternatives. Each fuel cycle stage is subject to competition and supply from international sources which in many cases dominate the industry segment. At present the domestic nuclear fuel supply is highly dependent on imports for mined uranium concentrates, uranium conversion and enrichment, and almost all fuel fabrication requirements are met by domestic sources.

URANIUM RESERVES, PRODUCTION AND CONVERSION

In 2012, according to data published by the United States Energy Information Administration (EIA), production of indigenous uranium from mining was over 4.3 million pounds (1 667 tonnes uranium [tU]) uranium oxide equivalent (U_3O_8), 5% more than in 2011. There were six underground mines producing uranium ore during 2012, one more than during 2011. Uranium ore from underground mines is stockpiled and shipped to a mill, to be milled into uranium concentrate (a yellow or brown powder). Additionally, in 2012 five in-situ-leach (ISL) mining operations produced solutions containing uranium; these solutions were processed into uranium concentrate at ISL plants. Overall, there were 11 mines that operated during part or all of 2012 (EIA, 2013).

Total production of uranium concentrate in 2012 was over 4.1 million pounds U_3O_8 (1 595 tU), 4% more than in 2011, from six facilities: one mill in Utah (White Mesa Mill) and five ISL plants. The states of Nebraska, Texas and Wyoming produced uranium concentrate at the five ISL plants in 2012.

As of the end of 2012, one uranium mill, the White Mesa mill in Utah, was operating at a capacity of 2 000 short tonnes of ore per day (1 815 metric tonnes). Two other mills, located in Utah and Wyoming, were on stand-by with a total capacity of 3 750 short tonnes of ore per day (3 400 tonnes) while one mill is planned for Colorado.

The EIA estimates that domestic uranium reserves were 52 million pounds U_3O_8 (approximately 20 000 tU) at a maximum forward cost of up to USD 30 per pound

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(USD 80 per kilogrammes of uranium [kgU]). At up to USD 100 per pound (USD 130 per kgU), estimated reserves were 304 million pounds U_3O_8 (117 000 tU). At the end of 2012, estimated uranium reserves for mines in production were 21 million pounds U_3O_8 (8 075 tU) at a maximum forward cost of up to USD 50 per pound.

Annual United States uranium requirements for the period 2010 to 2035 are projected to increase by roughly 25% from 19 138 tU in 2010 to 24 158 tU (high case) in 2020 and to 28 069 tU (high case) in 2035 (NEA/IAEA, 2012). This increase is based on the expected 60-year extended life cycle of existing NPPs as well as the assumption that nearly 80% of existing NPPs will receive a second 20-year licence renewal, thereby extending their operating lives to 80 years, and the anticipated addition of 25 GW by 2035. The high case now looks unlikely to be achieved.

URANIUM ENRICHMENT

The uranium enrichment business in the United States was transferred in 1993 from DOE to a government-owned company; the United States Enrichment Corporation Inc. (USEC). USEC was created in 1992 under the EPACT1992 to make the United States more competitive in the global enrichment industry. USEC was privatised in 1998 via an initial public offering of common stock. USEC operated an enrichment facility (leased from DOE) at Paducah, Kentucky. A second facility at Portsmouth, Ohio has stopped operations.

The Russian Federation and the United States signed a 20-year government-to-government agreement in February 1993 for the conversion of 500 metric tonnes of Russian highly enriched uranium (HEU) from nuclear warheads to low-enriched uranium (LEU) (the Megatons to Megawatts programme). The LEU value at the time was USD 12 billion (USD 8 billion for enrichment and USD 4 billion for natural uranium and conversion components). In 2013, 14 000 metric tonnes of LEU derived from 500 metric tonnes of HEU were delivered to USEC, the executive agent for the HEU Agreement. This volume represents the equivalent of over 20 000 nuclear warheads. USEC was responsible for the purchase of the enrichment component of the HEU-derived low-enriched uranium. Under an Agreement signed in March 1999, the natural uranium and conversion components are purchased by a partnership of three uranium suppliers (Cameco, Cogema and RWE Nukem) known as the Western Consortium. Russia did not renew the arrangement after its expiry at the end of 2013.

In 1994, the federal government declared 174.3 tonnes of HEU as surplus. Of this material, approximately 22 tonnes was to be disposed of as waste, and the remainder was to be down-blended. In October 2005, DOE announced that an additional 200 tonnes of HEU beyond the initially declared 174.3 tonnes of HEU would be permanently removed from further use as fissile material in US nuclear weapons. Of the additional 200 tonnes HEU, 20 tonnes was to be blended down to LEU for use in power or research reactors, and another eight tonnes deemed unsuitable for Naval Reactor use was also to be down-blended. Through 2012, 134 tonnes of HEU have been blended down to produce 1 771 tonnes of LEU fuel for use in power reactors, plus 11 tonnes of high-assay LEU (19.75% U-235) for use in research, space, and isotope production reactors. The remaining HEU will be down-blended over the next ten to 20 years.

Enrichment services have also been imported from facilities in the United Kingdom, France, Germany, the Netherlands and Russia.

In the enrichment sector, URENCO began commercial enrichment operations in June 2010 at its facility, in Lea County, New Mexico. This was the first new operating enrichment plant in the United States since gaseous diffusion plants were built in the 1940s and

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1950s. URENCO plans to reach a capacity of 5.7 million separative work units (SWU) by 2015. Three other firms are considering plans to build enrichment plants in the United States.

AREVA received a licence from the NRC in October 2011 to construct the Eagle Rock enrichment facility, near Idaho Falls, Idaho. As an initial phase, AREVA planned to install 3.0 million SWU of capacity at Eagle Rock but construction of the plant has not yet begun and project has been placed on hold because of short-term uncertainties regarding its overall financing.

USEC received a licence from the NRC in April 2007 to construct and operate a commercial facility, the American Centrifuge Plant (ACP), at Piketon, Ohio. On 13 June 2012, the Department of Energy, USEC and the American Centrifuge Demonstration signed a set of agreements that have enabled a research, development and demonstration project at the ACP. Under the cost-shared co-operative agreement with strengthened management structures, the participants are working to reduce the technical and financial risks of deploying the ACP technology by building out and testing the first cascade and plant support systems at commercial scale. The ACP is currently the only initiative in the United States to establish an advanced domestic enrichment capability based on US-origin technology, which is necessary to support national defence programme needs.

General Electric's Global Laser Enrichment (GLE) received a licence from the NRC in September 2012 to construct and operate an enrichment plant, based on laser separation ("SILEX") technology, at Wilmington, North Carolina. GLE continues to conduct testing and engineering activities but has not yet made a decision on commercial deployment.

FUEL FABRICATION

Three companies (AREVA, Global Nuclear Fuels, and Westinghouse) fabricate uranium fuel for light water reactor fuel. Plants are located in Columbia, South Carolina; Wilmington, North Carolina; Richland, Washington; and Lynchburg, Virginia.

NUCLEAR WASTE MANAGEMENT

Commercial nuclear power reactors currently store most of their spent fuel onsite at the nuclear plant, although a small amount has been shipped to off-site facilities. The 2012 spent fuel inventory in the United States was approximately 70 000 metric tonnes of uranium, with around 2 800 tonnes stored at sites that have shutdown reactors. Approximately one-third of this material is stored in dry casks with the remainder in hardened pools; the share of fuel in dry storage will continue to grow as pools reach their capacities. The NRC licenses dry storage containers for 20 years and has said that fuel can safely be stored at reactor sites for at least one hundred years.

The federal government bears the responsibility for the long-term management of used fuel, including the ultimate disposal of high-level waste. The government entered into contracts that obliged it to manage the fuel in exchange for a fee levied on nuclear power sales that has been set at USD 1.0 per MWh since 1982. The fees that have been collected have been held by the Treasury in a Nuclear Waste Fund that currently has USD 28 billion dedicated for used fuel management. The contracts with utilities also required the government to begin removing fuel from reactor sites in 1998. Delays in establishing a functioning management system meant that the government was unable to meet this deadline and utilities have had to bear the cost of continued storage operations at these sites.

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The Nuclear Waste Policy Act (NWPA) of 1982, as amended in 1987, provides for the siting, construction and operation of a deep geological repository for disposal of spent nuclear fuel (SNF) and high-level waste (HLW). The amendments in 1987 directed DOE to focus solely on Yucca Mountain as the future site of a geological repository. The NWP Act limits the emplacement of waste at the geological repository to 70 000 metric tonnes of heavy metal (MTHM). SNF and HLW disposed of at the repository were expected to include about 63 000 MTHM of commercial spent fuel, about 2 333 MTHM of DOE spent fuel, and the equivalent of about 4 667 MTHM (or MTHM-equivalent) of DOE HLW from defence-related activities.

In 2002, DOE determined that the Yucca Mountain site would be suitable for a repository, and in July 2002, the President of the United States and Congress accepted the recommendation and directed that DOE submit a licence application to the NRC. In June 2008, DOE submitted a licence application to NRC to receive authorisation to begin construction of a repository at Yucca Mountain, and in September 2008, the NRC formally docketed the application.

President Obama announced in March 2009 that the proposed permanent repository at Yucca Mountain "was no longer an option" and a "Blue Ribbon Commission" was created to evaluate alternatives to Yucca Mountain. In the interim, the NRC ceased its review of the Yucca Mountain licence application, and issues related to the decision not to proceed with the Yucca Mountain repository were reviewed by the US Court of Appeals for the District of Columbia Circuit and the DOE was ordered to stop collecting funds from utilities.

The Blue Ribbon Commission on America's Nuclear Future provided a series of recommendations, many of which have been adopted as the backbone of a new management strategy but are yet to obtain Congressional approval. Key features of this approach include a consent-based approach to siting storage facilities, the development of consolidated interim storage capability, and a new government organisation dedicated to executing this mission.

In autumn 2012, a Federal Appeals Court ordered the NRC to perform more thorough evaluations in support of its new Waste Confidence Rule, particularly with respect to the potential impacts of long-term storage of spent fuel at plant sites. While those evaluations are being performed, the NRC has suspended all new plant licensing and plant licence renewals.

ASSESSMENT

The United States has been a leader in nuclear technology since the early days of civilian nuclear power. As such, it has a mature industry with high availabilities and low stable costs, and a mature regulatory environment. Such a source of electricity production provides for diversity in supply and very low carbon emissions across the whole fuel cycle. It has avoided large amounts of GHG emissions. In the recent past, however, the loss of four reactors has led to the first significant decline in nuclear capacity for many years, while many other reactors are moving into extended lifetime operation and only five new reactors are under construction. This will ultimately lead to further fleet reductions. As a result of the advent of shale gas, the United States nuclear industry is at a pivotal point as a consequence of declining economic competitiveness.

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In most countries that use it, the case for nuclear is made on arguments of security of supply, decarbonisation of the electricity sector and affordable electricity. Within the United States, with the growing share of renewables and the availability of cheap gas and coal, security of supply is not a key driver. This situation may change if the penetration of renewables increases significantly, but with its spare capacity and large reserves of gas, the case for nuclear is not as strong as in the past. If concerns were to grow, however, over the strong dependence on shale gas and oil, the lack of diversity from other sources and the relatively small share of renewables, then the lack of investment in nuclear may come to affect security of supply over the next few decades.

With regard to decarbonisation, there are no large-scale carbon-pricing mechanisms in the United States, with the exception of a few regions such as California and the Northeast. During the period since the last in-depth review, a broad bill to cap the level of GHG emissions passed the House of Representatives in 2009. Implementation of this mechanism would have provided a strong market incentive for companies to value non-emitting technologies and invest in nuclear power. This legislation was not passed by the Senate and was therefore not adopted.

An alternative mechanism could be possible using the proposed Clean Power Plan rules. With gas included in this mechanism (but with a half credit), the achievement of 80% emissions reduction would seem to offer a role for increased nuclear and renewables. Actions to achieve this growth would need to be taken in the near future and there is no evidence of significant government actions to change the challenging financing issues, especially in liberalised markets.

In addition to the high capital costs of new nuclear plant construction itself, the economic situation for nuclear power has been severely challenged by competition from shale gas developments as well as weak power prices and slow growth in electricity demand. In addition, nuclear is adversely affected by the treatment of renewable energies and energy efficiency mechanisms.

- With regard to renewable sources of energy, renewable energy standards promote the achievement of certain penetration levels of renewables and these are often supported by the availability of subsidies, as well as grid priority. These cause grid system costs for backup or grid extensions, which are generally not transparent and are paid through taxes or consumer tariffs. As renewable sources increase in penetration, base-load sources, such as nuclear and coal, have their profits affected by the need to reduce power to accommodate these subsidised renewables and this will inevitably lead to their exit from the market as they reach their replacement time, without specific actions. Such a situation is current in European countries but this effect is also beginning to appear in the United States.
- In terms of energy efficiencies, which are a key source of demand reduction, 24 states provide incentives to utilities to reduce demand but these disadvantage high capital-intensive investments such as nuclear that require higher rates of return to cover the riskier investments (since they can limit the rate of return on capital).
- The potential exit of these base-load sources may also affect security of supply, since it reduces diversity, under current understanding of technologies and without major advances in energy storage.

Thus existing mechanisms do not favour investment in high capital-intensive nuclear technology. The impact of these factors on the nuclear business model can even affect decisions on lifetime extension. For example, in June 2013, Exelon announced that it was

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cancelling plans to expand the generating capacities of its Limerick nuclear plant in Pennsylvania and LaSalle nuclear plant in Illinois. The company blamed falling demand for electricity and competition with wind generators as the main reasons for the cancellation. Power market conditions have also seen four uprate projects cancelled and a reactor completion slowed. Overall, approximately 1 587 MW_e of capacity now looks unlikely to be online at the end of the decade.

It is part of DOE's strategy to "enable new nuclear power plants to be built for electricity production and improve the affordability of nuclear energy". Two approaches to encourage new build have been considered.

The first goes back to Title XVII of the Energy Policy Act of 2005, which allows the Secretary of Energy, in conjunction with the Secretary of the Treasury, to provide loan guarantees for qualifying energy projects that use certain innovative technologies, to a limit of 80% of the project cost. To qualify, projects must "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases" and "employ new or significantly improved technologies as compared to technologies in service in the United States at the time the guarantee is issued."

Among the types of projects meeting those criteria are advanced, or third-generation, nuclear reactors. In exchange for a guarantee, DOE is authorised to charge sponsors a fee that covers the guarantee's estimated budgetary cost. In 2008, Congress authorised USD 18.5 billion to cover the cost of guaranteeing loans for the construction of advanced nuclear power facilities and USD 2.0 billion to cover the cost of guaranteeing loans for the construction of facilities for enrichment.

As of April 2011, DOE had received a total of 19 applications for credit assistance from 17 different companies for the construction of 14 NPPs. The requested loan guarantees amounted to USD 188 billion. Of those applications, only one – a USD 8.33 billion guarantee for the addition of two new reactors at Southern Company's Plant Vogtle in Georgia – was finalised in February 2014. A guarantee offer was also extended to Constellation Energy in October 2012 to build a plant in Maryland, but the company declined to take it, citing the high cost of the guarantee fee (NEA, 2011). Observers pointed to lower projections of energy demand in the region as another possible factor. In general, the subsidy provided by a loan guarantee may be insufficient to make a project economically viable.

In addition, Section 1306 of the Energy Policy Act 2005 established a tax credit of USD 1.018 cents per kW_e payable during the first eight years of operation of the nuclear reactor. The production tax credit is limited to the first 6.0 GW_e of generation.

Construction of new reactors at Vogtle and Summer can play a key role in the future of the US nuclear industry. If they succeed within reasonable time and budget, then there are other similar regulated markets where the model could be applied. The market incentives for further new build, however, would need to be continued beyond the 6.0 GW_e and beyond the cut-off date for this incentive to apply to other projects. Elsewhere, where liberalised markets dominate, there would need to be further incentives for investors with some form of longer-term price certainty.

The second response in the United States was a decision from DOE to cost-share the development of small modular reactors (SMRs). To date, two rounds of funding have been announced and two proposals (mPower and NuScale) have received support from the USD 452 million funding pool for SMRs. SMRs are attractive because they would be a much smaller capital investment (maybe around USD 1.0 to 2.0 billion overnight cost) and therefore

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less financing would be at risk. In addition, they offer more flexible options for grid operators and could even have off-grid applications. They can be seen as a way to create high-value technology jobs. Small light water reactors would also more easily obtain regulatory approval as they are closer to existing designs. They are likely to suffer from loss of economy of scale and have yet to be demonstrated on a commercial scale so that no offer is currently available to the market (see NEA, 2011). SMRs also offer the United States an opportunity to take global leadership in the development of a promising technology.

Many challenges remain for SMRs, including building a supply chain, demonstrating cost reductions through modularisation and factory assembly, and constructing enough reactors to prove the concept. At this stage, despite many SMR designs having been promoted around the world, there is no reactor of this type being built, other than the Floating Power Plant in the Russian Federation. Nonetheless, commercial and DOE expectations are that the first SMRs will be deployed in the first half of the 2020s. One could expect that the retirement of a portion of the current nuclear fleet would create additional opportunities for SMRs to replace the lost base-load capacity.

In summary, the development of SMRs offers prospects of more flexible and less costly nuclear power enhancements, but there are many hurdles to overcome, including regulatory, supply chain and sufficient numbers of construction to show cost reductions from modularisation and factory assembly.

WASTE MANAGEMENT

The United States has developed an effective funding mechanism for managing spent nuclear fuel and high-level waste, but the failed attempt to locate a deep geological repository at Yucca Mountain has set back the process of final disposal many years. The recommendations of the Blue Ribbon Commission, as the basis for the response by DOE on a new way forward are commendable, but the route to finding a new site (or in fact several sites, if the level of 70 000 tonnes of heavy metal is maintained) will be difficult and will require long-term commitment. Further policy changes will be harmful to this strategy. In the interim, the licensing and construction of interim storage will require immediate attention. Nevertheless, the process of consultation is supported as consistent with best international practice. Despite this, there appears to be no consensus in Congress on how this strategy will be implemented.

TECHNOLOGY DEVELOPMENT AND INTERNATIONAL CO-OPERATION

The United States has been a leader in the safe and secure development of nuclear power across the world and has maintained a high level of technological R&D. The DOE budget is reported to be sufficient to fund a wide range of technologies and to engage internationally through bilateral and multilateral agreements. This role is of global importance in the safe development of nuclear power, especially in developing countries and in the promotion of “breakthrough” technologies that are important to a nuclear future.

The country has, in particular, been a leader in international nuclear research and engagement, including through the Generation IV Forum, the Global Nuclear Energy Partnership (now the International Forum for Nuclear Energy Cooperation) and the International Atomic Energy Agency’s International Project on Innovative Nuclear Reactors and Fuel Cycles (IAEA INPRO) as well as in many non-proliferation issues. A decline in nuclear capacity and nuclear technology development may alter this leadership role and could be another possible consequence of a declining nuclear industry.

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The United States has a network of national laboratories, which provide a foundation for high-quality research and underpin its domestic and international nuclear research. The capabilities of these laboratories are impressive and are capable of supporting the development of small modular reactors, the life extension of existing power plants and the development of Generation IV reactors and advanced fuel cycles. However the latter can only be done effectively on an international basis and the United States should continue to support these international efforts, which offer promise of more efficient, safer and more sustainable nuclear power development.

In addition to overseeing the operating nuclear fleet and new reactor construction, the Nuclear Regulatory Commission has been a leader in co-operating with other national nuclear regulatory authorities to address advanced reactor oversight. The NRC is participating in an international effort, the Multinational Design Evaluation Program, to more efficiently review new reactor designs. The goal of this programme is to make all new reactor reviews more safety-focused and enhance common approaches.

PUBLIC SUPPORT

Despite the Three Mile Island accident and more recently the Fukushima Daiichi accident, public opinion is generally favourable to nuclear expansion (latest figures suggest more than 65% in favour, despite a drop after Fukushima), and the US response to the accident seems to have been well received generally. This is, in a major way, attributable both to industry actions and to the NRC response to Fukushima, where it has adopted a tiered and systematic approach to reactor safety enhancements. This provides a good basis for nuclear expansion, if it can be financed.

RECOMMENDATIONS

The government of the United States should:

- *Develop and articulate a clear strategy for nuclear power, including a statement of how it will provide long-term support. Given the long lead times for construction and the declining share of nuclear power in the energy mix, these considerations should be concluded quickly.*
- *Promulgate accompanying mechanisms that allow the diversity, grid stabilisation and low-carbon capacity of nuclear power to be valued and remunerated. In particular, the government should move to finalise the loan guarantees for existing new build and consider extending tax credits beyond the existing limit of 6.0 GW_e and the end date of 2020.*
- *Pursue faster routes to market for small modular reactors, working with industry and the national laboratories to tackle the technology and fabrication challenges.*
- *Work with the regulatory authorities to provide greater regulatory certainty for licensing and establishing security requirements for small modular reactors.*
- *Maintain momentum established through the Blue Ribbon Commission to reach an agreement on a policy and a strategy for implementing a solution to spent fuel and high-level waste disposal. In this respect:*
  - *A process for vigorously pursuing the establishment of a deep geological disposal should be a high priority, since this is a key element in ensuring public confidence in nuclear power.*

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- *Attention should be given to ensure rapid and co-ordinated action to facilitate the licensing and construction of interim storage for spent fuel.*

☐ *Try to avoid, for such long-term issues, frequent changes of policy, which are harmful in ensuring the necessary long-term commitments and implementing the detailed public consultation that is needed*

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5. RENEWABLE ENERGY

Key data (2013 estimated)

Share of renewable energy: 6.4% of TPES and 12.9% of electricity generation (IEA average: 9% of TPES and 21.7% of electricity generation)

Biofuels and waste: 4.2% of TPES and 1.7% of electricity generation

Hydro: 1.1% of TPES and 6.3% of electricity generation

Wind: 0.7% of TPES and 4% of electricity generation

Geothermal: 0.4% of TPES and 0.4% of electricity generation

Solar: 0.1% of TPES and 0.4% of electricity generation

SUPPLY AND DEMAND

Renewable energy accounted for 6.4% of total primary energy supply (TPES) in the United States in 2013, or 140.5 million tonnes of oil-equivalent (Mtoe). Renewables are dominated by biofuels and waste (4.2% of TPES), followed by hydro (1.1%), wind (0.7%), geothermal (0.4%) and solar (0.1%). The penetration of renewable energy in TPES has increased from 4.6% in 2003 to 6.4% in 2013.

Renewable energy growth has surged over the past decade. Wind power has boosted significantly since the early 2000s, increasing fourteen-fold from 1.0 Mtoe in 2003 to 14.6 Mtoe in 2013. Solar power has doubled from 1.4 Mtoe in 2003 to 2.7 Mtoe in 2013, while biofuels and waste, and geothermal, have expanded by 30.6% and 6.2% over the same period, respectively. Conversely, hydropower production declined by 2.6% from 2003 to 2013, a fall which could be attributed to low water flow rather than fewer dams over the past decade.

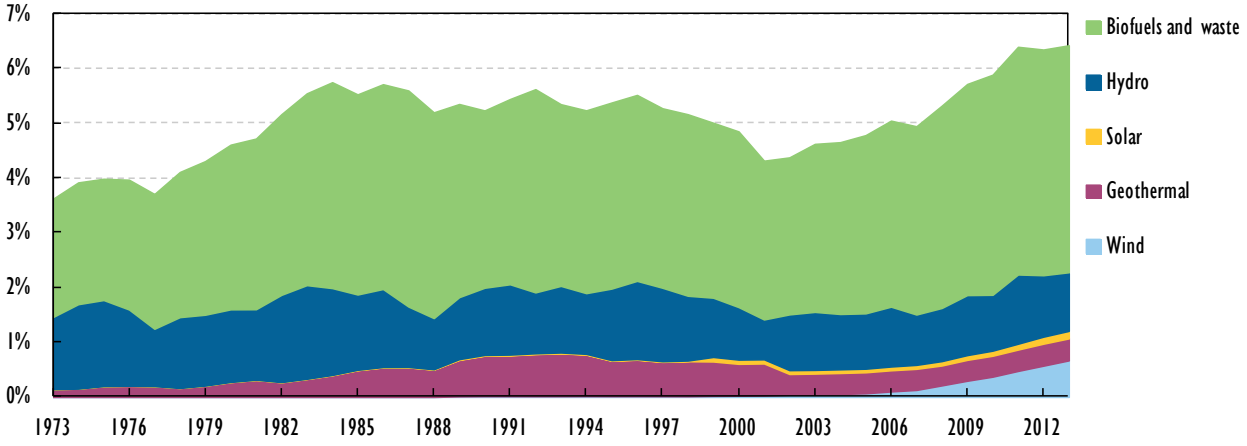
Government projections indicate that renewable energy sources will continue to expand at a faster rate compared to fossil fuels over the next two decades. Renewables are expected to hold a share of 12.1% of TPES by 2040. Biofuels and waste will remain the largest source of renewables with a share of 7.9% of TPES in 2040, followed by geothermal (2%), hydro (1%), wind (0.8%) and solar (0.5%). Under the IEA's New Policies Scenario (NPS), expressed as a share of total primary energy demand (TPED), renewable energy is seen accounting for 14.8% of TPED in 2035, up from 7.4% in 2011. Under the IEA's 450 Scenario, which shows the energy mix needed to better meet long-term climate change objectives, renewable energy would account for 25.7% of TPED in 2035 (IEA, 2013). The United States ranks seventh-lowest among IEA member countries with regard to the share of renewable energy in electricity generation (Figure 5.2). The IEA median is 22.3%.

The federal government projects that only 16% of electricity generation will come from renewable sources by 2040, with slow growth in hydro to be offset by a boom in other technologies. However, IEA analysis suggests a more significant rise in renewable electricity ahead. The *Medium-Term Renewable Energy Market Report 2014* forecasts that over 16% of US electricity generation will come from renewables by 2020. While hydropower

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remains the largest absolute component, growth is led by onshore wind and solar PV (IEA, 2014b). In IEA scenario analysis, renewables account for 23% of electricity generation in 2035 under the NPS and for almost 39% under the 450 Scenario (IEA, 2013).

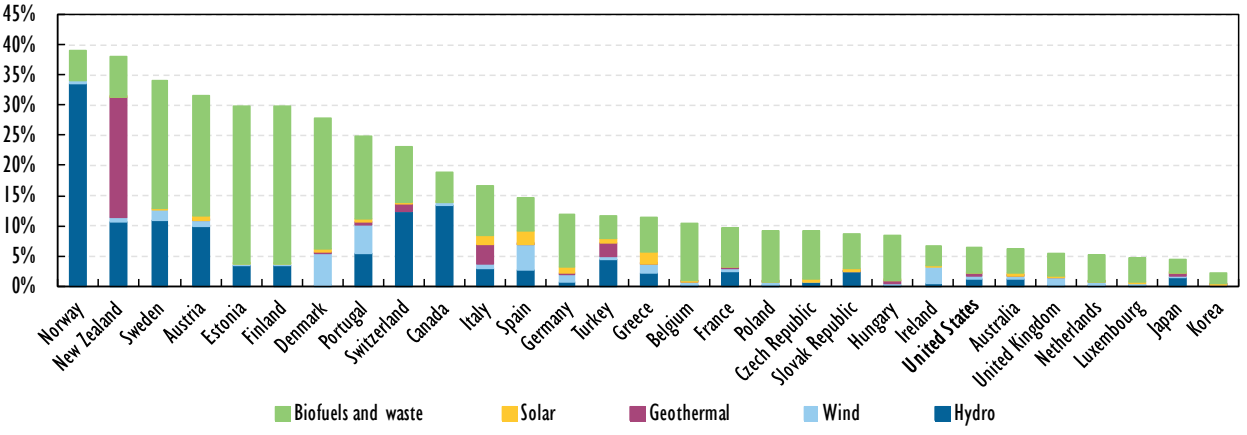
Figure 5.1 Renewable energy as a percentage of TPES, 1973-2013



Note: estimated for 2013.

Source: IEA (2014a), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

Figure 5.2 Renewable energy as a percentage of TPES in IEA member countries, 2013



Note: estimated data.

Source: IEA (2014a), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

ELECTRICITY GENERATION

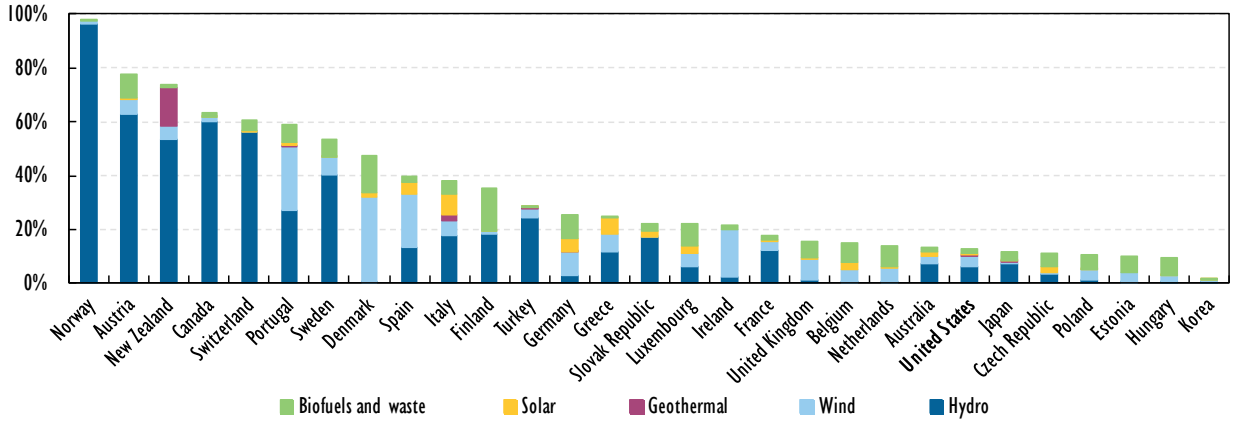
Electricity generation from renewable sources was 549.3 terawatt-hours (TWh) in 2013, accounting for 12.9% of total generation. Hydropower accounted for 6.3%, followed by wind (4%), biofuels and waste (1.7%), geothermal (0.4%) and solar (0.4%).

Electricity production from renewable sources has grown at an average rate of 4.6% per year in the ten years to 2013. As such, the share of renewables in generation has grown from 9.3% in 2003 to 12.9% in 2013. Most of the increase is a result of a surge in wind and to a lesser extent solar power generation, both of which have swelled thirteen-fold during the decade. Generation from geothermal, biofuels and waste, and hydro has also expanded albeit at a slower rate.

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The federal government projects that 16% of electricity generation will come from renewable sources by 2040, with slow growth in hydro to be offset by a boom in other technologies. The United States ranks seventh-lowest among IEA member countries with regard to the share of renewable energy in electricity generation (Figure 5.3). The IEA median is 22.3%.

Figure 5.3 Electricity generation from renewable sources as a percentage of all generation in IEA member countries, 2013



Note: estimated data.

Source: IEA (2014a), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

INSTITUTIONS

The **Office of Energy Efficiency and Renewable Energy** (EERE) in the Department of Energy (DOE) conducts research and administers programmes to improve the performance, efficiency, utility, and reliability of renewable energy technologies. The **Office of Energy Policy and Systems Analysis** and EERE's **Office of Strategic Programs** work to form and promote renewable energy policies aligned with national goals and interests. The DOE maintains 17 national laboratories and technology centres that conduct research in a variety of disciplines, dealing among others with climate change issues, and energy technology research, including on renewable energy. The **National Renewable Energy Laboratory** in Golden, Colorado, is focusing specifically on the renewable energy sector, whereas other labs are at least partially covering issues relevant to the renewable energy sector. The **Advanced Research Projects Agency-Energy** (ARPA-E) advances high-potential, high-impact energy technologies that are too early for private-sector investment. ARPA-E awardees are unique because they are developing entirely new ways to generate, store and use energy.

The **Department of the Interior** (DOI Bureau of Land Management) works with federal, state and local regulators to provide regulation and oversight on the siting and permitting of onshore solar, wind and geothermal renewable energy development projects located on federal land. For offshore renewable projects, the DOI **Bureau of Ocean Energy Management** (BOEM) issues leases, easements and rights of way to allow for renewable energy development on the Outer Continental Shelf (OCS). BOEM's renewable energy programme occurs in four distinct phases: planning, leasing, site assessment, and construction and operations. To date, BOEM has awarded five commercial energy leases off the Atlantic coast (two additional leases were pending in early October 2014). The **Bureau of Reclamation** manages, develops, and protects water and related resources in an environmentally and economically sound manner in the interest of the American public. It operates 53 hydropower plants and is the second-largest producer of hydroelectric power in the United States.

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The US **Department of Agriculture** (USDA), alongside DOE and a number of other federal government agencies, co-ordinates research and development (R&D) activities under the Advanced Biomass R&D Board. USDA also oversees a number of biofuel/bioenergy programmes, including the Biomass Crop Assistance Program and a number of Rural Development Energy Programs. It also offers loan guarantees and grants for renewable energy systems such as solar panels or anaerobic digesters and for energy efficiency improvements under the Rural Energy for America Program (REAP).

The US **Environmental Protection Agency** (EPA) oversees a number of renewable energy regulations and deployment programmes, including the State and Local Climate and Energy Program, which provides technical assistance, analytical tools and outreach support to state, local and tribal governments. To support these activities, the EPA has developed the Financing Program Decision Tool to help officials at state and local level to identify clean energy financing programmes suited to their jurisdiction's specific needs. EPA is responsible for developing and implementing regulations to ensure that transportation fuel sold in the United States contains a minimum volume of renewable fuel. The EPA also supports the Green Power Partnership, a voluntary programme that encourages organisations to use renewable power as a way to reduce the environmental impacts associated with conventional electricity use.

The **National Science Foundation** (NSF) funds research in basic science and engineering, including research in the energy area. For example, the Energy for Sustainability programme funds research in biomass conversion, solar PV, wind energy and advanced batteries for vehicles. The **National Aeronautics and Space Administration** (NASA) also conducts R&D in renewable energy.

The **Department of State's** Bureau of Energy Resources, Energy Transformation, Office of Alternative and Renewable Energy (ENR/ETR/ARE) works to promote market forces that sustain transformational energy policies regarding alternative energy, electricity, development and reconstruction.

The **Federal Energy Regulatory Commission** (FERC) has a role in permitting non-federal hydro developments. Its responsibilities include: issuance of licences for the construction of a new project; issuance of licences for the continuance of an existing project (relicensing); and oversight of all ongoing project operations, including dam safety inspections and environmental monitoring.

Individual **state legislatures** have the autonomy to determine renewable portfolio standards (RPS), and establish renewable energy deployment mandates. Utilities operating within the state are responsible for generating adequate renewable energy or buying renewable energy certificates (RECs) to meet the mandate.

POLICIES AND MEASURES

The policy environment in the United States, which has no national renewable energy target, is broadly supportive of renewable energy. At the outset of his first term in 2009, President Obama announced a goal to double renewable electricity from wind, solar and geothermal resources from a 2008 baseline. This goal was achieved in 2013, and the federal government announced a goal to again double generation of electricity from wind, solar and geothermal sources by 2020 (from a 2012 baseline). In the absence of an explicit federal support mechanism, state renewable portfolio standards, including renewable energy certificates/credits, state-level net energy metering policies and federal production and/or

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fiscal incentives act as the main drivers of renewable energy deployment. Furthermore, compliance with anticipated EPA emission regulations together with weak growth in electricity demand have led utilities to announce the retirement of around 60 gigawatts (GW) of coal-fuelled plants between 2012 and 2020. This power sector situation, combined with federal and state policy incentives, should help support deployment of renewables over the medium term, even as electricity demand is expected to grow slowly (IEA, 2014b).

FISCAL INCENTIVES

Federal Renewable Energy Production Tax Credit (PTC): The PTC is an inflation-adjusted, per kilowatt hour, tax credit for electricity produced from qualifying renewable energy sources or technologies. The PTC was initiated with the Energy Policy Act of 1992, and subsequently renewed and amended several times, most recently in the American Recovery and Reinvestment Act (ARRA) of 2009 and the American Taxpayer Relief Act of 2012. Eligible projects can take an inflation-adjusted tax credit for electricity generated over ten years, with some exceptions. The tax credit amount is USD 1.015 kWh in 1993 dollars (indexed for inflation) for some technologies and half of that amount for others. The rules governing the PTC vary by resource and facility type. Table 5.1 outlines two of the most important characteristics of the tax credit, the begin construction deadline and the credit amount, as they apply to different facilities:

Table 5.1 Renewable energy production tax credit

Resource type	Begin construction deadline	Credit amount
Wind	31 December 2013	USD 0.023/kWh
Closed-loop biomass	31 December 2013	USD 0.023/kWh
Open-loop biomass	31 December 2013	USD 0.011/kWh
Geothermal energy	31 December 2013	USD 0.023/kWh
Landfill gas	31 December 2013	USD 0.011/kWh
Municipal solid waste	31 December 2013	USD 0.011/kWh
Qualified hydroelectric	31 December 2013	USD 0.011/kWh
Marine and hydrokinetic (150 kW or larger)	31 December 2013	USD 0.011/kWh

Source: IEA analysis based on data from the Database of State Incentives for Renewable Energy (DSIRE).

At various times, several forms of renewable energy have become eligible for this credit. They include closed- and open-loop biomass, geothermal, landfill gas, irrigation-produced power, municipal solid waste, wind facilities, and marine and hydrokinetic energy. The service dates and their application to certain technologies have also been subject to changes, most recently in early 2013, when the federal government extended for one year its renewable electricity PTC for wind, which had expired at the end of 2012. Under the present law, all eligible projects had to be in service or under construction by 31 December 2013.

In April 2013, the Internal Revenue Service (IRS) issued guidance, which was later clarified, on how it was to evaluate whether construction had commenced for the purpose of the year-end 2013 deadline. The guidelines established two paths for meeting this benchmark. In the first case, a project is considered to have begun construction when "physical work of a significant nature" has started. Under the alternative, construction of a facility is

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considered to have commenced when 5% of the total cost of the facility has been incurred by the taxpayer, and the taxpayer makes continuous efforts to complete the facility thereafter. The guidance also provides that in certain circumstances the evaluation can take place on a project-wide basis rather than separately for each individual piece of equipment.

Federal Renewable Energy Investment Tax Credit (ITC): The Energy ITC is another fiscal incentive. An investment tax credit can be taken for the equipment (property) eligible to receive the PTC, and for facilities that produce electricity from solar and geothermal sources, qualified fuel-cell power plants, stationary micro-turbine power plants, geothermal heat pumps, small wind plants, and combined heat and power plants. Investors can either take the ITC, which generally provides for a 30% tax credit, or the PTC described above. To be eligible for the ITC, the system must be placed in service between 31 December 2005 and 31 December 2016.

Residential Renewable Energy Tax Credit (RTC): A personal tax credit can be taken for residential energy property including solar-electric systems, solar water heaters, small wind plants, geothermal heat pumps and qualified fuel-cell power plants. The RTC provides for a tax credit of 30% of qualified expenditures on systems placed in service before 31 December 2016.

OTHER FEDERAL MECHANISMS

The US also encourages the development and expansion of renewable energies by other means. In June 2013, President Obama announced his **Climate Action Plan** (CAP), a broad-based plan to cut carbon pollution. In line with the CAP, the federal government facilitates the deployment of solar, wind and geothermal energy on public lands by means of prioritised permitting and environmental review processes. For example, the DOI Bureau of Land Management is processing 23 renewable energy projects (14 solar, six wind and three geothermal) representing about 5.3 GW of capacity. The CAP also highlighted the need to expand and upgrade the electricity grid to make power supply more reliable, to reduce consumer costs and to promote clean energy sources. In this regard, in June 2013, the President signed a Presidential Memorandum that directed federal agencies to streamline the siting, permitting and review processes for transmission projects across federal, state and tribal governments. In June 2014, the President published a CAP Progress Report.

Renewable energy in federal facilities: The Energy Policy Act of 2005 requires a share of electricity consumed by the federal government to come from renewable sources: no less than 3% in fiscal years 2007-09, no less than 5% in fiscal years 2010-2012, and no less than 7.5% in fiscal year 2013 and thereafter. In addition, the Energy Independence and Security Act (EISA) of 2007 requires 30% of hot water demand in new federal buildings be met with solar water-heating equipment that is life-cycle cost-effective. The EISA also requires a reduction in fossil fuel consumption in new federal buildings and major renovations relative to 2003: 55% by 2010; 65% by 2015; 80% by 2020; and 100% by 2030. THE EISA also facilitates financing of renewable energy projects using Energy Savings Performance Contracts (ESPCs). The Federal Energy Management Program (FEMP) provides technical assistance and resources to help federal agencies evaluate and implement renewable energy technologies.

NATIONAL RENEWABLE ENERGY LABORATORY

The National Renewable Energy Laboratory (NREL) is the US Department of Energy's primary national laboratory for renewable energy and energy R&D. NREL develops renewable energy

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and energy efficiency technologies and practices, advances related science and engineering, and transfers knowledge and innovations to support the achievement of US energy and environmental goals. Its work focuses on advancing renewable energy and energy efficiency technologies from concept to the commercial marketplace through industry partnerships.

RENEWABLE PORTFOLIO STANDARDS AND OTHER STATE-LEVEL MECHANISMS

State-level renewable portfolio standards (RPS) policies have been a significant driver for renewable energy growth in the United States and 29 states and the District of Columbia (DC) have an enforceable RPS or similar laws. Seven other states have non-binding goals in place. Utilities are regulated at the state level, thus any binding targets must be implemented and enforced by the state regulators. Eighteen states (and DC) offer performance-based financial incentives, including tradable renewable energy credits (RECs) schemes.

State RPS policies appear to have motivated substantial renewable capacity development: 67% (46 GW) of all non-hydro renewable capacity additions from 1998 to 2012 occurred in states with active/impending RPS compliance obligations (Barbose, 2013). According to the EIA, a number of factors have helped to create an environment favourable for RPS compliance, including:

- a surge of new RPS-qualified generating capacity timed to take advantage of federal incentives
- significant reductions in the cost of wind, solar, and other renewable technologies
- generally slower growth of electricity sales
- complementary state and local policies that either reduce the cost (e.g. equipment rebates) or increase the revenue streams (e.g. net metering) associated with RPS-eligible technologies (EIA, 2014b; see also Box 5.1).

At present, most states are meeting or exceeding their required levels of renewable generation, based on qualified generation or purchase of renewable energy credits (Barbose, 2013). The EIA projects that, overall, RPS-qualified generation will continue to meet or exceed aggregate mandatory targets for state RPS programmes through 2040 (EIA, 2014b).

Despite the success of the RPS in promoting the growth of renewable energy, legislators in some states have drafted proposals to roll back RPS schemes in order to control policy costs, although none has rescinded the obligations. In Ohio, a bill was recently adopted that pushes back its RPS compliance year from 2025 to 2027 and reduces the obligation of utilities to source in-state renewables production. In 2014, NREL published a study that estimated the costs and benefits of renewable portfolio standards in the United States. The study found that, among the 24 states for which the requisite data were available over the 2010-12 period, average estimated incremental RPS compliance costs in the United States were equivalent to 0.9% of retail electricity rates when calculated as a weighted average, or 1.2% when calculated as a simple average, although substantial variation exists around the averages, both from year-to-year and across states (NREL, 2014).

Alternatively, in terms of the incremental cost per unit of renewable generation, average RPS compliance costs during 2010-12 ranged from USD 4.0/MWh (i.e. a net saving) to USD 44/MWh across states. The study also found that utilities in eight states assess surcharges on customer bills to recoup RPS compliance costs which in 2012 ranged from about USD 0.50/month to USD 4.0/month for average residential customers.

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States have most commonly attempted to quantitatively assess avoided emissions and associated human health benefits, economic development impacts, and savings from reductions in wholesale electricity prices. Six states, for example, report emissions or human health benefits of tens to hundreds of millions of USD on an annual basis, translating to USD 4.0/MWh to USD 23/MWh of renewable energy procured. Economic benefits of USD 22/MWh to USD 30/MWh were also found.

EXAMPLES OF STATE-LEVEL RPS SCHEMES

Texas

Texas's RPS require all market participants to acquire a total of 5 880 MW of renewable energy resources by 2015 (corresponding to about 5% of the state's electricity demand), including a target of 500 MW of renewable energy capacity from resources other than wind, and 10 000 MW by 2025 (DSIRE, 2013).[1] Renewable energy generation totalled 29.9 TWh in 2013, with wind accounting for 28.9 million MWh (ERCOT, 2014). The Public Utility Commission of Texas established a renewable energy credit (REC) trading system that began in 2001 and will continue through 2019. As of 2012, Texas penalises entities USD 50/MWh if a utility falls short of compliance with its REC requirements under the RPS targets. However, with over 12 GW of renewable generating capacity, Texas has exceeded its goal of 10 GW by 2025.[2]

California

Established in 2002 under Senate Bill 1078, accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2, California's RPS is one of the most ambitious renewable energy standards in the United States. It applies to all electricity retailers in the state, including publicly owned utilities, investor-owned utilities, electricity service providers, and community choice aggregators. All of these entities must adopt the new RPS goals of 20% of retail sales from renewables by the end of 2013, 25% by the end of 2016, and the 33% requirement to be met by the end of 2020.

In 2011, Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company spent approximately USD 1.0 billion, USD 1.3 billion and USD 0.17 billion, respectively, on direct RPS procurement, whereas RPS deliveries represented 19.8%, 21.1%, and 20.8% of the utilities' retail sales, respectively. Total RPS expenditures have increased over time, as the utilities have increased their purchases of renewable resources, and the mix of renewable resources has changed (CPUC, 2013). In 2011, the utilities' RPS portfolios (in USD terms) were primarily comprised of geothermal (35%), wind (34%) and biomass (12%).

New York

New York state, by means of regulations adopted by the Public Service Commission (PSC), first enacted its RPS in 2004 with the goal of increasing the amount of renewable electricity used by consumers to 25% by 2013. In an Order issued in January 2010 following a comprehensive mid-course review, the PSC expanded the RPS target from 25% to 30% and extended the terminal year of the programme from 2013 to 2015.

1. Market participants are municipally owned utilities, generation and transmission co-operatives, and distribution co-operatives that offer customers a choice of retail providers; retail electric providers (REPs); and investor-owned utilities IOUs that have not been unbundled under deregulation.

2. All examples in this section were sourced from the Department of Energy, Database of State Incentives for Renewables and Efficiency.

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The New York state RPS requires 30% of electricity sales from renewables by 2015, of which 20.7% will be from existing renewable energy facilities, and 1% is expected to be met through voluntary green power sales. Unlike most other states with an RPS, New York state uses a central procurement model whereby the New York State Energy and Research and Development Authority (NYSERDA) administers programmes which are responsible for the majority of the RPS goals. Specifically, NYSERDA is responsible for obtaining the main tier (larger utility-scale resources) and customer-sited tier (smaller, behind the meter resources) targets with the remainder to be made up by the voluntary market and purchases made by state agencies.

Total new renewables capacity supported by the main tier and customer-sited tier could reach nearly 2.2 GW by the end of 2014, of which 98% of total capacity will be located in New York state. Under the main tier component of the programme, 54 projects representing approximately 1.8 GW were operating as of 31 December 2013 (NYSERDA, 2014).

ELECTRICITY FROM RENEWABLE ENERGY

Renewable energy sources, including water (hydroelectric), wind, biomass wood and biomass waste, geothermal, and solar, generated approximately 13% of the electricity produced in the United States during 2013. Hydropower remains the largest source of electricity generated by renewable sources in 2013 with 52% of supply, followed by wind (32%), biomass wood (8%), biomass waste (4%), geothermal (3%) and solar (2%). Most hydropower comes from large dams, which were completed before the 1970s, much of it from dams that are operated by federal agencies. Since 1990, however, the amount of non-hydropower renewables has more than quadrupled and the United States is the world's largest producer of electricity from non-hydro renewable sources. The largest amount of non-hydro renewable power was generated in Texas followed by California. The proportion of non-hydro renewable sources in its generation was about 9% in Texas.

Table 5.2 Top ten US states in terms of 2013 wind and solar capacity additions (MW)

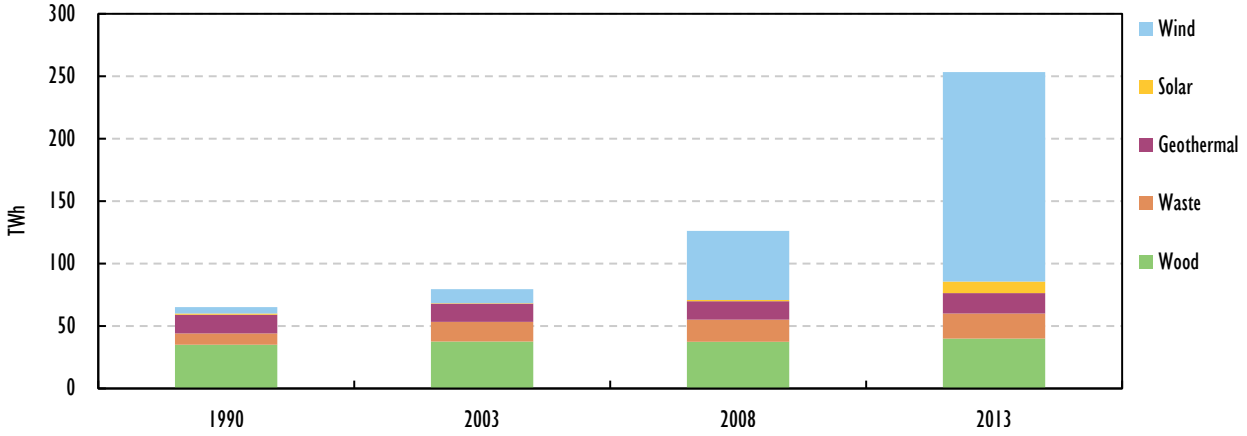
State	Wind (MW)	State	Solar Photovoltaic (PV) (MW)
California	269	California	2 621
Kansas	254	Arizona	421
Michigan	175	North Carolina	335
Texas	141	Massachusetts	237
Nebraska	75	New Jersey	236
Iowa	45	Hawaii	146
Colorado	32	Georgia	91
Massachusetts	3	Texas	75
Alaska	3	New York	69
Indiana	1	Colorado	56

Sources: IEA (2014b), *Medium-Term Renewable Energy Market Report*, OECD/IEA, Paris; GTM Research/SEIA (Solar Energy Industries Association (2014), *US Solar Market Insight Report Q1 2014*, GTM Research/SEIA, Washington, D.C.; IEA analysis based on AWEA (2014), *AWEA US Wind Industry Annual Market Report Year Ending 2013*, AWEA, Washington, D.C.

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The amount of electricity generated by wind has increased substantially in the past decade while solar generated a significant amount of power at small-scale installations. The increase in wind power can be largely attributed to the availability of federal financial incentives and renewable portfolio standards mandated by state governments. Regional onshore wind additions declined in 2013, as a result of uncertainty over the extension of the production tax credit (PTC), to a small fraction of capacity added in 2012. With a one-year PTC extension granted in early 2013, a more robust US onshore wind project pipeline emerged for 2014 and 2015 (IEA, 2014b).

Figure 5.4 Non-hydropower renewable electricity generation by source, 1990-2013



Source: EIA (2014a), *Electric Power Monthly*, Energy Information Administration, Washington, D.C., March.

GEOTHERMAL

The development of geothermal energy resources for utility-scale electricity production in the United States began in the 1960s. Since that time, the continual development of geothermal resources and technology has positioned the United States as a leader in the global geothermal industry (GEA, 2012). The United States is the world's leader in terms of installed geothermal energy capacity with approximately 3.4 GW. Most geothermal capacity is concentrated in California (2 700 MW) and Nevada (426 MW) but there are also geothermal power plants in Alaska, Hawaii, Idaho, Oregon, Utah and Wyoming. As of January 2013, the Bureau of Land Management managed 818 geothermal leases, including 59 producing leases with 1 275 MW of installed capacity, over 40% of US geothermal energy capacity. Since the completion of a 2008 Programmatic EIS, the Bureau of Land Management (BLM) has competitively leased over one million acres of federal lands in six states. In 2008, the US Geological Survey (USGS) estimated that 30 GW of undiscovered geothermal resource exists in the western United States. The EIA *Annual Energy Outlook 2014* (EIA, 2014b) projects that geothermal power will be the second-fastest-growing source of renewable electricity generation in its Reference case, increasing from less than 16 billion kWh in 2012 to 67 billion in 2040 or a 5.4% average annual growth rate.

The resource characteristics of different geothermal reservoirs vary and a range of technologies are used to generate geothermal energy. Dry-steam power plants located in California account for approximately 50% (almost 1 600 MW) of installed geothermal capacity. Steam-flash power plants, many of which are also located in California, account for another 900 MW of capacity. The development of binary geothermal technology in the past decade has supported the emergence of lower temperature resources, which has driven much of the development outside California.

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In a report published by DOE in 2011, industry stakeholders identified the permitting timeline as a major barrier to increasing geothermal power plant development. In response the DOE Geothermal Technologies Office (GTO) collaborated with the National Renewable Energy Laboratory (NREL) to create a Geothermal Regulatory Roadmap. The purpose of the roadmap is to assist project developers manage regulatory requirements at every level of government to support the deployment of geothermal energy projects.[3]

HYDROPOWER

Hydropower, the largest source of renewable electricity, provided approximately 7% (269 TWh) of US electricity supply in 2013. Total conventional hydropower capacity was 78 GW in 2012, a number that has been relatively static over the past decade. Pumped storage facilities accounted for a further 22 GW of capacity. The share of hydropower in total US annual electricity generation has fallen as other sources of generation have increased in recent years and only 1.4 GW of new hydropower capacity is planned for the period between 2013 and 2017 (EIA, 2014b). Conversely, a study conducted by Oak Ridge National Laboratory (ORNL) for the DOE, found that 61 GW of hydroelectric power potential exists at waterways without existing dams or diversion facilities. This value excludes Alaska, Hawaii and federally protected lands. The difference in the two sets of numbers represents the significant gap between technical potential on the one hand and economic and operational potential on the other hand (ORNL, 2014). The 58 hydroelectric power plants at the facilities operated by the Federal Bureau of Reclamation facilities generate over 40 billion kWh of electricity per year, enough to power over 3.5 million homes, and providing nearly a billion USD in revenues. A previous study estimated that existing non-powered dams have the potential to add up to 12 GW of electrical generating capacity. This can be achieved at lower cost, with less risk, and in a shorter timeframe than development requiring new dam construction (ORNL, 2012).

The contribution of hydropower to electricity supply varies: in some years, hydroelectric generation increases while in others it declines as a result of variations in rainfall and melting snowfall as well as changing operational considerations.

WIND POWER

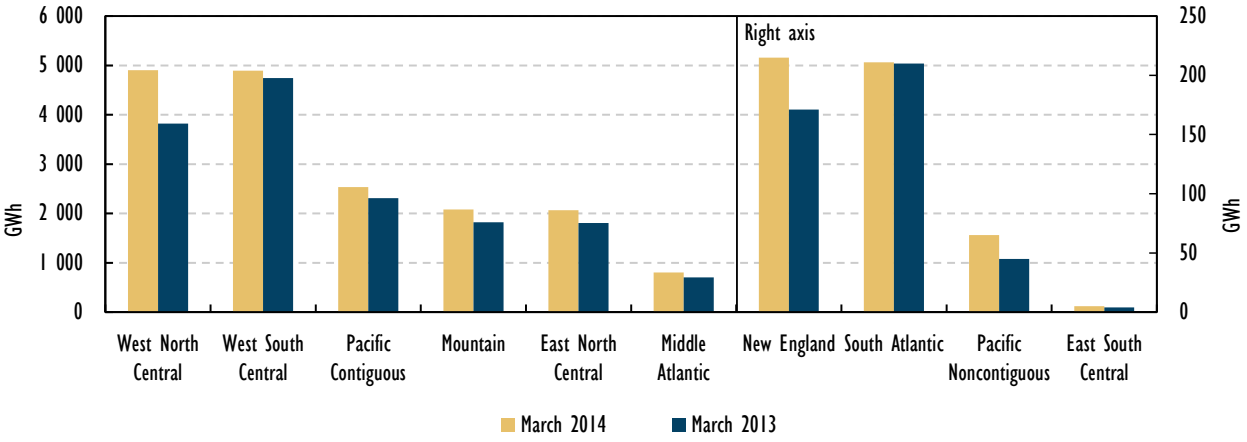
In 2012, there was 59.6 GW of cumulative wind power capacity in the United States with a further 6 GW planned over the period between 2013 and 2017. Wind power increased its share of total electricity generation in 2013 from 3.5% to 4.1%. In 2013, wind power contributed 167.7 TWh to electricity supply, an increase of 19% over the previous year. Onshore wind is expected to grow strongly, with a significant number of projects coming on line over 2014-15. Beyond this, the onshore wind outlook is expected to stabilise at a lower level owing to the expectation that the production tax credit (PTC) will no longer be available for new projects.

Twelve states accounted for 80% of wind-generated electricity: Texas was the top wind power state with nearly 36 TWh of electricity, followed by Iowa, California, Oklahoma, Illinois, Kansas, Minnesota, Oregon, Colorado, Washington, North Dakota and Wyoming (EIA, 2014b). Texas was the first state to reach 10 GW of wind power generating capacity. As a proportion of wind in total electricity generated Iowa enjoys the greatest contribution with 27.4% of its net electricity production coming from wind. South Dakota follows with 26%.

3. http://en.openei.org/wiki/RAPID/Roadmap/Geo, last accessed 1 June 2014.

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Figure 5.5 Net generation from wind in March 2013 and March 2014 (GWh)



Source: EIA (2014a), *Electric Power Monthly,* Energy Information Administration, Washington, D.C., March.

Offshore wind

No commercial offshore projects have been installed in the United States, where the projected near-term cost of offshore wind energy remains high. Furthermore, planning, siting and permitting can be challenging. Nonetheless, interest in developing offshore wind energy exists in several parts of the country. DOE provides 90-metre height, high-resolution wind maps and estimates of the total offshore wind potential that would be possible from developing the available offshore areas. In 2012, the National Renewable Energy Laboratory (NREL) provided an assessment of potential generating capacity from offshore wind, totalling 4 150 GW. Subsequently, in 2011, DOE published a national offshore wind strategy (DOE, 2011).

The National Offshore Wind Strategy details a plan to accelerate offshore wind deployment in the United States through targeted technical R&D, partnerships to remove market barriers, and implementation of pioneering demonstration projects. The purpose of the strategy is to guide US efforts to achieve a scenario of 54 GW of deployed offshore wind generating capacity by 2030, at a cost of USD 0.07 per kilowatt-hour (kWh), with an interim scenario of 10 GW of capacity deployed by 2020, at a cost of energy of USD 0.10/kWh.

Several offshore wind farms in the US Northeast are moving towards the initial construction phases. The 30 MW Deepwater Block Island Offshore Wind Farm, which has financing and a power purchase agreement in place, received its final federal permits in September 2014. The 468 MW Cape Wind Offshore Wind Farm has a power purchase agreement in place for part of its output and is partially financed. Both projects are targeting 2016 for completion (Navigant Consulting, 2014).

SOLAR POWER

By the end of 2013, the United States had more than 13 GW of installed solar capacity or almost 15 times the amount installed in 2008 (DOE, 2014). Supported by a federal investment tax credit and state-level incentives for net metering, solar photovoltaic (PV) installations surged by almost 5 GW, while solar PV generation almost doubled to 14 TWh in 2013. Over 0.4 GW of solar thermal electricity (STE) capacity was added in 2013 and a

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further 0.6 GW came on line in early 2014. These projects had benefited from DOE's loan guarantee programme, which helped investors to access more attractive financing terms. At state level, California led the deployment in solar PV with almost half of new solar PV additions, followed by Arizona and North Carolina. Although Arizona's and New Jersey's solar PV additions decreased versus 2012, North Carolina and Massachusetts achieved significant growth.

The BLM has conducted a comprehensive environmental analysis through which it identified 17 "solar energy zones" (SEZs) on public lands in six western states where solar energy development would be encouraged. The analysis also identified lands where solar energy development would be excluded and lands where solar energy could be developed if additional analysis showed appropriate. The BLM finalised its land-use allocations in October 2012. The BLM also launched the Restoration Design Energy Project (RDEP) in FY 2012. The initiative identified lands across Arizona most suitable for solar and wind power projects, with a focus on disturbed areas, and those with few potential conflicts over natural and cultural resources. A Record of Decision was issued in January 2013 to incorporate land-use allocations and programmatic and SEZ-specific design features into eight Arizona BLM land-use plans.

Projects associated with about 5 200 MW of capacity have been approved by BLM. In FY 2012, DOI collected USD 8.4 million in solar rentals, up from USD 6.8 million in FY 2011. This rental is based on a per-acre "base rent" fee and a per-MW of installed capacity fee. Solar rent is phased in over a five-year period after construction. Most solar projects are photovoltaic facilities, which have the lowest capacity fee.

The interaction of financial incentives (state and federal), state renewable portfolio standards (RPS), and the evolution of debates over rules for distributed solar PV (see Box 5.1) will play a large role in shaping the medium-term forecast with proposed federal emissions regulations likely to provide a boost in the longer term (IEA, 2014b).

The EIA projects that between 2012 and 2040 solar energy will be the fastest-growing source of renewable electricity generation, increasing by 7.5%/year. This expansion comes about as a result of increased photovoltaic capacity in both the electric power (central station) and end-use (customer-sited) sectors (EIA, 2014b).

Within DOE's Office of Energy Efficiency and Renewable Energy, the Solar Energy Technologies Office (SETO) drives research, manufacturing and market solutions through its management of the DOE SunShot Initiative, launched in 2011, which is a collaborative national initiative to make solar energy fully cost-competitive with other traditional forms of energy by 2020. Investments funded under the SunShot Initiative support innovation in solar energy technologies that aim to improve efficiency and reduce the costs, as well as making it easier, faster and cheaper for home-owners, businesses, and state, local, and tribal governments to "go solar", thus reducing "soft costs".

Sunshot was launched in February 2011 with the goal of making solar energy as cheap as conventional, non-renewable sources of electricity. By the end of the decade, its target is to drive down the installed cost of solar electricity to USD 0.06/kWh for both utility-scale PV and concentrated solar power (CSP) plants. The SunShot Initiative envisions reaching by 2020 a USD 1.50/W installed system price for residential rooftop PV systems, a USD 1.25/W installed price for commercial rooftop PV systems by 2020, and a USD 1.0/W installed price for utility-scale PV system by 2020.

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Box 5.1 As deployment ramps up, US states debate rules for distributed solar PV

Increasingly strong growth of solar PV in the United States is raising debates over the system integration of distributed generation. Currently, 45 states offer net energy metering, an arrangement that allows the netting on a consumer's bill of the solar PV output injected into the grid and the electricity consumed from the grid. Combined with falling solar PV costs, this rate structure has been an important driver for the scale-up of small-scale solar PV. Increasingly favourable economics for self-consumption are also creating new opportunities for deployment, without explicit subsidies. These trends are reinforced by the advent of third-party leasing schemes that help defray high upfront investment costs of ownership.

In reaction to these trends, there is ongoing debate in at least 15 states over fair rules and appropriate electricity rate design for allocating the costs (e.g. recovery of fixed grid costs) and benefits from fast-growing distributed solar PV. These considerations are complex and have provoked various regulatory responses that may impact future solar PV deployment. For example, Arizona regulators have chosen to institute fixed charges on solar net metering, approving in 2013 a hotly contested fee of USD 0.70/kW per month to be administered by the state utility. Minnesota, by contrast, is employing an alternative to net metering. In 2014 it implemented a value of solar tariff (VOST) policy, where utilities would remunerate distributed PV owners for all their production according to long-term, transparent pricing that values the environmental benefits of solar produced. At the same time, solar owners would consume and pay for all their electricity from the grid. Still, the offering of VOST versus net energy metering remains a voluntary choice of utilities.

Some states have started to apply limits on total net metered capacity through caps based on the percentage of peak demand met by residential solar PV generation while some others implemented limits on installed distributed generation capacity. Recent developments in California may be indicative of more balanced policy measures. Faced with an impending cap on new solar PV capacity under net energy metering, a bill adopted by the state legislature in September 2013 removed that cap and required the public utility commission to develop a new standard contract of tariff for new net metering customers based on the electricity system costs and benefits. At the same time the bill allowed investor-owned utilities to eventually employ a time-of-use pricing option for residential customers. Moreover, the bill would allow the adoption of a fixed charge for all rate payers to help recover investment costs, up to USD 10 per month (about 10% of household electricity bills) – a level that will not likely threaten the economics of solar PV deployment.

For many states, the penetration of distributed solar PV remains low and the current system impact is minor. Still, over the medium term, the IEA sees the residential and commercial segments accounting for 55% of the 37 GW of new solar PV in the United States expected over 2013-20. This deployment could be higher, with stronger-than-expected system cost reductions or an enabling breakthrough in battery storage technology. As such, states may need to continually address system concerns as they arise. Ultimately, policy makers may need to consider more fundamental changes to the electricity tariff structure in order to better recover fixed grid investment costs and decrease system costs. However, these changes would need to be done with care, avoiding retroactive measures, and strike a balance among various risks in order to continue providing a supportive framework for solar PV growth.

Source: IEA (2014b), *Medium-Term Renewable Energy Market Report*, OECD/IEA, Paris.

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WASTE AND BIOMASS

Between 2002 and 2013, biomass energy consumption in the United States increased by more than 60%. This growth is almost entirely the result of increased consumption of biomass to produce biofuels, mainly ethanol but also a smaller amount of biodiesel and other biomass-based diesel fuels. In 2013, biomass accounted for about half of all renewable energy consumed and 5% of total US energy consumed. The major biomass energy sources in the United States are:

- wood, including wood-derived fuels such as charcoal and by-products of paper production
- waste, including municipal solid waste, landfill gas, sludge waste, agricultural by-products, and others
- organic raw material inputs (feedstocks) used to produce biofuels.

In 2005, Oak Ridge National Laboratory undertook a biomass-resource assessment of the United States that was updated in 2011, and which found that up to 1.0 billion tonnes of biomass could be made available for energy purposes.

Consumption of wood and waste energy increased by just 4% over the period between 2002 and 2013 as increases in the consumption of waste energy exceeded increases in wood use. About two-thirds of US wood energy is consumed for industrial processes. Nearly all US waste energy is consumed for electricity generation or industrial processes.

There are 86 waste-to-energy plants operating in 25 states, located mainly in the Northeast. The plants have a total electricity-generating capacity of 2 720 MW and process more than 28 million tonnes of waste per year. No new plants have been built in the United States since 1995, but some plants have expanded to handle additional waste and create more energy.

GRID AND SYSTEM INTEGRATION

According to a National Renewable Energy Laboratory study on the Western Electricity Co-ordinating Council (WECC), which includes parts of Canada, the United States and Mexico, the integration of 35% wind and solar PV into the electric power system will not require extensive infrastructure if changes are made to operational practices. The report also points out that the existing transmission capacity can be better used in order to reduce new transmission investment needs (NREL, 2013). System constraints, however, may persist in other regional grids at lower shares of variable renewable generation. For instance, ERCOT, the Electric Reliability Council of Texas, may experience periods of insufficient flexibility to balance renewable generation starting at around 25%, much higher than present levels, of annual variable renewable penetration, from 9% in 2013 (IEA, 2014b).

Improved co-ordination among different grid operators in the United States could facilitate the integration of high shares of variable renewables, and optimise regional transmission investments. The Edison Electric Institute projects transmission investments totalling USD 60.6 billion from 2014-24 (EEI, 2014), 76% of which are projects supporting the integration of renewable resources and 43% interstate transmission projects (projects may fall into more than one transmission investment category). Since the Federal Energy Regulatory Commission's (FERC) issuance No 1000 in 2011, TSOs have been developing compliance proposals that provide a cost allocation method for new interregional transmission facilities. Nonetheless, challenges remain over the co-ordination and cost allocation of these interstate projects among different stakeholders.

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In March 2014, FERC approved the Co-ordinated Transaction Schedule between PJM (the regional transmission organisation covering parts of 13 states in the mid-Atlantic and midwestern portion of the United States) and New York Independent System Operator (NYISO) that will improve scheduling efficiency and maximise transmission utilisation to enhance trading of electricity among the interconnected areas. Further improvements in curtailment levels were recorded in 2013, particularly in congested grids. In 2013, only 1.2% of wind generation was curtailed in ERCOT, down from 3.8% in 2012, 8.5% in 2011 and 17% in 2009 (DOE, 2014). Increased transmission capacity, in part from the competitive renewable energy zones programme, has helped increase wind load factors there.

The Western Interconnection, part of the US power system, is made up of more than 30 balancing authorities. In 2014 FERC conditionally accepted revisions to the California Independent System Operator Corporation's electricity tariff to implement the proposed energy imbalance market (EIM). The change will allow neighbouring balancing area authorities in the western states to participate in the imbalance energy portion of the California ISO's real-time market. PacifiCorp and NV Energy have entered into an implementation agreement with the CAISO to join the EIM, which started on 1 October 2014. The EIM builds upon CAISO's existing real-time market and will allow participants to buy and sell real-time energy at five minute intervals to meet energy imbalance needs.

TRANSPORT AND BIOFUELS

The United States is the world's largest biofuels market and over the past decade a number of regulations have been introduced to support the use of renewable energy in the transport sector. The Energy Independence and Security Act of 2007, for example, included provisions to increase the supply of renewable alternative fuel sources by setting a mandatory renewable fuel standard (RFS). It also included grant programmes to encourage the development of cellulosic biofuels.

Box 5.2 The Renewable Fuel Standard

The RFS is a federal programme that originated with the Energy Policy Act of 2005 and was expanded and extended by the Energy Independence and Security Act of 2007. The RFS programme requires renewable fuel to be blended into transportation fuel in increasing amounts each year, escalating to 36 billion gallons by 2022. Each renewable fuel category in the RFS programme must emit lower levels of GHG relative to the petroleum fuel it replaces.

Refiners and importers of gasoline and diesel fuel are obliged to blend renewable fuels in proportion to the volumes of gasoline and diesel fuel sold. There are four interrelated requirements: for cellulosic biofuels, biomass-based diesel, advanced biofuels, and total renewable fuels. Compliance with the RFS is tracked via renewable identification numbers (RINs), which are generated when eligible biofuels are produced or imported and conveyed with the physical volume of renewable fuel through subsequent sales until they are blended with a petroleum product. Once the fuel is blended, the RINs can be separated from the physical volumes and "retired" – that is, turned in to the Environmental Protection Agency (EPA) to demonstrate compliance. RINs also can be sold or saved ("banked") for compliance either in the year they were generated or in the following year. EPA sets the RFS target volumes every year in reference to legislated targets in Energy Independence and Security Act of 2007, public comments, and input from other government agencies.

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Box 5.2 The Renewable Fuel Standard (continued)

Since the expansion of the RFS programme for the 2009 compliance year, the EPA has adhered to the legislated volumes of total renewable fuel, advanced biofuel, and biomass-based diesel but has often set the requirement for cellulosic biofuel well below the legislated target, given the very low commercial availability of cellulosic biofuel. The Energy Security Act also included new corporate average fuel economy (CAFE) standards, which have played and will continue to play a role in reducing gasoline consumption. Declines in gasoline consumption reduce the number of gallons of ethanol that can be used in E10, a fuel containing 10% ethanol by volume that is compatible with all existing gasoline-powered vehicles. EPA announced in its 2013 RFS final rule that it expected to reduce the total renewable fuel and advanced biofuel obligations to levels below the statutory levels for 2014, in order to allow the ethanol share of the gasoline pool to remain close to 10%.

In November 2013, the EPA published a proposal to substantially lower the required volumes of biofuels under the renewable fuels standard 2 (RFS2), the principal instrument that sets the minimum annual volume of renewable fuel. The proposed rule for the 2014 RFS programme was the first time that the EPA sought to establish total renewable fuel and advanced biofuel requirements below the legislated targets. This effectively acknowledged the challenges related to blending increasing amounts of ethanol into the gasoline pool. When the RFS was expanded to 2022 under the Energy Security Act of 2007, US gasoline consumption was assumed to grow, as it had done until then. In fact, gasoline demand has since steeply contracted and, despite a partial rebound in 2014, current projections are for a renewed decline mainly because of the adoption of tighter fuel economy standards that lead to largely improved vehicle fuel efficiency.

The US biodiesel industry is also facing further challenges following the expiration of the USD 1.0 per gallon blender's tax credit at the end of 2013. In May 2014, the Expiring Provisions Improvement Reform and Efficiency Act that included the re-introduction of the blender's tax credit did not pass the Senate. The re-introduction in early 2013 of the credit, which had been allowed to expire at the end of 2011, was an important driver to fuel a 14 kb/d year-on-year increase in US biodiesel output that year, to 87 kb/d. In the absence of the blender's tax credit, biodiesel production is projected to fall in 2014, and eventually stay around 84 kb/d in the medium term, in line with the RFS mandate.

While EPA published the proposed rulemaking in November 2013, finalisation of the rule been significantly delayed and it will not be in place before the end of 2014. Action will be taken prior to, or in conjunction with, action on the 2015 standards rule (EPA, 2014).

Sources: DOE, EPA, IEA, EIA.

The **Emergency Economic Stabilization Act** authorised the Energy Improvement and Extension Act of 2008, which provided several provisions related to tax credits and exemptions for alternative fuels and fuel-efficient technologies.

The **American Recovery and Reinvestment Act of 2009** provided support for a variety of alternative fuel and advanced vehicle technologies through grant programmes, tax credits, R&D, fleet funding, and other measures.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, extended and reinstated several alternative fuel tax credits. The law extended until 31 December 2011 the qualified alternative fuel vehicle property tax credit, the volumetric

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ethanol excise tax credit, and the ethanol and biodiesel producer tax credits. It also reinstated, for the duration of 2011, the alternative fuel and alternative fuel mixture excise tax credits, as well as the biodiesel mixture excise tax credit.

The **American Taxpayer Relief Act of 2012** extended and reinstated several alternative fuel incentives. The law reinstated, for the duration of 2013, the alternative fuel infrastructure tax credit, biodiesel income tax credit, biodiesel mixture excise tax credit, and alternative fuel mixture excise tax credits. It also extended until 31 December 2014 the second-generation biofuel producer tax credit and second-generation biofuel plant depreciation deduction allowance. In addition, it extended discretionary funding for a variety of alternative, fuel-related programmes.

Some states have also introduced regulations to support the expansion of renewable energy use in the transport sector. In California, for example, the **low carbon fuel standard** (LCFS) requires producers of petroleum-based fuels to reduce the carbon intensity of their products, beginning with a quarter of a percentage in 2011 culminating in a 10% total reduction in 2020. Petroleum importers, refiners and wholesalers can either develop their own low-carbon fuel products, or buy LCFS credits from other companies that develop and sell low-carbon alternative fuels, such as biofuels, electricity, natural gas or hydrogen.

HEATING AND COOLING

Renewable energy use for heat in the United States stood at 1.7 exajoules (EJ) in 2012, of which 0.6 EJ was consumed in buildings, and 1.0 EJ in industry. The use of renewable heat in the latter has declined by 0.3 EJ since 2007, owing to overall decline in industrial energy use for heat as well as to a drop in production of pulp and paper and wood products in the same period. Overall, renewable energy accounted for 10% of total energy use for heat in 2012 in the United States.

Bioenergy is by far the largest renewable energy source for heat in both industry and buildings (1.6 EJ in 2012), whereas solar thermal (0.1 EJ) and geothermal energy (0.01 EJ) play only a relatively small but growing role. In addition, there is a rapidly expanding heat pump market. According to the Department of Energy, 50 000 ground-source heat pumps are installed each year in the United States.

The recognition of the role of renewable energy for heating in buildings and industry has increased over recent years, and led to the adoption of support measures on both federal and state levels. The federal investment tax credit supports solar water and space heating, ground-source heat pumps, as well as use of geothermal energy for heat in commercial buildings, industry and agriculture, among other technologies. A similar tax credit is also provided for residential energy equipment, including solar water-heating systems and ground-source heat pumps.

A considerable number of states have adopted additional support measures for renewable heat, such as the solar thermal programme in California, the home heating and cooling programme in Massachusetts and the ground-source heat pump tax credit in Iowa.

The DOE **Building Technologies Office** supports a range of R&D programmes that foster emerging technologies, including heating and cooling from renewable sources of energy. DOE, along with industry partners and researchers, also develops best practices, tests and guides designed to reduce market barriers and increase public awareness of these energy-saving technologies.

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The **Emerging Technology Office** conducts research in space heating and cooling technologies, with a goal of realising aggregate energy savings of 20% relative to a 2010 baseline. The Emerging Technology Office also conducts research in water-heating technologies, including solar and heat pump technology, with a goal of realising energy savings of 60% over 2010 usage. At present, for example, it supports research programmes related to the use of renewable energies in space heating and cooling with a focus on ground-source heat pump and geothermal heat pump technology and integration of optimised heat exchanger designs into new products and space-conditioning systems.

ASSESSMENT

In the United States, the deployment drivers of a portfolio of renewable sources remain robust, with strong state-level mandates, very good renewable resources, increasingly competitive deployment opportunities and innovative financing models for distributed solar PV. The energy portfolio strategies of utilities and large corporate entities are also driving deployment. Utilities are building onshore wind plants hand in hand with natural gas power plants to take advantage of the hedging value of low marginal cost wind power and guard against potentially higher gas prices in the years to come. Announced federal regulations on power plant emissions are also likely to boost renewable electricity use over the medium to long run. Moreover, President Obama has set a goal to double renewable energy production from wind, solar and geothermal sources by 2020 and has supported a number of policies to facilitate this goal, such as more efficient permitting of clean energy on federal lands and upgrading the electricity grid. The country has also supported policies to promote the use of renewable energies in the transport sector and the heating and cooling sector.

Renewable energy sources contributed 6.4% TPES in 2013 and 12.9% to electricity generation. The EIA's *Annual Energy Outlook 2014* projects that renewable generation will account for 16% of total electricity generation by 2040. However, IEA's medium-term forecasts and long-term scenario analysis suggest that progress will be much faster. The *Medium-Term Renewable Energy Market Report 2014* forecasts that over 16% of US electricity generation will come from renewables as early as 2020 (IEA, 2014b). In IEA scenario analysis, renewables account for 23% of electricity generation in 2035 under the New Policies Scenario and for almost 39% under the 450 Scenario (IEA, 2013).

Still, a number of uncertainties characterise the outlook. The durability of federal tax incentives for some forms of renewable energy, for example, remains a persistent uncertainty. In early 2013, the federal government extended, for one year, its production tax credit for wind. The renewed credit removed its "placed in service" requirement for projects to qualify for its new end-2013 deadline. Instead, plants merely need to begin construction by that date, effectively allowing potential capacity to benefit from the extension for more than a year. In 2013, onshore wind additions fell to 1.0 GW, a small fraction of more than 13 GW added in 2012, as a result of uncertainty surrounding the extension of the production tax credit. With a one-year PTC extension granted in early 2013, a more robust outlook for onshore wind projects has emerged, at least during 2014 and 2015.

Yet, there is uncertainty over whether there may be yet another renewal of the PTC, as per a bill introduced into the US Congress in September 2014. Such uncertainty continues to undermine investor confidence and contributes to the volatile pattern of annual wind deployment in the United States. Alternatively, extending the PTC for a fixed period of time while gradually reducing its level to zero on a permanent basis would provide greater investor certainty and spur continued reductions in wind costs.

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Solar tax incentives from the ITC and RTC run only through 2016, though the ITC will be reduced, rather than eliminated, from 30% to 10% at this time. The ITC reduction may create volatility in utility-scale solar PV deployment, though expectations of continued falls in solar PV system costs should provide some offsetting boost to development. Distributed solar PV generation costs in some states should become increasingly attractive versus the prices that households and industry pay for electricity. Still, rooftop solar PV system prices remain much more expensive in the United States than in markets such as Germany and Italy owing to high soft costs (IEA, 2014b). The Sunshot Initiative, if realised, would significantly reduce the costs of residential and commercial scale solar PV, as well as that for utility-scale systems, installed by the end of the decade.

Currently, 45 US states offer net energy metering. Combined with falling solar PV costs, this rate structure has been an important driver for the scale-up of small solar PV. Increasingly favourable economics for self-consumption are also creating new opportunities for deployment, without explicit subsidies. These trends are reinforced by the advent of third-party leasing schemes that help defray high upfront investment costs of ownership. Still, there is ongoing debate in at least 15 states over fair rules, total net metering programme capacity levels and appropriate electricity rate design for allocating the costs (e.g. recovery of fixed grid costs) and the benefits from fast-growing distributed solar PV. States may need to continually address system concerns as they arise. Ultimately, policy makers may need to consider more fundamental changes to the electricity tariff structure in order to better recover fixed grid investment costs and decrease system costs. However, changes would need to be done with care, avoiding retroactive measures, and strike a balance among various risks in order to continue providing a supportive framework for solar PV growth.

State renewable portfolio standards policies continue to be a significant driver for renewable energy growth in the United States and have largely held up against recent political challenges (Barbose, 2013). In total, 29 states (and the District of Columbia employ a mandatory RPS and eight states have renewable energy goals. Eighteen states (and D.C.) offer performance-based financial incentives, including feed-in tariffs or tradable renewable energy credits (RECs) schemes. Legislators in some states have drafted proposals to roll back RPS schemes to control policy costs, though none have rescinded the obligations. Still, policy uncertainty over the outcome of these debates could have the effect of delaying some renewable investments.

The DOE's loan guarantee programme has been instrumental in spurring innovation, helping investors access more attractive financing terms and driving commercial deployment in some less developed renewable technologies. The extension and expansion of the Section 1703 loan programme to include less developed technologies that are already commercialised, such as solar thermal electricity, would help to maintain this momentum.

The IEA also acknowledges federal efforts to drive renewable energy development through other mechanisms. The President's Climate Action Plan has sought to facilitate the deployment of solar, wind and geothermal energy on federal lands through prioritised permitting and environmental review processes. Between June 2013 and June 2014, 1 600 MW of new solar, wind and geothermal capacity had been permitted on federal land. Compared to Europe, offshore wind has remained an undeveloped resource in the United States. The federal government also auctioned a number of leases to build the first wind farms offshore Rhode Island and Massachusetts. Further developments are expected offshore Virginia.

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Following a proposal in 2013 to cap carbon emissions on new power plants, in June 2014 the US EPA released its Clean Power Plan, guidelines that would cut, for the first time, carbon pollution from existing power plants. The plan aims at reducing CO_2 emissions of the power sector by 30% below 2005 emission levels by 2030. For now, a degree of uncertainty exists over how the final rules will look and their ultimate timeline. However, these changes should provide a broad boost for renewables over the medium to long term. The rules would stimulate more retirements of coal plants than currently planned and increase demand for zero- to low-emission generation. While natural gas would likely continue to play a large part, the attractiveness of renewables outside existing state-level portfolio standards and incentive frameworks would grow. With 20 states having renewable portfolio standards that come due by 2022, these rules could provide a framework that spurs the adoption of longer-term state targets and boosts the value of renewables (and energy efficiency) as they move to an environment of lower financial incentives.

Over the medium term, the transmission grid should not act as a significant barrier to renewable energy deployment, though constraints may remain at regional and state levels. In this regard, President's Obama's Climate Action Plan has made the expansion and modernisation of the transmission grid a priority. The IEA welcomes efforts to refine the application process for transmission lines and efforts to expedite the permitting process on federal lands. Over the long term, the *Renewable Electricity Futures* study prepared by NREL indicates that the estimated electricity demand in 2050 could be met with 80% of generation from renewable energy technologies (NREL, 2012) if there is increased electric system flexibility from a portfolio of supply- and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations.

The power system needs to accommodate more generating capacity and increased renewable sources, which are located away from load centres, particularly variable sources (wind and solar) and geothermal. To facilitate more co-ordinated grid development, the Federal Energy Regulatory Commission order No. 1000 introduced in 2011, encourages regional transmission planning that accounts for state and federal energy policies and better cost allocation among the beneficiaries of transmission projects. In general, a greater federal role in enabling and co-ordinating energy priorities with states and regions can be beneficial and the federal agencies should continue to work to improve regional and interregional electricity planning processes. Opening up of RPSs schemes in the states, such as in the case of the Regional Greenhouse Gas Initiative, to renewable electricity produced in other states or regional transmission operator supply areas could provide greater incentives to investors to locate renewable electricity generation at the most economic production sites.

Finally, proposals to amend the US renewable fuels standard have created difficulty in the market for renewable transport fuels. With the volume of ethanol that can be blended before reaching the "blend wall" set to shrink with a reduction in gasoline consumption over the medium term, and biofuels qualifying for the "advanced biofuels" category under the RFS2 available only at limited volumes in the United States, the outlook on US ethanol output is substantially more pessimistic than previously forecast (IEA, 2014b). The substantial delay in publishing the final rulemaking for the 2014 RFS2 standard is undermining the framework conditions for biofuel production that had been instrumental in spurring investments and driving the growth of the biofuels industry.

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RECOMMENDATIONS

The government of the United States should:

- *Offer greater durability and predictability of fiscal incentives for renewable energy in order to maintain investor confidence.*
- *Continue to extend and expand the federal loan guarantee programme to support the deployment of less developed renewable technologies.*
- *Foster co-operation and exchange of best practices between federal and state levels by means of, for example, FERC-NARUC collaborative programmes on grid modernisation, or the State and Local Energy Efficiency Action Network on the interaction of state renewable portfolio standards and federal incentives or the harmonisation and interoperability of state-level standards with a view to enable interstate and inter-RTO trade of renewable certificates.*
- *Continue to facilitate the deployment of solar, wind and geothermal energy on federal public lands and marine areas through streamlined permitting and environmental review processes.*
- *Review, in close collaboration with industry and other relevant stakeholders, the existing renewable fuels standard in light of the new framework conditions, to ensure a solid, predictable and achievable framework for biofuels production and use in the years ahead.*

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6. CLIMATE CHANGE

Key data (2012)

Total GHG emissions excluding LULUCF*: 6 487.8 $MtCO_2$-eq, +4.3% since 1990

Total GHG emissions including LULUCF*: 5 546.3 $MtCO_2$-eq, +2.7% since 1990

CO_2 emissions from fuel combustion: 5 074.1 $MtCO_2$-eq, +4.2% since 1990

CO_2 emissions by fuel: oil 40.5%, coal 31.8%, natural gas 27.1%, other 0.6%

CO_2 emissions by sector: power generation 41.1%, transport 32.9%, manufacturing and construction 9.8%, residential 5.9%, other energy 5.6%, commercial and services 4.7%

* Source: UNFCCC.

OVERVIEW

In 2009, the United States announced a goal of reducing greenhouse gas (GHG) emissions in the range of 17% from 2005 levels by 2020.[1] In the period since the last in-depth review (IEA, 2008) was conducted, there have been sizeable reductions in emissions. While past attempts to introduce a carbon price have failed, the current approach to meet climate change objectives at the federal level using regulation (including stringent vehicle fuel economy standards, regulations for new and existing power plants, and others) appears to be delivering results, alongside the boom in natural gas production.

GHG EMISSIONS

According to the UNFCCC, total GHG emissions in the United States were 6 487.8 million tonnes of carbon dioxide-equivalent ($MtCO_2$-eq) in 2012. Emissions were essentially CO_2 (82.8%), while the remainder was made up of methane (CH_4, 8.5%), nitrous oxide (N_2O, 6.1%), hydrofluorocarbons (HFCs, 2.3%), perfluorocarbons (PFCs, 0.1%) and sulphur hexafluoride (SF_6, 0.1%). Including land use, land-use change and forestry (LULUCF), GHG emissions were lower at 5 546.3 Mt CO_2-eq and CO_2 accounted for 79.4%. CH_4 was at 10.2%, N_2O at 7.4%, HFCs at 2.7%, PFCs at 0.2%, and SF_6 at 0.1%.

GHG emissions have declined by 7.5% since 2002 and were 10.2% lower in 2012 than in 2005. On the whole, however, they are 4.3% higher than in 1990. In the ten years to 2012, emissions of SF_6 have experienced the strongest decline of 50.1%, while CO_2 emissions have fallen by 9%. Conversely, emissions of HFCs have increased by 35% and emissions of N_2O are 1.7% higher. GHG emissions peaked in 2007 at 7 287.8 $MtCO_2$-eq, which was also the peak year for CO_2 emissions (6 116.4 Mt).

1. In addition, on 11 November 2014, the United States and China made a joint announcement on climate change and clean energy co-operation including a new US target to cut net GHG emissions 26% to 28% below 2005 levels by 2025. This announcement has not been taken into account in the preparation of this report.

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According to the United States Environmental Protection Agency (EPA, 2014c), in 2012 GHG emissions were estimated at approximately 6 742 $MtCO_2$-eq. The data indicate that the power generation sector is the largest emitting sector and accounts for 31% of total GHG emissions. This is slightly lower than the 33% of 2011. EPA informs that emissions from this sector decreased by 6.3% during 2012 as a result of a switch from coal to natural gas in electricity generation, a slight decrease in demand attributable in part to increased energy efficiency, such as appliance efficiency standards.

The EPA estimates direct emissions (excluding the transport, residential and commercial sectors) at 3 129 $MtCO_2$-eq, made up of emissions from the power generation sector (66.8%), petroleum and natural gas transportation (6.9%), refineries (5.5%), chemical manufacturing (5.4%), metal manufacturing (3.4%), minerals production (3.4%), waste management (3.2%), pulp and paper manufacturing (1.3%), and others (3.9%). From 2011 to 2012, direct emissions declined by 4.5%, mainly thanks to a fall in emissions from electricity generation.

Table 6.1 GHGs and source categories that reported the largest quantity of each gas, 2012

GHG	The source contributing most to reported 2012 GHG emissions
CO_2	Electricity generation and stationary combustion.
CH_4	Municipal landfills, petroleum and natural gas systems.
N_2O	Nitric acid production, electricity generation and adipic acid production.
SF_6	Electrical equipment use and magnesium production.
NF_3	Electronics manufacturers.
HFCs	HCFC-22 production and HFC-23 destruction.
PFCs	Aluminium production and electronics manufacturers.

Source: EPA (2014c), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012*, EPA, Washington, D.C., April.

ENERGY-RELATED CO_2 EMISSIONS

SOURCES OF CO_2 EMISSIONS

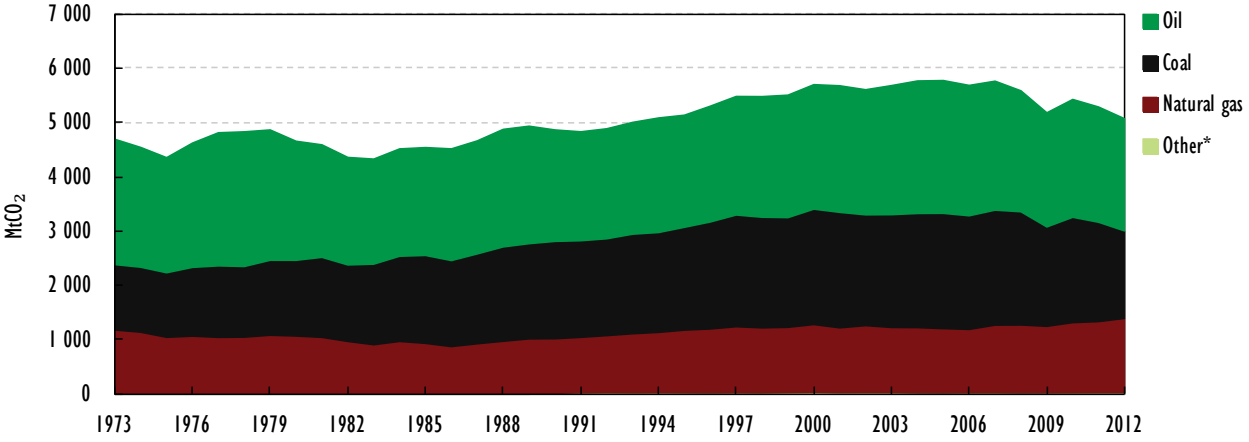
Total CO_2 emissions from fuel combustion in the United States were 5 074.1 Mt in 2012, accounting for 78.2% of GHG emissions. Energy-related emissions have increased by 4.2% since 1990, growing at a similar rate as GHG emissions. In the ten years since 2002, CO_2 emissions have declined by 9.5%. The most significant decline was in 2009 when CO_2 emissions fell by 7.2%.

The power generation sector is the largest emitter of CO_2 in the United States, with 2 086.6 Mt in 2012. This accounted for 41.1% of total CO_2 emissions. Total emissions in this sector have declined by 10.9% since 2002, albeit still 11.8% higher than in 1990. Emissions from power generation peaked in 2007 at 2 458.9 Mt. Other energy sectors, including refining and other transformations, emitted 283 Mt in 2012, or 5.6% of the total, which is 7.3% lower than the peak of 305.2 Mt in 2011. Transport is the second-largest sector with 32.9% of total emissions and CO_2 from this sector has declined by 3.3% since 2002. Manufacturing and construction represent 9.8% of energy-related CO_2 emissions, while residential and commercial sectors account for 5.9% and 4.7%, respectively. Emissions from manufacturing, residential and commercial use have also fallen over the past decade, by 19.3%, 14.8% and 12.5%, respectively.

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Energy-related emissions by fuel are from oil (40.5%), coal (31.8%) and gas (27.1%), with 0.6% from industrial waste. These proportions are in line with the share of total primary energy supply (TPES) of the same fuels. Since 2002, the share of coal in total CO_2 emissions has fallen from 36.4% while it has increased for gas from 22.1%. Oil's share has remained relatively unchanged. In aggregate emissions, those from coal have declined by 21%, those from oil by 10.3%, while those from gas have increased by 11%.

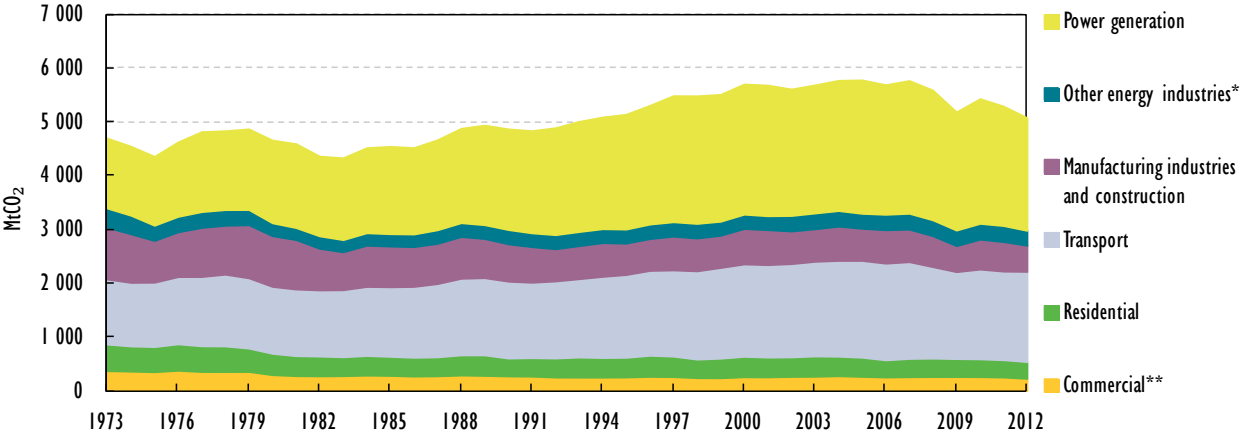
Figure 6.1 CO_2 emissions by fuel, 1973-2012



* *Other* includes industrial waste and non-renewable municipal waste.

Source: IEA (2014), *CO_2 Emissions from Fuel Combustion*, OECD/IEA, Paris.

Figure 6.2 CO_2 emissions by sector, 1973-2012



* *Other energy industries* includes refining and other transformations and energy own use.

** *Commercial* includes commercial and public services, agriculture/forestry and fishing.

Source: IEA (2014), *CO_2 Emissions from Fuel Combustion*, OECD/IEA, Paris.

PROJECTED EMISSIONS

Taking into account policies and measures being implemented as of September 2012 and economic projections, total gross US GHG emissions are projected to be 5.3% lower than 2005 levels in 2020 (DOS, 2014). The US *Biennial Report*, as part of the 2014 Climate Action Report, outlines how action on climate change puts the United States on a path to reach the ambitious but achievable goal of reducing GHG emissions in the range of 17% below 2005 levels by 2020 (DOS, 2014a). Implementation of the actions contained in the Climate Action Plan will achieve substantial additional emissions reductions.

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Between 2005 and 2011, total gross GHG emissions declined significantly as a result of a combination of factors, including the economic downturn and fuel switching from coal to natural gas. Emissions are projected to rise gradually between 2011 and 2020. Nonetheless, they are projected to remain below the 2005 level through 2030, despite significant increases in population (26%) and GDP (69%) over the same period. It should be noted that since 2012, the United States has continued to implement a number of new and substantial mitigation policies under the Climate Action Plan, including a major regulatory proposal on power plant emissions, a new suite of efficiency standards, and a comprehensive new approach to reducing methane. These new policies are not included in projections discussed here but have the potential to substantially reduce US emissions. Thanks to the policies in place in 2012, CO_2 emissions are expected to decline by 7.6% between 2005 and 2020. In-progress and new policies would realise additional reductions beyond that. Between 2005 and 2011, emissions declined by 8.1%, but they are projected to increase slightly between 2011 and 2020. Energy-related CO_2 is projected to decline slightly over this time period, while non-energy CO_2 emissions (e.g. process emissions) are expected to grow between 2011 and 2020.

According to estimates contained in the EIA *Annual Energy Outlook 2013* and its Reference Case, energy-related CO_2 emissions in 2020 are projected to be 8.8% below their 2005 level, totalling 5 243 teragrammes CO_2 in 2020, assuming current policies continue. On average, energy-related CO_2 emissions decline by 0.6% per year from 2005 to 2020, compared with an average increase of 1.2% per year from 1990 to 2005. Reasons for the decline include growing use of renewable technologies and fuels; vehicle efficiency improvements; slower growth in electricity demand; increased use of natural gas; and continued economic recovery (DOS, 2014).

CARBON INTENSITY

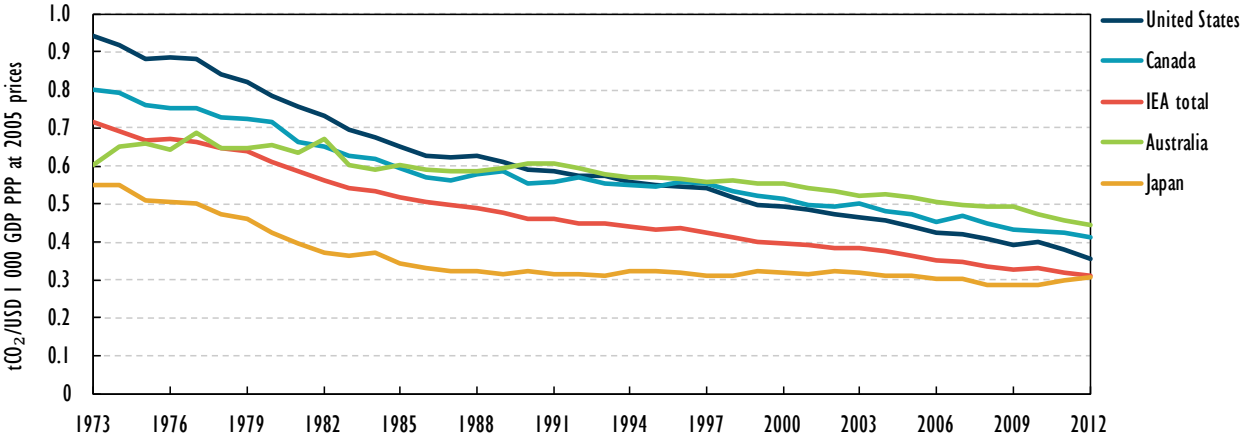
The carbon intensity of the economy, measured as the ratio of CO_2 emissions to real GDP, was 0.36 tonnes of CO_2 per USD 1 000 with purchasing power parity (tCO_2/USD 1 000 PPP) in 2012 (Figure 6.3). This is higher than the IEA average of 0.31 tCO_2/USD 1 000 PPP. The United States is ranked seventh-highest with regard to CO_2 emissions per GDP among IEA member countries, behind Estonia, Australia, the Czech Republic, Korea, Poland and Canada (in that order). Carbon intensity in the United States has been on a declining trend since 1970 when it amounted to 1 tCO_2/USD 1 000 PPP. Emissions per GDP have declined by 24.5% since 2002, which is a faster rate of decline compared to 19.1% for the IEA average.

Carbon intensity of total energy supply was 56.6 tCO_2 per terajoule (tCO_2/TJ) in 2012, which is 4.6% lower than in 2002. One of the key drivers for the fall in carbon intensity has been an increase in motor vehicle fleet efficiency. With regard to the carbon intensity of energy production, the United States ranks eleventh-highest among IEA member countries, after Australia, Poland, Estonia, Greece, Japan, Ireland, Turkey, the Czech Republic, Luxembourg and Germany. The average IEA carbon intensity of energy supply is 55.3 tCO_2/TJ, down by 3% compared to 2002.

In the electricity and heat generation sector, carbon intensity was 473.2 grams of CO_2 per kilowatt hour (gCO_2/kWh). This ratio has declined by 16.7% since 2002, falling at a faster rate than the IEA average which declined by 11.8% over the same period. The IEA average intensity was 411.9 gCO_2/kWh in 2012. The United States is ranked ninth-highest with regard to carbon intensity of its power generation sector among IEA members, behind Australia, Greece, Estonia, Poland, Japan, Korea, the Czech Republic and the United Kingdom.

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Figure 6.3 Energy-related CO_2 emissions per GDP in the United States and in other selected IEA member countries, 1973-2012



Source: IEA (2014), *CO_2 Emissions from Fuel Combustion*, OECD/IEA, Paris.

INSTITUTIONAL FRAMEWORK

At the national level, a number of federal agencies, commissions, and advisory offices to the President are involved in developing, co-ordinating, and implementing policies to act on climate change. The **Executive Office of the President**, overseen by the President's Chief of Staff, includes a number of offices that play important roles in US climate policy, such as the Domestic Policy Council, the Office of Science and Technology Policy, the Council on Environmental Quality, and the National Security Council. The legislative branch consists of the two bodies in the US Congress – **the House of Representatives** (the House) and the **Senate** – which are the primary law-making bodies of the US government. In Congress, climate change is addressed by individual members and committees that are charged with developing legislation on energy and other issues relevant to climate change. In the House, the Committees on Appropriations; Agriculture; Science, Space and Technology; Ways and Means; Natural Resources; and Energy and Commerce, among others, play essential roles in developing legislation related to climate change.

In the Senate, the Committees on Environment and Public Works; Finance; Foreign Relations; Agriculture; Commerce, Science, and Transportation; and Energy and Natural Resources develop legislation and are critical venues for debate. Because the legislative process requires the support of both chambers of Congress and also involves the executive branch, a strong base of support is necessary to enact new legislation. As climate legislation is developed, this high threshold will remain very relevant (DOS, 2014).

The **judicial branch** is the federal court system responsible for, among other things, interpreting the US Constitution. It plays a significant role in defining the jurisdiction of the executive departments and, in the case of climate change, in interpreting laws related to the implementation of climate and energy policies.

Some two dozen federal agencies and executive offices work together to advise on, develop and implement policies that help the US government reduce GHG emissions and promote a clean energy economy, and to assess and respond to the adverse effects of climate change. As with many other policy areas, jurisdiction for energy policy is shared by federal and state governments. Two of the most important federal institutions are the Department of Energy and the Environmental Protection Agency.

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The Department of Agriculture (USDA) and the Department of Interior (DOI) also play a role. The USDA Climate Change Program Office (CCPO) co-ordinates the department's responses to climate change, focusing on the implications of climate change on agriculture, forests, grazing lands, and rural communities. In September 2009, DOI launched a co-ordinated strategy to address current and future impacts of climate change on America's land, water, wildlife, cultural heritage and tribal resources.

The **Department of Energy** (DOE) has made addressing the effects of climate change a priority and climate change mitigation is a cornerstone of DOE's strategic plan. DOE supports research and innovation in clean energy technologies, energy efficiency policies and President Obama's Climate Action Plan. DOE also identifies vulnerabilities and devises solutions to enhance the climate resilience of energy sources and infrastructure. It is a leading sponsor of research and investment in emerging low-carbon technologies, and supports renewable energy programmes.

The **Environmental Protection Agency** (EPA) is responsible for the development and enforcement of environmental regulations based on laws enacted by Congress. A key role of the EPA is to address climate change and improve air quality. It has developed, implemented, and proposed a number of measures to reduce carbon pollution and other GHG emissions from the transport and electricity generation sectors.

Throughout the country, many regional, state, and local policies and initiatives exist to complement federal efforts to reduce GHG emissions. These include actions that directly regulate GHG emissions, as well as policies that indirectly reduce emissions. The federal government supports state and local government actions that reduce GHG emissions by sponsoring policy dialogue, issuing technical documents, facilitating consistent measurement approaches and model policies, and providing direct technical assistance As of July 2013, 21 states had adopted a state GHG reduction target or limit, although stringency, timing, and enforceability vary among them. State-wide GHG targets are non-regulatory commitments to reduce GHG emissions to a specified level in a certain timeframe (e.g. 1990 levels by 2020). Such targets can be included in legislation, but are more typically established by the governor in an executive order or a state advisory board in a climate change action plan (DOS, 2014a).

POLICIES AND MEASURES AT THE FEDERAL LEVEL

In the absence of a national policy using a market-based instrument, such as a carbon tax or cap-and-trade mechanism, the United States utilises a combination of near- and long-term regulatory and voluntary approaches for climate mitigation.[2] A large number of policies and measures, including federal-, state- and local-level strategies, are being implemented across the economy, including in the transport, energy supply, energy end-use, industrial processes, agricultural waste, and federal facilities sectors. In addition, the United States utilises cross-cutting policies and measures to encourage cost-effective reductions across multiple sectors.

In 2009, newly elected President Obama pledged that by 2020, the United States would reduce its GHG emissions in the range of 17% below 2005 levels if all other major economies agreed to limit their emissions as well. In June 2013, President Obama confirmed his commitment to achieve this goal and since 2009 there have been sizeable reductions in emissions as well as improvements in energy efficiency.

2. In 2009, there was an attempt to introduce the first GHG emissions trading scheme via the American Clean Energy and Security (ACES) Act of 2009, also known as the Waxman-Markey bill. The Act was passed by the House of Representatives on 26 June 2009, and had the support of the president, but failed to advance in 2010 for lack of sufficient support in the Senate.

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Table 6.2 Key parameters of the US economy-wide emissions reduction target

Parameters	Targets
Base year	2005
Target year	2020
Emissions reduction target	In the range of 17% below 2005 levels.
Gases covered	CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and NF_3.
Global warming potential	100-year values from the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (IPCC 2007).
Sectors covered	All IPCC sources and sectors, as measured by the full annual inventory (i.e. energy, transport, industrial processes, agriculture, LULUCF, and waste).
Land use, land-use change, and forests (LULUCF)	Emissions and removals from the LULUCF sector will be accounted using a net-net approach and a 2005 base year, including a production approach to account for harvested wood products. The United States is considering approaches for identifying the impact of natural disturbances on emissions and removals.
Other	To be in conformity with US law.

Notes: Consistent with the formal UNFCCC inventory reporting guidelines for developed countries (IPCC, 2006), the Inventory of US Greenhouse Gas Emissions and Sinks, which will be submitted to the UNFCCC in April 2015, will utilise 100-year global warming potential values from the IPCC Fourth Assessment Report (IPCC, 2007).

Source: DOS (US Department of State) (2014), *United States Climate Action Report 2014: First Biennial Report of the United States of America, Sixth National Communication of the United States of America Under the United Nations Framework Convention on Climate Change*, Washington, D.C.

THE PRESIDENT'S CLIMATE ACTION PLAN

On 25 June 2013, President Obama announced a package of new policies and measures to address climate change. The package, the President's Climate Action Plan, contained a series of measures and policies to reduce the country's GHG emissions, prepare the country for the impacts of climate change, and lead international efforts to combat climate change (IEA, 2013). In the absence of congressional agreement on climate policy, the plan relies exclusively on executive powers already granted to the Administration through existing legislation. The plan directs the EPA to develop regulations to control CO_2 emissions from power plants, using existing statutory authority.

The Climate Action Plan is built upon three key pillars:

- Cut carbon pollution in the United States by:
  - reducing CO_2 from new and existing power plants under the Clean Air Act. In June 2014, EPA proposed regulations for new and existing power plants that are expected to be finalised by June 2015
  - increasing clean energy, through the development of renewable energy on federal lands, government purchasing, and support for clean energy innovation for biofuels, batteries, and carbon capture and storage (CCS)
  - wasting less energy, through energy efficiency, including in buildings, appliances, and heavy vehicles
  - focusing on highly potent GHGs: HFC and methane emissions.
- Prepare the United States for the impacts of climate change by:
  - working with local agencies to make communities' infrastructure more resilient, including piloting coastal flooding resilience in the areas affected by Hurricane Sandy

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- providing climate preparedness data and tools
- maintaining agricultural productivity by helping farmers adapt to drought.

- Lead international efforts to combat global climate change and prepare for its impacts by:
  - bilateral and multilateral climate processes
  - ending US support for financing coal plants in developing countries.

In June 2014, the White House published an update of the Climate Action Plan. The Progress Report sets out details of the policies implemented since the plan was published in 2013.

Box 6.1 The social cost of carbon

US government agencies are required by executive order to assess the costs and benefits of proposed regulations. In recent years, cost-benefit assessments have included potential economic and human welfare benefits of reduced CO_2 emissions. Specifically, federal agencies such as EPA and DOE use a metric known as the social cost of carbon (SCC) to attach a dollar value (USD) of these benefits to proposed regulatory actions. Specifically, the SCC is a present-value estimation of the avoided worldwide damages associated with a one metric tonne reduction in CO_2 in a given year. These damages include, but are not limited to, changes in net agricultural productivity, human health, and property damages from increased flood risk.

Federal agencies use the SCC to estimate the climate benefits of rule-makings, whether these rule-makings are expressly designed to reduce CO_2 emissions or not.

In 2010, in an effort to promote consistency across federal agencies in how they value the social benefits of reduced CO_2 emissions, the US government selected four SCC values for use in regulatory analyses. These values were first applied to DOE's energy conservation standards for small motors in 2010. The US government updated its SCC estimates in 2013 to reflect how climate change impacts are represented in the latest peer-reviewed versions of the three academic models from which the2013 SCC is estimated. The four SCC estimates for 2020 are: USD 12, USD 43, and USD 65 per metric tonne (average SCC at discount rates of 5%, 3%, and 2.5%) and USD 129 per metric tonne (95th percentile SCC at a 3% discount rate, representing the potential for higher-than-average damages), in 2007 US dollars.

The SCC is meant to be a comprehensive estimate of global climate change damages; however, given current modelling and data limitations, it does not include all important damages. The IPCC Fourth Assessment Report noted that it is "very likely that it [SCC] underestimates" the damages. The climate-economic models used to estimate the SCC, known as integrated assessment models, do not currently include all the important geophysical, ecological and economic impacts of climate change recognised in the academic literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research. Nonetheless, the SCC is a useful measure to assess the benefits of CO_2 reductions.

Sources: DOS (US Department of State) (2014), *United States Climate Action Report 2014: First Biennial Report of the United States of America, Sixth National Communication of the United States of America Under the United Nations Framework Convention on Climate Change*, Washington, D.C.; DOE (US Department of Energy) (2014*), Strategic Plan 2014-2018*, DOE, Washington, D.C., March; EPA (2014b), *GHGRP 2012: Reported data* data set, EPA website, www.epa.gov/ghgreporting/ghgdata/reported/index.html, accessed on 8 July 2014.

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DEPARTMENT OF ENERGY'S STRATEGIC PLAN

The first strategic objective of the DOE is to advance the goals of the President's Climate Action Plan by supporting prudent development, deployment, and efficient use of "All-of-the-Above" (strategy for energy) energy resources that also create new jobs and industries. DOE has committed to energy solutions that make best use of domestic energy resources and help the nation achieve an approximately 17% reduction in GHG emissions below 2005 levels by 2020, and further reductions in the post-2020 period. The EPA Priority Goal (fiscal year (FY) 2014/15) for this strategic objective implements elements of the Climate Action Plan, including:

- supporting the goal of reducing cumulative carbon pollution by three billion metric tonnes by 2030 through standards set since 2009 and promulgating new standards for consumer products and industrial equipment by the end of calendar year 2016
- providing up to USD 8.0 billion in loan guarantees for advanced fossil energy technologies that reduce GHG emissions by the end of FY 2017.

CLEAN AIR ACT

The primary law governing air pollution control is the Clean Air Act (CAA). This Act defines the role of the US EPA and state, local and tribal air programmes in protecting and improving air quality and the stratospheric ozone layer by regulating emissions from mobile and stationary sources.

In April 2007, the Supreme Court of the United States ruled that GHGs are air pollutants covered by the Clean Air Act and must be regulated by the US Environmental Protection Agency (EPA) if they may reasonably be anticipated to endanger public health or welfare. In December 2009, EPA issued an "endangerment finding", that found that current and projected levels of six GHGs threaten the health and human welfare of current and future generations. Since this finding, EPA has set in place rules and regulations to limit GHG emissions from motor vehicles and has proposed national limits on the amount of GHG emissions that new and existing power plants will be allowed to emit. It has also issued guidelines for states to implement carbon intensity limits for existing power plants.

Carbon pollution standard for new power plants under the Clean Air Act

On 20 September 2013, the EPA announced implementation of a proposal to limit GHG emissions from new power plants.

The proposal for new sources will establish new source performance standards (NSPS) to limit emissions of CO_2 from newly built fossil fuel-fired power plants. The impact of the proposed rule is expected to be limited because no new coal-fired plants are expected to be built, even in the absence of new standards, largely due to economic factors. The EIA forecasts that all newly built fossil fuel capacity will be fired with natural gas, through the year 2035.[3] Only 2.9 GW of incremental coal-fired capacity (11 units) will be added in the period between 2013 and 2017. Over the same period, 34 GW of gas-fired capacity will be added or 242 units (see Chapter 10 on Coal for more details).

3. This excludes planned capacity and new coal-fired capacity with carbon capture and storage (CCS) technology built in response to federal incentives.

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The Clean Power Plan for existing power plants under the Clean Air Act

At the time of the announcement of the Climate Action Plan, there were no federal standards for CO_2 emissions from existing power plants. In June 2014, the EPA proposed the Clean Power Plan to cut carbon pollution from existing power plants.

The EPA rule requires states to achieve specific emission rate targets on a prescribed timeline. Specifically, the EPA proposes state-specific, rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. This rule, as proposed, builds on measures already under way to reduce CO_2 emissions from existing fossil fuel-fired power plants. The proposal was announced on 2 June 2014 for comment, with the intention of having the final rule in place by June 2015.

The proposed rule sets a carbon intensity limit in pounds of CO_2 per MWh of electricity generated with adjustments for renewable energy, energy efficiency, and new and retained nuclear capacity. An adjusted intensity target is set for each state, taking into account the differing policy considerations, such as varying emissions reduction opportunities and existing state programmes and measures, as well as the characteristics of the electricity system in each state (in terms of utility regulatory structure, generation mix and electricity demand). The proposed rule provides states with considerable flexibility for meeting the state-specific goals established by the EPA in a manner that accommodates a diverse range of state approaches. Notably, while the proposal lays out state-specific CO_2 goals that each state is required to meet, it does not prescribe how a state should achieve them. Each of the states will be required to develop a plan, subject to EPA approval, which will contain a set of measures and a timeline, showing how it will achieve this limit in 2030, and also an interim target for 2020-29.

States have considerable flexibility to reach their adjusted intensity targets, drawing from plant-level efficiency improvements, re-dispatching coal generation to natural gas generation, increasing renewable energy and energy efficiency; and adding or retaining nuclear capacity. In addition, measures can include multi-state compliance approaches such as emissions trading (which is already utilised in California and a number of states in the US Northeast). As proposed, EPA estimates that the rule would result in approximately 370 $MtCO_2$ to 380 $MtCO_2$ reductions (annually) by 2020, and those numbers increase to approximately 550 $MtCO_2$ by the end of the rule period in 2030 (EPA, 2014d).

VEHICLE FUEL ECONOMY AND GHG STANDARDS

The road transport sector is the second-largest emitter of CO_2 in the United States. The sector, excluding international aircraft and marine transport, accounted for 35% of CO_2 emissions, 23% of CH_4 emissions, and 43% of N_2O emissions from fossil fuel combustion. The largest sources of transportation GHGs in 2011 were passenger cars (41.2%) and light-duty trucks (17.4%), which include sports utility vehicles (SUVs), pick-up trucks, and minivans (EPA, 2014a).[4]

Private vehicles, which include cars, light trucks, vans, and motorcycles, are used for 84% of all trips nationwide, with the number of vehicle miles travelled by passenger cars and light-duty trucks increased by 34% from 1990 through 2012. Greenhouse gas emissions from transportation have increased by about 18% since 1990 (EPA, 2014c).

4. Freight trucks (21%); rail (6.5%); and commercial aircraft (6.1%) accounted for the remainder.

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In this regard, the introduction of tighter Corporate Average Fuel Economy (CAFE) Standards and GHG standards for light-duty vehicles (LDVs) are welcome steps. The updated standards issued jointly by the National Highway Traffic Safety Administration (NHTSA) and EPA are projected to effectively cut by half vehicle GHG emissions and double average vehicle fuel efficiency compared with 2011 cars and light trucks. The national highway programme is expected to cut six billion metric tonnes of GHGs during the lifetimes of the cars and light trucks sold in model years 2012-25 —more than the total amount of US CO_2 emissions in 2010 (DOS, 2014). These new standards will result in substantial increases in fuel economy over the next 11 years, and are projected to require the overall fleet to reach an average CO_2 emissions level of 163 grams per mile in 2025, while nearly doubling new vehicle fuel economy (DOS, 2014). In addition to GHG emissions savings, the new standards will also reduce costs for US consumers by reducing the fuel import bill. Notably, the level of motor fuel tax (gasoline and diesel) is among the lowest in the IEA, and gasoline is considerably less expensive at the pump in the United States compared to any other IEA member countries.

REGIONAL, STATE AND LOCAL MEASURES

Within the United States, there are many regional, state and local policies and initiatives that complement federal efforts to reduce GHG emissions. These include actions that directly regulate GHG emissions, as well as policies that indirectly reduce emissions. The federal government supports state and local government actions that reduce GHG emissions by sponsoring policy dialogues, issuing technical documents, facilitating consistent measurement approaches and model policies, and providing direct technical assistance. Federal support of this kind helps state and local governments learn from each other to leverage best practice approaches, helping reduce overall time and costs for both policy adoption and implementation (DOS, 2014a).

State clean energy and emission policies

As is the case in other areas of public policy, US states have often led the federal government in experimenting with and adopting climate and energy policies (WRI, 2012). As of August 2013, 29 states had adopted some form of state GHG reduction targets or limits, which vary in stringency, timing and enforceability. In some cases, emissions reductions from US state policies can be significant, notably where policies are adopted in states with large economies and/or a large population base, and therefore larger GHG contributions.

State-wide GHG targets are non-regulatory commitments to reduce GHG emissions to a specified level in a certain timeframe (e.g. 1990 levels by 2020). Such targets can be included in legislation, but are more typically established by the state's governor in an executive order or by a state advisory board in a climate change action plan. State-wide GHG limits reduce emissions within a certain timeframe, but are regulatory in nature and more comprehensive than emission targets. These policies can include regulations to require GHG emission reporting and verification, and may establish authority for monitoring and enforcing compliance.

State-level renewable portfolio standards (RPS) policies also have a role to play in reducing GHG emissions. Individual **state legislatures** have the autonomy to determine RPS, which establish renewable energy deployment mandates. Utilities operating within the state are responsible for generating adequate renewable energy or buying renewable energy certificates (RECs) to meet the mandate. Eighteen states (and the District of Columbia) offer performance-based financial incentives, including feed-in tariffs (FITs) or tradable renewable energy credits (RECs) schemes.

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Regional Greenhouse Gas Initiative (RGGI)

Launched on 1 January 2009, the RGGI was the first US mandatory market-based cap-and-trade programme to reduce GHG emissions. It currently applies to 168 electricity generation facilities in nine Northeast and Mid-Atlantic states, which account for approximately 95% of CO_2 emissions from electricity generation in the region.[5] In February 2013, the participating states agreed to make significant revisions to the programme, capping CO_2 emissions at 91 million short tonnes per year in 2014 or a 45% reduction from the previous cap of 165 million short tonnes. The cap will then be reduced by 2.5% each year from 2015 through 2020. Under the initiative, nearly 90% of allowances are distributed through auction. By March 2013, cumulative auction proceeds exceeded USD 1.2 billion. Participating states have invested approximately 80% of auction proceeds in consumer benefit programmes, including investments in end-use energy efficiency and renewable energy deployment programmes at the state and local levels.

California's Global Warming Solutions Act

Signed into law in 2006, California's Global Warming Solutions Act (AB 32) established a state-wide GHG emissions limit at 1990 levels to be achieved by 2020. As part of a portfolio of measures implemented to achieve this state-wide GHG emissions limit, the California Air Resources Board adopted cap-and-trade regulations in 2011. The regulations established a declining cap on sources responsible for approximately 85% of state-wide GHG emissions, including refineries, power plants, industrial facilities, and transportation fuels. In addition, the portfolio of programmes implemented to achieve the state-wide GHG emissions limit under AB 32 includes a mandatory GHG emissions reporting programme for large emitters, a renewable portfolio standard, and various energy efficiency measures and incentives. California's approach includes, among other initiatives, a low-carbon fuel standard, a 33% renewable portfolio standard, expanding and strengthening energy efficiency programmes and standards, and policies and incentives for meeting transportation-related GHG emission targets for regions throughout California (WRI, 2012).

In January 2014, California formally linked its programme with its counterpart in the Canadian province of Quebec. In December 2012, the government of Quebec adopted a regulation providing for linkage between the two programmes and, in January 2013, representatives of the two jurisdictions signed an agreement outlining steps and procedures to fully harmonise and integrate the two programmes. In April 2013, the Air Resources Board adopted a regulation setting 1 January 2014 as the start of the linkage, which enabled carbon allowances and offset credits to be exchanged between participants in the two jurisdictions' programmes. Further linkages may also be possible with programmes being considered by the provinces of Ontario and British Columbia.

Western Climate Initiative

The Western Climate Initiative (WCI) is a collaborative effort among US states and Canadian provinces to tackle climate change at a regional level. The WCI began in February 2007 when the governors of the states of Arizona, California, New Mexico, Oregon, and Washington signed an agreement directing their respective states to develop a regional target for reducing GHG emissions, participate in a multi-state registry to track and manage GHG emissions in the region, and develop a market-based programme to reach

5. Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont.

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the target. During 2007 and 2008, the premiers of British Columbia, Manitoba, Ontario, and Quebec, and the governors of Montana and Utah joined the original five states in committing to tackle climate change at a regional level. In November 2011, the WCI formed the Western Climate Initiative, Inc. (WCI, Inc.), a non-profit corporation that will provide administrative and technical services to support the implementation of state and provincial GHG emissions trading programmes.

British Columbia, California, Ontario, Quebec and Manitoba are continuing to work together through the Western Climate Initiative to develop and harmonise their emissions trading programme policies. They are also continuing to work with Western, Midwestern and Northeast states on a range of other climate and clean energy strategies through the North America 2050 Initiative. North America 2050 is a forum for states, provinces and stakeholders to identify leadership opportunities in climate and clean energy policy.

Power sector standards

As of February 2013, three states (New York, Oregon and Washington) have GHG emission standards for electricity-generating utilities, requiring power plants to have emissions equivalent to or lower than the established standard. For example, in New York, new or expanded base-load plants (25 MW and larger) must meet an emission rate of either 925 pounds (lb) of CO_2 per megawatt-hour (MWh) (output based) or 120 lb CO_2 per million British thermal units (MBtu) (input-based). Non-baseload plants (25 MW and larger) must meet an emission rate of either 1 450 lb CO_2/MWh (output based) or 160 lb CO_2/MBtu (input-based).

Three states (California, Oregon and Washington) also have standards that apply to electric utilities that provide electricity to retail customers. These standards place conditions on the emission attributes of electricity procured by electric utilities. And as of January 2013, 29 states had a renewable portfolio standard, which requires utilities to supply customers with a certain amount of electricity from renewable energy sources or install a certain amount of electricity-generating capacity from renewable energy sources in a set timeframe. Standards can vary, with annual or cumulative targets.

Energy efficiency programmes and standards

Since August 2013, 18 states have mandatory energy efficiency resource standards in place, which require utilities to reduce energy use by a certain percentage or amount each year. Many of these utilities use public benefit funds to invest in energy efficiency projects.

INTERNATIONAL CO-OPERATION

The United States is a party to the United Nations Framework Convention on Climate Change (UNFCCC) and participates in regular negotiations under the UNFCCC. The United States signed the treaty in June 1992 and ratified it in October of that same year, becoming the first industrialised country and the fourth nation overall to do so. Under the Copenhagen Accord of 18 December 2009 which followed the 15th Conference of the Parties (COP15), and inscribed at COP16 in Cancun, the United States committed to a reduction of GHG emissions in the range of 17% below 2005 levels by 2020.

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The President's Climate Action Plan

The plan envisages the United States among the countries leading international efforts to address global climate change, in particular through active engagement with the UNFCCC. In addition, the Plan foresees the country leading bilateral initiatives with other major emitting countries; calling for the end of US public-sector financing of new coal-fired power plants overseas (except if with CCS or efficient coal in world's poorest countries); and strengthening global resilience to climate change.

International climate finance

The United States is committed to assisting developing countries in their efforts to mitigate and adapt to climate change. It uses a wide range of institutions, bilateral, multilateral, development finance, and export credit, to mobilise private finance and invest strategically in building lasting resilience to impacts; to reduce emissions from deforestation and land degradation; and to support low-carbon development strategies and the transition to a sustainable, clean energy economy. In the FY 2011 and 2012, US climate finance was USD 5.5 billion, comprised of approximately USD 3.1 billion in congressionally appropriated assistance, USD 496 million of export credit, and USD 1.8 billion of development finance. The United States organises its support according to three pillars: adaptation, clean energy and sustainable landscapes (DOS, 2014).

ASSESSMENT

Over the past decade, there have been sizeable reductions in US GHG emissions as well as improvements in energy efficiency and growth in clean energy, much of which has been driven by policy at the federal and state levels. In 2012, emissions were on the same level as in 1995. EPA data indicate that the power generation sector is the largest emitter and accounts for 31% of total GHG emissions, slightly less than in 2011. Emissions from the power sector decreased during 2012 largely as a result of a switch from coal to natural gas in electricity generation and a slight decrease in production. There are several underlying reasons for this change. The three most important factors were:

- the impact of the global economic crisis, which slowed demand growth and affected energy consumption behaviour;
- the mild heating season, which dampened energy demand;
- the shift from coal to gas in the power sector as a result of the shale gas revolution.

In the absence of market-based instruments, such as a carbon tax, the United States' preferred approach to meeting climate change objectives at the federal level relies on regulation. While investment certainty and reasonable cost can also be obtained through well-designed regulations, economists have tended to argue that putting a price on GHG emissions (e.g. cap-and-trade or a carbon tax) coupled with effective technology policy is the most cost-effective approach to reducing GHG emissions. A regulatory approach to emission abatement, even one with built-in flexibility for states in how they implement the policy, can be more costly than a market mechanism (OECD, 2014). Under some conditions, it may be argued that a more conventional form of regulation such as the use of a clean energy standard (or other functionally equivalent intensity standards, such as those being proposed by EPA for existing power plants) may be more cost-effective when interactions with the tax system are taken into account (Goulder et al., 2014).

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In addition, by inducing the re-dispatch of base-load power from coal plants to natural gas plants (which are currently under-utilised), and possibly fuel switching within particular plants, EPA's proposed rule may achieve some reductions at relatively low cost. Care is needed, however, to prevent the marginal abatement costs from different emission sources from diverging too much (which would raise total costs). States will have flexibility in how they meet the proposed rule, thereby allowing them to choose locally appropriate compliance methods. They will also be able to co-ordinate their efforts and jointly meet (i.e. trade) their compliance obligations, potentially through existing or newly formed cap-and-trade programmes.

The IEA welcomes President Obama's Climate Action Plan. It presents a significant boost for clean energy progress in the United States and also internationally. The policies set out in the CAP should not damage economic growth or jobs and contribute to the continued recovery of the US economy while strengthening energy security. IEA's publication, *Redrawing the Energy-Climate Map* (2013), demonstrated that a package of policies similar to those proposed by the United States – increasing energy efficiency, targeting methane emissions, phasing down fossil fuel subsidies and reducing reliance on highly polluting coal plants – could be delivered at zero GDP cost between now and 2020. Beyond this time, it found that the policies improved the competitiveness of the economies concerned, enhancing the ability of their energy systems to move to a low-carbon base in the long term. The IEA regularly highlights the need for technology development and innovation, particularly in renewable energy and carbon capture and storage, and welcomes CAP proposals and achievements in this regard. The IEA also welcomes US efforts to strengthen energy system resilience; IEA views efforts on resilience as going hand in hand with emissions reductions, and should not be given up.

The June 2014 EPA Clean Power Plan proposes to cut carbon pollution from existing power plants which represent the largest source of CO_2 emissions ahead of transportation. The IEA welcomes these proposals, as it is the first time the federal government has mandated CO_2 reductions, which build on trends already under way in states and in the power sector to cut carbon pollution from existing power plants, making them more efficient.

The rapid development of US shale gas resources coupled with more stringent air quality regulation has helped to reduce emissions by substituting natural gas for coal. Whether the trend in emissions reduction resulting from coal-to-gas switching in power generation will continue depends on relative coal and gas prices (IEA, 2013). The coal-fired power sector is facing the potential imposition of tighter emissions rules from the EPA. This has resulted in growth in the number of retirements in the coal-fired power sector and greater concentration of gas-fired generation in the gas-producing regions. Furthermore, greater electricity output from natural gas turbines would reduce, but not eliminate, the intermittency problem associated with some renewable energy sources, facilitating the expansion of renewable generation. Low natural gas prices can also reduce emissions from the transport sector to the extent that natural gas-powered vehicles are used more (see Chapters 3 on Electricity, 9 on Natural Gas and 10 on Coal).

There is, however, a risk that the current trend in emissions could turn again, e.g. if prices develop in favour of coal compared to natural gas as has been occurring recently although the new proposed standards go some way towards addressing this concern. There is also concern that some of the CO_2 reductions from switching from coal to gas could be offset by methane emissions from shale gas production and distribution, if these are not controlled. Fugitive methane emissions from hydraulic fracturing create a global environmental concern. More work remains to quantify the scale of these emissions and at what point in production and transportation they occur. More is known about

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production than distribution (OECD, 2014). These concerns have been acknowledged and the federal government and EPA are actively working to understand and address matters related to fugitive emissions through the comprehensive Methane Strategy.

The road transport sector is the second-largest emitter of CO_2 in the United States. In this regard, the introduction of tighter Corporate Average Fuel Economy (CAFE) Standards and GHG standards for light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs) are welcome steps.

RECOMMENDATIONS

The government of the United States should:

- ☐ *Continue efforts to obtain a nationwide carbon price that provides investment certainty to the energy markets in the transition towards a low-carbon energy system.*
- ☐ *Continue technology programmes to increase efficiency and bring down the costs of low-emission technologies with the aim of making these technologies competitive in the market and thus achieving reductions in GHG emissions.*
- ☐ *Support investments in gas and electricity infrastructure with regulatory instruments where appropriate, enabling integration of variable renewable energy sources and minimise losses from the transportation of energy, benefiting energy markets as well as the environment.*

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7. ENERGY EFFICIENCY

Key data (2013 estimated)

Energy supply per capita: 6.9 toe (IEA average: 4.5 toe), -11.3% since 2003

Energy intensity: 0.15 toe per USD 1 000 GDP PPP (IEA average: 0.13 toe per USD 1 000 GDP PPP), -18.6% since 2003

TFC (2012): 1 432.7 Mtoe (oil 50.2%, electricity 22.4%, natural gas 20.7%, biofuels and waste 4.6%, coal 1.5%, heat 0.5%, solar 0.1%), -5.9% since 2002

TFC by sector: transport 41.7%, industry 24.6%, residential 17.7%, commercial and other services 15.9%

OVERVIEW

The United States remains an energy-intensive economy relative to other IEA countries in terms of both GDP and per capita income, owing to its large transport sector (41.7% of total final consumption [TFC]) and its relatively high living standards. TFC has fallen by 8.8% since 2007, mostly as a result of the economic slowdown, but also through the steady diffusion of energy efficiency policies. An important trend for consumers has been the fall in household expenditure on energy consumption. Consumers spent almost 20% less on energy in 2011 than in 2000, a trend that is likely to continue as gas prices remain low and the impacts of energy efficiency policies grow.

Investment in energy efficiency measures by manufacturers, builders and consumers is strongly influenced by policies at both federal and state levels. These policies drive energy efficiency investments in two ways: by compelling spending in order to comply with regulatory requirements (e.g. energy performance standards for buildings and appliances, energy efficiency resource procurement standards for utilities), and by stimulating spending through economic and fiscal policies (e.g. stimulus spending, tax incentives).

The United States has made significant improvements in energy efficiency policies since the last in-depth review, notably in the areas of vehicle fuel economy and appliance standards, but also in state-level energy efficiency resources standards. These policies are projected to more than treble the estimated 2011 annual site energy savings by 2020 (Table 7.1). Primary energy savings from these policies would be considerably higher but are not estimated here.

FINAL CONSUMPTION OF ENERGY

United States' TFC was 1 432.7 Mtoe in 2012. This level of consumption was 5.9% lower in 2012 than in 2002. The most significant decline was during 2008 and 2009 when TFC fell by 3% and 5.4%, respectively. The transport sector is the largest energy consumer, accounting for 41.7% of TFC in 2012. Around 93% of transportation is fuelled by oil products, with the remainder from biofuels and waste (4.3%), natural gas (2.9%) and

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electricity (0.1%). The use of biofuels in transport has increased sixfold compared to 2002, while the use of oil products has declined by 4.1% over the same period. Overall energy consumption in transport has remained unchanged compared to 2002.

Industry consumed 352.7 Mtoe in 2012, accounting for 24.6% of TFC. Compared to 2002, consumption in this sector has declined by 18.4%, with its share of TFC falling from 28.4%. The largest drop was during 2009 and 2012, as consumption fell by 11% in each year. Industry energy use is dominated by natural gas (32.7%), oil (31.5%) and electricity (20.6%). Over the past decade, oil demand by the industrial sector has experienced the strongest decline, with the share of oil falling from 39.1% in 2002. Conversely, natural gas and electricity shares have increased from 29.6% and 17.4%, respectively.

The share of residential and commercial sectors in TFC was 17.7% and 15.9% in 2012, respectively. Energy consumption in these sectors has declined only marginally compared to 2002, down by 2.9% in the residential sector and by 1.2% in the commercial and public services sector (including agriculture). Electricity accounts for half the energy used in the two sectors together, followed by natural gas (33.9%) and oil (11.4%). Demand for coal, oil and natural gas in these sectors has experienced the strongest decline, while the use of electricity, heat, biofuels and waste, and solar power has grown.

Table 7.1 Energy efficiency policies and results

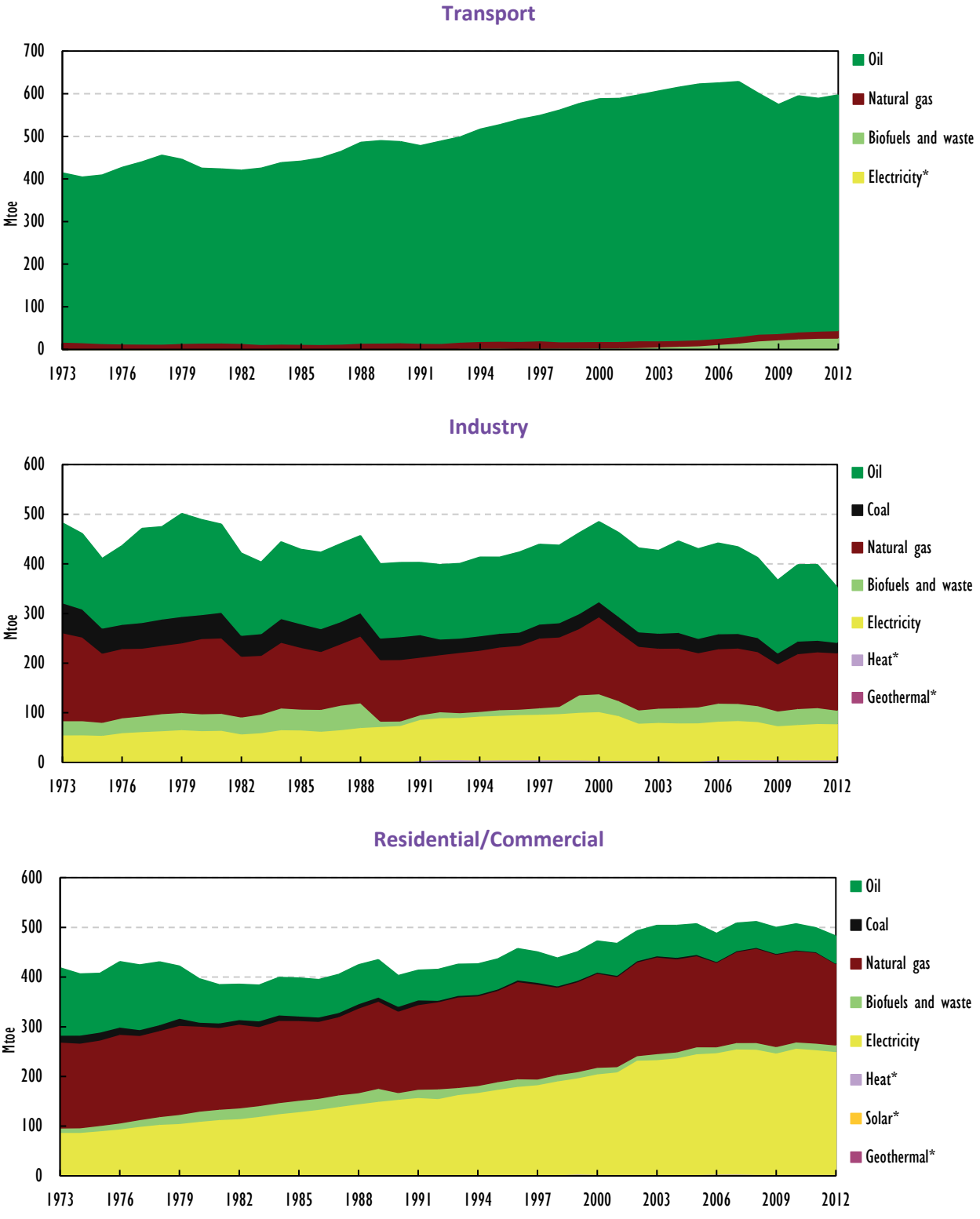
Sector and policy	Policy/legislation	2011 annual site energy savings (TWh)	Forecast annual site energy savings in 2020 (TWh)
Light- and heavy-duty vehicle fuel economy standards	US EPA/NHTSA Joint Rule-makings for 2012-16 and 2017-25.	N/A	962
Appliance and equipment standards programme	National Appliance Energy Conservation Acts of 1987 and 1988 (NAECA). Energy Policy Act of 1992 (EPAct1992). Energy Policy Act of 2005 (EPAct 2005). Energy Independence and Security Act 2007 (EISA).	400 (242 electric) (156 gas)	695 (610 from standards in place today; 85 from new standards)
Ratepayer-funded energy efficiency	State-level legislation and regulation establishing energy efficiency resource standards, and savings obligations.	117.3 (81 electric) (36 gas)	Medium: 210 High: 255
Building codes	State-level residential and commercial building codes.	64 (37 electric, 26 gas, 0.5 heating oil)	244 (89 electric, 67 gas, 1.0 heating oil)
Energy services companies (ESCO) industry	EISA, Section 432. American Recovery and Reinvestment Act (ARRA).	270	770
Total		**851.3**	**2 926**

Note: ASHRAE = American Society of Heating, Refrigerating and Air-Conditioning Engineers; N/A = not applicable; NHTSA = National Highway Traffic Safety Administration; TWh = terawatt hour; US EPA = United States Environmental Protection Agency. IECC = International Energy Conservation Code.

Source: IEA (2013b), *Energy Efficiency Market Report 2013*, OECD/IEA, Paris.

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Figure 7.1 TFC by sector and by source, 1973-2012



* Negligible.

Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

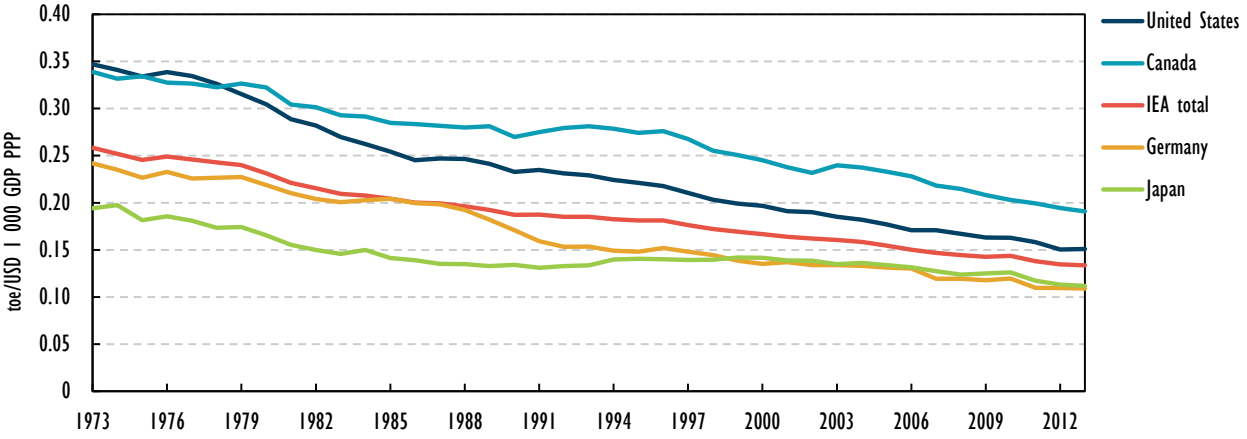
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ENERGY INTENSITY

Energy intensity, measured as the ratio of energy supply to GDP, has decreased by 18.6% over the ten years to 2013, down from 0.19 to 0.15 tonne of oil-equivalent (toe) per USD 1 000 GDP PPP (toe/USD 1 000 GDP PPP). The United States ranks as eighth most-intensive country among IEA member countries, behind Estonia, Finland, Canada, the Slovak Republic, the Czech Republic, Korea and Poland. The average IEA energy intensity is 0.13 toe/USD 1 000 GDP PPP has declined at a similar rate to that of the United States over the past ten years.

Energy supply per capita is 6.9 toe, which is higher than the IEA average of 4.5 toe. In 2013, the United States ranked third among IEA member countries in terms of TPES per capita, behind Luxembourg and Canada. Energy supply per capita has declined by 11.3% since 2003, while the top-three ranking has remained unchanged.

Figure 7.2 Energy intensity in the United States and in other selected IEA member countries, 1973-2013



Note: data are estimated for 2013.

Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

INSTITUTIONS

Generally, the **federal government** is directly responsible for energy efficiency policies affecting appliances and equipment, and vehicles (some state policies and standards beyond the national ones exist). Appliance and equipment standards are promulgated by the **Department of Energy** (DOE) while the **Environmental Protection Agency** (EPA) and **Department of Transportation** share responsibility for light- and heavy-duty vehicle fuel economy standards. State energy offices and state regulators are responsible for energy efficiency resource standards placed on gas and electric utilities. The federal government has no direct responsibility regarding energy efficiency policies for buildings and retail energy providers. Nonetheless, DOE plays an important supporting role in building the capacity of state regulators, legislators, and energy offices to consider and implement energy efficiency policies. Both the federal and state governments employ economic and fiscal policies to promote energy efficiency investment (Table 7.2).

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Table 7.2 Energy efficiency institutional map

	Major policies	Responsibility
Transformation sector	Clean Air Act	US Environmental Protection Agency
Residential and commercial sector	Appliance and equipment standards	US Department of Energy
	Building codes	States and localities
	Tax incentives	Federal and some states
	Ratepayer-funded energy efficiency programmes	Energy utilities State regulators Energy efficiency offices
	Stimulus spending under ARRA	US Department of Energy State and local energy and community agencies
Industrial sector	Equipment standards Tax incentives	US Department of Energy Federal government and some states
Transport sector	Vehicle fuel economy standards	US EPA and DOT NHTSA

Note: EPA = Environmental Protection Agency: DOT NHTSA = Department of Transportation, National Highway Traffic Safety Administration.

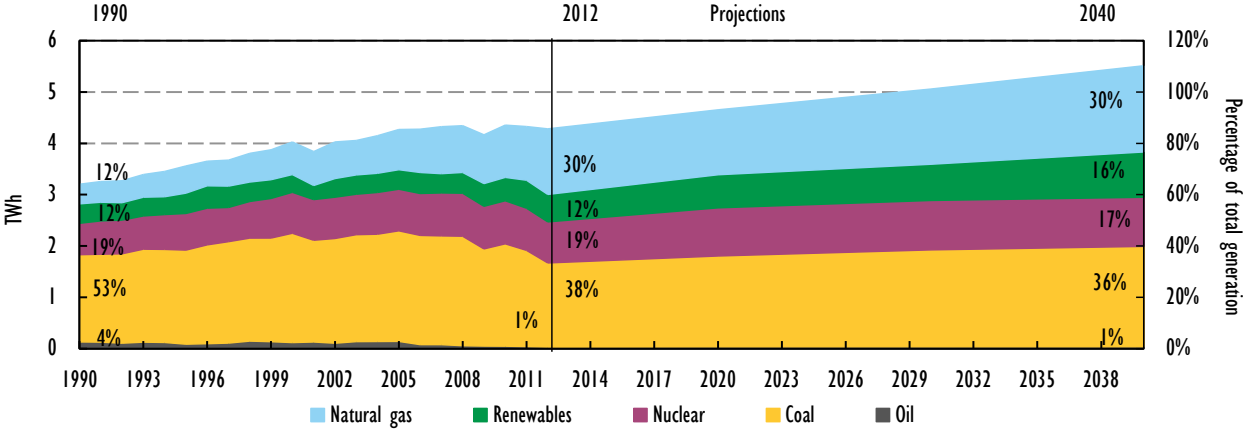
SECTORAL DEVELOPMENTS

TFC has fallen by almost 10% since 2007, largely as a consequence of the financial crisis but also of structural changes and the growth in energy efficiency markets. Consuming sector shares have remained remarkably constant over the past ten years, with transport accounting for the largest share (approximately 40%) and the industrial and residential sectors contributing nearly 20% each.

TRANSFORMATION SECTOR

Electricity consumption dipped over the period 2006-13 largely as a result of the global economic downturn, but is expected to resume at an annual growth rate of 0.7%. Renewable generation continues to grow in relative importance, with nuclear remaining stable and coal dipping sharply. Gas-fired generation grew most rapidly.

Figure 7.3 Power generation by fuel source, actual and projected, 1990-2040



Source: IEA (2014), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

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RESIDENTIAL AND COMMERCIAL SECTOR

The residential/commercial sector constitutes a major portion of energy use, accounting for one-third of total final energy use and over 70% of electricity consumed. Regional climate differences – from hot, humid and arid climates to severe cold – contribute to high energy demand for space cooling and heating.

The population is growing by an average of between 2.5 million to 3 million people per year, through births and immigration. While new buildings construction slowed as a result of the financial crisis and of a sharp decline in real estate prices, the construction market started to recover in 2012 – suggesting a reversal in this trend. The residential housing stock is expected to grow substantially in the coming decades, driven by rising population and decreasing occupancy rates (people per household). Services floor area will increase also, albeit at a slower pace (Table 7.3).

Table 7.3 Indicators for energy demand in the United States buildings sector

Indicator	2010	2020
Population (million)	310	337
GDP (million 2010 USD at PPP)	14 678	18 902
Per capita income (USD GDP/capita)	47 289	56 071
Services floor area (million m^2)	7 534	8 278
Residential floor area (m^2)	22 950	26 290
Number of households (million)	113	126
Occupancy rate (people per household)	2.8	2.7

Note: PPP is purchasing power parity.

Sources: UN DESA (United Nations Department of Economic and Social Affairs) (2011), *Rural Population, Development and the Environment 2011*, UNDESA, IEA (2012), World Energy Outlook 2012, OECD/IEA, Paris, other data from IEA analysis.

The buildings sector has advanced significantly over the last three decades encouraged by incentives for efficiency investments, voluntary labelling of many high-efficiency buildings, renovation programmes for low-income housing and government buildings, and numerous technology development and deployment initiatives. Policy activity has also resulted in more aggressive appliance and equipment standards and more rigorous building codes.

The American Recovery and Reconstruction Act of 2009 directed a large influx of stimulus funding into the sector. The Act, the federal government's direct response to the economic crisis, earmarked approximately USD 16 billion in relation to energy efficiency, weatherisation and state grants, that is likely to be fully spent before the end of 2014. While future funding is expected to be modest, policies and funding for efficiency programmes for buildings continue to enjoy significant support across the political spectrum.

INDUSTRIAL SECTOR

According to the Energy Information Administration's abridged version of its *Annual Energy Outlook* (2014), approximately one-third of total United States delivered energy in 2012, or 23.6 quadrillion British thermal units (Btu) was consumed in the industrial sector, which includes manufacturing, agriculture, construction, and mining (EIA, 2013b). In August 2012, the President of the United States signed an executive order, "Accelerating

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Investment in Industrial Energy Efficiency". The purpose of the executive order was to accelerate investments in industry to strengthen the competitiveness of the manufacturing sector, lower energy costs, free up future capital for businesses to invest, reduce air pollution, and create jobs. The Order also directs the acceleration of greater investment in industrial energy efficiency and in combined heat and power (CHP) production.

Manufacturing sector: Advanced Manufacturing Office

Programmes to support energy efficiency in the manufacturing sector are overseen by the DOE's Advanced Manufacturing Office (AMO). The AMO works with industry, small businesses, universities, regional entities, and other stakeholders to identify and invest in emerging clean energy technologies. The AMO works to play a leadership role in the national interagency Advanced Manufacturing Partnership. The goal of the AMO is to reduce by 50% in 10 years the life-cycle energy consumption of manufactured goods by targeting the production and use of advanced manufacturing technologies.

Chemical and refining sector

The chemical and petrochemical sector is by far the largest industrial energy user, accounting for roughly 10% of total worldwide final energy demand and 7% of global GHG emissions (American Chemistry Council, 2012). The deployment of best practice/established technologies (BPT) such as state-of-the-art equipment, better catalysts, separations, among others, in existing plants or new facilities can result in substantial energy savings. The most cost-effective way to implement BPT is during building of new plants.

In the United States, typically 26% of capital investments go into replacing plant equipment and another 26% into expanding capacity of existing plants. As a result, the energy intensity of the chemical sector improved by 39% and GHG emissions intensity was reduced by 10% between 1994 and 2007. The cumulative energy saved would have been enough to supply Japan with electricity for one year. The United States has about 150 refineries, which account for roughly 25% of the world refinery output; they consume 3.4 EJ of energy and emit some 244 $MtCO_2$-eq. of process-related GHGs. Studies show that BPT refineries consume 20% to 30% less energy than the industry average (IEA, 2013a).

Combined heat and power and utility sector

The average efficiency of power generation in the United States has remained at 34% since the 1960s and the energy lost in wasted heat from power generation in the United States is greater than the total energy use of Japan (DEEPA, 2012).

Combined heat and power (CHP or co-generation) represents approximately 8% of United States generating capacity and the present Administration is supporting a target to achieve 40 GW of new, cost-effective CHP by 2020. Meeting this target would increase CHP capacity by 50% in less than a decade and save one quadrillion Btu of energy – the equivalent of 1% of all energy use in the United States. The DOE and EPA have established the Industrial Energy Efficiency and Combined Heat and Power Working Group providing guidance on model programmes and policies that support industrial efficiency and implementation of CHP. The working group has developed a blueprint for action that drives the following goals:

- achieve a 2.5% average annual reduction in industrial energy intensity through 2020
- install 40 GW of new, cost-effective CHP by 2020.

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Network losses

According to EIA data, national electricity transmission and distribution losses average about 7% per year of the electricity that is transmitted in the United States.

TRANSPORT SECTOR

Transport remains by far the largest energy-consuming sector, accounting for 600 Mtoe, around 42% of total final energy consumption. Transport sector demand, however, has been flat over the past decade, as a result of higher gasoline prices, slow improvements in vehicle fuel economy, gradual changes in commuting patterns, and the knock-on effects of the economic downturn. Vehicle fuel economy standards in 2012 remained among the least-stringent of all car-producing countries, lower than in Canada, Japan, Korea, China, the European Union, and India.

By far the most significant transportation energy efficiency policy development since the last in-depth review was published in 2008 was the 2012 adoption of a 15-year national programme to improve the fuel economy of cars and trucks sold in the United States. If the automotive industry keeps to the agreed trajectory, light-duty vehicle fuel economy will rise from 25.5 miles per gallon (mpg) in 2008 to 35.5 mpg in 2016 and 50 mpg in 2025 (EPA, 2012).

POLICIES AND MEASURES

POLICIES AND LEGISLATION

Federal government energy efficiency policies are determined by legislation and subsequent rulemaking. Landmark energy efficiency legislation enacted over the past 25 years includes the National Appliance Energy Conservation Acts of 1987 and 1988 (NAECA); the Energy Policy Act of 1992 (EPAct1992); the Energy Policy Act of 2005 (EPAct2005); the Energy Independence and Security Act 2007 (EISA); and, under current consideration, the Shaheen-Portman Energy Efficiency Bill (2014). Taken together this package of legislation provides the basis for most federal government energy efficiency policies, including vehicle fuel economy standards, appliance and equipment energy performance standards, federal support to the adoption of building energy codes, and obligatory energy-saving targets for federal agencies and facilities (Table 7.1).

PROGRAMMES AND MEASURES

Utility ratepayer-funded programmes

Ratepayer-funded energy efficiency programmes have been a pillar of energy efficiency efforts since the late 1990s. Spending levels have grown from USD 1.0 billion in 2000 to USD 7.0 billion in 2012 (Figure 7.4). Energy savings from these programmes are significant. The latest industry report, a collaborative initiative by the Consortium for Energy Efficiency, the America Gas Association and the Institute for Electric Efficiency, estimated gross annual energy savings of 117 TWh from cumulative spending on energy efficiency through 2011 (Forster et al., 2013).

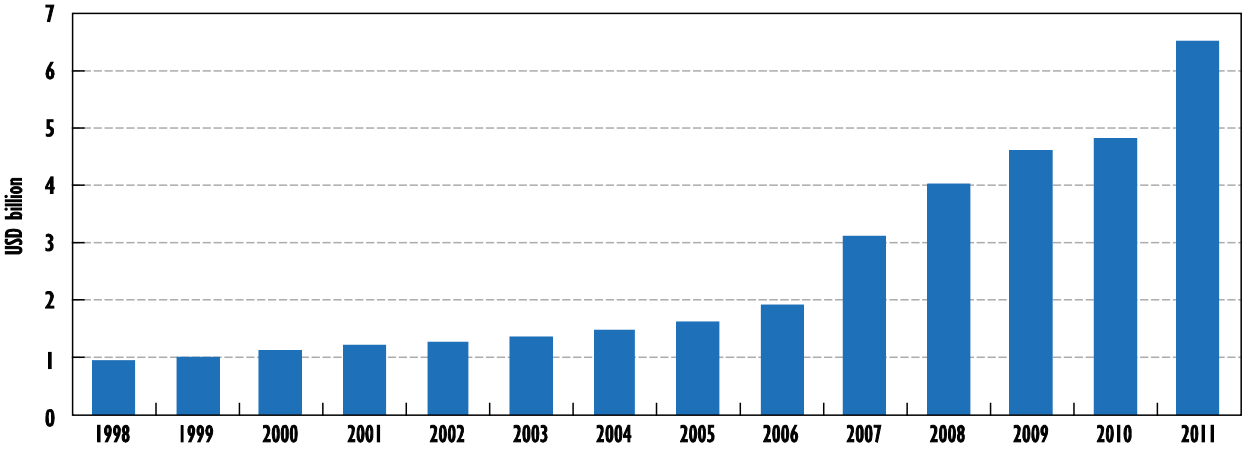
Until recently, only a handful of western and northeastern states used ratepayer funds to invest in energy efficiency programmes. In 2010, ten states with less than one-third of total natural gas and electricity sales accounted for two-thirds of total ratepayer-funded energy efficiency. These regional disparities are beginning to ease, as a result of wider adoption of

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regulatory mechanisms promoting energy efficiency.[1] By the end of 2013 there were 25 states with energy efficiency resource standards (EERS), and another nine states adopting policies requiring significant energy-provider involvement in energy efficiency (ACEEE, 2012).[2] Ten states doubled their ratepayer-funded energy efficiency expenditure in 2010 (IEE, 2012).[3]

Of the 25 EERS schemes, 18 incorporate incremental energy savings targets that, if followed, could result in a 30% annual (cumulative) energy savings or more by 2020. Some analysts question whether this rapid growth can be sustained. A recent study published by the Lawrence Berkeley National Laboratory (LBNL) examined the outlook for ratepayer-funded energy efficiency. The study projected ratepayer-funded energy efficiency spending and savings for three scenarios (low, medium and high), based on a review of state-level policies and plans, and interviews with regulators and utility experts. The low scenario projects lower interest by regulators in energy efficiency as a resource, with spending remaining at 2010 levels. The medium scenario projects continued growth in spending by the states with ambitious EERS plus continued expansion of energy efficiency policies in other states, subject to constraints of technical capacity and rate/spending caps imposed by statute or regulatory order. Under this scenario, ratepayer-funded spending growth is lower than historical rates: about 4% annually. The high scenario is based on adoption of energy efficiency regulatory mechanisms by those states that have not yet pursued energy efficiency. This scenario foresees a tripling of combined gas and electric energy efficiency spending over the period to 2025, towards USD 16 billion annually (Figure 7.5) (Barbose et al., 2013).

Figure 7.4 Ratepayer-funded natural gas and electric energy efficiency spending in the United States, 1998-2011



Sources: Forster H.J., Wallace P. and Dahlberg N. (2013), *2012 State of the Efficiency Program Industry – Budgets, Expenditures, and Impacts*, Consortium for Energy Efficiency, 28 March ; Barbose, G., Goldman, G., Hoffman, I. and Billingsley, M. (2013), *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*, LBNL-5803E, January; ACEEE (American Council for an Energy Efficiency Economy) (2012), *Three Decades and Counting: A Historical Review and Current Assessment of Electric Utility Energy Efficiency Activity in the States, Report Number U123*, ACEEE, June.

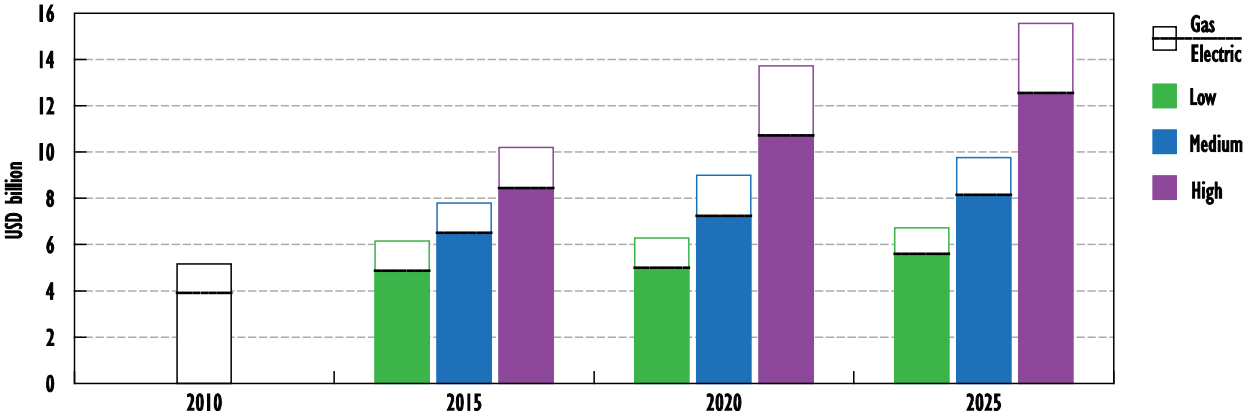
1. Regulatory mechanisms promoting energy efficiency include resource standards, statutory requirements setting goals or criteria for ratepayer-funded energy efficiency efforts, system benefit charges, integrated resource planning requirements and decoupling of revenues from sales (Regulatory Assistance Project, 2012).

2. An energy efficiency resource standard (EERS) is a regulatory mechanism used by regulators to establish specific energy savings targets that regulated gas and electricity companies must achieve, or face penalties. An EERS is similar in concept to a renewable portfolio standard (RPS), in that an EERS requires utilities to reduce energy use by a specified and increasing percentage or amount each year.

3. Louisiana, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Dakota, Tennessee, Virginia and Wyoming.

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Figure 7.5 Electric and gas energy efficiency programme spending projected to 2010-25



Source: Barbose, G., Goldman, G., Hoffman, I. and Billingsley, M. (2013), *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*, LBNL-5803E, January.

Energy savings projections follow a similar path, with energy savings from ratepayer-funded electric efficiency programmes projected at 210 TWh to 255 TWh in 2020, equivalent to 6% of projected electricity consumption in that year (EIA, 2013a). Depending on electricity sales growth over the period, these annual energy savings levels could possibly result in a net decline in electricity sales (Barbose et al., 2013; IEE, 2013).

RESIDENTIAL/COMMERCIAL SECTOR HIGHLIGHTS

Tax incentives

Tax incentives can be used to promote residential and commercial energy efficiency investments. Tax credits for energy-efficient appliance purchases and efficiency upgrades of residential buildings were first authorised in 1978 via the Energy Tax Act, and more recently via the Energy Policy Act of 2005. The most successful (based on participation) tax incentives were for new appliances and home improvements, including new homes. These tax incentives encouraged manufacturers to develop high-efficiency models within appliance product classes (refrigerators, washing machines, dishwashers). The high-efficiency models which qualified for tax credits eventually became the basis for more stringent minimum energy performance standards, thus creating a virtuous market transformation and an efficiency improvement circle between incentive policies and regulatory policies (ACEEE 2012). The non-business energy property tax credit encourages home-owners to invest in a variety of energy-saving home improvements, such as insulation, window treatments, and furnace and air-conditioner replacement. By 2009 some 6.8 million households claimed credits accounting for total spending of over USD 25 billion (GAO, 2012).

Although "free ridership" is a major drawback of many tax incentive programmes, these policies remain cost-effective. Tax incentives are a flexible tool; they can be used to provide incentives not only to consumers but to manufacturers also. The Appliance Manufacturer's Tax Credit, which was in place from 2008 to 2009 resulted in the production and sale of 13 million dishwashers, washing machines and refrigerators resulting in an annual energy savings of 1.4 TWh. Federal tax incentives have encouraged manufacturers to develop higher-efficiency refrigerators, washing machines and dishwashers (appliance manufacturer's tax credit) and home-owners to invest in insulation, window treatment, and furnace and air-conditioner replacement as well as to purchase electric vehicles, hybrid electric vehicles, and develop energy-efficient commercial buildings (Energy Property Tax Credit).

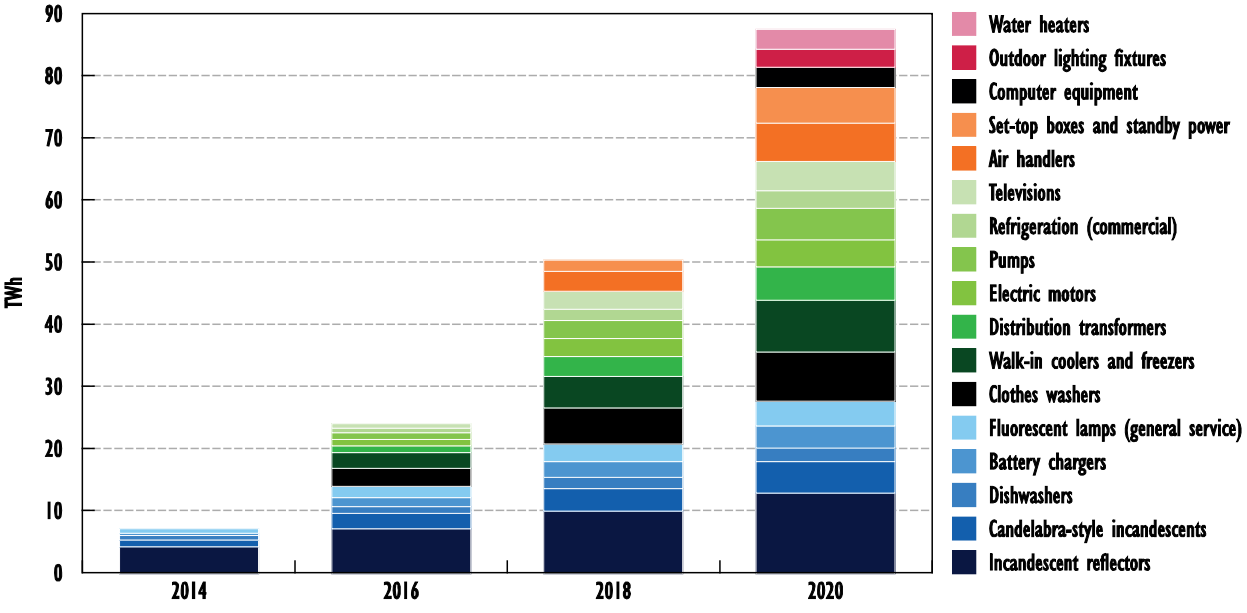
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Optimising the type and level of tax incentives and managing questions of free ridership could improve the prospects for, and results of, this important type of incentive policy. Keeping stable tax incentives in place for extended periods can create stable expectations for consumers and contractors alike. On the whole, tax incentives seem to be an under-utilised policy instrument relative to regulatory approaches and direct investment.

Appliance and equipment standards

Minimum energy performance standards for household appliances and commercial equipment date back to measures introduced by the state of California in 1974. These early efforts by California, beginning with refrigerators, led to a movement for national energy performance standards for common household appliances and resulted in the Energy Policy and Conservation Act (EPCA) of 1975, which called for establishment of energy conservation programmes and efficiency targets. Since 1987, Congress has directed the Department of Energy (DOE) to set efficiency standards for more than 55 product categories. DOE also updates standards to reflect technological improvements and new products. Recent years have seen a record pace of new standards set as a result of court-ordered and statutory deadlines imposed on DOE. Some 20 new standards have been completed since 2009, with more expected over the medium term. Activity will likely focus on the appliance and equipment categories not yet covered, such as battery chargers, consumer electronics, pool pumps and spas, and lighting. According to a recent study by appliance standards advocates, as many as 30 new product categories could be covered over the next six years with an aggressive DOE programme. The American Council for an Energy Efficiency Economy (ACEEE) and ASAP estimate that savings from these new product categories could add up to over 80 TWh of annual energy savings by 2020 (Figure 7.6) (ACEEE/SAP, 2012; ASAP, 2013).[4]

Figure 7.6 Potential energy savings from new appliance energy performance standards



Sources: ACEEE/ASAP (Appliance Standards Awareness Project) (2012), *The Efficiency Boom- Cashing in on the Savings from Appliance Standards, Report Number ASAP 8/ACEEE-A123*, ACEEE/ASAP, March.; ASAP (Appliance Standard Awareness Project) (2013), "*Products*" website, www.appliance-standards.org/products.

4. The IEA derived 2020 annual savings estimates from the effectiveness data of individual standards together with the annual energy savings in 2025 and 2035 projected by ACEEE and ASAP.

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Appliance standards produce long-lived energy savings. According to a recent analysis by the Lawrence Berkeley National Laboratory, the standards in place today produced 400 TWh of energy savings in 2011, with savings expected to top 600 TWh by 2020 (Meyers et al., 2013). Adding in the savings estimated from new appliance and equipment standards that may be implemented in the coming years yields a potential annual energy saving of as much as 695 TWh in 2020 (ASAP, 2013).

Building energy codes

Building codes are the responsibility of states, which can adopt or reject new code requirements. Some states have a legislative process; others have a regulatory process. Some "home rule" states devolve the authority to set building codes to localities. States often amend the model codes according to local needs and interests; these procedures are influenced by stakeholders within the development and construction industries. These state and local jurisdictions are also responsible for enforcing compliance with the building codes as adopted. The DOE and state energy agencies play a leading role in encouraging adoption of building energy codes and developing the capacity for inspection and enforcement. In response to the Energy Policy Act of 1992 (EPAct1992), the DOE established the Building Energy Codes Program (BECP) to support the model national building energy codes development process and help states adopt and implement more efficient energy codes. Since its inception 20 years ago, BECP has become the central information resource on national energy codes and standards.

Energy efficiency standards for new buildings have been progressively tightened over the past decade, culminating in the recent introduction of two new model building energy codes: the 2012 International Energy Conservation Code (IECC) covering residential buildings; and the 2010 ASHRAE Standard 90.1-2013 covering commercial buildings. These codes are projected to produce a 30% improvement in the energy efficiency of new buildings compared to buildings constructed to comply with the 2006 model code.[5] The Pacific Northwest National Laboratory estimates today's savings from building code changes over the past two decades to be 42 TWh (Livingston et al., 2013). The 2012 code changes will produce additional, although difficult-to-estimate, annual energy savings by 2020. The IECC code includes stringent prescriptive elements, such as mandatory whole-house pressure tests, insulated domestic hot water piping and significantly lower duct leakage rates. Diffusion of the latest model building energy codes is expected to proceed quickly because of the ongoing assistance provided by BECP, with energy savings from implementation of more stringent building energy codes expected to triple between 2011 and 2020 (Livingston et al., 2013).

Energy services industry

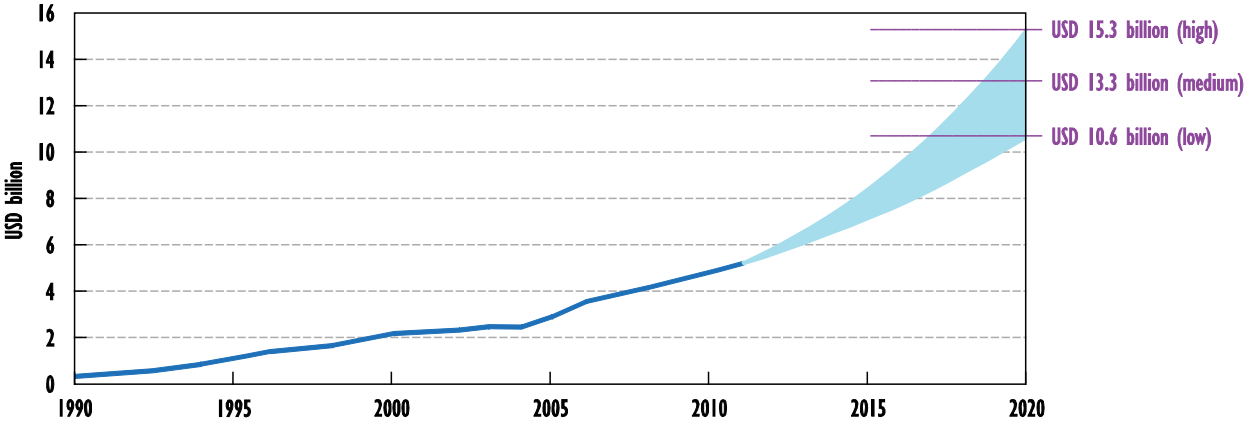
Energy services companies (ESCOs) are another pillar of the energy efficiency industry. The ESCO industry has grown at 7% to 10% annually despite the financial crisis. The American Recovery and Reinvestment Act (ARRA) helped by directing over USD 10 billion of additional government spending into energy efficiency (DOE, 2012). The ESCO industry is expected to see continued growth of 10% per year in the coming years. A recent LBNL report forecast that the sector will more than double in size over the medium term,

5. Both codes are updated on a three-year cycle. The next cycle will conclude in 2015. As a point of reference, a building constructed to meet ASHRAE 90.1-2010 will consume about half the energy consumed under the first model building energy code, ASHRAE 90-75 (Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2013).

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reaching annual turnover of USD 13 billion by 2020 (Stuart et al., 2013) (Figure 7.7). Because the energy savings measures implemented by ESCOs are typically long-lived, the annual energy savings delivered by this industry is expected to grow even faster than annual investment, reaching an estimated 770 TWh (Table 7.1) by 2020 (Larsen and Goldman, 2013).

Figure 7.7 Historical and forecast revenues of US ESCO industry, 1990-2020

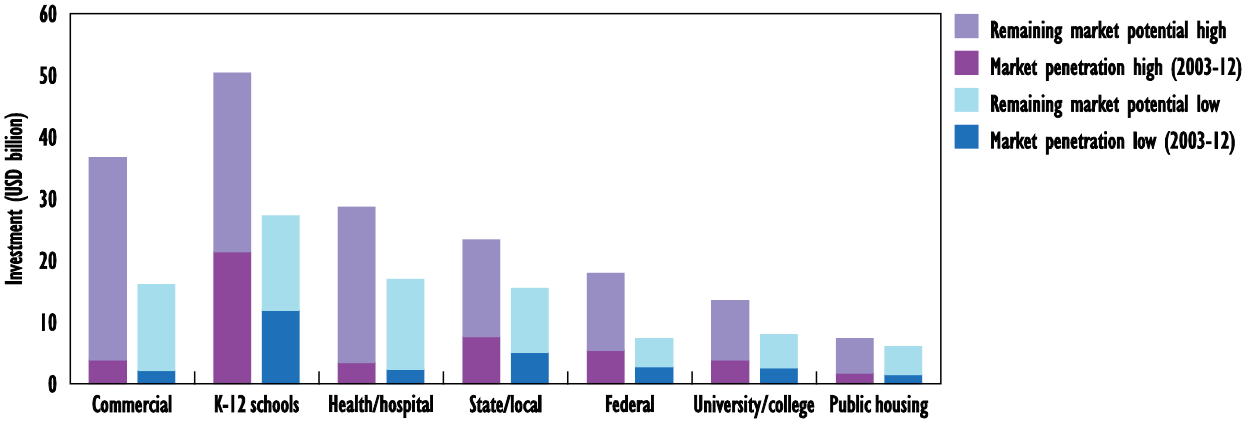


Source: Stuart, E. et al. (2013), *Current Size and Remaining Market Potential of U.S. ESCO Industry, LBNL Report 6300-E*, July.

ESCOs have benefited from policies requiring federal agencies to meet energy savings standards. The Energy Independence and Security Act (2007) and subsequent executive orders require agencies to undertake specified energy and water efficiency measures. Many of these are procured from the ESCO industry via a procurement process such as Energy Services Performance Contracts (ESPCs) and Super-ESPCs (Figure 7.8).

Since its inception, the ESCO industry has remained heavily reliant on the public and institutional buildings sector – the so-called MUSH markets (municipal, universities, schools and hospitals). Industry analysts estimate that 85% of ESCO industry revenues in 2009 came from the public sector (Satchwell et al., 2010). A recent LBNL study examined the market saturation of energy efficiency improvement projects in the commercial and MUSH sectors, estimating the remaining market potential at between USD 71 billion and USD 133 billion (Stuart et al., 2013) (Figure 7.8).

Figure 7.8 Estimated ESCO market potential in commercial and MUSH sectors



Note: MUSH = municipal, universities, schools and hospitals.

Source: Stuart, E. et al. (2013), *Current Size and Remaining Market Potential of U.S. ESCO Industry, LBNL Report 6300-E*, July.

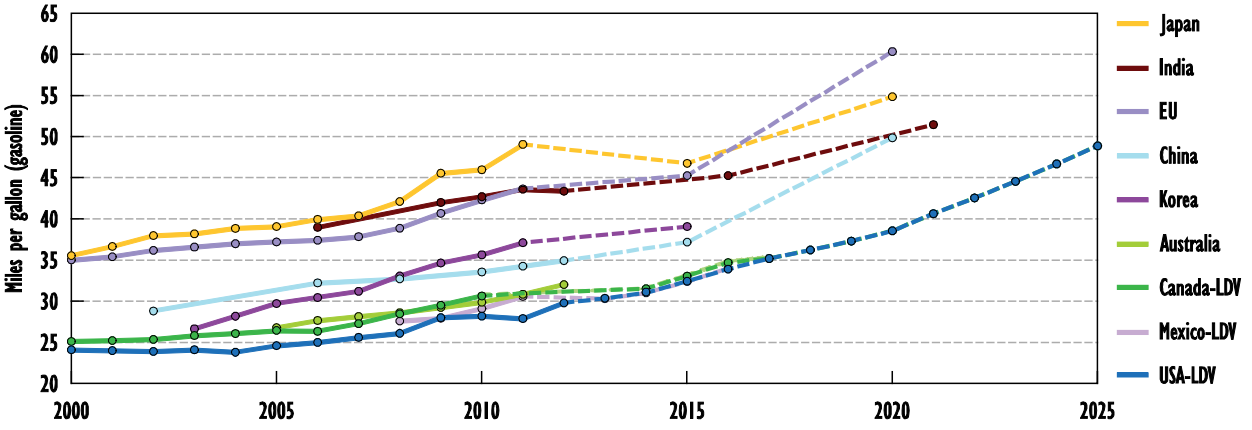
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The outlook for ESCO industry growth is strong. The industry will benefit from continuation of ratepayer-funded energy efficiency and federal energy efficiency procurement requirements. Federal spending will remain at a level of about USD 1 billion in the coming years (Alliance to Save Energy, 2013). Finally, there is ample opportunity for ESCO market growth in both the core MUSH sector and the broader commercial sector (Stuart et al., 2013).

TRANSPORT SECTOR HIGHLIGHTS

As of 2012 the United States ranked last in terms of vehicle fuel economy standards among developed countries and some developing countries – lower than Canada, Japan, Korea, China, the European Union, Mexico, and India (Figure 7.9). This dubious distinction will be relieved, however, as a result of the 2012 adoption by the EPA and the Department of Transportation's National Highway Traffic Safety Administration (NHTSA) of a 15-year national programme to improve the fuel economy and reduce tailpipe carbon dioxide emissions of cars and trucks sold in the United States. The programme is driven by a joint EPA/NHTSA rulemaking establishing progressively more stringent fuel economy standards for light-duty vehicle model years 2012 to 2016 and model years 2017 to 2025. A companion rulemaking provides the first-ever American fuel economy standards for heavy-duty vehicles – tractor-trailers, heavy-duty pick-up trucks and vans, and recreational vehicles – manufactured during model years 2014 to 2018. These standards call for manufacturers to deliver a fleet of light and heavy-duty vehicles with steadily improving fuel economy over a 13-year period. Light-duty vehicle fuel economy is set to rise from 25.5 miles per gallon (mpg) in 2008 to 35.5 mpg in 2016 and more than 50 mpg in 2025 (EPA, 2012).[6] These policies will result in a vehicle fuel economy improvement trajectory from 2014 roughly parallel to the improvements expected in the European Union, Japan and China (albeit from a much lower starting point).

Figure 7.9 International comparisons of light-duty vehicle fuel economy standards



Notes: standards have been developed using the US Corporate Average Fuel Economy (CAFE) test cycle. China's target reflects gasoline vehicles only; the target may be higher after new energy vehicles are considered. The US, Canada and Mexico light-duty vehicles include light commercial vehicles. Solid lines represent historical performance. Dashed lines represent enacted targets. Dotted lines represent proposed targets or targets under study.

Source: ICCT (International Council on Clean Transportation) (2012), *Global comparison of light-duty vehicle fuel economy/GHG emission standards*, ICCT, Washington, D.C.

6. A comprehensive mid-term evaluation of progress in implementing the standards, including public notice and commenting, will be undertaken by the US EPA and NHTSA in conjunction with other federal and state agencies. This review will take place in 2015 and may result in changes to the fuel economy targets.

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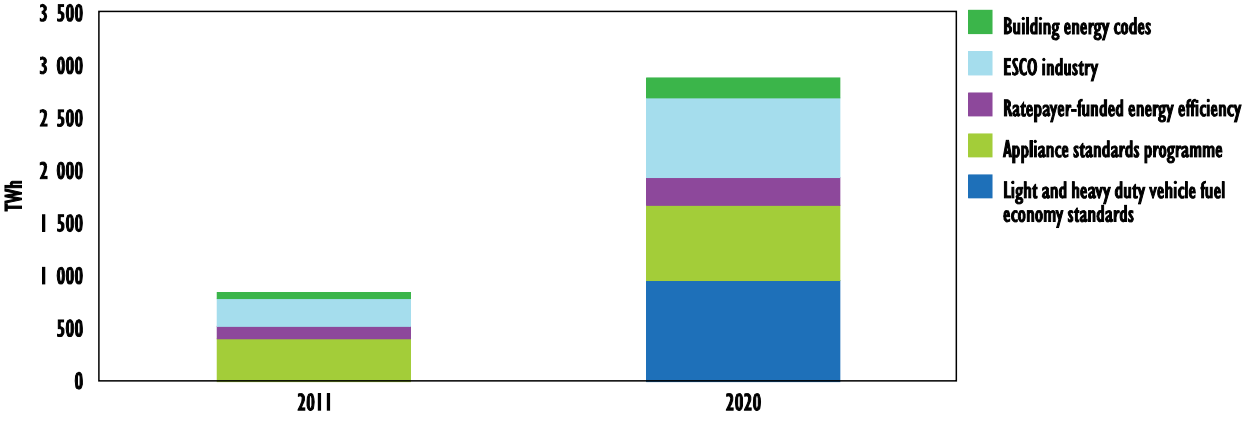
These vehicle fuel economy standards are projected to save about 6.3 billion barrels of oil over the life of light-duty vehicles built from between 2012 and 2024 and heavy-duty vehicles built from 2014 to 2018 model years, or 1.5 million b/d – equivalent to almost one-half of US oil imports in 2012. The standards will also save almost USD 2 trillion for consumers in cumulative fuel costs through 2020 (EPA, 2012).

ASSESSMENT

The United States has made significant progress with implementing energy efficiency policies since the last in-depth review was conducted in 2008 and the country is a leader in facilitating private-sector energy efficiency investments. The 2009 economic stimulus package included new energy efficiency initiatives and substantial additional funding for existing programmes. The direct and indirect funding for these programmes totalled more than USD 30 billion, five times more than 2008 funding levels.

The country is on track to become one of IEA's most energy-efficient countries by 2020. Energy efficiency improvements will continue to unfold over the medium term, as energy efficiency improvement targets for vehicles, appliances and equipment, and new buildings are implemented. These regulatory policies will be supplemented by continued modest growth in ratepayer-funded energy efficiency and the ESCO industry. Tax incentives could provide an additional stimulus to energy efficiency spending by households and businesses. In the aggregate, these policies have the potential to triple annual savings from energy efficiency between 2012 and 2020 (Figure 7.10). Some analysts even predict lower demand for gas, electricity and transport fuels in the coming years as a result of this energy efficiency scaling-up.

Figure 7.10 Actual and forecast annual savings from energy efficiency policies and markets, 2011 and 2020



Source: IEA (2013b), *Energy Efficiency Market Report 2013*, OECD/IEA, Paris

A realistic outlook on energy efficiency in the United States, however, needs to take into account the potential obstacles to continued steady growth (Table 7.4). There are concerns about whether spending on energy efficiency can be sustained, especially in light of the downward pressure on public budgets and continued low natural gas prices. There are concerns that the delivery capability of the energy efficiency industry may not be able to keep up with ambitious targets for savings and efficiency improvements. Delays in technology development could result in downward adjustments in appliance standards or vehicle fuel economy improvement targets.

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Table 7.4 Drivers and impediments to energy efficiency policies in the United States

Drivers	Impediments
Consensus federal and state policies in place	Low natural gas prices
Pipeline of new energy efficiency technologies	Downward pressure on public budgets
Diffusion and rising stringency of state-level efficiency policies	Reaction of energy providers to declining sales
Improved co-ordination in delivering energy efficiency	Workforce sufficiency
New market methods for procuring energy efficiency	Compliance monitoring capacity
New federal legislation – Shaheen-Portman Act and the Sensible Accounting to Value (SAVE) Act	Upward pressure on the cost of delivering energy savings Opposition to increased energy efficiency spending

Source: IEA (2013b), *Energy Efficiency Market Report 2013*, OECD/IEA, Paris.

FACTORS DRIVING SCALED-UP ENERGY EFFICIENCY

Recent advancements and emerging trends in institutional capacity, consumer behaviour, technology development, and the arrival of new energy-efficient technologies should favour continued growth of energy-efficient markets over the next decade.

Factors which will support continued energy efficiency improvements over the next few years include the following examples.

In many cases, there is strong political consensus on federal and state energy efficiency policies. Appliance and equipment standards, vehicle fuel economy standards, and building codes all enjoy bipartisan support. These policies will deliver the bulk of projected energy savings over the next decade. The diffusion of state-level policies, such as energy efficiency resource standards, will result in the gradual disappearance of long-standing regional patterns that differentiate leading states from lagging states. Many states traditionally slow to introduce such measures, are implementing energy efficiency policies, such as Missouri and Arkansas. Some regions (e.g. the Southwest) that were only recently lagging behind are now national leaders (Geller, 2012).

There is increased co-ordination and competence in implementing energy efficiency, and institutions are becoming more adept at co-ordinating energy efficiency policies and programmes. Energy providers now facilitate adoption and enforcement of appliance standards and buildings energy codes. Community organisations use a combination of ratepayer-funded, state and federal funding to deliver low-income weatherproofing programmes. State legislation has placed energy efficiency resource standards on public power entities (municipal utilities and rural electricity co-operatives) for the first time. The emergence of third-party administrators has provided an alternative for delivering ratepayer-funded energy efficiency (ACEEE, 2012).

New technologies and energy-saving opportunities have emerged, leading to new energy-saving opportunities. For example, solid-state lighting will grow in importance as the purchase price falls, taking a market share from compact fluorescent lamps (CFLs). Communications, information technology and smart metering, along with new feedback and control mechanisms, will result in seamless methods to optimise consumption of all types, from industrial process controls and buildings energy management, to intelligent transport systems and smart homes.

New markets and market mechanisms for energy efficiency are being developed in the United States and energy efficiency technology innovation is being accompanied by

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innovative energy efficiency procurement. For example, ISO New England, the balancing authority for the Northeast, operates a forward capacity market (FCM), a competitive auction designed to procure least-cost capacity resources in response to projected capacity needs. Energy efficiency and other demand-side resources can compete in this market on an equivalent basis with generation. ISO New England acts as the market administrator, managing the auctions and setting requirements for participation (Heffner, 2013). In addition, the Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade system for the Northeastern and Mid-Atlantic region, which provides a vehicle for proceeds from selling emission allowances to be used for energy efficiency spending. RGGI generated USD 300 million in energy efficiency programme spending in 2009.

FACTORS IMPEDING SCALED-UP ENERGY EFFICIENCY

Having accomplished a solid decade of often double-digit growth, energy efficiency markets have grown from a footnote to a force to be reckoned with. Like any developing sector, energy efficiency will experience growing pains, market competition, and the effects of larger trends within the economy. Since energy efficiency markets derive largely from federal and state policies, they are particularly vulnerable to political and economic developments.

Factors which may impede potential energy savings include: low natural gas prices, declining federal financial support for energy efficiency, and the effect of flat or declining sales on the viability of energy providers. The ability to deliver projected savings can also be impeded by lack of skilled manpower resources, insufficient compliance monitoring and enforcement capacity, the increasing cost of energy efficiency measures and political opposition to increased energy efficiency spending.

Wholesale natural gas prices have rebounded from historical lows, but remain significantly lower than in most IEA member countries. Low natural gas prices reduce the economic incentive for investing in energy efficiency, and lower the technical cost-effectiveness of ratepayer programmes. Energy Trust of Oregon recently received a temporary exception to continue operating their gas weatherisation programme, even though it is not cost-effective at today's natural gas costs (Energy Trust of Oregon, 2013). Low prices also make it more difficult to sustain and increase ratepayer spending levels, as consumers see the energy efficiency surcharge on bills growing even as commodity costs are going down. This combination could create opposition by some utilities and regulators to continued energy efficiency spending.

The energy efficiency industry received an unprecedented infusion of USD 10 billion in spending through the Recovery Act ARRA. This spending benefited state and local governments and low-income weatherisation programmes, as well as the ESCO industry, which grew rapidly over the period between 2008 and 2011 as thousands of energy-saving retrofits took place in schools, hospitals and other public buildings (DOE, 2012). The low-income weatherisation industry also received a huge infusion relative to long-term average spending levels. Both industries face challenges as federal financial support declines as a consequence of the ending of ARRA funding and lower federal budgets in general.

The combination of flat or declining growth in sales, lower avoided costs and rate impacts from energy efficiency spending is creating concern among some energy utility managers. Steady erosion of revenues over several years has affected share prices and earnings. Concerns over profitability and growth of energy providers may impede the diffusion of energy efficiency resource standards and other regulatory mechanisms in some states (Barbose et al., 2013).

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Studies have shown that energy efficiency policies are effective in creating jobs. However, many of these jobs require on-the-job training and experience. Several studies have predicted that ramping up energy efficiency spending will create shortages in qualified workers needed to deliver high-quality energy efficiency investments (Goldman et al., 2010).

Over the next few years, a growing number of appliance standards and building codes will be implemented. Federal appliance and equipment standards are imposed on manufacturers and importers while buildings energy codes come at the state/local level and are imposed on builders through local building departments. The promulgation of new model building energy codes to more state and local jurisdictions may strain compliance and enforcement capacity.

In some states with a history of energy efficiency programmes, the availability of low cost, short-payback-period energy efficiency is declining. As appliance and equipment stock turns over, and coverage and stringency of energy performance standards expand, there may be fewer cost-effective energy-saving opportunities. Developing new energy efficiency measures and programme offerings that are affordable and accessible to customers is critical if energy efficiency markets are to continue growing (Larsen et al., 2012).

Energy regulators in many states have played an activist role in creating regulatory mechanisms and supporting increases in ratepayer-funded energy efficiency spending. However, in some jurisdictions there have been challenges by state legislators to these new regulatory policies, especially when there is a perception that they are adding to the consumers' energy bills. Regulators that have been active in promoting energy efficiency in Illinois, New Jersey and elsewhere are facing political opposition from legislatures and sometimes the judiciary (Heffner and Migden-Ostrander, 2012).

RECOMMENDATIONS

The government of the United States should:

State and local energy efficiency policies

- ☐ *Prioritise funding to support state and local energy efficiency policies, especially model building energy codes and energy efficiency resource standards. The Safety and Environmental Enforcement Action Network and new initiatives such as the proposed energy policy grants competition (e.g. Race to the Top for state energy efficiency policy) can channel and support aspirations of energy efficiency policy advocates within and outside state governments.*

Tax incentives

- ☐ *Review the results of tax incentives for residential and commercial energy efficiency improvements at the state and federal levels, and develop a more efficient and effective tax incentive structure for the renovation of buildings.*

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8. OIL

Key data (2013 estimated)

Crude oil, NGL and other hydrocarbons production: 439.7 Mtoe, +30% since 2003

Crude oil, NGL and other hydrocarbons net imports: 431.9 Mtoe, -20.7% since 2003

Oil products net exports: 86.9 Mtoe

Share of oil: 35.9% of TPES and 0.8% of electricity generation

Consumption by sector (2012): 771.3 Mtoe (transport 71.7%, industry 14.4%, other transformations 5.8%, residential 3.6%. commercial 3.5%, power generation 1%)

OVERVIEW

The United States became a net importer of oil in the mid-1940s and has, since the mid-1970s, accounted for around one-quarter of the world's oil trade, as demand consistently outstripped domestic supply. Times have changed: oil demand has started to fall back from a historic high of 20 million barrels per day (mb/d) while production has been on an upward trend. Since 2008, domestic production has climbed largely as a result of the deployment of the same technologies used to produce shale gas. In the space of less than a decade, the United States has transformed from being the world's largest oil product importer to the world's second-largest exporter behind Russia. Net product imports went from 1.4 mb/d in 2005 to 1.5 mb/d net exports in 2013. Furthermore, the United States went from importing a net 13 mb/d of oil in 2005 to 6.7 mb/d in 2013. Crude oil net imports have been reduced from 10.9 mb/d in 2005 to 7.8 mb/d in 2013. While it remains an importer, and will continue to be, the changes that have taken place are unprecedented. Notably, from close to zero in 2005, production of light tight oil (LTO) in the United States reached 4.0 mb/d. Net crude oil imports had fallen to under 30% by mid-2014 (EIA, 2014a and 2014b). US crude oil exports are currently prohibited by law except under certain conditions.

SUPPLY AND DEMAND

PRODUCTION, IMPORTS AND EXPORTS

Oil is the most significant energy source in the United States, accounting for 35.9% of total primary energy supply (TPES) in 2013. Total energy supply from oil was 784.6 million tonnes of oil-equivalent (Mtoe) in 2013, increasing by 1.7% from the previous year. Oil supply, however, has been on a downward trend since a peak in 2005 when it reached 929.2 Mtoe. Over the ten years from 2003 to 2013, oil supply in the United States fell by 12.8%.

Crude oil, natural gas liquids and other hydrocarbons

The United States produces about 47% of its domestic demand for crude oil, including conventional and non-conventional oil sources (US crude oil production figures include field condensate) in 2013.

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Total production was 439.7 Mt in 2013, with 367.3 Mt of crude oil, 68.7 million tonnes (Mt) of natural gas liquids (NGLs) and 3.7 Mt of other hydrocarbons. In 2013, the United States was the third-largest producer of crude oil in the world, behind the Russian Federation and Saudi Arabia.

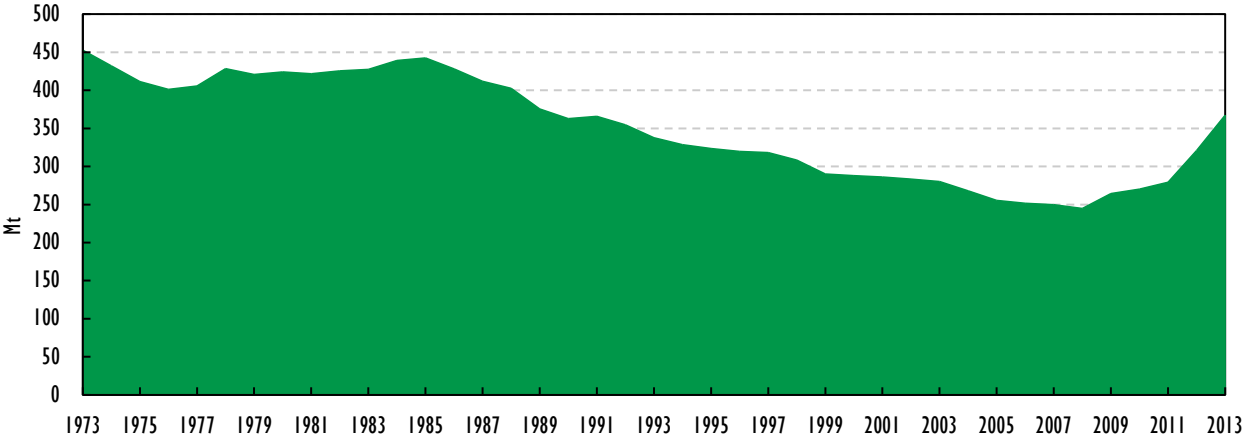
The United States is the world's largest producer of NGLs, and production is growing strongly along with the general growth in natural gas production from shale plays, as well as producers' increasing focus on those shale gas plays that yield a higher output of liquids, given the favourable economics. A large and growing ethane-based petrochemical industry in the country and neighbouring Canada has encouraged investment in offtake capacity for NGLs. The country is also the world's largest producer of biofuels, mostly ethanol from corn, most of which is blended into gasoline sold in the domestic market.

Domestic production of all petroleum liquids was 11.7% higher in 2013 than in 2012, which is the second consecutive year of strong growth. Compared to 2003, production was 30% higher. An important factor is increased production of light tight oil (LTO), which reached 4.0 mb/d by mid-2014, a turnaround that has been dramatic for the North American oil industry and, taken together with the growth in shale gas, has had significant implications for global energy markets. Furthermore, productivity of oil and natural gas wells is increasing in many basins as a result of the increasing precision and efficiency of horizontal drilling and hydraulic fracturing in oil and natural gas extraction (EIA, 2014b).

Reserves

In April 2014, the EIA updated its estimates of US crude oil and natural gas reserves (EIA, 2014a). In 2012, oil and gas exploration and production companies added 4.0 billion barrels of crude oil and lease condensate (light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells) to proved reserves, an increase of 15%, taking the total to 30.5 billion barrels, the greatest volume increase since the EIA began publishing proved reserves estimates in 1977. Proved reserves of crude oil and lease condensate increased by 3.3 billion barrels in 2011, the previous record. The largest increases in reserves were located in Texas and North Dakota which, taken together, accounted for 90% of the net increase in total US proved oil reserves in 2012. In addition to the effects of new discoveries, revisions to existing fields, and the changes made possible by application of new technology, prices play a very important role in the calculation of proved reserves.

Figure 8.1 Crude oil production, 1973-2013

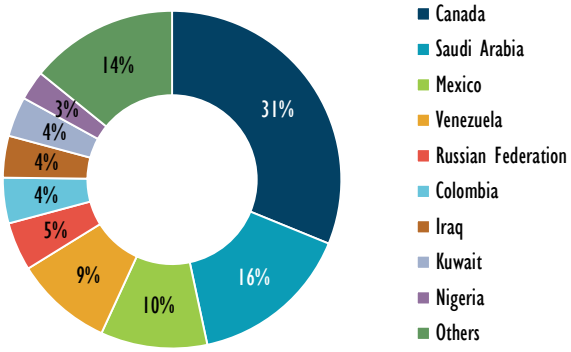


Source: IEA (2014a), *Oil Information*, OECD/IEA, Paris.

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As production accounts for less than half of domestic demand, the United States is a net importer of crude oil. During 2013, 431.9 Mt of oil was imported from Canada (32.1%), Saudi Arabia (15.5%), Mexico (10.2%), Venezuela (9.3%), Russia (4.6%), Colombia (4.4%), Iraq (4%), and others. The United States exported 6.1 Mt of crude oil and 16.3 Mt of NGL and other hydrocarbons, largely to Canada (48.6%) as well as Mexico (10.8%) and other countries, including mainly Latin America. Refinery throughputs have increased since 2010 while net product imports have fallen into negative volumes as the United States became a net product exporter in 2011. Net imports were 24.3% lower in 2013 than in 2003 but increased sharply over the last few years, with a surge in gas and oil supplies creating favourable refinery economics.

Figure 8.2 Imports of crude oil, NGL and other hydrocarbons by country of origin, 2013



Source: IEA (2014a), *Oil Information*, OECD/IEA, Paris.

Oil products

The United States is the largest producer (and consumer) of refined oil products in the world, holding almost one-fifth of the world's refining capacity. The country has the most sophisticated refineries in the world, able to produce high yields of high-value, light products. Production of refined oil products was 807.3 Mt in the United States in 2013. This includes 340.5 Mt of gasoline (42.2% of the total), 228.7 Mt of diesel (28.3%), 69.4 Mt of kerosene-type jet fuel (8.6%), 57.7 Mt of petroleum coke (7.1%) and others. Total refinery output has remained relatively consistent over the past decade, decreasing only marginally by a total of 2% from 2003 to 2013.

The majority of the oil products are consumed locally and net exports amounted to 86.9 Mt in 2013. The United States has been a net exporter of oil products since 2011, previous to which it had been a net importer for decades. During 2013, the largest exports were in diesel (54.7 Mt), petroleum coke (34.7 Mt) and fuel oil (20.3 Mt). Exports of gasoline were also significant, at 23.5 Mt, but imports were higher at 28.9 Mt, with 5.4 Mt of net imports of gasoline. Other larger imports included fuel oil (14 Mt) and diesel (8.8 Mt).

Oil product imports were mainly sourced from Canada (32.9%), the United Kingdom (8.5%) and the Netherlands (6.4%), while exports were destined mainly for Mexico (14.5%), Canada (7.7%), the Netherlands (7.6%) and Latin America.

In early 2014, two companies were given permission to export condensates, as it was considered to be a product since the condensate undergoes some processing before it can be exported. Beyond these two limited permits, however, the federal government has not made a broader decision about allowing the export of this liquid hydrocarbon.

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DEMAND

The transport sector is the main consumer of oil in the United States, with demand of 553.1 Mtoe in 2012 (the latest data available for consumption by sector), or 71.7% of total oil consumption. Oil use in transport has been decreasing since a peak of 600.1 Mtoe in 2005, with a total decline of 4.1% from 2002 to 2012. Demand for oil products in the transport sector has contracted at a slower rate compared to the demand for oil in the rest of the economy, and as such the share of oil consumption by the transport sector increased from 65.7% in 2002 to 71.7% in 2012.

According to the Environmental Protection Agency (EPA), fuel economy for new light-duty vehicles in the United States reached an all-time high in the 2013 model year, averaging 24.1 miles per gallon, up 0.5 mpg on the year. At the same time, average carbon dioxide emissions fell to a record low. US fuel economy has increased in eight of the last nine years and is up nearly 5.0 mpg since 2004 (EPA, 2014).

Industry accounted for 14.4% of oil consumption in 2012, which is a lower share compared to 19.3% in 2002. Other transformations and energy own use represent 5.8% of consumption, followed by the residential and commercial sectors with 3.6% and 3.5%, respectively. The power generation sector is the smallest user of oil, accounting for 1% of total consumption. This sector has downsized oil use significantly over the past few decades, with total consumption decreasing by 70.3% from 2002 to 2012.

Gasoline and diesel together account for 73.9% of oil products consumed in the United States in 2012, with gasoline at 49.9% and diesel at 24% (Figure 8.4).

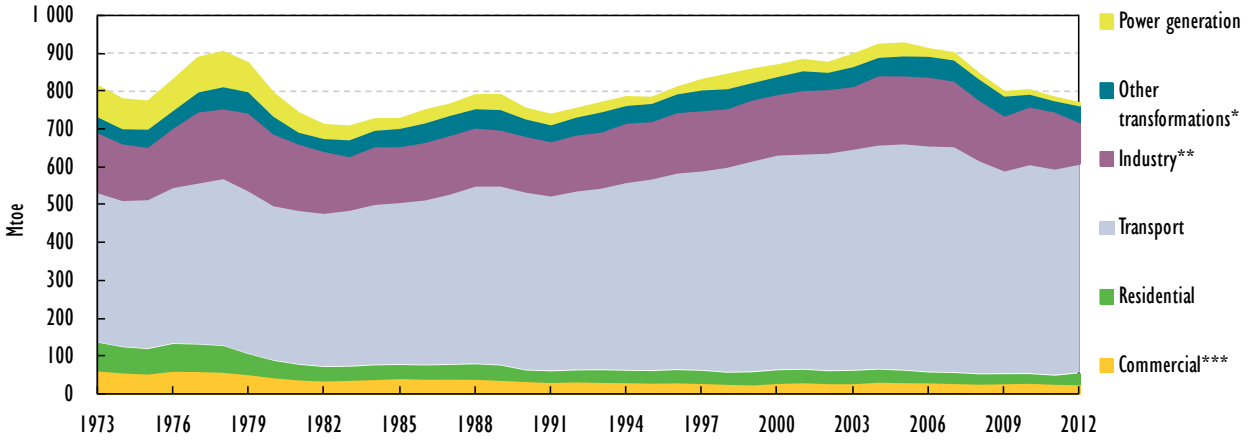
PROJECTIONS

The IEA forecasts that North America will continue to dominate global liquids production in the next five years as it has since 2012. Total liquids production in the United States is projected to surge to a high of 13.1 mb/d in 2019, from 10.3 mb/d in 2013, an average increase of about 470 thousand barrels per day (kb/d) per year. This growth rate is significantly lower, however, than the 1.1 mb/d growth recorded in 2013, the all-time record for a non-OPEC producer. Between 2013 and 2019, tight oil production is expected to rise by 2.5 mb/d, accounting for most of the total net increase in output. The second-largest source of supply growth comes from non-crude liquids, specifically NGLs, the production of which is expected to jump by more than 1.0 mb/d to 3.6 mb/d in 2019. By the end of the decade, NGLs will account for more than one-quarter of total US liquid output, up from 2.1 mb/d in 2010. Light tight oil production in the Bakken and Eagle Ford shale plays remains the backbone of US production growth, but other non-conventional areas provide support, including the Barnett, Niobrara and Permian basins (IEA, 2014b).

In its *Short-Term Energy Outlook*, the EIA expects crude oil production to continue rising in 2014 (EIA, 2013c). Improvements in advanced crude oil production technologies are expected to lift domestic supply, with domestic production increasing in the Reference Case before declining gradually beginning in 2020 for the remainder of the projection period. The projected growth results largely from a significant increase in onshore crude oil production, particularly from shale and other tight formations, which has been spurred by technological advances and relatively high oil prices. Tight oil development is still at an early stage, and the outlook is highly uncertain. In some of the alternative cases presented in the *Annual Energy Outlook for 2013* (EIA, 2013a), tight oil production and total US crude oil production are significantly above their levels in the Reference Case.

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Figure 8.3 Oil supply by sector, 1973-2012



Note: TPES by consuming sector.

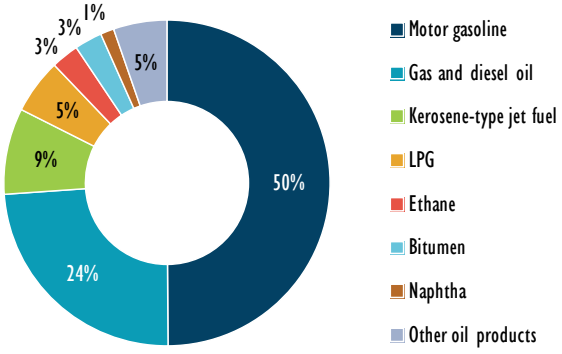
* *Other transformations* includes coal mining, gas and oil extraction and other energy sector consumption.

** *Industry* includes non-energy use.

*** *Commercial* includes commercial, public services, agriculture/forestry and fishing.

Source: IEA (2014a), *Oil Information*, OECD/IEA, Paris.

Figure 8.4 Oil products consumption by product, 2012



Sources: IEA (2014a), *Oil Information*, OECD/IEA, Paris.

OIL EXPLORATION AND PRODUCTION POLICIES

Onshore federal lands managed by the Bureau of Land Management of the Department of Interior and the US Forest Service of the Department of Agriculture are available for leasing and development, subject to multiple-use restrictions. Lands managed by the US Fish and Wildlife Service and the National Park Service, which are agencies within the Department of Interior, have much less availability. For example, the Arctic National Wildlife Refuge (ANWR) remains closed to oil and gas development. Wilderness designations and restrictions imposed in favour of wildlife habitat or recreational use make other lands either unavailable or too expensive to develop.

One of the most interesting features about the United States, making it distinct from nearly all other IEA member countries, is that privately held land includes sub-soil rights in the title. This has been one of the reasons why LTO production could grow quickly in the United States, as landowners can receive a greater share of the proceeds of development.

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Legislation and regulations regarding oil (and natural gas) exploration, development and production from US offshore lands developed over many decades in response to a variety of concerns and disputes that were most often engendered by competing priorities. The most common early disputes revolved around ownership of coastal waters. Eventually, as offshore activities became more abundant, more complicated issues arose over the need to ensure that operations were accompanied by safety, equity, and the protection of marine and coastal environments.

In response to the 2010 Deepwater Horizon explosion and resulting oil spill in the Gulf of Mexico, President Obama's Administration launched the most aggressive and comprehensive reforms to offshore oil and gas regulation and oversight in US history. Notably, the Minerals Management Service (MMS) was separated into three independent entities to better carry out its three missions of: ensuring the balanced and responsible development of energy resources on the Outer Continental Shelf; ensuring safe and environmentally responsible exploration and production and enforcing applicable rules and regulations; and ensuring a fair return to the US taxpayer from offshore royalty and revenue collection and disbursement activities.

The MMS was renamed Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). Subsequently, in 2011, BOEMRE was separated into two independent entities: the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE).

BOEM is responsible for managing the development of US offshore resources in an environmentally and economically responsible way. Its functions include: leasing, plan administration, environmental studies, National Environmental Policy Act (NEPA) analysis, resource evaluation, economic analysis and the renewable energy programme.

The new BSEE was created to enforce safety and environmental regulations. Its functions consist of all field operations, including permitting and research, inspections, offshore regulatory programmes, oil spill response, and newly formed training and environmental compliance functions.

The Office of Natural Resources Revenue (ONRR) manages an average of USD 11 billion in annual revenues from energy and mineral leases and other monies owed for the use of public natural resources on the Outer Continental Shelf and onshore federal and American Indian lands. Its revenue sources include royalties, rents, and bonuses generated throughout the life of the lease. The ONRR is a trustee of royalty assets from Indian trust properties and is an advocate for the interests of Indian mineral owners. In conjunction with the Bureau of Indian Affairs, ONRR provides revenue management services for mineral leases on American Indian lands. All monies collected are distributed to the respective Indian tribes and individual Indian mineral owners through the Office of Trust Funds Management.

FIVE-YEAR OUTER CONTINENTAL SHELF (OCS) OIL AND GAS LEASING PROGRAM

The BOEM Five-Year Program consists of a schedule of oil and gas lease sales indicating the size, timing, and location of proposed leasing activity that have been determined to best meet national energy needs for the five-year period following its approval. An area must be included in an approved Five-Year Program before it is offered for leasing. Section 18 of the OCS Lands Act prescribes the major steps involved in developing a Five-Year Program including extensive opportunities for public comment. Under Section 18, a Five-Year Program must, to the maximum extent practicable, strike a balance between the potential for environmental damage, discovery of oil and gas, and adverse impacts on

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the coastal zone, based on a variety of factors that must be considered under section 18 (Bureau of Ocean Energy Management, 2012). The latest Five-Year Program (2012-2017) offered a total OCS area of 219 million acres, including 125 million acres in Alaska and 94 million acres in Offshore Gulf of Mexico.

INFRASTRUCTURE

REFINING SECTOR

Surging North American crude oil, condensates and natural gas supplies, and restrictions in place to prevent the exports of these supplies, have led to a spectacular renaissance of the US refining industry over the last few years. Healthy refinery margins look set to spur more than 700 kb/d of new topping and condensate splitter capacity in North America over the next few years. The supply revolution and a downtrend in domestic consumption have helped turn the country, long the world's top importer of refined products, into one of the largest net exporters. Cheap natural gas, when compared to many other markets and "advantaged" (i.e. discounted from global benchmark prices) crude have dramatically increased the competitiveness of its refineries, which also benefit from economies of scale, good logistical links to export terminals (the capacity of which is rising) and state-of-the-art technology. Refiners also have benefited from fast rising demand and from a lack of refining capacity in Latin America, which have provided them with ready export markets for excess gasoline and distillate production. As output of light products keeps rising, refiners may face increasing international pressure in marketing their surplus, however (IEA, 2013).

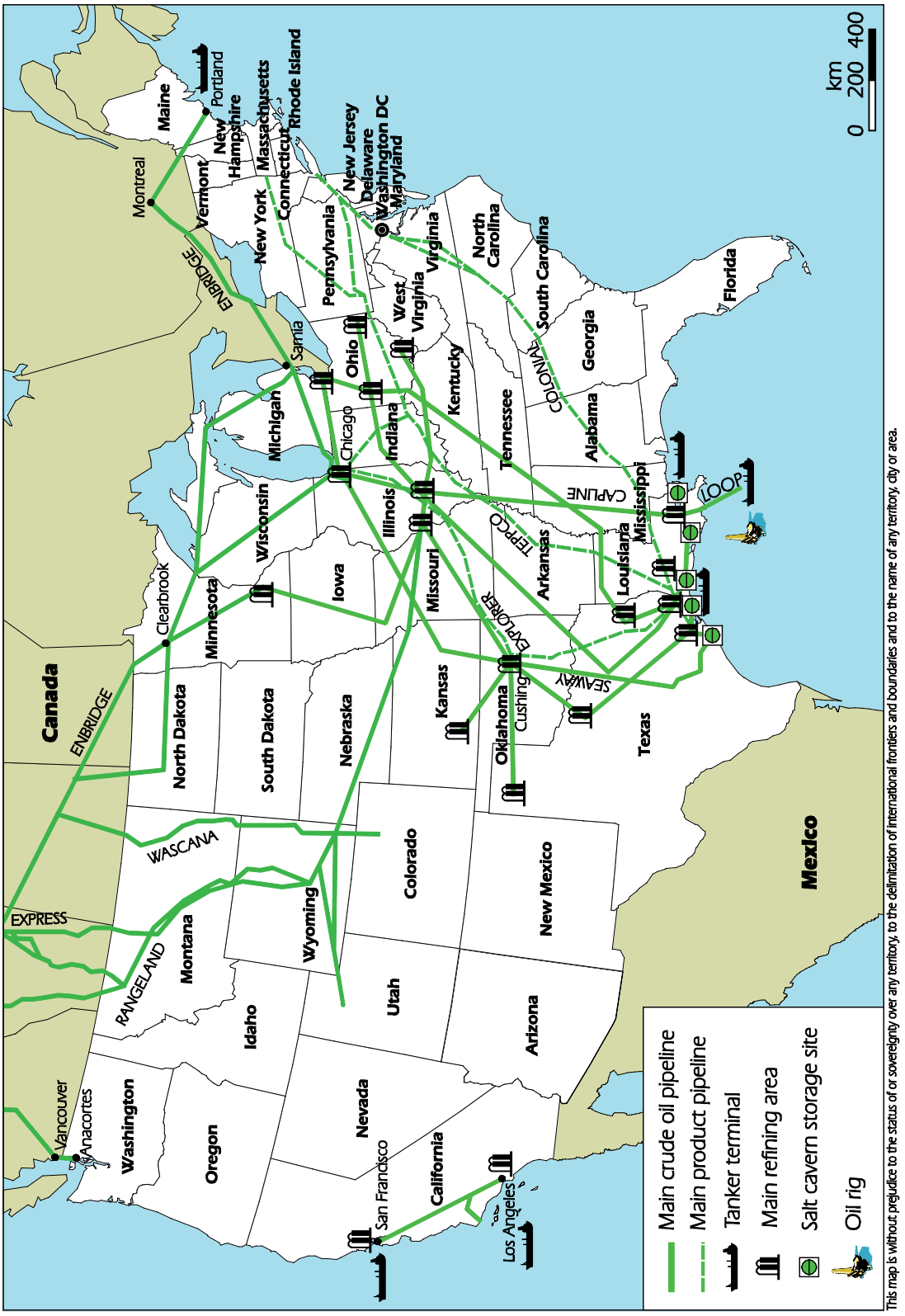
As of 1 January 2013, the United States had 143 refineries (of which four were idle) with a total crude oil throughput refining capacity of 17.8 mb/d according to EIA figures (EIA, 2013c). About 44% of this capacity was located along the Gulf Coast. The largest refinery operator is Valero Energy with operational refining capacity of more than 1 863 kb/d. The next largest operator is ExxonMobil followed by Phillips 66, BP, Marathon Petroleum, Motiva Enterprises and Chevron (EIA, 2013b). The top 18 refiners account for 90% of total refining capacity. The three largest refineries are:

- The Port Arthur refinery, located on the Gulf of Mexico at Port Arthur in Texas. It is operated by Motiva Enterprises, a 50/50 joint venture between Shell and Saudi Aramco. The refinery has a capacity of 600 kb/d.
- The Baytown refinery, located at Baytown in Texas, and is owned and operated by ExxonMobil. It has a capacity of 584 kb/d.
- The Garyville refinery, located in Louisiana, is owned and operated by Marathon Petroleum Corporation. It has a capacity of 522 kb/d.

Total refining capacity in the continental United States remained relatively flat in the period 2005 to 2013. While there were some capacity additions as well as refinery closures during this period, they largely cancelled each other out. Nonetheless, there were two significant expansions – one by Marathon, Garyville (Louisiana) and the other by Motiva, Port Arthur (Texas) – totalling 535 kb/d of new refining capacity. There were also a number of reductions in refining capacity or refinery closures during this period (525.5 kb/d in total). The majority of the closures (489.3 kb/d) were at facilities located on the east coast, where refiners have not benefited from the surge in US gas and crude oil production to the same extent as has been the case on the Gulf Coast and in the mid-continent. Furthermore, a 500 kb/d refinery on the United States Virgin Islands also shut down although this refinery may be sold and restarted.

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Figure 8.5 Oil infrastructure in the United States



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To take advantage of new domestic production, such as the Eagle Ford and Bakken plays, and increased Canadian crude exports, many refiners have begun or are planning upgrades, modifications and expansions. BP's Whiting refinery in Indiana brought online a 102-kb/d coker in November 2013 in order to take advantage of heavier Canadian crudes. Some refiners have implemented upgrades and modifications in order to produce ultra-low sulphur diesel (ULSD) to meet clean air requirements. Others are not only altering their refining processes to take advantage of new domestic production, but they are adding rail facilities to make their refineries accessible to new production from the mid-continent. In addition to adapting to surging new domestic production and the availability of Canadian crudes, a small number of new refineries are planned in North Dakota and South Dakota to process locally produced Bakken crude. New infrastructure to transport and process natural gas is needed, as flaring is now heavily restricted by new regulations that came into effect in 2014.

REFINERY INFRASTRUCTURE HARDENING IN RESPONSE TO 2008 HURRICANE

Hurricanes along the Gulf Coast periodically result in major storm damage, electrical power outages, large-scale flooding and mandatory evacuations that severely impact Gulf Coast petroleum refining operations and product distribution capabilities. Since Hurricane Katrina in 2005, federal and state governments, public utilities and industry stakeholders have worked to address the vulnerability of the refining sector to hurricanes by hardening infrastructure and increasing resilience measures. Hurricane Sandy also caused large disruptions to East Coast fuel supply in 2012. While less frequent, hurricane/storm damage on the densely populated East Coast is also of concern.

In 2010, the DOE Office of Electricity Delivery and Energy Reliability conducted a study to identify specific industry efforts related to this area. Although a lot of progress has been made, the study found that infrastructure and personnel safety are still vulnerable to hurricanes, limiting the reliability of refined product supply.

Refinery hardening efforts

One of the most significant vulnerabilities for refineries across the Gulf Coast can be the lack of access to electricity supply. A number of refineries have invested in portable generators, but the majority of facilities have instead established plans that enable them to quickly lease generators in advance of an approaching hurricane. Even the largest mobile generators, however, cannot provide sufficient electricity supply to operate a refinery. Refiners rely on portable generators only to provide critical service (the data control centre, critical IT facilities, and the water pumps) or safely shut down operations until grid power can be restored.

Winds of hurricane strength can cause severe damage to refineries, and their cooling towers are especially susceptible to wind damage. High winds can cause the fan blades inside a cooling tower to become dislodged and launched from the tower if they are not properly secured. Several refiners have installed special braces to stop the fan blades from dislodging.

Hurricane rains and flooding can also cause extensive damage to refineries, and normally result in extended recovery times. The hurricanes of 2005 and 2008 caused extensive water damage to refineries control systems, electrical equipment, and pump motors, and caused storage tanks to move off their foundations. Common flood protection structures such as floodwalls, levees, and berms have been built by either government

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or industry. In response to extensive water damage, many refineries have also elevated substations, control rooms, and pump stations above the likely flood level. In many cases, facilities have been elevated 15 to 25 feet above ground level.

Distribution terminals and pipeline hardening efforts

The Colonial and Plantation product pipelines, which supply refined products to the Southeast and East Coast, have numerous pipeline injection points and pump stations across the Gulf Coast, which are vulnerable to commercial electric power system outages. To avoid a recurrence of accidents during the 2005 hurricane season, the Colonial Pipeline Company purchased 12 trailer-mounted Mitsubishi portable generators, seven transformers, and large amounts of associated cabling in 2006 (DOE, 2010). These large portable generators are maintained at a site in Mississippi and can be deployed to any of its pump station locations in order to maintain its pipeline operations. The Plantation Pipeline has not purchased portable generators but has stated that it has contingency plans for the rental of portable generators in the event of electric power outages. The Colonial Pipeline has indicated a capability to deploy its generators and return to operations within one week (subject to product supplies).

Hurricane vulnerabilities remain

Investments in refineries and pipelines have improved their resilience to hurricanes and other catastrophic events. Nonetheless, major hurricane vulnerabilities remain. Gulf Coast refiners are highly dependent on commercial power, personnel and supporting industry operations. Even with co-generation operations, refineries are dependent on commercial power sources. They shut down in advance of a hurricane owing to the high risk of power loss and do not restart until stable commercial power has been restored.

A major concern for the ability to recover quickly is not only whether the infrastructure has been hardened, but also whether key personnel are available. Most jurisdictions now order mandatory evacuations in the event of a major hurricane and personnel are therefore displaced and unavailable. It takes time for roads to reopen, personnel to return to work and managers to assess the extent of damages and organise the necessary repairs.

Another concern is supporting industry operations. Most Gulf Coast refineries rely on their supply chain for industrial gas, services and product distribution operations. Unless they are all operating, the refinery often cannot restart.

With regard to the assessment of critical oil and natural gas infrastructure points and key vulnerabilities more generally, the DOE assesses these on a continuous basis. The focus of each assessment varies, depending on the priorities at the time, with the DOE working to define critical nodes based on specific scenarios, since the critical nature of nodes varies according to the type of challenge.

PORTS

There are significant numbers of oil port facilities all around the United States. Most have import terminals for crude and product imports, with a small number restricted to product imports only.

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STORAGE CAPACITY / STORAGE REQUIREMENTS

For the purposes of tracking oil storage, the United States is divided into five Petroleum Administration for Defense Districts (PADD):

- PADD 1 (East Coast, divided into three sub-districts)
- PADD 2 (Midwest)
- PADD 3 (Gulf Coast)
- PADD 4 (Rocky Mountain)
- PADD 5 (West Coast, Alaska, Hawaii).

Twice a year, the EIA provides data on storage capacity for crude oil, petroleum products, and selected biofuels in its *Working and Net Available Shell Storage Capacity* report. The most recent report, published in November 2013 and based on data as of 30 September 2013, indicated that the total operating shell storage capacity of the United States was 2.21 billion barrels (EIA, 2013e).

Cushing is the market hub for West Texas Intermediate (WTI) crude oil; therefore, both the storage capacity and level of inventories held at Cushing are closely watched market indicators. At the end of March 2014, the working crude oil storage capacity in operation at the Cushing storage and trading hub was 80.96 million barrels.[1] In the past, high inventory levels at Cushing have been a symptom of transportation constraints that have resulted in WTI trading at a discount relative to comparable grades of crude oil since early 2011.

CRUDE OIL PIPELINES

Pipelines are the most commonly used mode of transport for shipping oil in the United States. The country has 172 048 miles of crude gathering and distribution pipelines operated by 2 338 companies, with the top ten operators alone responsible for approximately 55 000 miles (88 500 km) of pipeline. The highest concentration of pipelines is in the Gulf Coast region (which also has almost 50% of the country's refining capacity).

The largest crude pipelines in the United States were constructed to move oil between PADD3 which is centred on the Gulf Coast and PADD2 which is centred on the Midwest region. The major pipelines are the Capline, Centurion, Border, MidValley, Seaway and the Basin with a combined capacity of 2.6 mb/d and a combined utilisation rate in 2011 of 36%. The low utilisation rate was primarily a result of significant under-utilisation of the Capline pipeline.

A number of major pipelines were constructed to transport crude from the offshore Gulf of Mexico to refining centres in Texas and Louisiana. These include: the Cameron Highway with a 600 kb/d capacity, the Louisiana Offshore Oil Port pipeline with a capacity of 2.4 mb/d, the Shell-Mars pipeline with a capacity of 600 kb/d and the BP Endymion pipeline with a capacity of 750 kb/d. Smaller-capacity pipelines that transport oil from the Gulf of Mexico include the Diana-Hoover pipeline, the Delta pipeline, the Eugene Island pipeline, the Poseidon pipeline and the Ship Shoal pipeline. These have a combined capacity of around 5.6 mb/d.

1. Working and Net Available Shell Storage Capacity: Net Available Shell Storage Capacity by PAD District as of 31 March 2014 (thousand barrels), US Energy Information Administration, 29 May 2014.

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In the northern United States, there are four major pipelines shipping oil from the hubs in Alberta, Canada. These are the Enbridge Mainline pipeline, the Kinder Morgan Trans Mountain pipeline, the Kinder Morgan Express pipeline, and the TransCanada Keystone pipeline (which is distinct from the proposed TransCanada Keystone XL pipeline). These pipelines have a combined capacity of almost 3.5 mb/d, and there are plans to expand their capacity to over 5.4 mb/d by 2017.

Box 8.1 The Keystone XL Pipeline Project

The Keystone XL Pipeline Project is a proposed 1 897 km, 36-inch-diameter crude oil pipeline, connecting Alberta, Canada to Nebraska. It is designed to transport up to 830 000 barrels per day of crude oil from Alberta, across the US border near Morgan, Montana and onwards through Montana, South Dakota, and Nebraska. It will connect to existing pipeline facilities near Steele City, Nebraska for delivery to Cushing, Oklahoma and the Gulf Coast area. The pipeline would allow Canadian and American oil producers greater access to refiners found in the American Midwest and along the US Gulf Coast.

A Presidential Permit evaluation process focuses on whether the proposed Project serves the national interest, which involves consideration of many factors, including: energy security; environmental, cultural, and economic impacts; foreign policy; and compliance with relevant federal regulations. During this time the Department of State (DOS) will consult with, at least, eight agencies identified in Executive Order 13337: the Departments of Defense, Justice, Interior, Commerce, Transportation, Energy, Homeland Security and the Environmental Protection Agency.* As of September 2014, DOS is continuing to review the Presidential Permit application for the proposed Keystone XL pipeline.

* See www.keystonepipeline-xl.state.gov/.

Sources: IEA; US DOE; DOS.

As already mentioned, there are a number of proposals for expanding Canada-to-Gulf Coast pipeline capacity that will, if implemented, significantly increase the volume of Canadian crude oil flowing to the Gulf Coast region.

The new pipelines show a clear pattern of crude flowing from areas of increasing domestic and Canadian production, including the Alberta oil sands, the Bakken formation, and the Eagle Ford formation, to the major refining centres in the Gulf Coast. When complete, the Flanagan South Pipeline project will provide additional capacity to bring increased crude oil production to refinery hubs on the US Gulf Coast. The Westward Ho pipeline will transport offshore production to the US Gulf of Mexico starting in 2015 and is expandable to 900 kb/d. There are also several pipeline proposals in the Bakken formation, including an Energy Transfer Crude Oil Company pipeline to crude oil terminal facilities in Nederland, Texas and Dakota Access, a pipeline to Illinois.

There are a number of projects under way or under evaluation to move NGLs, primarily ethane, produced in the Marcellus shale to both the Gulf Coast and Mid-continent (*Oil and Gas Journal*, 2014). Oneok Partners LP placed the 600-mile Bakken NGL pipeline, transporting unfractionated NGLs from the Bakken shale to Overland Pass Pipeline in northern Colorado, into service in 2013. Williams Cos. and Boardwalk Pipeline Partners LPs proposed joint-venture Bluegrass Pipeline to transport mixed NGL from the Marcellus and Utica shales to US Gulf Coast petrochemical and export markets.

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OIL PRODUCT PIPELINES

As is the case with crude oil, pipelines are the most commonly used mode of transportation of refined products. Four major pipeline systems from the Gulf Coast provide products to the East Coast and Midwest regions. Another major pipeline system transports petroleum products on the West Coast. The major oil product pipeline systems can be summarised as follows:

- The Colonial Pipeline System originates in Houston, Texas and connects to most Gulf Coast refineries. The pipeline delivers refined products throughout the Southeastern United States and continues to the Northeast. The Colonial pipeline has four lines with a combined capacity of 2.4 mb/d that extends to North Carolina. Two lines, with a capacity of 1.1 mb/d, extend beyond North Carolina and continue delivery into the Northeast region. Plans have been announced to expand that capacity by 100 kb/d via pump and compressor upgrades.
- The Plantation Pipeline System (Kinder Morgan) transports products from the Gulf Coast to the East Coast. The pipeline originates near Baton Rouge, Louisiana and Pascagoula, Mississippi and terminates in Newington, Virginia. The Plantation pipeline is comprised of two lines with a combined capacity of 600 kb/d and runs largely parallel to the Colonial pipeline.
- The Explorer Pipeline System originates in the Gulf Coast near Lake Charles, Louisiana; Port Arthur, Texas; and Houston, Texas and terminates in Ardmore, Oklahoma and Hammond, Indiana. The Explorer pipeline consists of two lines and has a combined capacity of 720 kb/d.
- The Centennial Pipeline System originates near Beaumont, Texas and extends into Bourbon, Illinois. It has an operating capacity of 210 kb/d.
- The Kinder Morgan Calnev pipeline system transports refined products from Los Angeles, California and extends to terminals in Barstow, California, and Las Vegas, Nevada. The Calnev pipeline has a capacity of approximately 120 kb/d.

RAIL

Rail is a rapidly growing mode of transportation for crude oil and petroleum products. Generally, it is used where there is a lack of pipelines (e.g. because of a production boom), where existing pipelines lack sufficient available capacity, or where rail is the most cost-effective option. Rail transport is much faster than pipeline transport: for example, a market that takes five to seven days to ship Bakken oil by rail can take more than 30 days by pipeline. In addition, the increased price of rail transportation (transport via pipeline costs USD 4.0 to USD 4.50 per barrel whereas rail costs USD 6.0 to USD 7.0 per barrel) is lower than the oil price differential associated with being stranded in the Bakken Shale waiting for pipeline availability. Rail can also give shippers more flexibility to seek out the best available netback, although transport costs are higher on average.

In the past, crude oil generally moved from production areas to refineries by pipeline but changes in production patterns have led to significant increases in rail transportation of crude oil output. In 2008, Class I railroads originated just 9 500 carloads (a carload equals 30 000 gallons) of crude oil. In 2012, they originated nearly 234 000 carloads and 434 000 carloads in 2013. Expectations for 2014 are about 650 000 carloads, according to the US government. Crude oil accounted for 1.4% of total Class I originated carloads in 2013 through September, up from just 0.03% in 2008 (Association of American Railroads, 2013).

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In the recent past, North Dakota and the Bakken region have accounted for the vast majority of new rail crude oil originations. According to estimates from the North Dakota Pipeline Authority, as of mid-2013, approximately 640 000 barrels per day of crude oil were moving out of North Dakota by rail, equivalent to more than 60% of North Dakota's crude oil production.

Safety concerns

The boom in oil production and lack of pipeline infrastructure in some regions has forced unprecedented amounts of oil being transported by rail. US rail infrastructure was not built to manage large volumes of crude oil and has a limited number of specially designed rail trucks. The exponential growth in the amount of crude oil moving by rail has given rise to safety and environmental concerns and there have been a number of serious accidents across North America some of which involved oil being moved from the Bakken Shale (which tends to be more volatile and flammable than crude produced elsewhere, according to a recent US government finding). An important issue is the widespread use of older-model tank cars, which are not as safe as new models. If large movement of oil by rail is to continue, then major infrastructure investments need to occur, alongside significant strengthening of regulations. In this regard, the Department of Transportation announced, in July 2014, a comprehensive rulemaking proposal to improve the safe transportation of large quantities of flammable materials by rail, including rules for enhanced tank car standards and rules seeking to expand response planning requirements for shipments of flammable materials in the event of an oil spill.

MARITIME TRANSPORT

According to the US Energy Information Administration (EIA), America's domestic maritime industry moves tens of millions of barrels of crude oil and petroleum products throughout the United States, all of it using Jones Act's approved vessels. Increased production of crude oil from the Bakken region and the Eagle Ford and Permian basins in Texas (and western Canada) has stimulated new routes for shipping crude oil to North American refineries. Where pipelines are unavailable, or have insufficient capacity, to move all the crude from these locations, producers have opted for rail alongside barges, and to a lesser extent tankers.

The Jones Act requires that any cargoes being shipped by water between US ports be transported on a vessel owned by a US company, crewed by US mariners, and manufactured in a US shipyard. At the moment there is high demand to move shale oil between American coastal ports, and US shipyards are experiencing the greatest volume of shipbuilding activity in more than three decades. Nonetheless, the costs of building a Jones Act-vessel is four times the price of a similar ship built in the world's leading shipbuilding countries. Operating costs are also significantly higher (Fritelli, 2014).

The limited number of American-built tankers (11 tankers and 86 seagoing barges) makes it difficult for shippers to charter tankers for a short period or for as little as a single voyage. It often results in more oil moving by rail than otherwise would be the case. Some Texas oil is moving to refineries in eastern Canada, bypassing refineries in the northeastern United States, because shipping to Canada on foreign-flag vessels is much cheaper than shipping domestically on Jones Act-eligible ships. According to industry sources, the price for moving crude oil from the Gulf Coast to the US Northeast on Jones Act-tankers is USD 5.00 to USD 6.00 per barrel, while moving it to eastern Canada on foreign-flag

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tankers is USD 2.00 (Fritelli, 2014). Some industry sources argue, therefore, that the Jones Act is imposing additional costs on US consumers. Alternatively, it makes importing of oil from other markets more attractive than refining domestically produced oil.

OIL EMERGENCY RESPONSE POLICY AND EMERGENCY ORGANISATION

LEGISLATION AND EMERGENCY RESPONSE POLICY

Oil emergency response policies in the United States are based primarily on the Energy Policy and Conservation Act (EPCA). The EPCA provides the statutory authority for the establishment of both the Strategic Petroleum Reserve (SPR) and the Northeast Home Heating Oil Reserve (NEHHOR). It also gives the President the authority to direct a drawdown of the SPR in the event of a "severe energy supply interruption", or to meet the obligations under the International Energy Program (IEP). In May 2014, in response to Hurricane Sandy, DOE established a Northeast regional gasoline reserve at two locations near New York Harbor and in New England. Each location will store 500 000 barrels of gasoline, enough to provide some short-term relief in the event of significant disruptions and will complement the NEHHOR.

Part B (Sections 151-172) of the EPCA provides the legal framework for the establishment, operation and management of the SPR programme. Section 161 provides specific authorities and conditions governing the release or drawdown of oil from the SPR. In addition, under the federal rulemaking process, the SPR has established and published standard sales procedures controlling the sale of petroleum from the SPR, and procedures for the acquisition of petroleum for the SPR.

Part D (Sections 181-191) of the EPCA provides the legal framework for the establishment, operation and management of the NEHHOR. Section 183 provides specific authorities and conditions governing the release or drawdown of oil from the NEHHOR. Other relevant legislation includes the Department of Energy Organisation Act, the Federal Energy Supply and Environmental Co-ordination Act, and the Federal Energy Administration Act.

NATIONAL EMERGENCY STRATEGY ORGANISATION (NESO)

The DOE serves as the country's NESO, with the responsibility of initiating and co-ordinating a response to an oil supply disruption. The NESO is composed of two teams – the Crisis Assessment Team and the Executive Team.

The Crisis Assessment Team is led by the DOE Office of International Affairs (IA). The IA would convene the Crisis Assessment Team as they are responsible for interacting with the IEA.

The Executive Team is comprised of the Secretary of Energy, the Deputy Secretary of Energy and senior management from the OPIA, EIA and SPR. The Executive Team analyses and discusses the findings of the Crisis Assessment Team and co-ordinates a response with other departments and White House Staff Offices. The Secretary of Energy is responsible for forwarding the Executive Team's recommendations to the President.

Personnel from the DOE's Offices of International of Affairs, Intelligence, and Fossil Energy, and also from the Energy Information Administration, as well as the Crisis Assessment Team and the Executive Team are required to undergo regular training to maintain their capacity to act as an effective emergency response team. At the executive level, DOE has a protocol in place to conduct a crisis simulation, known as Shockwave, to simulate an oil supply crisis. At the staff level, personnel from the Office of Petroleum Reserves and the

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OPIA have participated in the IEA's Emergency Response exercises. Additionally, the Office of Petroleum Reserves conducts biannual "Eagle" and "Pride" drills to simulate large and small crisis response situations.

Other mechanisms

The federal government's preferred response to an oil supply disruption is to release stocks from the SPR. However, the country has other statutory mechanisms for use in certain situations such as natural disasters, e.g. hurricanes.

The Office of Electricity Delivery and Energy Reliability is responsible for federal disaster response activities for energy. This agency prepares for, and responds to, all hazards including natural disasters. The Stafford Act is the key piece of legislation in this regard as it provides the statutory authority for the Federal Emergency Management Agency (FEMA). "Stafford Act events" include hurricanes, floods, earthquakes, ice storms and wild fires. The Office also responds to non-Stafford Act events such as electricity blackouts and oil spills, and physical infrastructure events such as refinery and pipeline disruptions.

DOE activities to enhance preparedness include: federal, state and local exercises and Emergency Support Function (ESF) No. 12 (ESF-12), Regional Co-ordination, which involves working with industry, federal, state and local partners through DOE; and ESF-12 regional co-ordinators. Federal, state and local exercises take place regularly.

The private sector also has emergency response plans in place but these are not mandated.

Hurricane Sandy response

Hurricane Sandy made landfall in the United States (as a Post-Tropical Cyclone) on 29 October 2012. At landfall, the storm was 1 000 miles across with sustained winds of 80 miles per hour. It affected coastal states from North Carolina in the south to Maine in the north. Storm damage to energy infrastructure was significant. On the "worst day" refining capacity of 308 kb/d was shut down (at two out of six refineries in the storm area), the Buckeye, Colonial and Plantation product pipelines were affected, as was the New Jersey natural gas pipeline. Crude pipelines were not impacted but several ports were disturbed with shutdowns at 57 petroleum terminals (some tanks leaked or came off their base; there was flooding and saltwater corrosion, and docks were damaged). Electricity infrastructure was also damaged with 20 states and the District of Columbia experiencing power outages affecting 8.5 million customers.

DOE emergency response measures included:

- The Office of Electricity Delivery and Energy Reliability produced frequent emergency situation reports that provided situational awareness of energy infrastructure outages and restoration activities for federal, state and local stakeholders.
- The EIA provided information resources on energy infrastructure in the path of Hurricane Sandy, including an interactive infrastructure map that displayed the track of Hurricane Sandy over energy infrastructure, and a motor gasoline supply report that summarised the status of retail fuelling stations in the New York City metropolitan area.
- The DOE worked in partnership with FEMA and other federal agencies to assist the affected states and help to restore utilities. This included daily conference calls between utility executives and Secretary Chu, and participation in an interagency taskforce on power restoration and fuel supply and availability at the FEMA National Response

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Co-ordination Center. The taskforce focused on eliminating any bureaucratic roadblocks to restoring the power supply as quickly as possible. As part of this, the taskforce facilitated the movement of utility workers by working with the Department of Transport to issue the appropriate permits for utility trucks crossing state lines. At the peak of this effort 70 000 workers from around the country were working to restore power in affected areas.

- The DOE also provided "boots on the ground" support with the deployment of 35 DOE personnel.
- 235 personnel and equipment from the DOE's Power Marketing Administration (PMA) offices in western states were also involved in restoration efforts.
- The Army Corps of Engineers deployed water pumps to a flooded Con Edison power substation in New York to help clear out the water. Diesel generators were used to energise substations.

With regard to addressing fuel shortages:

- Jones Act Waiver: the Department of Homeland Security (DHS) in co-ordination with DOE, the Maritime Administration and the Department of Defense, issued a waiver of the Jones Act allowing foreign vessels to ship petroleum products from the Gulf of Mexico to northeastern ports.
- Fuel Flexibility Waivers: the EPA, in co-ordination with DOE, issued a number of waivers that allow for fuel flexibility in the use of a number of fuel products.
- For the first time, diesel fuel from the NEHHOR was released for use by emergency responders, generators and emergency equipment and buildings, as well as to alleviate fuel shortages in Connecticut. The reserve loaned 120 000 barrels to the Defense Logistics Agency, which in turn loaned 100 000 barrels to one company for 30 days, and 20 000 barrels to another company for 30 days.
- Additional efforts included: opening ports, providing generators for gas stations and providing fuel to first responders and, in the longer term, the establishment of a regional gasoline reserve.

Libya Collective Action

The United States' share of the stock drawdown for the IEA Libya Collective Action (LCA) in June 2011 was 30.2 million barrels. The federal government responded by making the required amount of stock (100% of which was crude oil) available from the SPR by market tender. The amount of stock that was taken up by the market was 30.64 million barrels, slightly more than the required amount. The 30.64 million barrels sold from the SPR has not been replenished and there are no plans to do so.

EMERGENCY OIL RESERVES

Stockholding regime

The Strategic Petroleum Reserve (SPR) is the world's largest supply of emergency crude oil. The federally owned oil stocks are stored in huge underground salt caverns along the coastline of the Gulf of Mexico. It was established in 1975 under the Energy Policy and Conservation Act (EPCA) "to reduce the impact of disruptions in supplies of petroleum products" and to "carry out obligations of the United States under the International

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Energy Program". The SPR has a total storage capacity of 727 million barrels of crude oil, and as of 25 September 2014 it had an inventory of 691 million barrels – equivalent to 106 days of net imports.

In August 2014 the United States established the Northeast Regional Refined Petroleum Product Reserve, which consists of 1.0 million barrels of gasoline stored in leased commercial terminals in Maine, Massachusetts and New Jersey.

There is no statutory obligation on industry to hold stocks for emergency purposes. Nonetheless, ample industry stocks (362 million barrels as of 21 February 2014) held for commercial purposes have ensured that the United States remains fully compliant with its IEA 90-day stockholding obligation.

The SPR consists of 62 large storage caverns in underground salt dome formations located at four sites in Texas and Louisiana along the Gulf Coast. The oil stored in the SPR is around 99% available for sale and delivery. Stocks within the salt caverns can be fully drawn down to within 150 000 barrels (which is retained to protect the roof and casing seat). Table 8.1 provides information on the SPR sites, stocks, and designed drawdown rates; actual distribution rates (the rates at which crude would be taken into the market) would be less than the designed drawdown rates and would vary depending on the nature and location of a supply disruption.

Table 8.1 Site capacity and drawdown of the Strategic Petroleum Reserve (mb)

Storage facility and location	Type	Product	Capacity	Current inventory	Drawdown rate (mb/d)
Bryan Mound, Freeport, TX	Salt Cavern	Crude	254	241	1.5
Big Hill, Winnie, TX	Salt Cavern	Crude	170	162	1.1
W. Hackberry, Hackberry, LA	Salt Cavern	Crude	227	214	1.3
Bayou Choctaw, Plaquemine, LA	Salt Cavern	Crude	76	74	0.5
Total		Crude	727	691	4.4

Source: US Department of Energy.

The Northeast Home Heating Oil Reserve (NEHHOR) was established in 2000 (also under the EPCA) to protect the Northeast from winter-related heating oil supply shortages. Originally established as a two-million barrel reserve, the NEHHOR inventory was converted to cleaner burning ultra-low sulphur distillate by the DOE in 2011, and the size of the reserve was reduced to one million barrels owing to declining levels of heating oil consumption.

The NEHHOR is located at two sites in Massachusetts and Connecticut. The heating oil stored in the NEHHOR has no minimum operating requirements. The government's storage contract requires the terminal operator to maintain the stocks above the tank bottoms and therefore 100% available for sale and delivery.

The Energy Policy and Conservation Act (EPCA) provides the statutory authority for the establishment and operation of both the SPR and the NEHHOR. DOE has overall responsibility for the management and administration of the SPR and the NEHHOR programmes. Within DOE, the Office of Petroleum Reserves under the auspices of the Office of Fossil Energy is responsible for the management, operations and maintenance of both the SPR and NEHHOR programmes.

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Table 8.2 Site capacity and drawdown of the Northeast Home Heating Oil Reserve (barrels)

Storage facility and location	Type	Product	Capacity	Current inventory	Drawdown rate (b/d)
Global, Revere, MA	Steel tanks	ULSD	500 000	500 000	200 000
Hess, Groton, CT	Steel tanks	ULSD	500 000	500 000	160 000
Total		ULSD	1 000 000	1 000 000	360 000

Note: ULSD = ultra-low sulphur distillate.

Source: US Department of Energy.

Industry stocks

The oil industry has significant minimum operating requirements as a result of the large number of refineries and extensive pipeline system. The industry's minimum operating requirements have been estimated to be approximately 543 million barrels owing to volumes located outside the refinery tankage (for example, contained in pipelines and as inventory in marine transit), stocks inside the refinery tankage (tank bottoms, lease stocks, and fuel), and stocks used as working inventory at the refinery to support day-to-day operations, such as blending.

The minimum operating requirement of 543 million barrels is a relatively constant value, so the percentage of accessible stocks varies according to the total commercial stocks. At the end of 2011, the industry reported a total stock level of 779 million barrels which would mean the total accessible stocks were 236 million barrels or approximately 30%.

Table 8.3 Stocks summary (mb)

Industry stocks	Minimum operating requirements	Accessible stocks	Total stocks
Crude	256	74	330
Products	287	162	449
Total	**543 (70%)**	**236 (30%)**	**779**

Source: IEA methodology on minimum operating levels; National Petroleum Council Methodology on Potentially Available Stocks.

Decision making and responding to a call for collective action

To authorise a full drawdown from the SPR, the President must determine that an emergency situation exists; that there is a reduction in supply of significant scope and duration; that a severe increase in the price of petroleum products has resulted; and that the price increase is likely to have a major adverse impact on the US economy. The EPCA makes no distinction between a domestic supply disruption and an IEA collective action, but different authorities are more used to respond to domestic short-term local or regional oil supply disruptions than are used to respond to a global disruption.

In some situations, the President may also authorise a limited SPR drawdown (maximum 30 million barrels for up to 60 days). To authorise a limited drawdown from the SPR, the President must determine that a circumstance exists that constitutes, or is likely to become, a domestic or international energy supply disruption of significant scope or duration; and that a limited release would assist directly and significantly in preventing or reducing the adverse impact of such a disruption.

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In addition to the President's SPR drawdown authority, the EPCA provides the Secretary of Energy with an "exchange authority" whereby SPR stocks can be loaned to industry participants to address domestic needs. The recipients of crude oil exchanges are generally required to return a premium quantity of oil (similar to interest) in addition to the quantity of crude oil that they borrowed. The exchange authority has been used in the past to change the crude oil mix of the SPR and to provide emergency supplies for short-term, local or regional supply interruptions.

Under the EPCA, the Secretary of Energy also has limited authority to conduct a test sale of not more than five million barrels through a sale or exchange of crude oil. The SPR most recently conducted a test sale in March 2014, selling five million barrels of crude oil to test and evaluate the drawdown capabilities of the reserve in the Gulf Coast, where major infrastructure changes have recently taken place. The detailed process for drawing down stocks in a disruption is contained in the *Drawdown and Distribution Management Manual* for the SPR, which describes each step required at both headquarters and the field offices, and the decision making process.

SPR crude oil can be exported in exchange for a corresponding import of refined petroleum products. Since the United States produces and imports far more crude oil than can be physically released from the SPR, this law arguably has no practical effect on the amount of oil available to the United States, other IEA member countries, or the world oil market during a collective action. In effect, during an IEA collective action, SPR oil will be effectively "exported" via displacement, either due to reduced crude oil imports or increased exports of non-SPR crude oil, rather than exported directly.

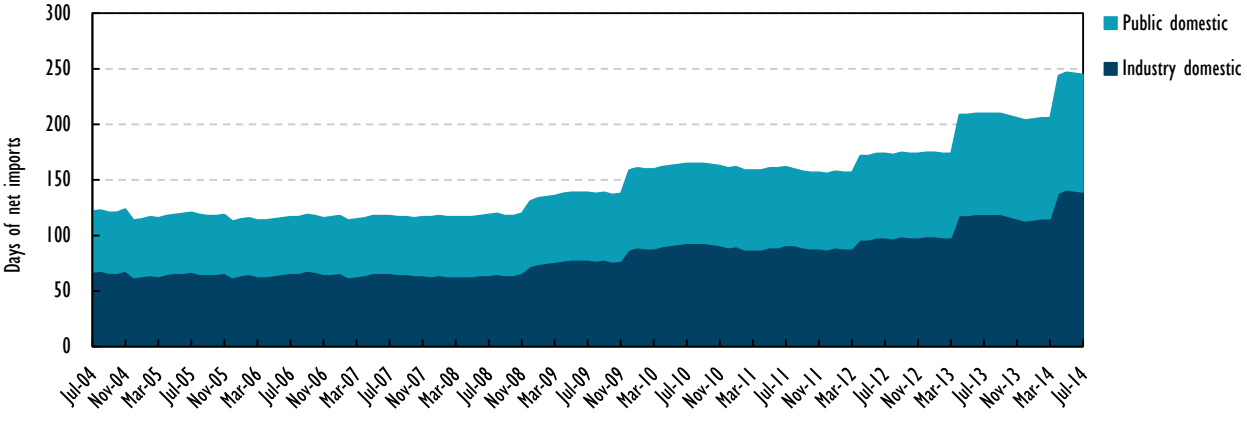
Financing and monitoring

The federal government has full ownership of all petroleum stocks in the SPR and NEHHOR, as well as all SPR storage facilities. The facilities were paid for through federal government appropriated funds. There is no programme financing obligation or charges. Both SPR and NEHHOR programme funding requirements are included in the Department of Energy's budget request which is integrated into the President's annual budget request to Congress. Congress then passes annual appropriation bills to fund the Departments and other agencies.

Compliance with the IEA 90-day obligation

The United States consistently meets its IEA 90-day stockholding obligation and always holds storage well in excess of the required amount.

Figure 8.6 United States compliance with IEA 90-day obligation, July 2004 to July 2014



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Its 90-day stockholding obligation for 2012 was 80.76 Mtoe and the actual amount of stock held as of 1 January 2014 was 183.63 Mtoe. The amount of stock held in excess of the IEA 90-day obligation was therefore 102.86 Mtoe or 115 days.

Oil demand restraint

Oil demand restraint is not among the policy options available for use by the federal government during an oil supply disruption. Nonetheless, oil demand restraint policies and regulations exist at state level and vary from state to state. For example, during Hurricane Sandy in 2012, the New York City Mayor issued an Executive Order (number 163) which restricted gasoline purchases to odd and even days corresponding to vehicle licence plates.

OTHER OIL EMERGENCY RESPONSE MEASURES

Surge production

Domestic oil production is already taking place at maximum rates. The country does not maintain a potential for surging petroleum production during an oil supply disruption. The federal government holds the view that market forces alone would induce any available incremental crude oil production during an oil supply disruption (if such capacity existed).

Fuel switching

The United States has no specific policies to promote fuel switching in an emergency. The electricity generation sector, however, maintains significant fuel-switching capacity.

The EIA estimates current fuel-switching capability by the net summer capacity of generators, using the "EIA860" form on generator-level specific information. The form was adjusted in 2005 to have more accurate estimates of switching capability following the threat of Hurricane Katrina to the natural gas supply. Capacity numbers from the summer season are used as standard practice, based on the principle that summer sees the highest average peak load on power generation across the entire country.

The total net summer capacity of all generators reporting petroleum as the primary fuel was 47 GW in 2012 (EIA, 2013b). The net summer capacity of petroleum-fired generators reporting the ability to switch to natural gas was 15.6 GW, or about 33% of the total. The fuel switchable capacity as a percentage of total capacity for utilities was 28.6% while it was 42% for independent power producers.

Because transmission constraints, fuel supply constraints and other variables will reduce fuel switchable capacity in plants that otherwise could switch in an emergency, EIA asks producers to estimate a "maximum achievable net summer capacity", which takes these factors into account. The maximum achievable net summer capacity using natural gas across all producer sectors to replace petroleum liquids was 14 GW in 2011.

Other emergency measures

The temporary waiver of mandatory fuel specifications is another potential measure for use during an oil supply disruption. If the fuel supply is disrupted because of an unforeseen emergency situation, the Environmental Protection Agency (EPA), with the concurrence of DOE, is authorised to issue a temporary fuels waiver to mitigate outages under the Clean Air Act. In such circumstances, the EPA works closely with state and federal agencies to determine an appropriate response. Except in unusual or emergency circumstances, a formal request for a fuels waiver is made by, or on behalf of, the governor of an affected state after consultation with EPA. Waivers can be enacted at both state and federal levels

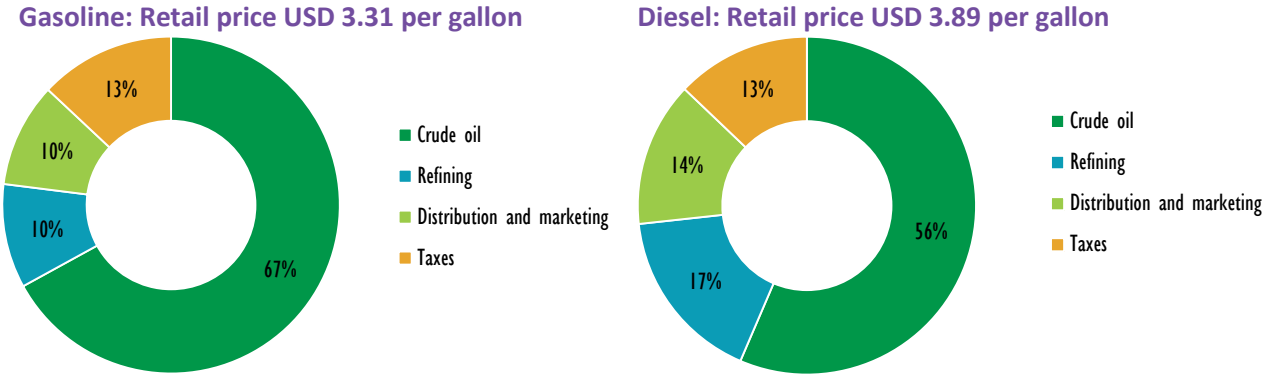
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but federal waivers generally take precedence over state waivers. Fuel waivers of this type were used during August and September 2012 after Hurricane Isaac caused a number of Louisiana refineries to be shut down for about a week, causing gasoline outages in the Southeastern United States. At this time, the EPA issued a temporary waiver on summer gasoline volatility standards for the region, thereby enabling greater quantities of gasoline to be produced to mitigate the supply outages. Various fuel and environmental waivers were also used in October 2012, in the aftermath of Hurricane Sandy.

DISTRIBUTION AND MARKETING POLICIES

The United States petroleum industry is fully privately owned. The distribution network is based on common carrier pipelines and proprietary pipelines, barge and tanker fleets, and storage installations. Companies active in the sector can be fully integrated or operate as independent traders in specific market segments.

Figure 8.7 Breakdown of gasoline and diesel prices in the United States (January 2014)



Source: EIA (2014c), *Gasoline and Diesel Fuel Update*, EIA, Washington, D.C.

In May 2006, The Federal Trade Commission (FTC) published a report of its investigation into whether gasoline prices were "artificially manipulated by reducing refinery capacity or by any other form of market manipulation or price gouging practices" and into gasoline pricing by refiners, large wholesalers and retailers in the aftermath of Hurricane Katrina (FTC, 2006). In its investigation, the FTC found no instances of illegal market manipulation that led to higher prices during the relevant time periods but found 15 examples of pricing at the refining, wholesale or retail level that fit the relevant legislation's definition of evidence of "price gouging." In 2009, a new rule to prohibit fraud or deceit in wholesale petroleum markets (and omissions of material information that are likely to distort petroleum markets) was introduced by the FTC. A further FTC study, published in September 2011, concluded that, while a broad range of factors influence the price of gasoline, worldwide crude oil prices continue to be the main driver of prices at United States' pumps (FTC, 2011).

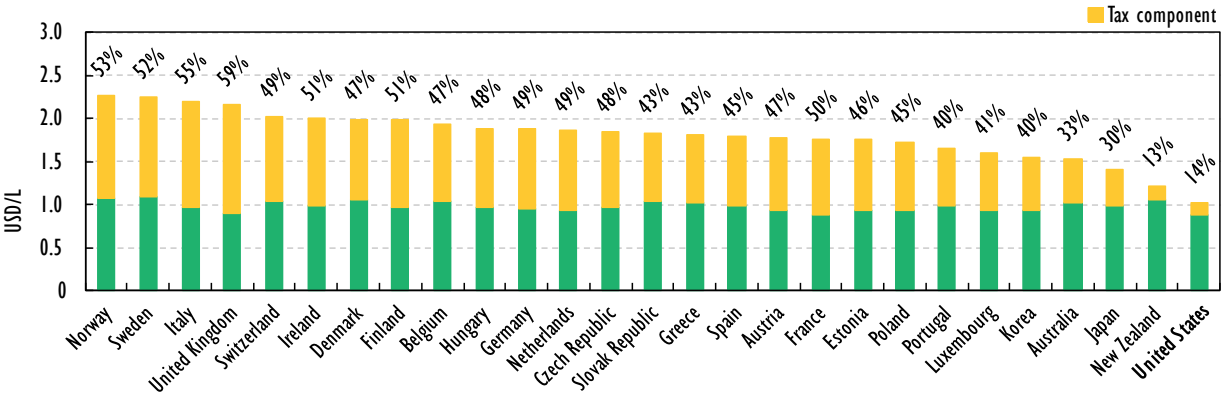
PRICES

The oil product and refining market in the United States is generally very competitive and the prices for oil products remain the lowest among IEA/OECD member countries. Pre-tax prices are at the lower end of the IEA scale, and the price of automotive diesel and premium unleaded gasoline is the lowest among OECD member countries. Low taxation levels and the fact that oil is traded in US dollars on the world market, make transport fuel prices much more responsive to world market developments than, for example, European or Japanese prices.

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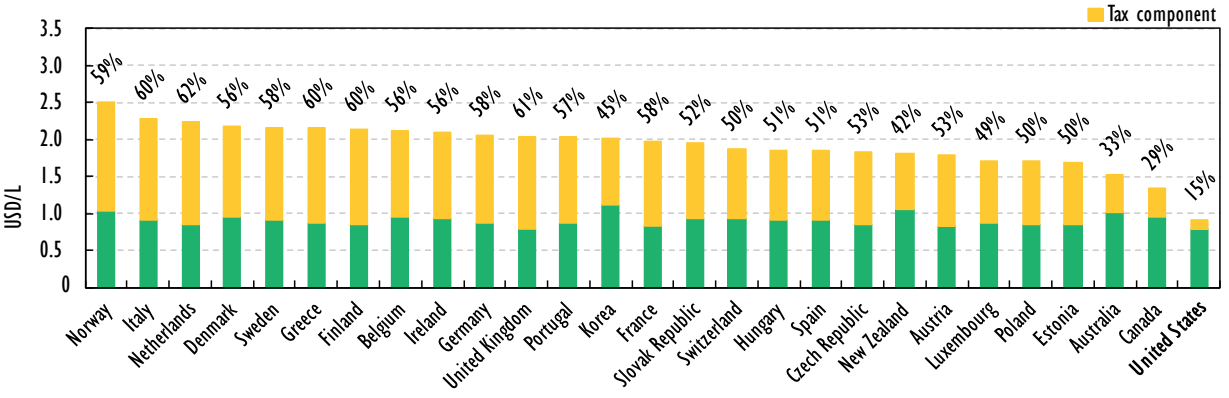
Figure 8.8 IEA fuel prices and taxes, 4th quarter 2013

Automotive diesel



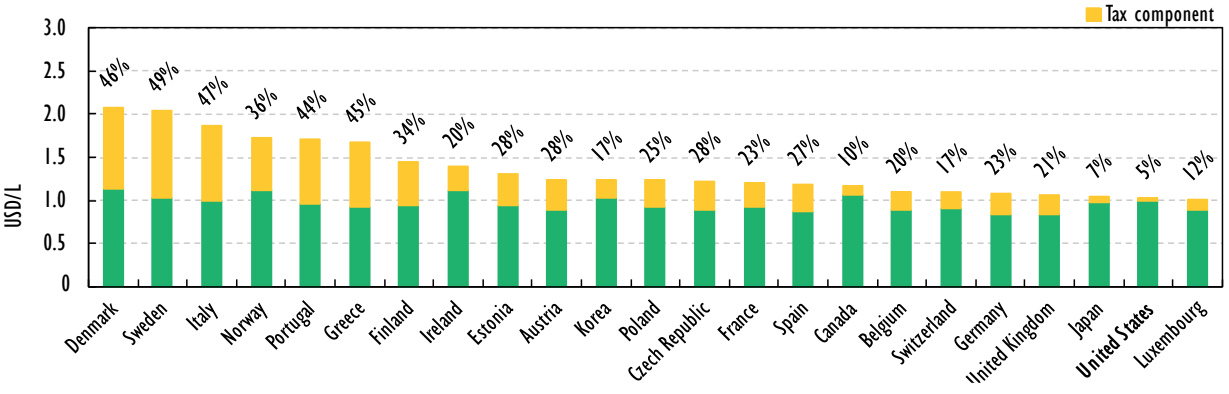
Note: data not available for Canada and Turkey.

Premium unleaded gasoline (95 RON)



Note: data not available for Japan and Turkey.

Light fuel oil



Note: data not available for Australia, Hungary, the Netherlands, New Zealand, the Slovak Republic and Turkey.

Source: IEA (2014c), *Energy Prices and Taxes*, Vol. 2014/2, OECD/IEA, Paris.

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ASSESSMENT

While oil continues to be the main source of energy in the United States, its share in total primary energy supply has declined markedly since the early 1970s, from 47% in 1973 to 36.5% in 2012. Nonetheless, the past six years have seen a resurgence of oil (and natural gas) production, where output had been widely assumed, even as recently as a few years ago, to be in inevitable decline. Improvements in advanced crude oil production technologies, such as hydraulic fracturing, which were previously considered economically non-viable, are widely expected to continue to lift domestic supply into the medium term. Together with efficiency measures that are set to curb oil consumption, this trend has far-reaching consequences for energy markets, trade and, potentially, even for energy security, geopolitics and the global economy.

The renaissance that the oil industry is undergoing is largely the result of spectacular growth in light tight oil (LTO) production, a boom that is expected to continue. From close to zero in 2005, production of LTO in the United States reached 4.0 million barrels per day (mb/d) by mid-2014, a turnaround which, taken together with the growth in shale gas, has had profound effects across the energy sector. The changes occurring in the US energy system become strikingly evident when examining the projected future trends in interregional energy trade. Surging LTO production is projected to boost total oil output (excluding ethanol and refinery processing gains) from 9.2 mb/d in 2012 to 11.6 mb/d in 2020, before declining to 10.9 mb/d in 2035. Taking into account falling demand, oil import needs will decline from 7.9 mb/d to 3.1 mb/d in the period to 2035 and oil import bills will be cut by more than half.

As of January 2013, the country had 143 refineries (of which four are idle) with a total crude oil refining capacity of 17.8 mb/d according to the EIA. About 44% of them are located along the Gulf of Mexico, and total refining capacity remained relatively flat in the period 2005-12. Recently, many refiners have begun, or are planning, upgrades, modifications and expansions (even adding rail facilities) to take advantage of new domestic production (Eagle Ford and Bakken), and diluted bitumen and synthetic crude oil and imports from Canada.

While the United States does not have an explicit economy-wide energy efficiency target it is focusing increasingly on improving energy efficiency in road transport. New standards adopted in 2011 will increase average fuel economy to 54.5 miles per gallon (compared with less than 35 mpg today) for cars and light-duty trucks by Model Year 2025. In 2013, it was announced that standards for heavy-duty vehicles that currently target the model year 2018 will be extended and further tightened. The IEA projects that such policies will allow the United States to cut oil consumption by some 1.5 mb/d by 2035. The United States is also investing in electric vehicle technologies and has blending mandates and the Renewable Fuel Standard in place to support the production and use of biofuels in road transport.

The present government invested significant resources in renewable energies. The renewable fuel standard (RFS), adopted in 2005 and extended in 2007, mandates 36 billion gallons (136 billion litres) of biofuels to be blended into transportation fuel by 2022. The RFS also contains a general waiver based on technical, economic or environmental feasibility where the Environmental Protection Agency has the authority to adjust the mandates for biofuels. The development of E85 infrastructure has lagged expectations, however, and EIA projections of refuelling station development have consequently been revised down while cellulosic biofuels have not developed as fast as hoped. Slow growth in gasoline consumption along with limits in the amount of ethanol that can be blended into

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gasoline because of engine manufacturer specifications has created the so-called blend wall, inhibiting larger increases in consumption. Furthermore, there is still substantial uncertainty about the extension of current national support measures for renewables beyond 2014. The long-term future of tax credits for biodiesel and advanced biofuels (among other renewable energy sources) remains uncertain. Ethanol import taxes were removed in late 2011, and the Department of Energy's loan guarantee programme is uncertain.

Imports are also declining as a result of a variety of factors, notably significant supply-side changes resulting from increased domestic oil production (biofuels, crude oil and natural gas plant liquids) and moderating energy demand during the sluggish economic recovery in the wake of the financial crisis of 2008. Another important contributing factor has been the greater fuel efficiency in vehicle fleets and a slowing of the growth in total vehicle miles and in demand growth. The IEA welcomes the federal government's implementation of corporate average fuel economy (CAFE) and other fuel efficiency standards, which will deliver reduced oil consumption and CO_2 emissions in the transport sector (which accounted for 69% of total oil demand in 2012).

EMERGENCY PREPAREDNESS

The United States meets its 90-day stockholding obligation to the IEA through public stocks held in the Strategic Petroleum Reserve (SPR) and has consistently met it. As of 25 September 2014, the SPR had an inventory of 691 million barrels of crude oil or the equivalent to 106 days of net imports. There is no statutory obligation on industry to hold stocks for emergency purposes, but commercial stocks equate to around 140 days of net imports. The United States also has a Northeast Home Heating Oil Reserve with an inventory of one million barrels of low-sulphur diesel and a Northeast Regional Refined Petroleum Product Reserve with an inventory of one million barrels of gasoline.

The federal government's preferred response to an oil supply disruption is to release stocks from the SPR. The country also has other statutory mechanisms for use in certain situations such as natural disasters. The effectiveness of these other mechanisms has been demonstrated by the response to hurricanes, including Katrina, Gustav, Ike and, most recently, Sandy. The Northeast Home Heating Oil Reserve (NEHHOR) was established in 2000 to protect the Northeast of the United States from winter-related heating oil supply shortages. The usefulness of the NEHHOR in an emergency situation was demonstrated in October 2012 when, as a result of Hurricane Sandy, storm damage to energy infrastructure was significant and, for the first time, diesel fuel from the NEHHOR was released. It was loaned to the Department of Defense in support of the Federal Emergency Management Agency for use in emergency operations and support to the region affected by Hurricane Sandy. Further exchanges with commercial terminals provided diesel fuel supplies for the state of Connecticut and New York City. This case demonstrated the usefulness of holding product stocks in addition to existing SPR crude oil reserves for use during emergency situations when there is a severe short-term disruption to product supplies.

Since 1983, the EIA has published its *Short-Term Energy Outlook* (STEO), a monthly report covering energy prices, oil, gas, electricity and renewables. Since 2010, the EIA includes "Energy price volatility and forecast uncertainty" in the STEO, which focuses on crude oil, petroleum products and natural gas. In addition, the EIA has begun posting a set of key energy commodity spot and futures prices on the *Today in Energy* webpage. The IEA commends EIA efforts to provide up-to-date information to make energy markets, especially the oil sector, more transparent and predictable.

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RECOMMENDATIONS

The government of the United States should:

- ☐ *Update the Renewable Fuel Standard (RFS) programme to take into account recent technology developments regarding second-generation biofuels.*
- ☐ *Develop a central point of reference for the emergency response policies and regulations of the states.*

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9. NATURAL GAS

Key data (2013 estimated)

Production: 564.5 Mtoe (689.2 bcm), +27.3% since 2003

Share of natural gas: 27.8% of TPES and 26.9% of electricity generation

Imports: 81.6 bcm (Canada 96.6%, Trinidad and Tobago 2.4%, Yemen 0.4%, Qatar 0.3%, Norway 0.2%)

Exports: 44.5 bcm (Canada 58%, Mexico 42%)

Inland consumption by sector (2012): power generation 38.2%, industry 19.4%, residential 16.2%, other energy sector 12%, commercial and public services 11.3%

OVERVIEW

In 2012, the United States was the world's largest consumer and producer of natural gas. While the share of natural gas in total primary energy supply (TPES) had been in steady decline since the early-1970s, this trend experienced a rapid reversal in the period since the last in-depth review in 2008, when vast resources of inexpensive shale began to be produced. The government projects that the country will become a net exporter of natural gas by 2018, with total exports of around 45 billion cubic metres (bcm) in 2025 and 100 bcm by 2040 with further growth of shale gas dwarfing unconventional developments outside North America. At the same time, the United States may become a credible liquefied natural gas (LNG) exporter, providing much-needed relief to tight LNG global markets.

SUPPLY AND DEMAND

SUPPLY

Between 2008 and 2013, US natural gas production increased by 20.7%, from 571.1 bcm to 689.2 bcm. Put another way, US gas production gained 118 bcm over 2009-13, an amount greater than the production of Norway, the largest European producer. The United States is the world's largest producer of natural gas, with more gas produced than in the Russian Federation and more than the whole of the Middle East region, the Asia and the Pacific regions, and Europe. The country overtook the Russian Federation as the largest gas producer in 2012, as more reserves led to buoyant growth in production.

Domestic production met 93.7% of US natural gas requirements in 2013. This is more than 88% in 2010 as natural gas imports to the United States have continued to decline from a peak of 130.4 bcm in 2007. Imports declined to 88.9 bcm in 2013 or 37.4% lower than 2007 volumes, when the United States depended on imports for 18% of its natural gas needs. Nonetheless, imports will continue as the marginal source of supply, largely during cold weather and pipeline maintenance outages.

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In 2013, production reached the highest levels ever, increasing to 689.2 bcm or 1.1% over 2012 levels, the smallest gain since the increase in shale gas-driven production started in 2005. Shale gas production represented around 39% of total gas production in 2012, rising from 34% in 2011 and just 3% in 2002. In a period of five years (2007-12), US shale gas production grew six-fold, increasing from 45 bcm to around 264 bcm, with more than 75% of the current production taking place in four shale plays – Marcellus, Barnett, Fayetteville and Haynesville. Over the last two years, the production of associated gas from the plays rich in oil and liquids exceeded that of dry gas plays. In 2012, the production of associated gas with oil and liquids expanded to 51% of total US production, from an average of 49% in 2011. By 2014, this production is expected to rise to 54%.

As prices remain relatively low in North America, growth has slowed down considerably compared to 2010 or 2011. As gas prices declined, drillers began to focus more on wet shale plays such as Eagle Ford and Bakken where they could use the same techniques (horizontal drilling and hydraulic fracturing) to produce tight oil. According to the US Energy Information Agency's (EIA) *Annual Energy Outlook 2014* (*AEO 2014*), shale gas production in 2013 declined from 275 bcm in 2012 to 265 bcm (EIA, 2014c).

According to the EIA, the proved gas reserves in the United States have doubled since 2000, up to 322.6 trillion cubic feet (or 9.137 trillion cubic metres) in 2012. These are the fourth-highest reserves after Russia, Iran and Qatar. Reserves in Russia and Iran have not changed much over the same period, while reserves in Qatar have nearly tripled since 2000.[1]

Natural gas production has been increasing since 2005 and reached a peak of 689.2 bcm in 2013, up by 27.3% since 2003. This is the highest increase over a ten-year period since the early 1970s. Government projections indicate that gas production will continue to grow to 2040, albeit at a slower rate than it has in the past decade.

Total supply of natural gas, which includes production, net trade and net stock changes, was 607.4 million tonnes of oil-equivalent (Mtoe) in 2013, accounting for 27.8% of TPES. Thanks to the strong growth in production, this share has increased from 22.1% in 2003.

Supply projections

The US Energy Information Administration's (EIA) *Annual Energy Outlook 2014* (EIA, 2014c), presents long-term annual projections of energy supply, demand, and prices to 2040, based on results from EIA's National Energy Modeling System (NEMS) (EIA, 2014c).

The *AEO 2014* Reference Case projects a 56% increase in total US natural gas production from 2012 to 2040. This increase in production results from the increased development of shale gas, tight gas and offshore natural gas resources. Shale gas production is the largest contributor to this growth. The *AEO 2014* also projects that the United States will become a net exporter of natural gas in 2018.

DEMAND

The power generation sector consumes 38.2% of all gas supply and has been the driving force behind growing demand for gas in the United States. Gas consumption in electricity and heat production has increased by 53.9% from 2002 to 2012, with its share increasing from 27.6% of the total in 2002 to 38.2% in 2012. Natural gas accounts for 27% of all electricity produced in the United States at present, up from 17.7% in 2002.

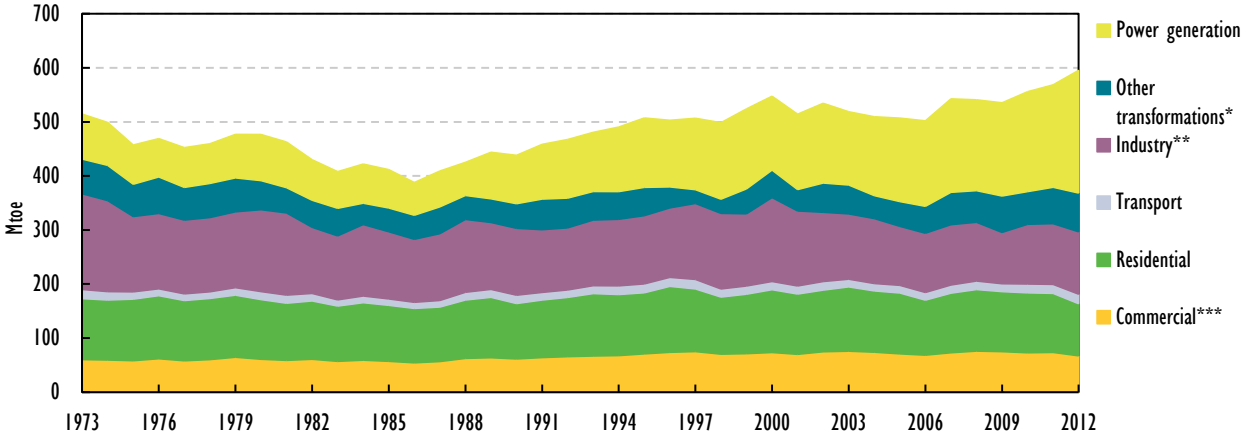
1. US Energy Information Administration, www.eia.gov.

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Demand from oil refineries and the transport sector has also grown over the past decade, increasing by 32.5% and 10.9% since 2002, respectively. Oil refiners and energy own use account for 12% of total gas consumption while the transport sector has maintained a share of around 3% for three decades.

Demand from the industry sector and the residential and commercial sector was lower in 2012 than in 2002. However, since 2008, demand from the industry sector has been growing owing to the rise in shale gas production, increasing by 6.1% in 2009-12. Consumption by households and services (including agriculture, forestry and fishing) has declined each year since 2007. The industry sector is the second-largest consumer of gas in the United States, at 19.4% of total supply, followed by households at 16.2% and commercial and public services at 11.3%.

Figure 9.1 Natural gas supply by sector, 1973-2012



Note: TPES by consuming sector.

* *Other transformations* includes refining and energy sector consumption.

** *Industry* includes non-energy use.

*** *Commercial* includes commercial and public services.

Source: IEA (2014a), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

Natural gas consumption is projected to increase by 35% to 2040. The government expects that the strongest growth in demand will come from transport, more than tripling to 2040, as well as power generation and the fuel refining sector. Demand from industry will also recover, while the residential and commercial sectors are likely to continue to curb their direct natural gas use.

Demand projections

In the *AEO 2014* Reference Case, total natural gas consumption grows from 25.6 trillion cubic feet (tcf) (724.9 bcm) in 2012 to 31.6 tcf (894.8 bcm) in 2040 and natural gas use is projected to increase in all of the end-use sectors except the residential sector. Consumption of natural gas for electricity generation will account for 33% of the increase in total natural gas consumption by 2040. Relatively low prices make natural gas an attractive fuel for serving growing power demand. Natural gas is also the fuel of choice for replacing coal-fired generation as it retires. As the energy-intensive industries take advantage of relatively low natural gas prices, their gas demand is expected to increase, particularly during the period up to 2028. For the remainder of the projection period, consumption of natural gas in the industrial sector continues to grow but at a slower rate in response to rising prices.

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While the transport sector accounts for only a small portion of total natural gas consumption at present, natural gas use by heavy-duty vehicles (HDVs), trains, and ships shows the largest percentage growth of any fuel in the projection scenario (see later section).

NATURAL GAS TRADE

IMPORTS AND EXPORTS

Despite being the world's top producer, the United States is a net importer of gas. In 2013, imports totalled 81.6 bcm while exports came to 44.5 bcm. Net imports account for 5% of total supply and are concentrated in areas where transport of domestic gas is either impossible or uneconomical. Canada and Mexico are the main trading partners, with net imports from Canada at 53.1 bcm in 2013, while the United States exported 18.7 bcm to Mexico. Other smaller trading partners include Trinidad and Tobago, Yemen and Qatar.

In *AEO 2013*, the United States was projected to become a net exporter of natural gas by 2020 (and of LNG by 2016), with projected total exports of 44.7 bcm (1.58 tcf) in 2025, 72.2 bcm (2.55 tcf) in 2035, and 100.5 bcm (3.55 tcf) in 2040. In the *AEO 2014* Reference case, however, the United States becomes a net exporter of LNG in 2016, and it becomes an overall net exporter of natural gas in 2018, two years earlier than previously anticipated. Exports of LNG from new liquefaction capacity are expected to surpass 57 bcm (2.0 tcf) by 2020 and to increase to 98 bcm (3.5 tcf) in 2029. Net pipeline imports from Canada are expected to fall steadily until 2033, and then increase through 2040. Net pipeline exports to Mexico grow by more than 400% in the Reference case, with additional pipeline infrastructure added to enable the Mexican market to receive more pipeline natural gas from the United States.

Cumulative net LNG exports from 2012 to 2040 are 160% higher in *AEO 2014* compared with *AEO 2013*, supported by increased use of LNG in markets outside North America, strong domestic production, and low natural gas prices relative to other global markets.

Nonetheless, it is unclear whether, or to what extent, domestic regulations will limit the quantity of natural gas that can eventually be exported. As of 10 September 2014, the Department of Energy (DOE) had granted three final and six conditional long-term authorisations to export domestically produced lower-48 LNG to countries with which the United States does not have a Free Trade Agreement (non-FTA); 26 applications are currently pending.

In 2012, the Department of Energy commissioned a two-part study in order to gain a better understanding of the cumulative economic impact of LNG exports. Part one of the report, conducted by EIA, concluded that natural gas markets in the United States balance in response to increased natural gas exports largely through higher natural gas production. Increased natural gas production satisfies about 60% to 70% of the increase in natural gas exports, with a minor additional contribution from increased imports from Canada. Across most cases, shale gas resources account for about three-quarters of this increased production.

Part two of the report, conducted by NERA Economic Consulting, concluded that the United States would gain net economic benefits from allowing LNG exports, for every market scenario examined. It also found that US natural gas prices would increase if the United States exports LNG, but that the global market will limit by how much US natural gas prices can rise.

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In May 2014, DOE announced that it will undertake an additional two-part economic study in order to gain a better understanding of how potential US LNG exports between 12 billion cubic feet per day (bcf/d) and 20 billion bcf/d (339 mcm/d and 566 mcm/d) could affect the public interest. The first part of the study will be conducted by EIA, which had only looked at export cases of 6.0 bdf/d and 12 bcf/d (169 mcm/d and 339 mcm/d) in its 2012 report. Following the EIA update, DOE will again contract for an external analysis of the economic impact of this increased range of LNG exports and other effects that LNG exports may have on the US natural gas market.

Box 9.1 Authorisation of LNG imports and exports

The Natural Gas Act of 1938, as amended, requires anyone who wants to import or export natural gas, including liquefied natural gas (LNG) from or to a foreign country, to first obtain an authorisation from the Department of Energy. The Office of Oil and Gas Global Security and Supply, Division of Natural Gas Regulatory Activities is the one-stop-shopping place to obtain these authorisations in the Department. The import/export authorisations are necessary for anyone who wants to import or export natural gas, including LNG. Authorisation is granted automatically to those who wish to export natural gas to countries that have a United States Free Trade Agreement (FTA) that requires national treatment for trade in natural gas, but all other applications must first be deemed consistent with the public interest.

There are basically two types of authorisations, blanket and long-term authorisations. The blanket authorisation enables a party to import or export on a short-term or spot market basis for a period of up to two years. The long-term authorisation is used when a party has a signed gas purchase or sales agreement/contract, or tolling agreement, or other agreement resulting in imports/exports of natural gas, for a period of time longer than two years.

Source: DOE.

LNG EXPORT AND TRADE OUTLOOK

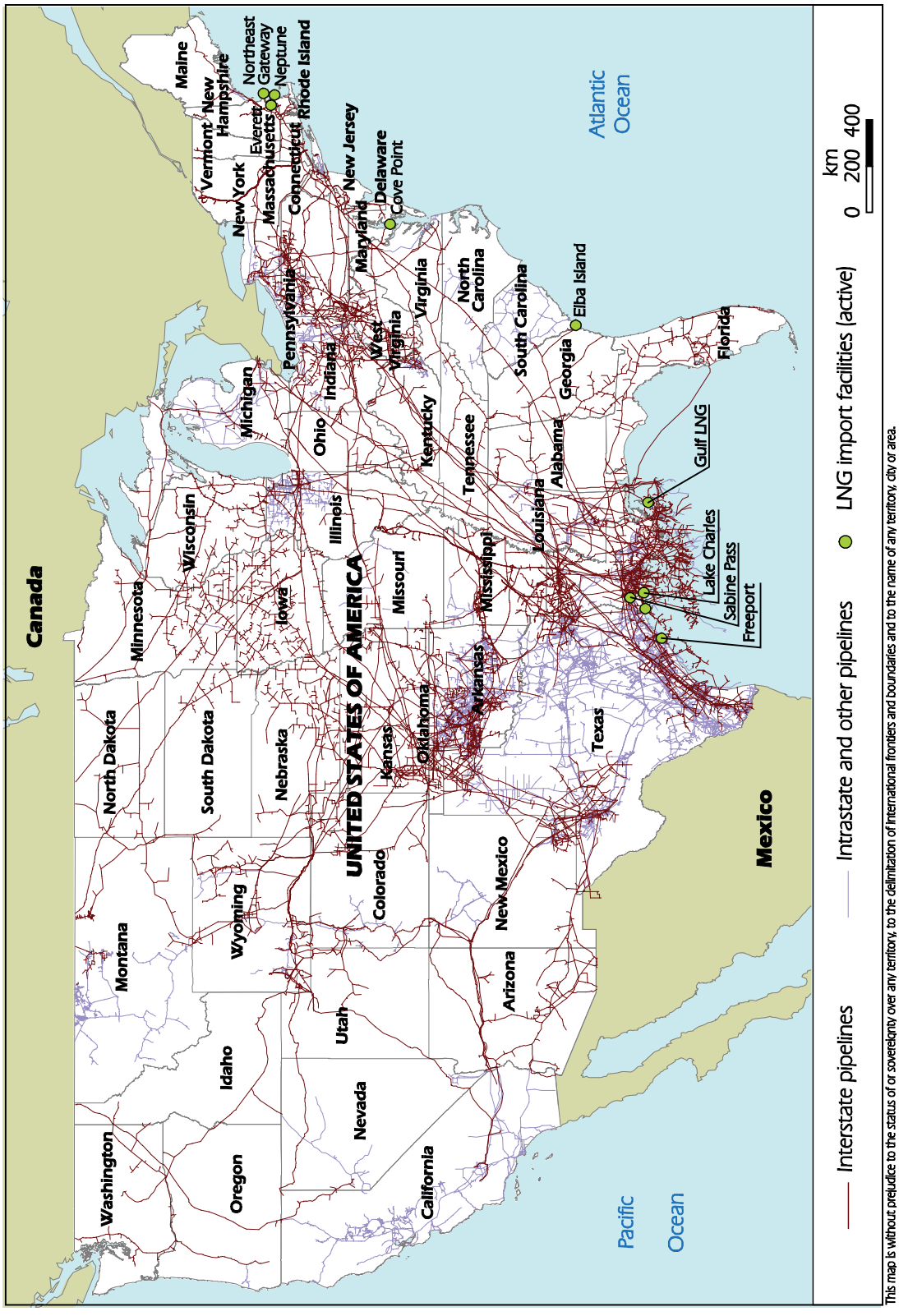
As of 20 June 2014, the Federal Energy Regulatory Commission (FERC) had approved two terminals for construction, Cheniere's Sabine Pass (which is under construction) and Sempra-Cameron LNG.

In August 2014, DOE finalised a change to its procedures for processing LNG export authorisations. DOE will now make final public interest determinations only after completion of the review required by environmental laws and regulations that are included in the National Environmental Policy Act (NEPA), suspending its practice of issuing conditional authorisations. This means that LNG export projects will be required to work with FERC (or other relevant agency) to prepare a final environmental impact assessment before DOE will consider their export application complete, and take action on an export authorisation.

With DOE approval for deliveries to non-FTA countries, the United States has overcome its biggest obstacle yet to being on track to become one of the world's largest LNG suppliers, as the majority of LNG buyers are from non-FTA countries. The caveat exists, however, that the DOE can revoke the export licence any time if it deems that the project is no longer in the public interest.

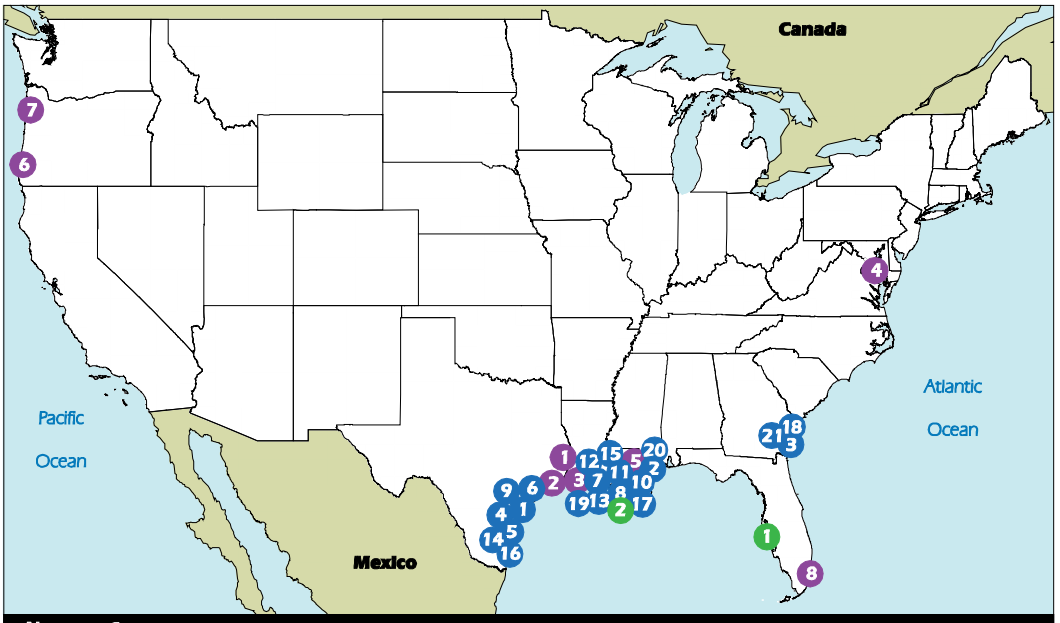
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Figure 9.2 Map of US natural gas infrastructure in the United States



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Figure 9.3 LNG liquefaction plants under construction and planned in the United States



No.	Company	Applied export volumes (bcf/d)
	Applications to export LNG to both FTA and non-FTA countries approved by DOE	
1	Sabine Pass	2.2
2	Freeport LNG	1.8
3	Lake Charles	2
4	Cove Point LNG	0.77
5	Cameron LNG	1.7
6	Jordan Cove Energy	0.8
7	Oregon LNG	1.25
8	Carib Energy	0.04
	Applications to export LNG to FTA countries approved by DOE but under DOE review for non-FTA countries	
1	Gulf Coast LNG	2.8
2	Gulf LNG	1.5
3	Southern LNG	0.5
4	Lavaca Bay LNG	1.38
5	Golden Pass	2.0
6	Corpus Christi LNG	2.1
7	CE FLNG	1.07
8	Waller LNG Services	0.19
9	Pangea LNG	1.09
10	Magnolia LNG	1.08
11	Gasfin Development	0.2
12	Main Pass - Freeport-McMoRan	3.22
13	Venture Global	0.67
14	Eos LNG & Barca LNG	3.2
15	Delfin LNG	1.8
16	Texas LNG	0.27
17	Louisiana LNG Energy	0.28
18	Trunkline LNG	2.0
19	Freeport McMoRan	3.22
20	Sabine Pass	1.38
21	Venture Global	0.67
	Applications pending approval to export LNG to FTA countries and under review for export to non-FTA countries	
1	Strom	0.02
2	SCT&E LNG	1.6

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA (2014b), *Medium-Term Gas Market Report 2014*, OECD/IEA, Paris; US DOE.

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Nevertheless, the likelihood for the DOE to exercise this option is considered remote for two reasons. First, it would be hard for the Department to prove the basis of "not in the public interest" and the DOE has also mentioned that it would not revoke an export permit except in the event of extraordinary circumstances. Second, most of the countries where the major LNG importers are based are in the midst of discussing the FTA with the United States and will no longer be subject to this condition, should they sign the FTA agreement.

At the same time, the DOE also received complaints from groups against the development of the US LNG export industry. Besides strong opposition from the chemical industry, in particular, the America's Energy Advantage group led by Dow, the DOE also received strong reaction from industrial energy consumers. All these developments may influence the DOE to further elucidate the requirements for applications for exporting to non-FTA economies.

To date, the total approved quantity for exports to non-FTA countries from the seven projects which have received final or conditional export approvals is 10.56 bcf/d (299 mcm/d), equivalent to around 80 million tonnes per annum (Mtpa). By comparison, Qatar, which is currently the largest LNG exporter in the world, has a total production capacity of 77 Mtpa. As of September 2014, the DOE was currently reviewing 26 non-FTA applications.

If the six projects with DOE approval and conditional approval obtain all necessary approvals including from FERC, and take final investment decisions (FID) in a timely manner, the United States could be the third-largest LNG exporter in the world by the end of the decade. Until now, only Sabine Pass and Cameron have received approvals from both the DOE and FERC. Carib Energy, the third project that has received final approval, did not need FERC approval.

Table 9.1 LNG projects with DOE approval for non-FTA countries (as of 31 August 2014)

Company	Approved export volumes to non-FTA countries	Major stakeholders	Expected final investment decision (FID)	DOE approval	FERC approval
Sabine Pass	2.2	Cheniere Energy	2012	2011	2012
Freeport LNG	1.8	Freeport, Macquarie	2014	2014	2014
Lake Charles	2.0	Magnolia LNG	2015	2013	Pending
Dominion Cove Point	0.77	Freeport, Macquarie	2014	2013	2014
Jordan Cove	0.8	Veresen Inc.	2014	2014	Pending
Cameron LNG	1.7	Sempra, GDF SUEZ, Mitsui and Japan LNG Investment	2014	2014	2014
Oregon LNG	1.25	Leucadia National Corp.	2015	2014	Pending

Sources: company websites; DOE; FERC; IEA.

The United States has a number of competitive advantages that put the country in the lead over other regions in capturing LNG demand from LNG buyers. First, an extensive gas infrastructure is already in place to support the LNG industry, especially for the production and transportation of shale gas to the LNG projects. Second, liquid and transparent gas markets based on spot markets allow the projects to offer LNG contracts with Henry Hub-indexed pricing and no take-or-pay obligation, two items that are exceptionally

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desirable for Asian buyers. Third, the capital cost for developing LNG plants in the United States also contributes to the success of the country's LNG export industry, as it is relatively cheaper than other regions thanks to the brown-field nature of some of its LNG export projects. While it may be true for Sabine Pass and several others, the rest of the proposed projects are green-field and as such will be one of the deciding factors for the total LNG export quantity from the United States in view of competition from other regions.

REGULATORY OVERSIGHT

The natural gas market is dynamic and highly competitive, with a very active spot and futures market. The industry has a high degree of private ownership with little vertical integration. Production, transmission and distribution are usually separate entities with limited examples of upstream or downstream integration although some large gas distributors own transmission pipelines. Gas distribution systems are both publicly owned and investor-owned.

The Federal Energy Regulatory Commission (FERC) is responsible for the regulation of the interstate gas industry, including LNG import terminals. The US Coast Guard and the states are responsible for the planning and safety regulation of LNG terminals and their connection points onshore. For purely intrastate gas undertakings, the state regulatory commission is the responsible economic regulator. Issues such as standards are regulated by a number of entities, including the Department of Transportation.

Generally, applications to FERC for interstate natural gas pipeline projects require some level of co-ordination with one or more other federal agencies: the Environmental Protection Agency (EPA) assists FERC and/or state authorities in determining if the environmental aspects of a pipeline development project meet acceptable guidelines. FERC is also required to take the lead on the environmental reviews under the National Environmental Policy Act, the Endangered Species Act, the National Historic Preservation Act, and the Magnuson-Stevens Act. The Department of Transportation's Office of Pipeline Safety (OPS) is responsible for safety standards, procedures, and development and expansion of any pipeline system.

Acquisitions and mergers are overseen by FERC, the Department of Justice, the Federal Trade Commission and the Internal Revenue Service. State public utility commissions, or their equivalent, also have responsibility for oversight in mergers and acquisitions of pipeline companies.

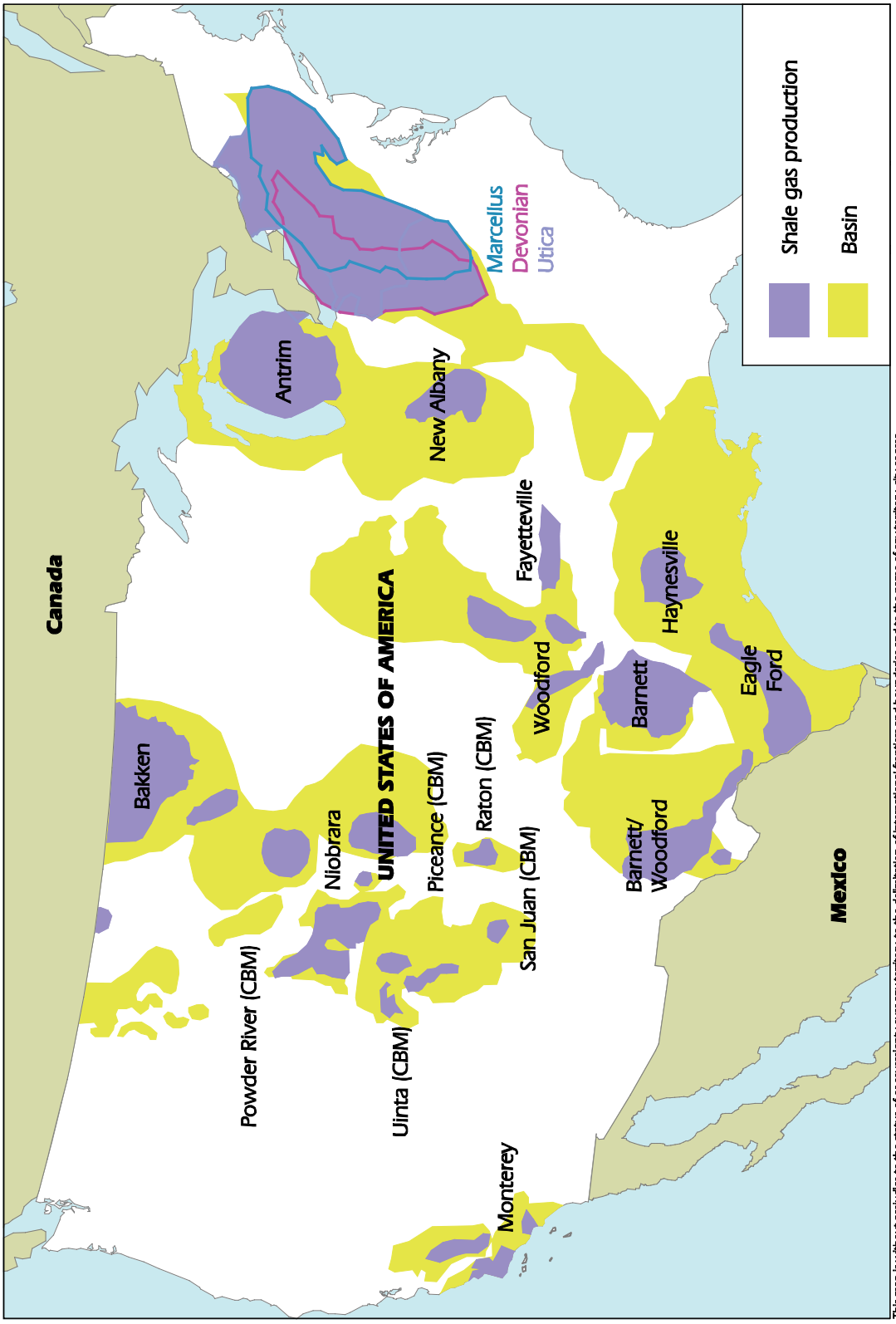
THE SHALE GAS PRODUCTION BOOM

SHALE GAS

The production of natural gas from shale formations has greatly transformed the natural gas industry in the United States and had a significant impact on global natural gas markets. Shale gas has been produced from the Barnett Shale play in Texas for more than a decade and experience and information gained from developing this resource has been used to great advantage throughout the country. Other notable plays include the Haynesville (on the Texas-Louisiana border), Fayetteville (in Arkansas) and Marcellus (in the northeastern United States) shales. The Marcellus Shale is a play so large that only a limited portion of the entire formation has been extensively production-tested. The EIA projects that shale gas will provide the largest source of growth in US natural gas supply: the share of shale gas in total US natural gas production will increase from 40% in 2012 to 53% in 2040.

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Figure 9.4 Shale gas plays in the United States



Source: IEA (2013), *Resources to Reserves: Oil, Gas and Coal Technologies for the Energy Markets of the Future*, OECD/IEA, Paris.

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Shale gas, often considered a sub-category of tight gas, is a natural gas contained within predominantly organic-rich, fine-grained rocks and silts dominated by shale. Shale itself is a very fine-grained sedimentary rock that can easily be broken into thin, parallel layers. However, it is the organic material that is important; when buried sufficiently deep underground, and the conditions of pressure and temperature are appropriate, gas is formed. Where the gas has not been able to escape the source rock and remains trapped within its structure, it is referred to as shale gas. Significant volumes of natural gas may be contained in layers of shale rock, often hundreds of metres thick.

Environmental considerations

Advances in combining horizontal drilling and hydraulic fracturing have been very successful in producing energy from gas (and tight oil) deposits in the United States that were previously uneconomic. Hydraulic fracturing is the high-pressure injection of water containing high-viscosity fluid additives to open or create fractures in the rock.

These fractures allow the hydrocarbons to bypass a large part of the low-permeability rock and to move freely from the rock pores to a production well and thus to the surface. With horizontal drilling, longer and more complex wells are drilled, fractured in numerous stages along their length. This lowers the unit production costs.

Until the mid-2000s, however, producing the gas from shale formations was unprofitable because of the low permeability of the rock and the low yields. While often found in regions with conventional oil and gas resources, shale gas can also be found in areas with no conventional oil or gas resources. As exploration in those areas has been minimal, resources of shale gas may be significantly higher than previously predicted.

Box 9.2 Success factors in shale gas development

The following factors contribute to the successful development of shale gas plays:

- early identification of the location and potential of the best producing areas
- efficient leasing of large prospective areas
- experimentation and adaptation of drilling, completion techniques, and development
- adequate local infrastructure (particularly transportation), since most equipment and supplies (especially the vast quantities of water used and then disposed of) have to be trucked to and from the wells
- adequate gas transportation infrastructure
- awareness and acceptance by local communities
- resolution of environmental issues related to water use and disposal
- market pricing of gas
- sanctity of contracts and stable investment climate.

While many of these factors have been successfully addressed in the United States, some require yet further effort.

Source: IEA (2013), *Resources to Reserves 2013: Oil, Gas and Coal Technologies for the Energy Markets of the Future*, OECD/IEA, Paris.

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Commercial development of shale gas depends on the geology of the play, the availability of sufficient quantities of water for drilling and completing wells, as well as on the cost and environmental impact of treating and disposing of the water that is produced with the gas. Outside North America, shale gas extraction is still largely in the experimental or exploratory phase (IEA, 2013).

Water management, including water usage during drilling and hydraulic fracturing, and the protection of surface and ground water during drilling, fracturing, production and disposal activities, is a central environmental issue for unconventional gas production. Although water consumption for natural gas production generally represents less than 1.0% of regional water demand (NETL, 2014), a large increase in water demand over a relatively short period of time can place significant stress on local water resources. The DOE/NETL estimates that between two and six million gallons of water may be necessary to fracture one horizontal well in a shale formation.

Inadequate management of water and chemicals on the surface, both before injection and after (as flowback and produced water), can lead to groundwater contamination and surface water contamination. Causes of pollution may be spills on the surface, improper well design, and/or improper storage of chemicals and produced water. Sub-surface impacts can also result from the migration of fracturing fluids, formation waters, and methane along well bores and through rock fracture networks. It is important to note that while there have been incidents of pollution and water contamination associated with the development of unconventional gas, the hydraulic fracturing process itself has generally not been implicated.

States have the power to implement their own requirements and regulations for unconventional gas drilling under federal oversight. All of the states that produce gas have at least one agency to permit drilling wells, and many federal regulations for oil and gas production allow states to implement their own programmes as long as these programmes have been approved by the appropriate federal agencies. While state requirements differ, any requirements set forth in federal regulations must be met at a minimum – in other words, state requirements can be more stringent than federal regulations, but they cannot be less stringent than federal regulations. The federal Clean Water Act and Safe Drinking Water Act are the main federal laws applicable to water management in shale gas development. The Clean Water Act regulates the surface discharge of flowback and other drilling waters and storm water run-off. The Safe Drinking Water Act regulates the underground injection of wastewaters.

In partnership with states, EPA is examining the different disposal methods employed by industry to ensure that there are regulatory and permitting frameworks in place to provide safe and legal options for disposal of flowback and produced water. Many states where unconventional production takes place have modified their regulations – creating chemical disclosure requirements, changing wastewater disposal rules, requiring the testing of groundwater, creating setback requirements for development in populated areas, for example. In June 2010, Wyoming became the first state to approve rules requiring public disclosure of the chemicals in fracking fluid. In 2011, Texas became the first to enact legislation requiring public disclosure.[2] A number of states have rules requiring various degrees of public disclosure of hydraulic fracturing chemicals. In Colorado, the most comprehensive regulations to date require drillers to disclose not only chemical names,

2. Texas Legislature, HB 3328: An Act relating to the disclosure of the composition of hydraulic fracturing fluids used in hydraulic fracturing treatments, 2011.

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but also their concentrations. In February 2012, the US Department of Interior, Bureau of Land Management, released draft regulations that would require operators on federal lands to seek approval to conduct hydraulic fracturing and disclose the chemical ingredients of the proposed fracking fluid, but trade secrets are protected. Disposal of flowback and produced water via underground injection is regulated under the Safe Drinking Water Act's Underground Injection Control (UIC) Program (EPA, 2014).[3]

In some cases, drilling operators choose to recycle some wastewaters to replace and/or supplement fresh water in formulating fracturing fluid for a future well or re-fracturing the same well. Reuse of shale gas wastewater is, in part, dependent on the levels of pollutants in the wastewater and the proximity of other fracturing sites that might reuse the wastewater. This practice has the potential to reduce discharges to treatment facilities or surface waters, minimise underground injection of wastewater and conserve water resources (EPA, 2014). The EPA recommends that operators should integrate source reduction and recycling measures into their operations, where practicable.

Water acquisition is regulated by local authorities, groundwater management areas and regional planning bodies. State and federal bodies are responsible for environmental management and stewardship. States may have their own regulations and the Department of Interior can regulate hydraulic fracturing on federal land. In this context, both more comprehensive regulation and industry initiatives to address environmental concerns would increase public confidence in hydraulic fracturing (IEA, 2012). State and federal regulators need to monitor the situation closely and strengthen regulations as needed.

FLARING

All oil and gas production can result in flaring and venting of gas (and there is usually at least some of one or the other). Flaring of associated natural gas also occurs when natural gas is burned on location as a result of a lack of gathering pipeline infrastructure or other economic alternatives. The flaring of associated natural gas is becoming a problem in the United States which, in 2012, was estimated by the World Bank to be the fifth-largest flarer of natural gas: flared associated gas from the Bakken oilfields was the main reason why the United States jumped to fifth from 14th rank (behind Russia, Nigeria, Iran and Iraq) on the list of gas-flaring nations. While relatively low volumes of natural gas are flared overall in the United States, less than 1% per year on average, volumes of gas flared increased significantly between 2007 and 2011, from 2.2 bcm to 7.1 bcm (WB, 2012).

Methane emissions, including venting from shale gas production, are not regulated as a pollutant in the United States. Therefore, the EPA does not require companies to report the flared or vented methane emissions. Other constituent parts, such as non-methane volatile organic compounds and hazardous air pollutants, are regulated by EPA. Consequently, flaring, controlling and reporting of these releases is required. In addition to federal air quality regulations, many oil- and gas-producing states often have their own set of rules and standards. In some cases, they may be more stringent than the federal standards.

EPA regulations issued in 2012 set the first federal air standards to reduce volatile organic compound emissions from hydraulically fractured natural gas wells. The key requirement is for drillers, beginning in 2015, to perform “green completions” that reduce the quantity of natural gas that would otherwise be vented or flared during the well completion process. However, these rules will not affect oil wells.

3. The federal regulations for the UIC Program are found in Title 40 of the Code of Federal Regulations.

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Box 9.3 Flaring in North Dakota

North Dakota accounts for the greatest part of natural gas flaring in the United States. Between 2008 and 2013, oil production from North Dakota's Bakken formation, the largest oilfield in North America, increased by more than 500%. It grew from 63 million barrels per year to 313 million barrels per year, surpassing Alaska to become the third-largest oil-producing region in the United States after Texas and the Federal Offshore. The Bakken formation produces both crude oil and associated natural gas. While oil is the primary energy resource contained in the Bakken formation and is the main driver of activity in the region, the formation also produces associated natural gas, which in North Dakota is rich in natural gas liquids. For a number of reasons, such as the lack of pipeline infrastructure, a large percentage of this gas does not go to market and in 2012 nearly 30% of production was flared. The amount of non-marketed natural gas output continued to grow in North Dakota in 2013, rising to an average of 0.31 bcf/d (8.8 mcm/d), almost double the 0.16 bcf/d (4.5 mcm/d) levels in 2011, according to the North Dakota Department of Mineral Resources. The temporary closure of a processing plant at the end of 2013 led to an increase in both the volume and the percentage of non-marketed natural gas that continued into 2014 (NDPA, 2013). Similar problems, albeit on a lesser scale, also exist in Wyoming.

The industry is looking at a number of ways to reduce the volumes flared such as onsite power generation, trucking the natural gas and converting it to liquid fuel. In July 2014, for example, North Dakota adopted new rules that will require companies to reduce oil production if they do not meet flaring targets and two large proposed fertiliser plants have been proposed.

In the 2011 Blueprint for a Secure Energy Future, President Obama directed the Secretary of Energy Advisory Board (SEAB) to identify steps to improve the safety and environmental performance of hydraulic fracturing, and develop recommendations to protect public health and the environment. Among the SEAB report's recommendations were: manage short-term and cumulative impacts on communities, land use, wildlife, and ecologies; protect water resources; disclosure of fracturing fluid composition; Identify research and development needs; create a public, national portal improving public information; organise for sharing best practices; improve communication among state and federal regulators; reduce use of diesel fuel in fracturing; and improve air quality throughout the production process.

As part of his overall Climate Action Plan, released in June 2013, President Obama announced a new initiative to reduce methane emissions and directed several agencies, including DOE and EPA, to develop a comprehensive interagency methane strategy, to focus on assessing current emissions data and gaps, identifying technologies and best practices to reduce emissions, and identifying existing authorities and incentive-based opportunities for reducing methane emissions. A Strategy to Reduce Methane Emissions was published in 2014. The strategy identifies the sources of methane emissions, introduces measures to reduce methane emissions, and outlines efforts to improve the measurement of these emissions (Executive Office of the President, 2014).

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GOLDEN RULES

The IEA has emphasised that the potential of the world's vast resources of unconventional natural gas holds the key to a golden age of gas, but for that to happen governments, industry and other stakeholders must work together to address legitimate public concerns about the associated environmental and social impacts. The future of shale gas development hinges critically on the successful development of the world's vast unconventional gas resources.

Box 9.4 Golden Rules for a Golden Age of Gas

The recent North American experience shows that unconventional gas, notably shale gas, can be exploited economically and many countries hope to emulate this success. In many cases, governments are hesitant, or even actively opposed, responding to public concerns that production could involve unacceptable environmental and social damage. In 2012, as part of the *World Energy Outlook* series, the IEA developed its *Golden Rules for a Golden Age of Gas*, which suggested principles that can allow policy makers, regulators, operators and others to address these environmental and social impacts. Application of these rules can bring a level of environmental performance and public acceptance that can maintain or earn the industry a "social licence to operate" within a given jurisdiction, paving the way for the widespread development of unconventional gas resources on a large scale, boosting overall gas supply and making the golden age of gas a reality.

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting before exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, before commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water, and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

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Box 9.4 Golden Rules for a Golden Age of Gas (continued)

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas-bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.
- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero-venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.
- Find an appropriate balance in policy making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance.

Source: IEA (2012), *Golden Rules for a Golden Age of Gas*, *World Energy Outlook* Special Report, OECD/IEA, Paris.

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NATURAL GAS INFRASTRUCTURE

TRANSMISSION AND DISTRIBUTION

The natural gas pipeline network is a highly integrated transmission and distribution grid that can transport natural gas to and from nearly any location in the lower 48 states. There are approximately 210 natural gas pipeline systems and over 305 000 miles of pipeline (EIA, 2014b).

There are 49 entry/exit points in all: 33 active entry/exit points for pipeline imports/exports and eight active entry/exit points for LNG imports/exports. Natural gas may, and sometimes does, flow in both directions; however, at each of these sites the flow is either primarily import or export.

Six active entry points receive about 90% of all natural gas imports. Canadian pipeline imports via Eastport, Port of Morgan, Noyes, Sherwood, Sumas and Waddington accounted for 93% of total pipeline imports in 2013 (EIA, 2014c). The most active entry point for LNG imports is Everett, Massachusetts which received 64 bcf (1.8 bcm) LNG imports in 2013, out of 96 bcf (2.7 bcm) for the country as a whole.

While US natural gas production has increased dramatically over the past few years, pipelines have failed to keep up with these new supplies in some areas. This was especially the case in New England and New York, where prices surged to 20 times the Henry Hub level (above USD 100/MBtu) during the cold spell in early 2014. Nonetheless, several major new natural gas pipelines have been completed since 2007. These include the KM Rockies Express in 2008 (718 miles, with a capacity of 2.5 mcm/d or 1.5 bcf/d), the Ruby Pipeline Project in 2011 (673 miles, with a capacity of 42.5 mcm/d or 1.5 bcf/d), and the Mid-continent Express Pipeline in 2009 (507 miles, with a capacity of 40.5 mcm/d or 1.43 bcf/d). According to the Administration, despite recent natural gas pipeline capacity increases, natural gas futures contract prices signal that additional natural gas pipeline capacity may be needed to reduce peak winter premiums further in the big winter load centres like New York City and Boston that remain subject to pipeline constraints. As of May 2012, there are 40 announced projects, 22 approved, and 19 currently under construction.

Transmission constraints are placing pressure on prices in some regions: Since 2012, limited supply from the Canaport and Everett LNG terminals, coupled with congestion on the Tennessee and Algonquin pipelines has led to winter natural gas price spikes in New England (EIA, 2014a). The average bidweek natural gas price reached a high of USD 14.52 per MBtu for December 2013 and more than USD 20/MBtu for January 2014. Pipeline expansions could ease price spikes, but their cost-effectiveness, including their ultimate cost to consumers, remains a challenge. For example, New York City reduced spikes in prices by adding pipeline capacity and by using retail demand curtailment, solutions that could help New England as well.

There are about 1.2 million miles of distribution pipeline and 1 200 natural gas distribution companies in the United States. While many of these companies enjoy a monopoly their distribution region, many states are developing proposals for supply competition with respect to their natural gas distribution.

STORAGE

The United States has 411 natural gas storage facilities with a total capacity of 120 bcm (4.239 tcf). The facilities are broadly dispersed geographically and consist of a combination of salt caverns (37), aquifers (43) and depleted reservoirs (331). The advantage of having

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significant amounts of salt cavern storage is that it allows rapid injection and withdrawal to respond to market conditions and other short-term events. According to the EIA's *Weekly Natural Gas Storage Report*, working gas in storage as of 28 November 2014 was 3 410 bcf (96.6 bcm). This was 227 bcf (6.4 bcm) less than the previous year, and 372 bcf (10.5 bcm) below the five-year average of 3 782 bcf (107.1 bcm) (EIA, 2014f).

Table 9.2 Working gas in underground storage

Region	Stocks in bcf			Historical comparisons			
	28 Nov-2014	21 Nov-2014	Change	Year ago (28 Nov-2013)		Five-year average (2009-13)	
				Stocks (bcf)	% change	Stocks (bcf)	% change
East	1 830	1 864	-34	1 872	-2.2%	2 013	-9.1%
West	478	477	1	532	-10.2%	522	-8.4%
Producing	1 102	1 091	11	1 233	-10.6%	1 247	-11.6%
Total	**3 410**	**3 432**	**-22**	**3 637**	**-6.2%**	**3 782**	**-9.8%**

Source: EIA (2014), *Weekly Natural Gas Storage Report*, 4 December.

Underground natural gas working storage capacity for the Lower 48 states fell by 5.6%, or 204 bcf (5.8 bcm), between November 2014 and November 2013 and reached 3 410 bcf or (96.6 bcm). Capacity is divided among three regions: the East, West and Producing regions. Capacity as a percentage of working gas design capacity is lower in the West region than the East and Producing regions for several reasons. The West region has several still-active fields whose primary role is not seasonal storage. These include fields used for pipeline load balancing and fields that are being drawn down to be taken out of service. Also, some fields in the West region have large design capacities, but have infrastructure constraints such as limited pipeline and compression capacity that limit actual storage utilisation and peak capacity.

For the one-year period ending in November 2013, expansion projects led most of the 106 bcf increase in design capacity for the lower 48 states. Completion of new storage projects in 2014 could increase design capacity by 63 bcf, including 50 bcf from facilities currently under construction. Expansion of existing facilities totalling 13 bcf of new capacity is also planned for 2014 (EIA, 2014d).

FOCUS: NATURAL GAS USE IN ROAD TRANSPORT

The advantages of natural gas as a transportation fuel include its domestic availability, widespread distribution infrastructure, low cost, and inherently clean-burning qualities. Compressed natural gas (CNG) vehicles have achieved moderate popularity throughout the world, but they continue to suffer from limited range and, possibly, excessive weight. Liquefied natural gas (LNG) has demonstrated practicality in heavy-duty vehicles, but it is currently too heavy to store on board in light-duty vehicles. CNG and LNG are both considered alternative fuels under the Energy Policy Act of 1992 and there are approximately 112 000 natural gas-powered vehicles in the United States.[4]

4. This section is based on a chapter first published the *Medium-Term Gas Market Report 2013*, OECD/IEA, Paris.

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The EIA projects that the use of CNG and LNG in light-duty vehicles (LDVs), heavy-duty vehicles (HDVs), locomotives, buses, and marine vessels will grow from 43 trillion Btu in 2012 to 863 trillion Btu in 2040 in the *AEO 2014* Reference Case. Medium-duty and heavy-duty vehicles are projected to become the largest consumers of natural gas in the sector, increasing their consumption from 11 trillion Btu in 2012 to 613 trillion Btu in 2040. Furthermore, EIA projects that LNG consumption by freight rail locomotives grows to 148 trillion Btu by 2040, when it accounts for 35% of total freight rail energy consumption, with fuel cost savings offsetting the incremental capital costs of LNG locomotives. Nonetheless, CNG and LNG will account for only 3% of total energy consumption in the transport sector in 2040, no different to the amount of natural gas consumed in pipeline transport.

Optimism about domestic natural gas resources is largely responsible for the political push supporting the use of natural gas in sectors previously dominated by oil. Different factors are responsible for the growing interest in gas use in the United States transport sector: gas use in transport reduces dependence on imported oil, the large spread between oil and gas prices, as well as the environmental benefits of using gas. Customers as widely different as rubbish-collection fleets, taxis, school buses, mass transit operators, mail delivery system, and several industries have already converted their vehicles to gas: trucks involved in water disposal at many shale gas plays now run on LNG.

The key policy question is what part of the transport sector should be the primary focus: passenger cars, buses or heavy trucks, using CNG or LNG? The majority (112 000) of US natural gas vehicles (NGV) are light-duty vehicles (96 500), while buses and trucks, including medium-duty vehicles (MDV) and heavy-duty vehicles (HDV) represent only around 15 500 (2011 data). Motor cars offer a similar picture, with buses and trucks representing around 4% of the total number of US vehicles. The larger consumption of trucks (notably Class 8), and the fact that it is easier to put in place natural gas highways for trucks than to build filling stations across the whole country, seems favourable to LNG trucks. An additional striking fact is that one-half of newly produced US motor cars are commercial cars (including MDVs and HDVs), implying a much higher turnover and the possibility of replacing diesel-powered trucks with LNG-powered trucks, if vehicle manufacturers can deliver; sales of HDVs using natural gas peaked in 2003 at around 8 000, declining to around 1 000 in 2010.

POLITICAL BACKING IS ESSENTIAL

Increasing political backing at the federal and state levels is essential for the success of NGVs. The Energy Security Trust was proposed by the White House to provide USD 2.0 billion for research focused on developing cost-effective transportation alternatives, including natural gas-fuelled vehicles, in order to shift cars and trucks away from oil. This funding adds to support provided by the Department of Energy (DOE). Furthermore, the Energy Policy Act of 2005 provided for an income tax credit of 30% of the cost of gas refuelling equipment (up to USD 30 000 for large stations and USD 1 000 for home appliances). This tax credit, initially set to expire at the end of 2010, was extended twice. The first extension included an incentive allowing companies to claim 100% of the cost of new capital acquisitions in 2011 and 50% for 2012. The second extension, passed in early January 2013, maintained the bonus depreciation at 50% for 2013. There is also a USD 0.5 tax credit per gasoline gallon-equivalent (GGE) of CNG and per liquid gallon of LNG for use as a motor vehicle fuel, and an income tax credit – ranging from USD 2 500 to USD 32 000 – for the purchase of a new alternative fuel vehicle of 50% of the incremental cost of the vehicle (to which one could add 30% if the vehicle meets tighter emission standards).

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Many states have passed, or are considering passing, legislation to encourage the use of NGVs, notably by the public sector. As of March 2013, 16 states had signed a memorandum of understanding (MOU) to help car makers develop an original equipment manufacturer (OEM) fleet of NGVs. The states will co-operate to determine their specific needs for NGVs (e.g. by local agencies, municipalities and companies) and aggregate these requirements, as well as encourage private investment in fuelling stations. They also intend to change new fleet vehicle acquisitions to NGVs at a later point. For example, Wyoming introduced a law giving USD 200 000 to the Department of Transportation and the Department of Administration and Information to retrofit or acquire gas-powered vehicles.

Gas vehicles face opposition from those who consider gas as a dirty fuel, those who prefer to have electric cars, those against an increase in shale gas production for environmental reasons, and existing gas users, such as industry, who fear that faster depletion of natural gas resources could lead to an accelerated increase in prices.

Will opting for NGVs make economic sense?

The policy framework seems to be right, not only because of political backing from the federal government and the states, but also because of the price disparity between oil products and natural gas, as well as the increasing involvement of the natural gas industry. LNG trucks are attracting greater interest because of the large savings they can provide.

The premium to buy a natural gas-powered truck is currently estimated at USD 70 000, but could be significantly reduced when more trucks are built. With future premiums estimated at USD 20 000 to USD 30 000 above the diesel equivalent, the investments can be recovered within a short time in the current price environment. Meanwhile, retrofitting an 18-wheeler costs about USD 40 000, which means that retrofitting the eight million largest trucks would cost around USD 320 billion. The economic proposition for an investment in a natural gas-powered truck is based on a standard payback analysis, with an incrementally higher retail price being offset by lower future operating payments. The economics are already compelling enough for an operator to switch to natural gas fuel, and as engine manufacturers continue to reduce their production costs, the life-cycle fuel savings of a natural gas truck will continue to grow.

US fuel prices have seen such major changes over the past few years that a key uncertainty is whether the current LNG-diesel price spread will be sustained. There are also uncertainties on whether tax incentives will be extended, given that they had been cancelled last year before the federal government changed its mind. Another essential point would be the evolution of the fiscal policy regarding natural gas used as a motor fuel. With the progressive decline in gasoline consumption, fuel tax revenues fell by USD 1.0 billion between 2008 and 2010 and it may seem attractive to tax NGVs as their number increases. Finally, LNG trucks require driver training in terms of refuelling, and to have all the equipment and qualified personnel associated with handling LNG trucks.

A CLOSER LOOK AT THE LNG OPTION

The keys to solving the chicken-and-egg problem is the availability of refuelling infrastructure and co-operation among different parts of this value chain, i.e. LNG providers, refuelling station developers and truck operators/owners. LNG providers need to develop liquefaction capacity and the means of transporting LNG to the refuelling stations. There are indications of growing interest from several gas producers, notably Shell, Chesapeake and Apache.

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LNG infrastructure is more complex, and therefore more expensive, than CNG infrastructure. The benefits and risks must be carefully weighed by investors to avoid building an infrastructure which will not find its market. There are already several existing LNG facilities which could provide LNG in the United States; these include vehicular fuel facilities, nitrogen rejection units, peak-shaving plants, and LNG import terminals or even LNG export plants. One key difference between these facilities is the size (or volume per day). A vehicular fuel liquefaction facility can produce between 85 000 LNG gallons per day and 250 000 LNG gallons per day, while the available LNG from nitrogen rejections units or peak-shaving plants is 25 000 LNG gallons per day maximum. LNG import terminals can deliver much higher volumes. Furthermore, there is the possibility of transforming LNG into CNG to supply CNG vehicles.

When dealing with trucks, refuelling stations need to be strategically positioned along the main highway corridors. As LNG trucks typically have a range of 480 km (300 miles), putting stations every 200 miles would enable most trucks to operate efficiently. For longer distance line-haul applications, vehicles will be able to hold approximately 220 gallons of LNG, offering an estimated 720 miles in range, but this remains considerably lower than the current 1 200 miles offered by most diesel-powered trucks, which implies a change of behaviour for drivers. At the end of 2013, there were 1 344 natural gas refuelling stations in the United States, including 81 LNG stations, many of which are privately owned and not open to the public. The majority are concentrated in a few states such as California, which has 315 stations.

While current LNG infrastructure fails to adequately cover the country, many companies have stated their intention to build new LNG stations. The most ambitious, Clean Energy Fuels, provides fuel to over 35 000 vehicles each day at approximately 500 CNG and LNG fuelling stations throughout the United States and Canada. In September 2013, GE in partnership with Clean Energy Fuels and Ferus Natural Gas Fuels announced that it will develop regional LNG projects to meet growing demand. Other announcements have been made by companies such as China's ENN, which has plans to build 50 LNG stations for HDVs in 2013. Also, Shell announced it would partner with TravelCenters of America to sell LNG for trucks at 100 locations.

These numbers may seem encouraging but it does not follow that the switch to natural gas among truck fleet operators will be large-scale and sudden. As mentioned earlier, there are still many uncertainties. Operators of large fleets like United Parcel Service (UPS) are likely to be prime movers, as they can afford the large upfront costs. UPS announced it would buy 700 new LNG trucks by the end of 2014 and build fuelling stations in ten states. Smaller companies, which represent the bulk of fleet operators, may be reluctant to switch to natural gas in the early stages because of the high upfront investment costs and the potential risks associated with price evolution. They are more likely to experiment with a partial switch, with a small share of their fleet being converted and benefiting from the current price spread. One positive factor is that the HDV segment is quite competitive, so that the savings made by those who have switched, if sustained, could lead to a more rapid change, especially if car manufacturers have achieved significant cost reductions at the same time.

PRICES

PRICES AND TARIFFS

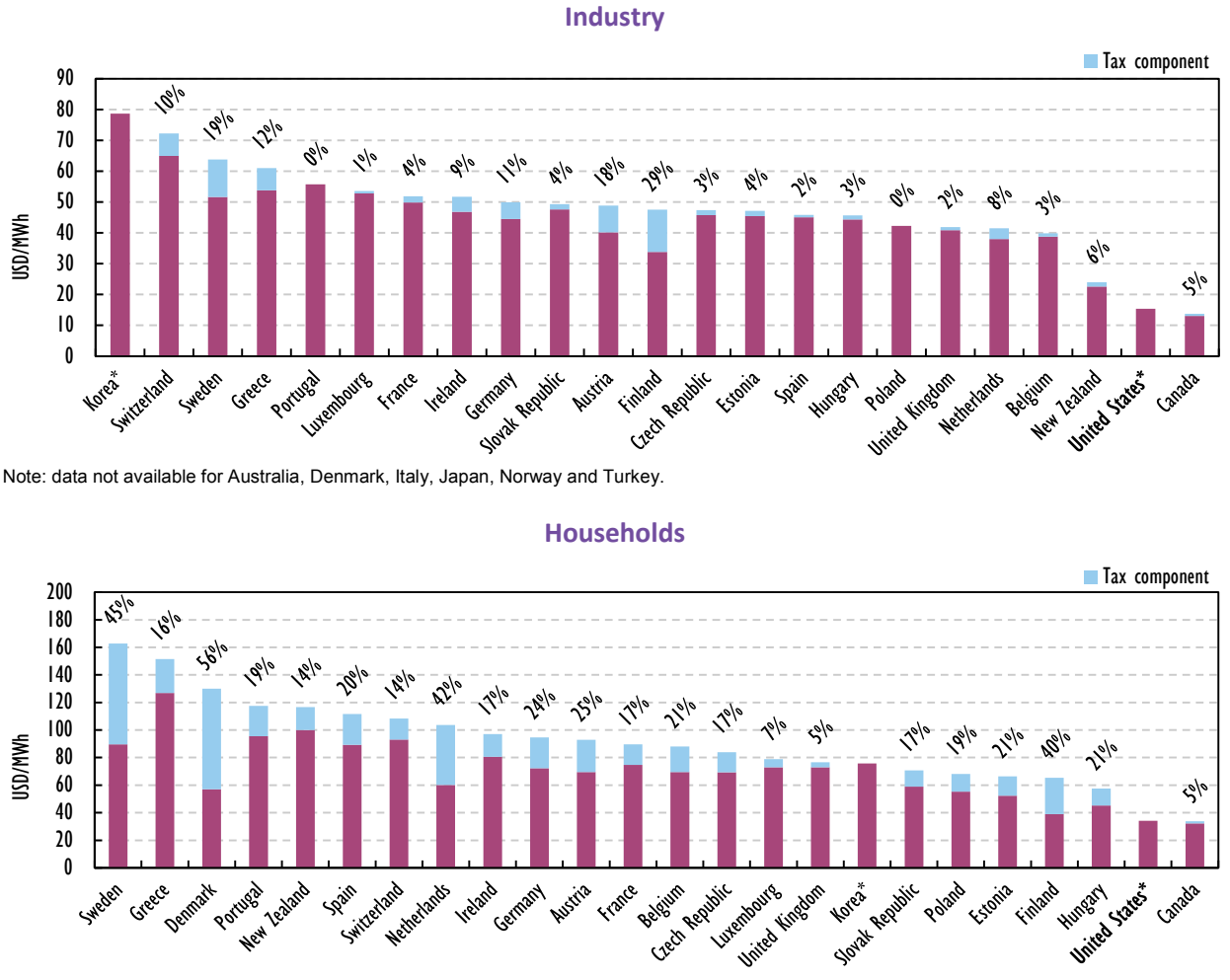
Domestic wholesale natural gas prices in the United States are determined at the Henry Hub through market pricing. Consumers have experienced a substantial drop in prices since the

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last in-depth review was published in 2008. Average citygate prices averaged USD 9.18/MBtu in 2008, by 2010 they had fallen to USD 6.18/MBtu, and by 2013 the average price was USD 4.88/MBtu. In May 2014, the EIA projected that Henry Hub natural gas prices average will average USD 4.74/MBtu in 2014 and USD 4.33/MBtu in 2015. Within the United States, there are variations in prices: in 2014, for example, citygate prices in the northeastern states were up to 25% higher than in the producing states of the midwest. Prices to industry and retail consumers demonstrate similar trends.

AEO 2014 projects that, on average, consumers will see an increase in their natural gas expenditure. On average, from 2015 to 2035, natural gas bills paid by end-use consumers in the residential, commercial and industrial sectors combined increase by 3% to 9% over a comparable baseline case with no exports, depending on the export scenario and case, while increases in electricity bills paid by end-use customers range from 1% to 3%. In the rapid growth cases, the increase is notably greater in the early years relative to the later years. The slower export growth cases tend to show natural gas bills increasing more towards the end of the projection period.

Figure 9.5 Gas prices in IEA member countries, 2013



Note: data not available for Australia, Denmark, Italy, Japan, Norway and Turkey.

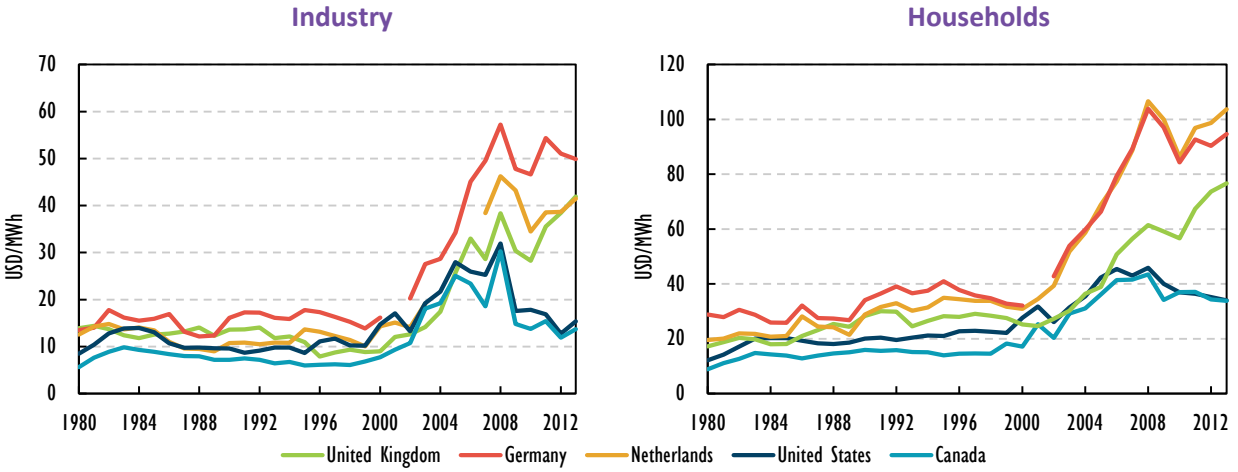
Note: data not available for Australia, Italy, Japan, Norway and Turkey.

* Tax information not available.

Source: IEA (2014c), *Energy Prices and Taxes, Vol. 2014/3*, OECD/IEA, Paris.

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Figure 9.6 Gas prices in the United States and in other selected IEA member countries, 1980-2013



Source: IEA (2014c), *Energy Prices and Taxes, Vol. 2014/3*, OECD/IEA, Paris.

ASSESSMENT

EVOLVING ROLE OF NATURAL GAS

Since the previous in-depth review in 2008, the United States has undergone a major shift in its primary energy supply and electricity generation mix, largely as a result of the unexpected rise in shale gas production and the abundance of inexpensive natural gas. Though shale gas (alongside other unconventional sources of tight gas and coalbed methane) has been produced for several decades, shale gas production only started to expand after 2005, reversing the previous decline in gas production. Proved gas reserves have increased by almost three-quarters since 2000, up to 322.6 tcf (or 9.137 tcm) by the end 2012, or the equivalent of more than 100 years of production at 2012 consumption rates. Natural gas production is projected to continue to increase over the period to 2040. Almost all of this increase is the result of the projected growth in shale gas production, and two of the largest shale plays that have been identified, the Marcellus and Haynesville formations, viewed as single reservoirs, are among the largest known gas fields of any type in the world.

With the advent of substantial shale gas production, the country has moved rapidly from two decades of increased dependence on imported gas to being a possible LNG exporter. The scale of the indigenous gas resource now available has implications for traditional sources of US imports, such as Canada, and may have price consequences globally. Historically, a large portion of Canadian gas production was transported by pipeline to the United States and as a result Canada is actively seeking out new export markets. At the same time, US LNG import capacity, much of it built in the early 2000s before shale gas production took off, is lying idle and only a handful of import terminals are operating. The absence of the United States from the LNG import market has also exerted downward pressure on global LNG prices as more gas becomes available for European and Asian markets.

As the natural gas industry in the United States looks to develop its export markets, it will be interesting to see the extent to which this may affect the dynamics of the global LNG market in price terms and support decoupling of gas prices from oil-linked pricing in long-term contracts.

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The abundance of cheap gas (between USD 4.0 and USD 6.0 per MBtu), depending on the distance between production sources and market, as well as access to pipeline transportation, has changed the dynamics of the domestic gas market and had significant impact on the power generation mix. The EIA projects that this trend will continue and gas-fired plants will account for 73% of capacity additions from 2013 to 2040 in their Reference Case (compared with 24% for renewables, 3% for nuclear and 1% for coal). Although further upward shifts in gas generation demand can be accommodated in the near term, there is a concern at the lack of a long-term plan as to how to mitigate possible consequences for the competitiveness of other fuels and shifting generation mix or indeed to consider scenario options and mitigation strategies if gas prices revert to levels prevailing before the shale gas boom. The EIA projects that 16% or 50 GW of coal-fired capacity will retire by 2020. These retirements will be accompanied by a loss of 6 GW of nuclear capacity. It is likely that these retirements will be replaced by natural gas and renewables, which is likely to result in higher electricity and natural gas prices for end-users.

ENVIRONMENTAL IMPACTS OF THE TIGHT OIL BOOM

The push to develop unconventional sources of gas in the United States using hydraulic fracturing techniques has attracted a great deal of criticism on environmental grounds. The technologies developed for shale gas production are now being successfully used for tight oil from shales. While this has benefited prospects for increased oil production, associated gas produced as a by-product of the process is not always captured and is having adverse environmental consequences in some regions. Despite this, and unlike in parts of Europe, public perception of unconventional oil/gas development by means of hydraulic fracturing remains positive, often on the basis that the economic benefits outweigh environmental concerns.

At low prices, there is little incentive to market the associated gas or build and upgrade the necessary infrastructure needed to transport the gas. Significant volumes of gas are being flared at the source rather than being captured and fed into the gas network or used as a feedstock. In North Dakota, for example, natural gas production has more than quadrupled since 2005, largely as a result of associated natural gas from growing oil production in the Bakken shale formation. As a consequence of insufficient natural gas pipeline capacity and processing facilities, much of North Dakota's natural gas has been flared or otherwise unmarketed (31% of production in 2012). Similar problems, albeit on a lesser scale, exist in onshore Texas and Wyoming. Concerns arise because not all producing states (it is worth noting that Texas and North Dakota, where new rules on natural gas flaring are to be implemented in June 2014, are among the exceptions) have effective laws in place to limit the practice of flaring, or where laws are in place, have the resources to enforce them (*Resources for the Future*, 2013).

Most shale gas-producing states have updated their regulatory frameworks. At present, methane venting is explicitly excluded from the Clean Air Act. However, EPA's new rules on "green completions" for shale gas wells will reduce gas venting and flaring significantly, although they will not apply to oil wells. Given the state and federal systems, it may be appropriate to devise a framework through a collaborative effort between federal and state regulators to develop a mechanism to address, at least in part, gas flaring and venting concerns. Parameters could also be developed for national industry codes based on best practice international experience. The lack of infrastructure to evacuate the gas needs to be addressed at state government level in co-operation with market participants and regulatory institutions. In this regard, the publication in March 2014 of the Strategy

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to Cut Methane Emissions represents positive progress as does United States' participation in the Climate and Clean Air Coalition Oil and Gas Methane Partnership.

There are examples of companies active in oil and gas production that have diversified their portfolio into gas-fired electricity generation to overcome the problem of lack of pipeline infrastructure to evacuate the gas and transport the energy produced over wires rather than by pipeline. Resource efficiency management questions arise in some locations, for example where there is already sufficient electricity on the network, particularly in areas where there is an abundance of hydro and/or renewables. On the other hand, there is the example of New England, where pipeline access is constrained; the region is increasingly vulnerable to interruptions in gas supply as a result of market design and interruptible contract arrangements which do not take account of wider energy supply concerns.

Water use also presents a problem. Shale gas production may consume large volumes of water and there is a risk that contaminated wastewater can threaten supplies of drinking water. In this regard, the publication in May 2012 by the Bureau of Land Management of a proposed rule that would require public disclosure of chemicals used during hydraulic fracturing after the fracturing operations have been completed is welcome. Also in April 2012, a Memorandum of Agreement was signed between the DOE, the Department of Interior, and EPA to develop a multi-agency research plan; this would address the highest priority research questions associated with safely and prudently developing unconventional shale gas and tight oil reserves. The EPA is also conducting a study to develop greater understanding of any potential impacts of hydraulic fracturing on drinking water resources. Results of this study, which US Congress requested the EPA to complete, are expected to be released in a draft for public and peer review some time in 2014. At least eight states have proposed casing, well spacing, setback, water withdrawal, flowback, waste regulation requirements or other measures to protect water resources (NCSL, 2012).

The Energy Policy Act of 2005 excluded hydraulic fracturing, except when diesel fuels are used for oil, gas or geothermal production from regulation under the Safe Drinking Water Act. The EPA revised its permitting guidance specific to gas (and oil) hydraulic fracturing activities using diesel fuels. Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Accordingly, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health wherever hydraulic fracturing occurs.

More and more areas of the United States are opened up to exploration and production. Public concern on the environmental effects on water resources as well as road use/ degradation, local traffic, ecosystems and urban disruption is likely to grow. The environmental consequences of hydraulic fracturing is not only of concern in the United States (which often has the advantage of working in areas remote from population centres), but worldwide as new areas of rich shale gas plays are being explored.

The United States has a significant leadership opportunity to develop and showcase best practice at a time when other countries seek to benefit from this resource. Each state develops and regulates these activities in a manner that reflects local topography, geology and environmental concerns. The diversity of regulatory approaches, however, can make it difficult to influence this process worldwide and help gain public acceptance. Nonetheless,

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the fact that there is no single federal regulation for all unconventional gas activity has not prevented US government agencies, including the Department of State, DOE, EPA and the Department of Interior, from sharing best environmental and regulatory practices with other countries. The federal government has worked with the IEA, for example in the "Golden Rules" process and the Unconventional Gas Forum. It also works on a bilateral basis with dozens of countries on these issues and many state officials have also shared their expertise with officials from other countries. A federal government initiative, in close collaboration with state and federal agencies and industry, could help develop an operating code, which incorporates best practice of the states that have established the highest standards. In this regard, the IEA's *Golden Rules for a Golden Age of Gas* provide a useful guide.

RECOMMENDATIONS

The government of the United States should:

- ☐ *Finalise and publish the EPA's Study of Hydraulic Fracturing for Oil and Gas for public comment and peer review.*
- ☐ *Work with federal regulators, state governments and regulators and industry stakeholders to develop a national regulatory framework for the avoidance of natural gas flaring and venting.*
- ☐ *Work with the Environmental Protection Agency, state governments and regulators, and industry stakeholders to adequately respond to concerns about potential water contamination from natural gas drilling, and to develop standards for disposing of waste water from the process.*
- ☐ *Ensure that adequate resources are in place to ensure monitoring and enforcement of existing regulations in relation to water contamination.*

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10. COAL

Key data (2013 estimated)

Production: 479.2 Mtoe, -9.1% since 2003

Net exports: 63.2 Mtoe, +601% since 2003

Share of coal: 19.9% of TPES and 40.2% of electricity generation

Consumption by sector (2012): power generation 90%, industry 4.9%, other transformation 4.9%, commercial and other services 0.2%

OVERVIEW

The United States holds extensive coal reserves and is estimated to have the world's largest estimated recoverable reserves of coal, approximately 233 734 million tonnes (Mt) in 2012 (EIA, 2013).[1] Coal is produced in three major coal-producing regions covering 25 states. Approximately 70% of coal was produced in five states: Wyoming, West Virginia, Kentucky, Pennsylvania and Illinois. While coal remains the largest source of energy for electricity generation, its annual share of total net generation is in decline and has fallen from 50.5% in 2005 as the sector switches to cheaper natural gas. Conversely, exports of hard coal have continued to grow: increasing from 3.6% of production in 2009 to 11.6% in 2013.

SUPPLY AND DEMAND

SUPPLY

Hard coal and lignite together account for a fifth of total primary energy supply (TPES), amounting to 435.4 million tonnes of oil-equivalent (Mtoe) in 2013.[2] The supply of coal has been falling since 2005 when it peaked at 558.4 Mtoe. The most significant decline was during the 2009 recession and again in 2012. In both years supply fell by around 11%. During 2013, supply recovered by 2.4% although it was still 18.2% lower than ten years before.

Hard coal production totalled 834.18 Mt in 2013. This includes 756.32 Mt of steam coal and 77.9 Mt of coking coal. The United States is the second-largest hard coal producer in the world, behind China; it produced 13.9% of the world total in 2011 while China accounted for 51% (EIA, 2013). Hard coal production has fallen from a peak of 993.1 Mt in 2008; it decreased by 8.7% in 2009, by 7.3% in 2012 and a further 3.2% in 2013, with plateau production during 2010 and 2011.

Lignite production was 69.8 Mt in 2013, decreasing by 2.5% compared to 2012. Lignite production reached a peak of 78.4 Mt in 2003 and has been falling since, with a slight

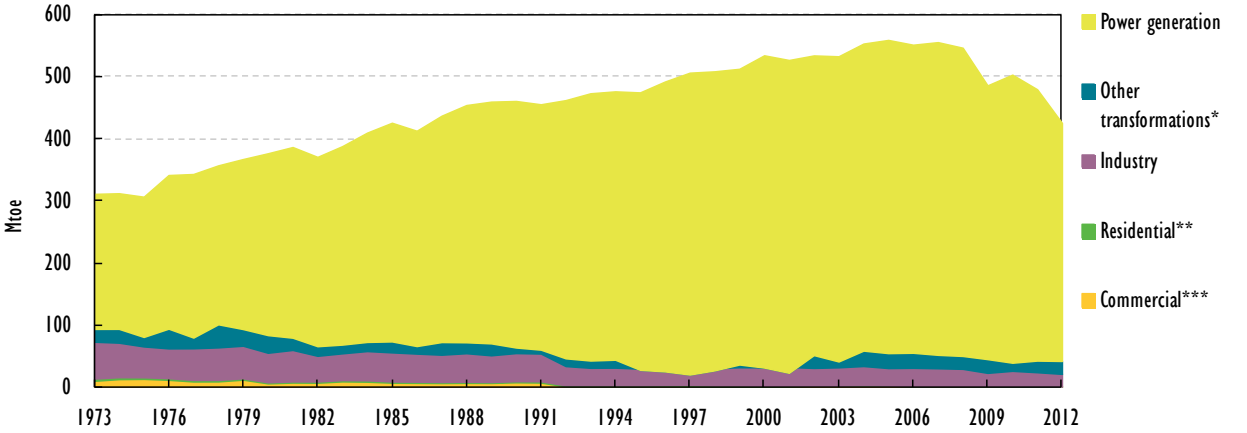
1. An estimate of coal reserves, based on a demonstrated reserve base, adjusted for assumed accessibility and recovery factors, does not include any specific economic feasibility criteria (EIA, 2013).

2. Energy supply includes imports.

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recovery during 2005, 2006 and 2011. The United States ranked fifth-largest in the world with regards to lignite production in 2011, behind Germany, China, the Russian Federation and Turkey (EIA, 2013).

Figure 10.1 Coal supply by sector, 1973-2012



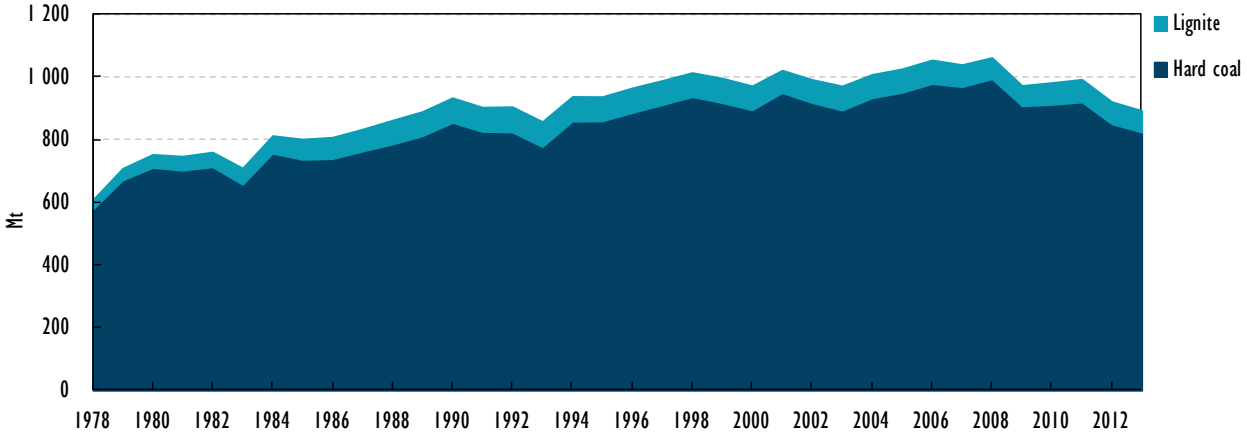
* *Other transformations* include coal refining and energy sector consumption.

** Residential consumption ceased in 2001.

*** *Commercial* includes commercial, public services, agriculture/forestry, fishing and other final consumption (negligible).

Source: IEA (2014a), *Energy Balances of OECD Countries 2014*, OECD/IEA, Paris.

Figure 10.2 Hard coal and lignite production, 1978-2013



Note: estimated data for 2013.

Source: IEA (2014b), *Coal Information*, OECD/IEA, Paris.

SUPPLY BY REGION

Coal is produced in 25 states but concentrated among three regions: the Appalachian coal region, the Western coal region (including the Powder River basin) and the Interior Coal Region. Wyoming is the top coal-producing state, followed by West Virginia and Kentucky.

The Appalachian coal region, which covers approximately 112 000 square miles in nine eastern states, produced approximately 27.4% of United States' coal in 2013 and stretches from Pennsylvania and Indiana in the north to Alabama in the south. Appalachian coal, two-thirds of which is produced in underground mines, is used for steam generation for

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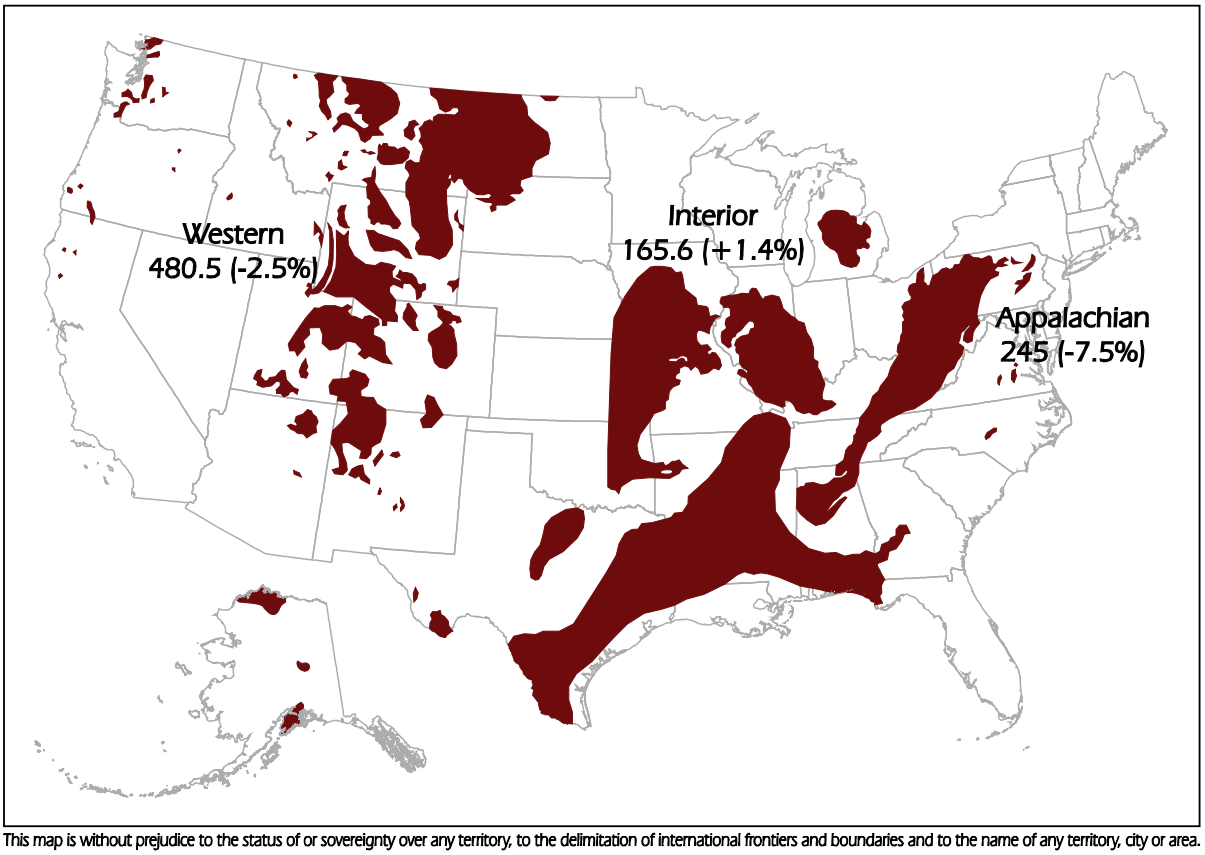
electricity, in industry, and for export. The region, which produced 245 Mt in 2013, can be further broken down in three sub-regions:

- the Northern Appalachian region covers approximately 53 000 square miles in Maryland, Ohio, Pennsylvania and West Virginia
- the Central Appalachian region, the largest of the three regions, covers approximately 35 000 square miles in Kentucky, Tennessee, Virginia and West Virginia
- the Southern Appalachian region comprises 23 000 square miles in Alabama, Georgia and Tennessee.

The Western coal region, which includes the Powder River basin, covers large parts of Arizona, New Mexico, Utah, Colorado, Wyoming and Montana. Lignite is mined in North Dakota and Montana. The Powder River basin (PRB) is located in northeastern Wyoming and southeastern Montana and contains the largest deposits of low-sulphur sub-bituminous coal in the world estimated to be in the range of 147 billion tonnes (Bt) of recoverable coal (USGS, 2013).

The Interior coal region is mostly concentrated on Illinois in the east and north, and Missouri, Kansas, Oklahoma and Texas in the west and south.

Figure 10.3 Coal production by region, 2013 compared to 2012 (Mt)



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Sources: EIA (2014), *Quarterly Coal Report October – December 2013*, EIA, Washington, D.C., March; EIA (2013), *Annual Coal Report 2012*, US Energy Information Administration, Washington, D.C., December.

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Table 10.1 Coal production by region, 2003-13 (Mt)

Region	2013	2008	2003
Appalachian	245	353.6	340.2
Interior	165.6	133.1	132.6
Western including Powder River basin	480.5	574.8	496.5
Total*	891.1	1 061.5	969.3

Note: data are preliminary for 2013.

* Less refuse recovery.

Source: EIA (2014), *Quarterly Coal Report*, October-December 2013, March 2014.

DEMAND

The power generation sector consumes 90% of total coal supply. Demand from this sector has declined since the mid-2000s, with consumption decreasing by 20.3% from 2005 to 2013. Coal accounted for 40.2% of electricity generation in 2013, a share that has declined from 50.5% in 2005. There are a number of reasons for this decline, including significant coal-to-gas switching in the power sector in response to lower gas prices and a reduction in coal-fired power plant capacity. Conversely, natural gas prices have increased since 2012 making coal somewhat more competitive. The impact of the growing competitiveness of natural gas in the power sector varied from region to region and from state to state, with Texas, home of the Barnett Shale, experiencing the greatest fall in coal use in the power sector. Other states that experienced a fall include Ohio, Wisconsin, Georgia, North Carolina, Tennessee and Indiana (IEA, 2012).

Other end-users of coal include the industrial sector (4.9%), transformation into coal products such as coke (4.9%) and the commercial sector including all other services (0.2%). The industrial sector mainly uses coal for autonomous/localised generation while coal products are mainly consumed in the steel and iron industry or again used in electricity or co-generation plants. Therefore, nearly all lignite and steam coal is ultimately used for electricity and heat generation. Metallurgical or coking coal is used in steel production. Small amounts of lignite are used in gas works transformations while steam coal is also consumed in blast furnaces, directly in the industrial and commercial sectors.

IMPORTS AND EXPORTS

Coal exports, which increased from 45.3 Mt in 2005 to a record 114.1 Mt in 2012 before declining slightly to 106.7 Mt in 2013, are an increasingly important source of revenue for both coal producers and coal transportation companies (generally railroads and barge companies). In 2012, coal export revenues were approximately USD 15 billion, representing about 25% of all coal revenues, despite the fact that coal exports in 2012 represented only 12% of total production (EIA, 2014).

The United States is a net exporter of hard coal with net exports of 87.6 Mt in 2013. Trade volumes have been on the rise since the early 2000s, flourishing in the past few years thanks to competitive prices, weakening domestic demand and growing demand from Europe and emerging economies. In 2013, exports are estimated to have declined by 9.9%, to 95.4 Mt, compared to 2012, after three years of strong growth. They tripled in only three years, increasing from 33 Mt in 2009, when they represented 3.6% of hard coal production, to 105.8 Mt in 2012 (12.4% of production). By 2013, exports represented 11.6% of production.

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Hard coal exports from the United States have a wide range of destinations. During 2013, exports were mainly destined for the Netherlands (11.4%), the United Kingdom (10.9%), Brazil (8.1%), China (7.5%), Italy (5.7%), Canada (5.2%) and Mexico (4.9%).[3]

Exports to IEA Europe were around 46.5 Mt in 2013, which is 12% lower than 53 Mt in 2012. Exports to European countries were growing in the three years up to 2012, with particularly strong growth in markets in Austria, Germany, Italy, Turkey and the United Kingdom. Exports to China and India also nearly doubled during 2012, contracting slightly during 2013.

In 2011, coal exports contributed an estimated 141 300 jobs to the economy, and 394 000 jobs in the mining sector. While most economic activity is concentrated in states that produce coal for export or ship coal abroad from their ports, coal exports also contribute to economies in other states through trade with suppliers of machinery and operating inputs. (NMA, 2013)

The United States imported 7.8 Mt of hard coal during 2013, from Colombia (76.8%), Canada (11.7%), Indonesia (7.8%), and others. Lignite is generally uneconomical to transport and trade volumes are very low. During 2013, net imports of lignite were 0.1 Mt.

OUTLOOK

The outlook for the coal sector is uncertain and is strongly linked to the implementation of new policies in relation to coal use as well as the market price for natural gas, which influences not only domestic coal use but volumes available for export to other markets, most notably Europe.

In its *Annual Energy Outlook 2014* Reference Case (*AEO 2014*), the Energy Information Administration (EIA) projected that low natural gas prices will continue to make coal an attractive fuel for new generating capacity, and in some regions, natural gas-fired generation will replace capacity formerly supplied by coal and nuclear plants. Coal-fired electricity generation has traditionally been the largest component of electricity generation in the United States, but by 2035, however, EIA projects that natural gas will start to surpass coal-fired generation. Coal and natural gas each represent 34% of total generation in 2035, but by 2040 the coal share drops to 32%, and the natural gas share increases to 35% (EIA, 2014).

After 2016, EIA projects coal-fired electricity generation will increase slowly for a decade, as remaining coal-fired capacity is used more intensively, but little capacity is added. Coal production is projected to grow at an average rate of 0.3% per year in the *AEO 2014* Reference Case, from 1 016 MMst in 2012 to 1 121 MMst in 2040.

While electricity generation accounted for 91% of total coal consumption (in Btu) in 2012, coal production declined by more than 7% in 2012, from 1 096 million short tons (MMst) in 2011, mostly in response to gas-on-coal competition. In the *AEO 2014* Reference Case, production recovers to 1 062 MMst by 2015, in response to a rise in natural gas prices along with a moderate increase in electricity demand. A wave of coal-fired generating capacity retirements in response to mercury and air toxics standards MATS requirements coincides with a secondary drop in coal production to 1 022 MMst in 2016.

3. The Netherlands is a major trans-shipment point for coal exports, ultimately being distributed throughout Europe from there. Many exporters simply report the Netherlands on their census forms, but the Netherlands consumes much less coal.

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Market concerns about GHG emissions continue to dampen the expansion of coal-fired capacity in the *AEO 2014* Reference Case, even with the assumption of current laws and policies. Low fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. As retirements far outpace new additions, total coal-fired generating capacity falls from 310 GW in 2012 to 262 GW in 2040 in the *AEO 2014* Reference Case. As with all projections, projected generation shares are highly sensitive to both fuel prices and changes in policies and regulations. Alternative cases in the full *AEO 2014* will quantify these sensitivities.

COAL TRANSPORTATION

In the United States, the vast bulk of coal (70% in 2012) is transported by rail, followed by barges (12%), road transport (11%) and tramways, conveyer belts or slurry pipelines (7%). The share of coal moved by rail has increased over the last 20 years largely because of the growth of Western coal that often moves long distances by train (EIA, 2013).

Most coal in the United States is consumed at coal-fired power plants and more than 70% of the coal delivered to those plants is delivered by rail. In 2012, in the rail transportation sector, coal accounted for 41% of all tonnage and 21.6% of gross revenue. The coal industry accounts for approximately one in five freight railroad jobs. Most coal transported by rail moves in highly productive unit trains, which generally follow direct shipping routes, and have lower costs per unit shipped than non-unit trains. Coal dominates rail traffic in major coal-producing states, for example in Kentucky, West Virginia and Wyoming, accounting for between 85% and 95% of total originated rail tonnage in 2011 (Association of American Railroads, 2013). Over the long term, transportation demand will grow and new rail capacity will be needed. Adequate investments can only be made if rail earnings are robust enough to attract the capital needed to pay for these investments (Association of American Railroads, 2014).

In 2011, port and cargo-handling activity related to coal exports employed 5 400 workers while shipments of coal for export comprised 16% of the total vessel weight of all exported goods passing through United States' ports (compared to 12% in 2007). Export activity was highest in Virginia, which accounted for 38% of coal export shipments and 22% of port operations and cargo-handling employment related to coal export shipments (USCB, 2013). Exports of coal from the Power River basin are limited by port capacity constraints on the West coast. There are two terminals in California and those in Canada are operating at full capacity. Plans for new capacity at the Millennium Bulk Terminals and Gateway Pacific Terminal in the State of Washington have been delayed for a number of years because of environmental and regulatory concerns. Similar problems have also delayed the development of the Coyote Island Terminal, which was to be constructed at the Port of Morrow in Oregon.

INDUSTRY STUCTURE

At present, high costs and ample supply capacity are driving consolidation and restructuring of mining industries in many countries. The United States experienced a wave of consolidation starting in 2012 with large-scale production cuts and mine closures, mainly in the Appalachian basins. However, since international coal prices dropped below USD 80/tonne for all key exporters in the summer of 2013, other countries have been affected as well. Australian

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and Canadian companies have reduced their workforce, idled unprofitable mines and revised or delayed investment in new mines and infrastructure (IEA, 2013).

The number of active mines in the United States stood at 1 229 in 2012, of which 1 126 were located east of the Mississippi River. A further 22 mines were working on collecting coal from refuse. Production from mines located west of the Mississippi accounted for 58% of total production in the same year, and east of the Mississippi for 42%. The 16 opencast mines in the Powder River basin alone accounted for 41% of coal production in 2012. Most United States' coal is produced in opencast mines, which accounted for 66% of total production in 2012. The largest 50 mines produced almost two-thirds of all coal produced and four mines in Wyoming alone accounted for 27% of output.

Four mining companies, Peabody Energy Corp., Arch Coal Inc., Alpha Natural Resources, and Cloud Peak Energy together accounted for 51.6% of total coal production or 479 Mt in 2012 while more than 500 other companies supplied 44.8%. By way of comparison, the fifth-largest coal producer in 2012, CONSOL Energy Company, contributed 40 Mt less than Cloud Peak Energy that holds the fourth-place and that produced 90.7 Mt. The large share of production held by the top four producers maintains a trend that began in the 1990s with the continued expansion of mining in the Powder River basin and with the divestment of coal properties by oil and gas companies.

The Department of Justice uses the Herfindahl-Hirschman Index (HHI) in guidelines for evaluating mergers: an HHI of less than 1 000 represents a relatively unconcentrated market while an HHI between 1 000 and 1 800 represents a moderately concentrated market. Markets having an HHI greater than 1 800 are considered to be highly concentrated. In the case of the coal-mining sector, the HHI of the 50 largest coal producers, based in EIA data, is approximately 818, suggesting that the industry is relatively unconcentrated.

Peabody is the world's largest privately owned coal producer and has been the largest producer in the United States for decades. It owns mines in the Western region, including the largest mine in the United States, the North Antelope Rochelle mine in the Powder River Basin, and Midwestern basins as well as mines abroad, most notably in Australia. Although most of this growth comes from its large, low-sulphur and highly productive surface mines of the Powder River basin, Peabody also owns mines in Arizona, New Mexico, Colorado, and states in the interior region. The second-largest producer, Arch Coal, operates mines in Wyoming, Colorado, Illinois, West Virginia, Kentucky, Virginia and Maryland. The company operates the Black Thunder mine in the Powder River basin in Wyoming, the second-largest mine in the United States.

Since 2007, the industry has seen several large-scale mergers and acquisitions in the coal-mining sector: in 2009, Foundation Coal Holdings (fourth-largest producer in 2008) merged with Alpha Natural Resources. This was followed in 2011 by the purchase of Massey Energy, the largest coal company in the Central Appalachian region, by Alpha Natural Resources for an estimated USD 7.1 billion.

In 2009, Rio Tinto Energy of America, the second-largest producer in 2008 divested itself of the Jacobs Ranch mine in Wyoming, selling it to Arch Coal. This purchase allowed Arch Coal, an eastern and western coal producer, to strengthen its second-place position in 2009. Cloud Peak Energy, exclusively a Powder River basin coal company, formed as a corporate spin-off from Rio Tinto Energy of America in 2009 and became a top-four producer where it has remained since.

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GOVERNMENT POLICY AND ENVIRONMENTAL REGULATION

The federal government is committed to developing clean coal technologies. With USD 3.4 billion in Recovery Act funding, the federal government investing in the development of carbon capture and storage (CCS) technologies. In addition, the federal government has convened an Interagency Task Force on Carbon Capture and Storage to identify ways to overcome barriers to widespread, cost-effective deployment of CCS technology within ten years.

Environmental regulations, rather than imposing strict legislation which is more difficult to pass in the current political climate, are likely to have a major impact on the coal and coal-fired power sector. In 2011, the federal government proposed a number of emissions regulations by the Environmental Protection Agency to significantly reduce coal use. Various studies indicate that the new EPA rules would result in a 60 GW to 75 GW reduction in domestic coal generating capacity and substantially reduce the likelihood of building new coal-based electricity generation capacity. EPA's estimation of lost coal generating capacity is considerably lower.

THE ROLE OF THE US DEPARTMENT OF THE INTERIOR

The Bureau of Land Management (BLM) manages large amounts of public lands and oversees federal onshore oil, gas and coal operations. It manages more federal land than any other agency – about 245 million surface acres as well as 700 million sub-surface acres of mineral estate. The Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act for Acquired Lands of 1947, as amended, gave BLM responsibility for coal leasing on approximately 570 million acres where the coal mineral estate is owned by the federal government. The BLM works to ensure that the development of coal resources is done in an environmentally sound manner and is in the best interests of the population. Public lands are available for coal leasing only after the lands have been evaluated through the BLM's multiple-use planning process. The Federal Coal Leasing Amendments Act of 1976 (FCLAA), which amended Section 2 of the Mineral Leasing Act of 1920, requires that all public lands available for coal leasing be leased competitively.

The Office of Surface Mining Reclamation and Enforcement (OSMRE) is a bureau within the DOI. OSMRE is responsible for establishing a nationwide programme to protect society and the environment from the adverse effects of surface coal-mining operations, under which OSMRE is charged with balancing the need for continued domestic coal production with protection of the environment. Its headquarters are located in Washington, D.C. It has three regional offices, the Appalachian, Mid-Continent and Western Regional Offices. The Regional Offices are composed of Area and Field Offices.

It mission is to carry out the requirements of the Surface Mining Control and Reclamation Act (SMCRA) in co-operation with states and tribes. Its primary objectives are to ensure that coal mines are operated in a manner that protects citizens and the environment during mining, and that the land is restored to beneficial use following mining, and to mitigate the effects of past mining by aggressively pursuing reclamation of abandoned coal mines.

Reclaiming abandoned mine lands

The Abandoned Mine Land Reclamation Program (AML) is OSMRE's largest programme and one of its primary responsibilities under SMCRA. Since SMCRA's enactment in 1977, the AML Program has collected over USD 10.1 billion in fees from present-day coal production and distributed more than USD 7.6 billion in grants to states and tribes,

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mandatory distributions to the United Mine Workers of America (UMWA) and OSMRE's operation of the national programme to reclaim land and waters damaged by coal mining before the law's passage.

In the early years, the AML programme focused on the physical reclamation of hazards affecting coalfield communities. More recently, the programme began working to reclaim the vitality of communities left impoverished and degraded by past coal mining.

MERCURY AND AIR TOXICS STANDARDS

In 2011, the Environmental Protection Agency (EPA) introduced two milestone environmental regulations aimed at reducing air pollution from the power generation sector. The Cross-State Air Pollution Rule (CSAPR) proposed to reduce sulphur dioxide (SO_2) and nitrogen oxide (NO_x) emissions while the Mercury and Air Toxics Standards (MATS) is intended to reduce the emissions of hazardous air pollutants, such as mercury and acid gases, from coal- and oil-fired power plants. While the CSAPR was dismissed at Court of Appeals for the District of Columbia Circuit following a legal challenge, MATS received a Consent Decree, which required EPA to issue a proposal by 16 March 2011, and a final rule on 16 December 2011. In April 2014, the District of Columbia Circuit Court upheld the MATS rule, allowing EPA to take into account environmental damages as well as health impacts when deciding to regulate the pollutants.

The MATS rule limits toxic emissions such as mercury, heavy metal, hydrochloric acid and other pollutants from coal- and oil-fired power plants larger than 25 MW. Existing sources of pollution are allowed up to four years to comply, with a one-year extension if needed.

Opponents of MATS argued that the new rule would reduce the reliability of the electricity system, lead to more volatile electricity prices and result in unnecessary plant closures. The American Coalition for Clean Coal Electricity (ACCCE) argued in 2012 that the introduction of stricter environmental regulation would result in the shutdown of 31 GW of coal-fired capacity by 2015 and the subsequent loss of between 13 000 and 17 000 jobs in the coal-mining industry (ACCCE, 2012).

CLEAN POWER PLAN

In June 2014, the EPA proposed the Clean Power Plan to cut carbon pollution from existing power plants. The EPA has proposed state-specific, rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. This rule, as proposed, builds on existing measures to reduce CO_2 emissions from fossil fuel-fired power plants. The proposed rule provides states with considerable flexibility for meeting the state-specific goals established in a manner that accommodates a diverse range of approaches. Notably, while the proposal lays out state-specific CO_2 reductions, it does not prescribe how a state should achieve its goal. The new EPA rules, which are under public consultation during 2014, must be finalised by June 2015 and in place by 30 June 2016.

CARBON POLLUTION STANDARD FOR NEW POWER PLANTS UNDER THE CLEAN AIR ACT

The Clean Air Act requires the EPA to establish national ambient air quality standards for certain common and widespread pollutants on the basis of the latest science. EPA has established air quality standards for six common "criteria pollutants": particulate matter (also known as particle pollution), ozone, sulphur dioxide, nitrogen dioxide, carbon monoxide, and lead (EIA, 2013).

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On 20 September 2013, the EPA announced its first element of President Obama's Climate Action Plan, a proposal to limit greenhouse gas (GHG) emissions from new power plants. The proposed carbon pollution standard for new power plants replaced an earlier proposal published by the EPA in March 2012. In accordance with the Clean Air Act, the new proposal will establish new source performance standards (NSPS) to limit CO_2 emissions from coal- and natural gas-fired power plants.

Rather than specify a technology, the NSPS generally establish a numerical emission limitation and allow industry to comply by using any method that achieves the required performance level. EPA is required to set standards that reflect the level of emission performance achievable through the best system of emissions reduction, considering cost and other factors, which have been adequately demonstrated. Updating of standards is required at least every eight years (EPA, 2013).

The proposed rules establish separate standards for gas-fired and coal-fired power plants. New gas-fired plants, with a capacity greater than 100 MW, can emit no more than 1 000 pounds (lb) of CO_2 per MWh (or 455 grammes of CO_2 per kWh) of electricity produced, a standard achievable with contemporary combined-cycle technology. Smaller, less efficient, plants have to meet a less strenuous standard of 1 100 lbs of CO_2 per MWh (or 500 grammes of CO_2 per kWh).

Coal-fired plants have two compliance options, both of which require the use of CCS technology. The first requires the generator to achieve a twelve-month average emission rate of 1 100 lb/MWh. The alternative requires the generator to begin using CCS within seven years of start-up and meet a seven-year average emission rate of between 1 000 lb/MWh and 1 050 lb/MWh.

Despite the perceived stringency of the proposed regulations, the impact will be very limited before 2022. Few new coal-fired plants are planned, even in the absence of new standards, as a result of the availability of cheap natural gas. The EIA forecasts that only 2.9 GW of incremental coal-fired capacity (11 units) will be added in the period between 2013 and 2017. Over the same period, 34 GW of gas-fired capacity will be added (242 units).

The second part of the President's Climate Action Plan directs EPA to address emissions from existing power sources in addition to new sources. In June of 2014, EPA issued a proposal for reducing carbon emissions from existing power sources. Under the NSPS, standards are set for new facilities and for modifications that increase the emission rate of existing facilities. The existing source performance standard (ESPS) defines the best system of emissions reductions as a method that can reduce CO_2 from the entire power sector.

In the proposal, EPA developed individual state targets that must be met in 2030. The method of calculation relies on four approaches to reducing emissions: improving the heat rate at existing coal-fired units; utilising existing capacity of natural gas in lieu of coal-fired generation; adding more renewable resources; and end-use efficiency. Although EPA has calculated the emission rate that states must meet, the rule allows states to use any available methods in developing their state plans. Under this proposal, state implementation plans are due in 2016; multi-state plans are due in 2017; and emissions reductions will gradually occur between 2020 and 2030.

CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS), is a family of technologies and techniques that enable the capture of CO_2 from fuel combustion or industrial processes, the transport of CO_2 via

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ships or pipelines, and its storage underground in depleted oil and gas fields and deep saline formations. CCS can therefore have a unique and vital role to play in the transition to a sustainable low-carbon economy, in both power generation and industry. The IEA considers CCS a crucial part of efforts to limit global warming by reducing GHG emissions.

According to the Department of Energy (DOE), the United States has at least 2 400 billion metric tonnes of possible CO_2 storage resource in saline formations, oil and gas reservoirs, and un-minable coal seams (DOE, 2012). There are 19 large-scale CCS projects in operation or in various stages of development, the greatest number for any country or region, and in CCS-related research, development and demonstration (RD&D). Major RD&D activities include the creation and maintenance of seven Regional Carbon Sequestration Partnerships and ongoing financial support for eight demonstration projects under the DOE programmes. Nevertheless, the legal and regulatory landscape for CCS in the United States remains unclear. A federal regulatory scheme for permitting underground storage facilities is in place, but gaps remain in areas such as pore space ownership, long-term liability and long-term stewardship – some of which have been addressed by individual states. Although CCS has not been identified as a requirement, CCS can be used as a compliance mechanism under the EPA's proposed regulation for existing fossil facilities, and all new coal-fired power plants will require some measure of CCS. In the absence of a national programme establishing a carbon price or other incentives to encourage CCS investment, the prospects for additional large-scale projects in the power and industrial sectors are uncertain. Potential revenue derived from carbon capture, use and storage (CCUS), and in particular CO_2 enhanced oil recovery, is being viewed as a possible pathway to build a business case for CCS and maintain US progress (GCCSI, 2014).

In February 2010, 14 Executive departments and Federal agencies established an Interagency Task Force on CCS. On 12 August 2010, the Task Force delivered a series of recommendations on overcoming the barriers to the widespread, cost-effective deployment of CCS within ten years. The report concludes that CCS can play an important role in domestic GHG emissions reductions while preserving the option of using abundant domestic energy resources. Widespread, cost-effective deployment of CCS, however, will occur only if the technology is commercially available at economically competitive prices and if supportive national policy frameworks are in place (DOE, 2013).

THE CARBON CAPTURE PROGRAM

DOE's Carbon Capture Program, administered by the Office of Fossil Energy and the National Energy Technology Laboratory, is conducting research and development (R&D) activities on second-generation and transformational carbon capture technologies that have the potential to provide step-change reductions in both cost and energy penalty as compared to currently available first-generation technologies.

The Carbon Capture Program consists of two core research technology areas: Post-Combustion Capture and Pre-Combustion Capture. Post-combustion capture is primarily applicable to fossil fuel-based systems such as conventional pulverised coal-fired power plants, where the fuel is burned with air in a boiler to produce steam that drives a turbine/generator to produce electricity. The CO_2 is captured from the flue gas after fuel combustion.

Pre-combustion capture is applicable to integrated gasification combined-cycle (IGCC) power plants, where solid fuel is converted into gaseous components (syngas) by applying heat under pressure in the presence of steam and oxygen. In this case, the carbon is captured from the syngas before completing the combustion process. In addition, the

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programme is starting to consider the use of carbon capture technologies to natural gas-fired power plants and industrial processes that utilise fossil energy for manufacturing fuels and chemicals.

DOE is focused on supporting R&D of novel technology solutions that address the three major issues with existing commercial CO_2 capture technology:

- reducing the impact of CO_2 capture on power generating capacity
- scaling up novel CO_2 capture technologies to the necessary size for full-scale deployment at fossil energy power systems
- improving the cost-effectiveness of novel technologies for CO_2 capture so that fossil-based systems with carbon capture are cost-competitive.

The core RD&D projects being pursued by the programme leverage public and private partnerships to support the goal of broad, cost-effective carbon capture deployment. The Office of Fossil Energy (OFE) is targeting demonstration of second-generation technologies that result in a captured cost of CO_2 less than USD 40 per tonne in the 2020-25 timeframe. The OFE is also committed to extending R&D support to even more advanced transformational carbon capture technologies that will further increase competitiveness of fossil-based energy systems beyond 2035.

Regional Carbon Sequestration Partnerships

DOE has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to help develop the technology, infrastructure, and regulations to implement large-scale CO_2 storage in different regions and geological formations across North America (McCoy, 2014). The RCSPs are public/private partnerships comprised of more than 400 organisations covering 43 states and four Canadian provinces. The RCSPs include representatives from state and local agencies, regional universities, national laboratories, non-governmental organisations, foreign government agencies, engineering and research firms, electric utilities, oil and gas companies, and other industrial partners. The RCSP Initiative established the foundation that is being further enhanced by additional small- and large-scale projects, addressing specific applied research on injectivity, capacity verification, and safe geological storage practices necessary to progress towards commercialisation of the technology.

The development phase builds on the findings generated during the characterisation and validation phases. The development phase involves the injection of 1.0 million metric tonnes or more of CO_2 by each RCSP into regionally significant geological formations of different depositional environments. These large-volume injection tests are designed to demonstrate that CO_2 storage sites have the potential to store regional CO_2 emissions safely, permanently and economically for hundreds of years.

In co-ordination with the EPA, two Partnership projects on large-volume injection are applying for Class VI permits in accordance with EPA regulations:

- Illinois Basin – Decatur Project: to date, the project has injected more than 500 000 tonnes into a saline formation located at the Archer Daniels Midland facility in Decatur, Illinois. This project will use enhanced measurement and verification.
- Big Sky RCSP – Kevin Dome Project: Kevin Dome is completing the characterisation phase, and plans to begin injection in 2015. Its current work includes project permitting,

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A 3-D seismic survey, environmental monitoring and site analysis, and geological modelling and analysis to support the issuance of a Class VI injection well permit for geological storage.

CCS from industrial sources

The DOE has allocated funding under the American Recovery and Reinvestment Act (Recovery Act) to more than 25 projects that capture and sequester CO_2 emissions from industrial sources. Three of these projects are aimed at testing large-scale industrial CCS. The projects, located in Texas, Illinois and Louisiana, were first selected for funding in October 2009 as part of a USD 1.4 billion effort to capture CO_2 from industrial sources for storage or beneficial use. The first phase of R&D included USD 21.6 million in Recovery Act funding and USD 22.5 million in private funding for a total initial investment of USD 44.1 million. The three selected projects have entered a second phase for design, construction and operation. This second phase includes USD 684 million in Recovery Act funding and USD 386 million in private-sector cost-sharing for a total investment of USD 1 070 million.

International collaboration and engagement

The United States is actively engaged in a number of international CCS efforts and international demonstration projects, including the Carbon Sequestration Leadership Forum (CSLF), the US China Clean Energy Research Center (CERC), and the North American Carbon Storage Atlas Partnership (NACAP). The DOE is active in projects elsewhere, including the Weyburn-Midale project in Canada, the Sleipner project in the North Sea, and the Otway Basin project in Australia.

CLEAN COAL PROGRAMMES

CLEAN COAL POWER INITIATIVE

With coal likely to remain one of the United States' lowest-cost electric power sources for the foreseeable future, the federal government has pledged to support more advanced clean coal technologies. Accordingly, the Clean Coal Power Initiative (CCPI) is a DOE programme that seeks to accelerate the commercial deployment of advanced coal technologies.

The CCPI provides federal government co-financing for new coal technologies which can help utilities cut emissions of sulphur, nitrogen and mercury pollutants from power plants. Furthermore, some of the early projects are showing ways to reduce GHG emissions by boosting the efficiency by which coal plants convert coal to electricity or other energy forms. Earlier rounds of the CCPI in 2003 and 2004 resulted in the delivery of four plants with a further one expected to be completed during 2014.

In 2009 and 2010, six projects were selected from third-round CCPI solicitations. These projects utilise carbon sequestration technologies and/or beneficial reuse of carbon dioxide. As a result of the addition of USD 800 million of funding to the CCPI Program through the 2009 Recovery Act, round three was conducted through two separate solicitations. Of the six overall projects selected, three projects from round three are still active. These are:

Summit Texas Clean Energy (Texas Clean Energy Project or TCEP) will integrate Siemens gasification and power generating technology with carbon capture technologies to effectively capture 90% of the CO_2 (approximately 2.6 million metric tonnes per year) at a 400 MW

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integrated gasification combined-cycle poly-generation plant to be built near Midland-Odessa, Texas. Approximately 2.0 Mt of the captured CO_2 will be treated, compressed and then transported by CO_2 pipeline to oilfields in the Permian basin of West Texas, for use in enhanced oil recovery (EOR) operations. The remaining CO_2 will be used for the production of urea. The Bureau of Economic Geology (BEG) at the University of Texas will design and assure compliance with a state-of-the-art CO_2 sequestration monitoring, verification and accounting programme. The DOE share of the project is USD 450 million.

The Hydrogen Energy California Project, which is owned by SCS Energy, plans to design, construct and operate an IGCC poly-generation power plant, located in Kern County, California, that will take blends of coal and petroleum coke and convert them into hydrogen and CO_2. The CO_2 will be separated from the hydrogen using the methanol-based Rectisol process. The hydrogen gas will be used to fuel the combined-cycle unit for power generation as well produce ammonia for subsequent conversion to urea and urea ammonium nitrate (UAN). The project will capture more than 3.0 Mt per year of CO_2 of which approximately 2.6 Mt will be used for EOR while the remainder will be used to produce urea. The CO_2 will be transported by pipeline to nearby oil reservoirs where it will be injected for storage and used for enhanced oil recovery. The DOE share of this project is USD 408 million.

NRG Energy's Post-Combustion Carbon Capture Demonstration Project involves the construction of a 240 MW carbon capture demonstration facility at the company's Parish Unit Eight in Thompsons, Texas. The project will demonstrate the innovative integration of the KM-CDR advanced amine carbon capture technology, developed jointly by Mitsubishi Heavy Industries and the Kansai Electric Power Co., and a highly efficient co-generation unit to provide the necessary steam and electricity for the carbon capture plant while not de-rating the base power plant. The captured CO_2 will be used for enhanced oil recovery at the West Ranch Oilfield, a field jointly owned by Petra Nova Parish Holdings (a joint venture between NRG Energy and JX Nippon Oil & Gas Exploration Corp.) and Hilcorp Energy Company, located about 80 miles from the Parish plant. The project will show that post-combustion carbon capture applied to existing plants can be done economically, especially when the plant has the opportunity to sequester carbon dioxide in nearby oilfields. The DOE share of the project is USD 167 million.

Southern Company's Kemper County IGCC Project is a lignite-fuelled two-on-one IGCC facility incorporating the air-blown transport integrated gasification (TRIG) technology which is being constructed in Kemper County, Mississippi. The plant is owned by Mississippi Power Company (MPC), a subsidiary of Southern Company, and will produce 582 MW of electricity at peak power production. Over 65% of the carbon dioxide (over 3.0 Mt per year) will be captured and used for enhanced oil recovery in Mississippi oilfields, making the Kemper facility's carbon emissions comparable to those of a natural gas-fired combined-cycle power plant. In addition to carbon dioxide, the plant will also produce ammonia and sulphuric acid as by-products. The Kemper County project team is currently completing the last phase of construction and initiating start-up/commissioning activities of the various units/subsystems. The commercial operation date is scheduled for May 2015. The DOE share of the project is USD 270 million.

FUTUREGEN 2.0

FutureGen 2.0 involves the repowering of an existing fossil-fuelled power plant with advanced oxy-combustion technology coupled with the capture, compression, pipeline transport, injection, and permanent geological storage of 90% or more of the CO_2 that

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otherwise would have been emitted into the atmosphere. The objective of the project is to demonstrate the full-scale integration of a base-load power plant with the entire carbon capture, transport and storage chain as it would be realised in a commercial power plant. Using oxy-combustion technology provided by the Babcock & Wilcox Company, the FutureGen Industrial Alliance, Inc. will construct and operate a 170 MW oxy-coal-fired boiler at the Meredosia Energy Center in western Illinois. Carbon dioxide will be captured from the flue gas using an innovative CO_2 purification unit developed by Air Liquide that will capture the CO_2 in the flue gas stream at an approximate rate of 1.0 Mt per year. The captured CO_2 will then be compressed and transported through a 30-mile pipeline and injected nearly a mile underground into the Mt. Simon Sandstone formation. The DOE share of the project is USD 1 054 million.

ASSESSMENT

The coal industry is undergoing a period of profound change driven by a number of factors such as the boom in domestic natural gas production, higher demand for hard coal in Asia and tougher domestic environmental regulations. Over the same period, coal production has remained relatively flat although there have been large changes in the nature of the coal produced and the location at which it is mined. Furthermore, exports have increased significantly, notably to Asia.

The bulk of metallurgical coal exports to Asia in 2012 was exported from eastern ports and the Gulf of Mexico. Conversely, exports of steam coal to Asia were exported from ports on the West Coast and the Gulf of Mexico although exports of steam coal to Europe have increased. In the past few years, steam coal exports exiting through the Pacific Northwest, a key outlet for low-sulphur Powder River basin coal, have been primarily destined for markets in Asia. If these trends are to continue, large investments are needed in mining capacity in the Power River basin coupled with investments in rail transport infrastructure, and ports, many of which are owned by federal agencies, on the West Coast.

The impact of the domestic shale gas boom has resulted in significant changes to the production of electricity. In 2005, coal-fired power plants accounted for 49.6% of electricity production, and by 2013, this had fallen to 40.2% while the share of natural gas in the electricity mix increased to 29.6% from 18.8% over the same period. This shift in electricity generation has also had an impact on CO_2 emissions from the power sector, which have declined by 10% since 2005. The coal-fired power fleet, which accounted for 32% of all CO_2 emissions in 2010, is the second-largest GHG emitting source in the United States, after the transport sector, and this is likely to continue to be the case for some time despite recent trends emerging from the electricity sector. The Blueprint for a Secure Energy Future, President Obama's long-term energy strategy, contains a target to reduce GHG emissions by 17% by 2020 and 83% by 2050 relative to 2005 levels; significant reductions will be required in the coal-fired sector in order to meet this objective.

Uncertainty regarding EPA regulations and their implementation, alongside low natural gas prices, present the coal industry with financial and technological challenges. The gradual shift from coal-fired power to natural gas has not resulted in any constraints in the electricity system but this may not be the case in the future, as some regions experience large-scale decommissioning of coal-fired capacity and uncertainty over new investments. Mercury and air toxics standards, new source performance standards and, eventually, existing source performance standards, which will establish CO_2 emission

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standards for certain new and existing fossil fuel-fired electricity-generating units are already having an impact on the sector: 5.4 GW of coal-fired power plant retirements have been announced since November 2013. Conversely, only 11% of new capacity additions in 2013 were coal-fired, a 937 MW conventional steam coal plant in Texas and a 571 MW integrated gasification combined-cycle plant in Indiana.

The average coal-fired power plant emits around 1 000 gCO_2 per kWh. Therefore, it can be argued that the new rules effectively ban the construction of new coal-fired power plants. Even the newest, most efficient, supercritical power plant will emit 800 to 880 gCO_2 per kWh (IEA, 2012). Conversely, the EPA argues that the proposed standards will ensure that new power plants are built with the best available clean technology to limit carbon emissions, a requirement that is in line with investments in clean energy technologies that are already being made in the power industry and supported by DOE-funded R&D programmes.

The cumulative impact of new environmental standards is likely to be the retirement of a significant amount of coal capacity. Natural gas is expected to become a larger percentage of the energy mix while the remaining coal-based generating capacity is expected to operate at a much higher utilisation rate with efficiencies resulting from the retirement of older, smaller and less efficient plants. This is expected to offset some retired coal capacity. Estimates of the amount of coal capacity likely to be retired vary between sources. EIA plant owner and operator survey respondents have reported that they expect to retire nearly 27 GW of capacity (net summer) from 175 coal-based generators between 2012 and 2016. The National Mining Association analysis estimates that more than 28 GW of coal-fired generation will be retired as a result of EPA regulations that have already been announced. The American Coalition for Clean Coal Electricity estimates that 39 GW or 273 units will be retired. In September 2013, the EPA extended the public comment period on the proposed carbon pollution standards for new power plants to May 2014.

The coal units retired since 2010 are on average 55 years old, with a capacity utilisation factor of less than 30%. The units being retired are generally older, unscrubbed and less efficient with low average heat rates, and the projected revenue from these units does not support the case for regulatory compliance expenditures. Conversely, existing base-load coal units are relatively cost-effective but will instead be subject to forthcoming existing source standards. Nonetheless, it is clear that the future of the coal-fired power generation in the United States remains closely tied to technological advances.

A cornerstone of the federal government's long-term energy strategy is the development of a Clean Energy Standard, which will double the share of electricity from clean energy sources to 80% by 2035. Coal-fired power with CCS is part of this 80%. Accordingly, the federal government has made significant investment in CCS and other clean coal technology and invested in the use of CO_2 for enhanced oil recovery.

The country is rich in CO_2 storage potential in both oil and gas reservoirs and saline formations. In 2013, it had 19 large-scale CCS projects in operation, or at various stages of development, including eight major CCS demonstration projects. The United States is also among the leaders in CCS-related RD&D. Major RD&D activities include the creation and maintenance of seven Regional Carbon Sequestration centres and financial support for demonstration projects. Potential revenue derived from CCS, and in particular CO_2 enhanced oil recovery, is being viewed as a possible mechanism to drive CCS and maintain commercially viable progress.

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Despite this, the legal and regulatory landscape for CCS remains unsettled. While a federal regulatory scheme for permitting underground storage facilities is in place, there are gaps in areas such as pore space ownership and long-term liability, some of which are being addressed by individual states. Without federal action on a carbon price mechanism or other incentives to encourage CCS investment, the outlook for private investment in the coal-fired power sector remains uncertain.

RECOMMENDATIONS

The government of the United States should:

- ☐ *Develop, in conjunction with states, land owners and other stakeholders, a framework for developing transport infrastructure which can support greater market access for coal.*
- ☐ *Continue to support international collaboration and partnerships with other countries on CCS RD&D while maintaining support for research and demonstration activities at home.*
- ☐ *Work with the Environmental Protection Agency to simplify environmental regulations and processes without compromising the intent of the rules.*

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11. ENERGY TECHNOLOGY RESEARCH, DEVELOPMENT AND DEMONSTRATION

Key data (2012)

Government energy R&D spending (2014 estimated): USD 7.0 billion

Share in GDP: 0.46 per 1 000 units of GDP (IEA median*: 0.37)

R&D per capita: USD 19.6 (IEA median*: USD 14)

* Median of 21 IEA member countries for which data are available.

OVERVIEW

The United States government remains the largest funding entity for energy technology research, development and demonstration (RD&D) in the world. Energy RD&D has historically played a critical role in achieving advances in all fields of energy, including nuclear, fossil fuels, renewables, and end-use technologies.

INSTITUTIONAL BACKGROUND

The Department of Energy (DOE) is the lead agency for identifying and promoting advances in fundamental and applied sciences. It supports the translation of cutting-edge inventions into technological innovations and the acceleration of transformational technological advances in energy areas that industry by itself is not likely to undertake because of technical or financial risk. DOE also leads national efforts to develop technologies to modernise the electricity grid, enhance the security and resilience of energy infrastructure, and expedite recovery from energy supply disruptions.

DOE is the largest federal sponsor of basic research in the physical sciences. The DOE Office of Science is the United States' largest source of funding for basic research in the physical sciences. Its research investments in basic sciences and user facilities are considered vital to advancing the US leading position in science and strengthening its national competitiveness. The DOE Office of Science manages its research portfolio through six programme offices:

Advanced Scientific Computing Research which supports research to discover, develop, and deploy computational and networking capabilities to analyse, model, simulate, and predict complex phenomena important to DOE. The National Energy Research Scientific Computing Center (NERSC) is the primary high-performance scientific computing resource for researchers supported by the DOE Office of Science.

Basic Energy Sciences (BES) which supports fundamental research to understand, predict, and ultimately control matter and energy at the electronic, atomic and molecular levels in order to provide the foundations for new energy technologies. The BES programme also supports 46 Energy Frontier Research Centers and two Energy Innovation Hubs.

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Biological and Environmental Research which supports fundamental research focused on three scientific drivers: exploring the frontiers of genome-enabled biology; discovering the physical, chemical and biological drivers and environmental impacts of climate change; and seeking the geological, hydrological and biological determinants of environmental sustainability and stewardship.

Fusion Energy Sciences (FES) which supports research to expand the fundamental understanding of matter at very high temperatures and densities and to build the scientific foundation of fusion energy. Research frontiers for the next decade include *i)* establishing the scientific foundations for obtaining high fusion power in the laboratory, *ii)* extending the duration of fusion conditions through leverage by means of international partnerships and advances in materials science, and *iii)* contributing to the construction of the international thermonuclear experimental reactor (ITER) project so as to enable the study of high fusion power plasmas. A fourth frontier is the exploration of plasma science on a broad front that is important for industry and for answering fundamental questions of nature in the laboratory. In all areas of FES research, high power computing plays a critical role in FES research. FES-sponsored research is supported at ten national labs, 15 private industries, and 65 universities.

High Energy Physics which supports research towards understanding how the universe works at its most fundamental level by discovering the most elementary constituents of matter and energy, probing the interactions among them, and exploring the basic nature of space and time itself.

Nuclear Physics which supports research to discover, explore and understand all forms of nuclear matter, supporting experimental and theoretical research to create, detect and describe the different forms and complexities of nuclear matter that can exist in the universe, including those that are no longer found naturally. Three national scientific-user facilities are supported: the Relativistic Heavy Ion Collider (RHIC) at Brookhaven National Laboratory; the Continuous Electron Beam Accelerator Facility (CEBAF) at Thomas Jefferson National Accelerator Facility; and the Argonne Tandem Linac Accelerator System at Argonne National Laboratory. In addition, the planned Facility for Rare Isotope Beams (FRIB) is scheduled to begin construction at Michigan State University during FY 2014.

The **Office of Science** supports more than 30 national scientific-user facilities, which provide researchers with the tools of modern science, including accelerators, detectors, colliders, supercomputers, light sources and neutron sources, and facilities for studying the nanoworld, the environment and the atmosphere. Today, about 29 000 researchers from academia, industry and government laboratories use these facilities to perform scientific research.

Other offices within DOE also support and fund RD&D activities, among them:

Advanced Research Projects Agency – Energy (ARPA-E), which supports high-impact energy research with real-world applications in areas including power electronics, batteries for electrical energy storage, battery management and sensing, grid networking technology, thermal energy storage, carbon capture technologies, natural gas vehicles, non-photosynthetic biofuels, and rare earth alternatives.

Office of Energy Efficiency and Renewable Energy (EERE), which supports research, development and demonstration (RD&D) by means of partnerships with innovative businesses and research institutions, with the explicit goal of making a wide array of clean energy technologies directly cost-competitive, without subsidies, with conventional energy technologies.

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Office of Electricity Delivery and Energy Reliability, which includes support for smart grid activities, the Electricity Systems Hub, and RD&D related to energy storage, grid resilience and cybersecurity.

The Office of Fossil Energy Research and Development, which leads federal RD&D efforts on advanced carbon capture, and storage (CCS) technologies as well as technological solutions for the prudent and sustainable development of unconventional domestic resources.

The Office for Nuclear Energy, which leads federal efforts in RD&D related to nuclear energy technologies, including generation, safety, waste storage and management, and security technologies.

The universities continue to form an essential link between government and private industry in the development and commercialisation of new energy technologies. Universities foster innovation in numerous ways. These include support for fundamental research, high-level initiative, and regional partnerships. Many universities have established high-level, multidisciplinary initiatives that aim to co-ordinate diverse research efforts and cross-cutting competences to address national and global energy and environmental challenges.

STRATEGIES AND POLICIES

STRATEGIES

In March 2011, President Obama published a Blueprint for a Secure Energy Future (the Blueprint). The Blueprint is a three-part energy strategy, the third part of which stresses the need to innovate the way to a clean energy future and position the United States as a global leader in developing and manufacturing cutting-edge clean energy technologies.

The Blueprint recognises the need to maintain leadership in research and development (R&D). It also notes that R&D activities are critical to the creation of quality jobs and to support the move towards a clean energy economy thereby reducing US reliance on oil. The Blueprint identifies the need for the federal government to lead by example as new technologies emerge and to maintain its leadership in R&D. More specifically, the Blueprint calls for:

- A doubling of funding for the Advanced Research Projects Agency – Energy (ARPA-E) programme in 2012 and a doubling of the number of Energy Innovation Hubs to include new hubs to advance grid technology, critical materials research, and smart grid technology.
- A new Energy Innovation Hub focusing on the development of smart grid materials and systems.
- Doubling investment in energy efficiency technology, increasing investments in renewable technology by over 70%, and continuing key investments in the smart grid, nuclear energy (including small modular reactors), and clean coal technologies.
- Supporting applied R&D that supports innovative manufacturing and technology deployment.

POLICIES

The federal government enables energy technology innovation in a variety of ways, including research funding, partnerships with industry, small business grants, the national laboratory system, and tax and regulatory policies.

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DEPARTMENT OF ENERGY STRATEGIC PLAN 2011-2018

The DOE Strategic Plan 2011-2018 sets out the mission and medium-term goals of the Department. One of these goals is to "advance foundational science, innovate energy technologies, and inform data-driven policies that enhance US economic growth and job creation, energy security, and environmental quality, with emphasis on implementation of the President's Climate Action Plan to mitigate the risks of and enhance resilience against climate change". Accordingly, the DOE works to closely integrate scientific research, applied energy R&D, and commercialisation activities to provide new solutions for a clean energy future in a manner that will enable job creation and economic growth. A key objective of the DOE is to deliver the scientific discoveries and major scientific tools that transform understanding of nature and strengthen the connection between advances in fundamental science and technology innovation. Three strategies to accomplish this objective have been developed:

- Conduct discovery-focused research to increase our understanding of matter, materials and their properties through partnerships with universities, national laboratories, and industry.
- Provide the nation's researchers with world-class scientific-user facilities that enable mission-focused research and advance scientific discovery.
- Use the national laboratory system and leverage partnerships with universities and industry to conduct mission-focused research.

An Agency Priority Goal for FYs 2014 and 2015

Support and conduct basic research to deliver scientific breakthroughs and extend our knowledge of the natural world by capitalising on the capabilities available at the national laboratories, and through partnerships with universities and industry. In support of this goal, DOE will, by the end of FY 2015:

- Incorporate science-user facility prioritisation into programme planning efforts.
- Identify programmatic drivers and technical requirements in co-ordination with other Departmental mission areas to inform future development of high-performance computing capabilities and in anticipation of capable exascale systems.[1]

QUADRENNIAL TECHNOLOGY REVIEW

The purpose of the Quadrennial Technology Review (QTR) is to establish a robust framework for the Department's energy technology activities, including principles it can use to prioritise its technology R&D. The first QTR was published in 2011 to establish a context and robust framework for DOE's energy technology activities, including principles that can be used to establish multi-year programme plans. It also offers high-level views of the technical status and potential of various energy technologies. Multi-year programme plans are needed to allow DOE provide the consistent, predictable support necessary for the success of its RD&D activities. The IEA supports multi-year programme plans but they need to be designed so that there are performance metrics to evaluate whether a programme should continue or end. This should be done to ensure that limited R&D budgets are spent effectively.

1. In computing, Exascale refers to a computer system capable of reaching performance in excess to one exaflop (i.e. 1018 floating point operations per second). Today, most advanced systems are in the petaflop range. A petaflop equals 1015 flops. (Source: Exascale Computing Research Centre).

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BASIC RESEARCH

Together, the research programmes and the scientific-user facilities provide the foundation for targeted investments by the Office of Science in research to advance energy research and its understanding of climate change. These include investments such as the three DOE Bioenergy Research Centers (BRCs); the Energy Frontier Research Centers (EFRCs); two Energy Innovation Hubs in Fuels from Sunlight and Batteries and Energy Storage; and atmospheric process and climate modelling research. Many EFRCs have reported that their fundamental scientific advances are already impacting both technology research and industry.

CO-ORDINATION WITH THE DEPARTMENT OF ENERGY

Co-ordination between DOE R&D programmes is achieved through a variety of activities, including joint participation in research workshops, strategic planning activities, solicitation development, and programme review meetings. For example, the DOE Hub Working Group meets regularly to co-ordinate oversight and to promote commonality across the DOE Energy Innovation Hubs. Basic Energy Sciences (BES) also co-ordinates with DOE technology offices on the Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) programmes, including the topical area planning, solicitations, reviews, and award selections.

BES programme managers regularly participate in intra-departmental meetings for information exchange and co-ordination on solicitations, programme reviews and project selections in the research areas of biofuels derived from biomass; solar energy utilisation; building technologies, including solid-state lighting; advanced nuclear energy systems and advanced fuel cycle technologies; vehicle technologies; improving efficiencies in industrial processes; and superconductivity for grid applications. These activities facilitate co-operation and co-ordination between BES and the DOE technology offices and defence programmes.

DOE programme managers have also established formal technical co-ordination working groups that meet on a regular basis to discuss R&D programmes with wide applications for basic and applied programmes, including the Office of Environmental Management. Furthermore, DOE Technology Office staff participates in reviews of BES research, and BES staff participates in reviews of research funded by the technology offices and the Advanced Research Projects Agency – Energy (ARPA-E).

Co-funding and co-siting of research by BES and DOE technology programmes at the same institutions has proven to be a valuable approach to facilitate close integration of basic and applied research. In these cases, teams of researchers benefit by sharing resources, expertise, and knowledge of research breakthroughs and programme needs. The DOE's national laboratory system plays a particularly important role in this regard.

Fusion Energy Sciences (FES) carries out a discovery-driven plasma science research programme in concert with the National Science Foundation (NSF), with research extending to a wide range of natural phenomena, including the origin of magnetic fields in the universe and the heating of the solar corona. FES also operates a joint programme with the National Nuclear Security Administration (NNSA) in High Energy Density Laboratory Plasma (HEDLP) physics. Both programmes involve co-ordination of solicitations, peer reviews, and workshops. The Fusion Energy Sciences Advisory Committee (FESAC) provides technical and programmatic advice to FES and NNSA for the joint HEDLP programme.

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PROGRAMMES

BIOFUEL RESEARCH CENTERS

To focus the most advanced biotechnology-based resources on the biological challenges of biofuel production, DOE established three Bioenergy Research Centers (BRCs) in September 2007. Each centre is pursuing the basic research underlying a range of high-risk, high-return biological solutions for bioenergy applications. Advances resulting from the BRCs will be used to provide the knowledge needed to develop new bio-based products, methods and tools that the emerging biofuel industry can use.

The scientific rationale for these centres and for other fundamental genomic research critical to the biofuel industry was established at a DOE workshop involving members of the research community. The DOE's BRCs have developed automated, high-throughput analysis pipelines that will accelerate scientific discovery for biology-based biofuel research.

The ultimate goal for the three DOE Bioenergy Research Centers is to better understand the biological mechanisms underlying biofuel production so that those mechanisms can be redesigned, improved and used to develop novel, efficient bioenergy strategies that can be replicated on a mass scale. New strategies and findings emanating from the centres' fundamental research ultimately will benefit all biological investigations and will create the knowledge underlying three grand challenges at the frontiers of biology:

- development of next-generation bioenergy crops
- discovery and design of enzymes and microbes with novel biomass-degrading capabilities
- development of transformational microbe-mediated strategies for biofuel production.

The three centres are:

1. DOE BioEnergy Science Center (BESC) led by DOE's Oak Ridge National Laboratory in Oak Ridge, Tennessee.
2. DOE Great Lakes Bioenergy Research Center (GLBRC) led by the University of Wisconsin in Madison, Wisconsin, in close collaboration with Michigan State University in East Lansing, Michigan.
3. DOE Joint BioEnergy Institute (JBEI) led by DOE's Lawrence Berkeley National Laboratory.

The centres are supported by multidisciplinary teams of top scientists from leading universities, DOE national laboratories, non-profit organisations, and a range of privately owned companies. The three centres are located in geographically distinct areas and use different plants both for laboratory research and for improving feedstock crops.

The complexity of the three biological grand challenges that must be overcome to achieve industrial-scale bioenergy production requires the co-ordinated pursuit of numerous research approaches to ensure timely success. Collectively, the DOE Bioenergy Research Centers provide a portfolio of diverse and complementary scientific strategies that address these challenges on a scale far greater than any effort to date.

ENERGY INNOVATION HUBS

The DOE's Energy Innovation Hubs are integrated research centres that combine basic and applied research with engineering for the purpose of accelerating energy-related

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scientific discovery that addresses critical energy issues. Energy Innovation Hubs are composed of a large, multidisciplinary team of investigators whose research integrate basic research to applied research and focuses on a single critical national energy need. Hubs include a central location for the research and extensive cross-team interactions to accelerate the research and technology development. They are funded as five-year, potentially renewable projects.

The Hubs were first established in 2010 with the creation of the Consortium for Advanced Simulation of Light Water Reactors, which focuses on improving nuclear reactors through computer-based modelling. There are four Hubs that work on everything from advanced research to produce fuels directly from sunlight (the Joint Center for Artificial Photosynthesis) to improving battery technology for transportation and the grid (the Joint Center for Energy Storage Research) to developing solutions for rare earth elements and other materials critical to a growing number of clean energy technologies (the Critical Materials Institute).

Batteries and Energy Storage Hub

Advanced energy storage solutions have become increasingly important to the United States with the expanded deployment of renewable energy sources coupled with growth in the numbers of hybrid and electric vehicles. For the electricity grid, new approaches to electrochemical energy storage can provide enhanced grid stability and enable intermittent renewable energy sources to meet continuous electricity demand. For vehicles, new batteries with improved lifetimes, safety and storage capacities are needed to expand the range of electric vehicles from a single charge while simultaneously decreasing the manufacturing cost and weight. Today's electric power storage approaches suffer from limited energy and power capacities, lower-than-desired rates of charge and discharge, life-cycle limitations, low abuse tolerance, high cost, and decreased performance at high or low temperatures. The Batteries and Energy Storage Hub is focused on understanding the fundamental performance limitations for electrochemical energy storage in order to launch the next generation of energy storage technologies.

The Batteries and Energy Storage Hub will accelerate the development of energy storage solutions that are well beyond current capabilities and approach theoretical limits. This development will be enabled by cross-disciplinary R&D focused on the barriers to transforming electrochemical energy storage, including the exploration of new materials, architectures, chemistries, systems, and novel approaches for transportation and utility-scale storage. Outside the Hub, battery research is typically focused on one particular problem or research challenge and thus lacks the resources and the diverse breadth of talent to consider holistic solutions. The Hub will provide this critical mass directed on research to overcome the current technical limits for electrochemical energy storage to the point that the risk level will be low enough for industry to further develop the innovations discovered by the Hub and deploy these new technologies into the marketplace.

The Hub's goal is to deliver revolutionary research that will result in new technologies and approaches, rather than focusing on a single technology or incremental improvements to current technologies. While advancing the current understanding and underpinning science for energy storage, the Hub will include the development of working bench-top prototype devices that demonstrate radically new approaches for electrochemical storage that are scalable. These should have the potential to be produced at low manufacturing cost from earth-abundant materials and possess greatly improved properties compared to present commercially available energy storage technologies.

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Joint Center for Artificial Photosynthesis

Established in September 2010, the Fuels from Sunlight Hub is designed as a potentially renewable five-year project to bring together a multidisciplinary, multi-investigator, multi-institutional team to create transformative advances in the development of artificial photosynthetic systems that convert sunlight, water, and carbon dioxide into a range of commercially useful fuels. This Hub, the Joint Center for Artificial Photosynthesis (JCAP), is led by the California Institute of Technology (Caltech) in primary partnership with Lawrence Berkeley National Laboratory (LBNL). Other partners include the Stanford Linear Accelerator Center (SLAC), the National Accelerator Laboratory and several University of California institutions. JCAP is composed of internationally renowned scientists and engineers that seek to integrate decades of community effort in light harvesting and conversion, homogeneous and heterogeneous catalysis, interfacing, membrane and meso-scale assembly, and computational modelling and simulation, with more current research efforts using powerful new tools to examine, understand and manipulate matter at the nanoscale. By studying the science of scale-up and benchmarking both components (catalysts) and systems (device prototypes), JCAP seeks to accelerate the transition from laboratory discovery to industrial use.

Fuel from Sunlight Hub

Established in September 2010, the Fuels from Sunlight Hub is designed as a potentially renewable five-year project to bring together a multidisciplinary, multi-investigator, multi-institutional team to create transformative advances in the development of artificial photosynthetic systems that convert sunlight, water, and carbon dioxide into a range of commercially useful fuels.

Critical Materials Institute

The Critical Materials Institute (CMI) focuses on technologies that make better use of materials and eliminate the need for materials that are subject to supply disruptions. The role of the CMI is to assure supply chains of materials critical to clean energy technologies. Led by the Ames Laboratory, Iowa, CMI consists of scientists and engineers at four national laboratories of the Department of Energy, seven universities, and six industrial partners. The DOE's 2011 Critical Materials Strategy reported that supply challenges for five rare earth metals may affect clean energy technology deployment in the coming years. The CMI focuses on these five "critical" rare earths and two "near-critical" materials: dysprosium, terbium, europium, neodymium and yttrium, as well as lithium and tellurium.

INTERNATIONAL FUSION RESEARCH

US researchers participate in experiments at international facilities that leverage US strengths. Such participation enables US researchers to pursue fusion science not accessible in the United States. Examples are collaborations on facilities in China (Experimental Advanced Superconducting Tokamak [EAST]), Korea (Korean Superconducting Tokamak Advanced Research [KSTAR]), the United Kingdom (Joint European Torus), Germany (Wendelstein 7-X), and Japan (Large Helical Device), among others.

ITER

The major international fusion project ITER, currently under construction in Cadarache, France, is designed to be the first magnetic confinement fusion facility to achieve self-

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heated (burning) plasmas. As ITER construction activities continue, careful and efficient management of the US contributions to the international project by the US ITER Project Office (USIPO) at Oak Ridge National Laboratory (ORNL) will be a high priority for fusion energy sciences. The ITER Project is being designed and built by an international consortium consisting of the United States, China, India, Japan, South Korea, the Russian Federation, and the European Union (the host). The United States is committed to the scientific mission of ITER and will work with ITER partners to accomplish this goal, while maintaining a balanced domestic research portfolio. Executing a fusion sciences programme with well-aligned domestic and international components will sustain US international leadership in fusion energy sciences.

The US magnetic fusion research programme in experiment, theory and computation is configured to make strong contributions to ITER's science and to bring a high level of scientific return from it. ITER joins the broader FES research portfolio in elevating plasma sciences for both practical benefit and increased understanding.

NATIONAL LABORATORIES

The Office of Science is also responsible for the oversight of ten of DOE's 17 national laboratories: Ames Laboratory, Argonne National Laboratory, Brookhaven National Laboratory, Fermi National Accelerator Laboratory, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, Princeton Plasma Physics Laboratory, SLAC National Accelerator Laboratory, and Thomas Jefferson National Accelerator Facility. The DOE laboratories complement the roles and capabilities of the nation's academic and industrial research efforts – they collaborate with universities in fundamental and applied research, and they partner with industry in technology development and deployment to aid the transfer of R&D to the marketplace (DOE, 2013). Besides contributing directly to the national research and development effort, the national laboratories play an important role in technology diffusion from government-funded research.

The most commonly used mechanisms for technology transfer include sharing intellectual property rights, co-operative R&D agreements, licensing, user facilities, technical consulting, and personnel exchanges. The Departments of Agriculture and Transportation, and the Environmental Protection Agency also support laboratories that conduct energy-related research relevant to their missions.

The national laboratories address large-scale, complex research and development challenges with a multidisciplinary approach that places an emphasis on translating basic sciences to innovation. Specifically, the national laboratories:

- Conduct high-calibre research in physical, chemical, biological, and computational and information sciences to advance understanding of the world around us.
- Advance US energy independence and leadership in clean energy technologies to ensure the ready availability of clean, reliable and affordable energy.
- Enhance global, national and homeland (domestic) security by ensuring the safety and reliability of the US nuclear deterrent, helping to prevent the proliferation of weapons of mass destruction, and securing the nation's borders.
- Design, build and operate distinctive scientific instrumentation and facilities, and make these resources available to the research community.

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Box 11.1 The Pacific Northwest National Laboratory

Located in Richland, Washington (state), the Pacific Northwest National Laboratory (PNNL) is one among ten national laboratories managed by DOE's Office of Science. Its research role is to strengthen the US foundation for innovation, and helps find solutions not only for DOE, but for the US Department of Homeland Security, the National Nuclear Security Administration, other government agencies, universities and industry.

PNNL provides the facilities, scientific equipment, and scientists and engineers to strengthen US scientific foundations through fundamental research and innovation.

It works to prevent and to counteract terrorism through applied research in information analysis, cybersecurity, and the non-proliferation of weapons of mass destruction.

It supports steps to increase US energy capacity and reduce dependence on imported oil through research of hydrogen and biomass-based fuels, and reduce the effects of energy generation and use on the environment.

Approximately 4 300 staff are employed at PNNL and the Richland campus, which is managed by Battelle, includes the William R. Wiley Environmental Molecular Sciences Laboratory, a DOE Office of Science national scientific-user facility. In addition to the Richland campus, PNNL operates a marine research facility in Sequim, Washington; and satellite offices in Seattle and Tacoma, Washington; Portland, Oregon; and Washington, D.C.

PNNL has recently developed commercial innovations linked to electric vehicle charging stations, airport security, grid control systems and utility planning and forecasting tools.

In 2013, the National Laboratory Policy Council (NLPC) and the National Laboratory Operations Board (NLOB) were created to strengthen the partnership between the DOE and the laboratories. The NLPC provides a forum for laboratory and departmental leadership to improve laboratory strategic direction and programme planning. Early topics addressed by the NLPC are expected to include accessibility of research facilities, support of technology transfer, and an enhanced role for the laboratories in addressing national priorities. The NLOB will focus on complex-wide management issues and is expected to provide input on developing, improving and implementing effective and streamlined management and operations.

Co-ordination between the basic and applied programmes is maintained through activities such as joint planning meetings, technical community workshops, joint research solicitations, and focused “tech teams” in targeted research areas. Joint funding of research activities and facilities at the DOE laboratories and funding mechanisms that encourage broad partnerships are additional means to facilitate greater integration of the basic and applied research communities (DOE, 2014a).

ENERGY FRONTIER RESEARCH CENTERS

OVERVIEW

The Energy Frontier Research Centers (EFRCs), initiated in 2009, bring together teams of investigators to perform energy-relevant, basic research with a scope and complexity beyond that possible in standard single-investigator or small-group awards. These multi-investigator, multidisciplinary centres foster, encourage and accelerate basic research to provide the basis for transformative energy technologies.

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In the first funding award cycle in 2009, there were 46 EFRC awards, 16 funded for a full five-year award term through the American Recovery and Reinvestment Act (ARRA) of 2009 and 30 more funded on a continuing basis through annual appropriations through this sub-programme and the Chemical Sciences, Geosciences and Biosciences sub-programme.

The EFRCs supported in this sub-programme are focused on: the design, discovery, synthesis, and characterisation of novel, solid-state materials that improve the conversion of solar energy and heat into electricity and fuels, and that enhance the conversion of electricity to light; the development of the understanding of the materials and processes required to enable improved electricity storage and to increase materials resistance to corrosion, decay or failure in extreme conditions of temperature, pressure, radiation or chemical exposure; and the exploration of emergent phenomena, such as superconductivity, that can optimise energy flow and boost the efficiency of energy transmission.

A variety of methods are used to regularly assess the ongoing progress of the EFRCs, including annual progress reports, monthly phone calls with the directors, periodic directors' meetings, and onsite visits by programme managers. BES has also conducted two in-person reviews by outside experts. Each EFRC underwent a review of its management structure and approach in the first year of operation (2010) and a mid-term assessment that focused on each EFRC's scientific programme and progress compared to its five-year research goals. Meetings are also organised between EFRC scientific staff to facilitate collaboration and information exchanges. These meetings and directors' meetings provide opportunities for communication between the EFRCs and DOE programmes. Representatives from the DOE technology programmes are invited to these events to discuss the latest advances in scientific understanding from EFRC research. The technology offices also help to ensure, through presentations and individual interactions, that the EFRCs are cognisant of the current problems facing different energy sectors.

A mid-term assessment in 2012 provided a comprehensive peer review of the entire EFRC portfolio. The mid-term assessment found the EFRC programme to be strong and to have a unique role in advancing fundamental science relevant to energy technologies. The centres provide an important bridge between basic research and energy technologies and complement other research activities funded by DOE.

In June 2014, DOE announced the second round of funding for EFRCs and the research supported by this initiative. The USD 100 million funding package will support 32 projects competitively selected from more than 200 proposals. Ten of these projects are new while the rest received renewed funding based on both their achievements to date and the quality of their proposals for future research. Twenty-three of the projects receiving funding are headed by universities, eight are led by DOE's national laboratories and one project is run by a non-profit organisation. The awards ranged from USD 2 million to USD 4 million per year per centre for up to four fiscal years, subject to a progress review in year two. DOE plans to open the EFRC programme to new applications every two years.

MERIT REVIEW PROCESS

DOE's Office of Science headquarters staff assures rigorous external merit review of research proposals, selection of appropriate peer review experts, development of award recommendations informed by peer review, and regular evaluation of research programmes.

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The Office of Science typically manages over 6 000 laboratory, university, non-profit and private industry research awards and receives between 5 000 and 6 000 new and renewal proposals annually, requiring over 15 000 peer reviews.

The Energy Innovation Hubs are reviewed annually. The Biofuel Research Centers were renewed in 2013 for an additional five years after receiving strong reviews at their five-year mark.

FUNDING

On 13 February 2009, in direct response to the economic crisis, US Congress passed the American Recovery and Reinvestment Act of 2009 – commonly referred to as the "stimulus" or the "stimulus package". Of the USD 90 billion funding under the Act, the DOE received USD 35.2 billion (USD 32.7 in contracts and grants; USD 2.5 in 1705 credit subsidy) to support nearly USD 80 billion in clean energy projects of which USD 2.9 billion was invested in RD&D, notably in favour of the Office of Science (USD 1.4 billion) and the Office of Energy Efficiency and Renewable Energy (USD 1.1 billion) programmes.

The federal government continues to recognise its role in fostering scientific and technological breakthroughs, and in the DOE budget for FY 2014, it committed USD 5.1 billion for the Office of Science to support basic research. The budget also included funding for the Advanced Research Projects Agency – Energy (USD 280 million), Energy Efficiency and Renewable Energy (USD 1.9 billion), Electricity Delivery and Energy Reliability activities (USD 147 million), Fossil Energy Research and Development (USD 779 million) and Nuclear Energy (USD 888 million), all of which provide support focusing more on applied research and development. In the DOE 2015 Budget request, the amount was roughly the same.

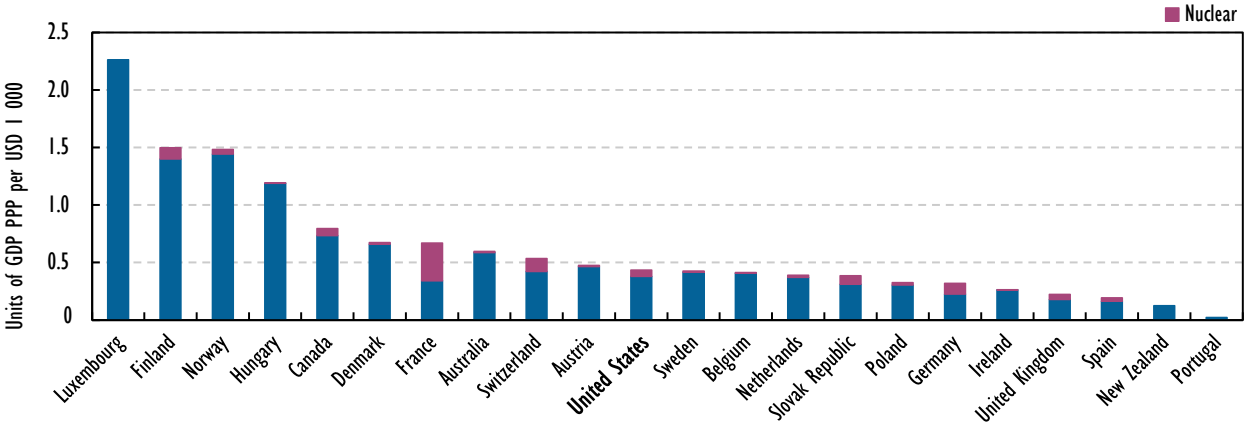
Table 11.1 Department of Energy Science budget, FY 2014 (discretionary USD thousands)

	FY 2012 current	FY 2013 annualised	FY 2014 request	FY 2014 vs. FY 2012	
		CR		USD	%
Advanced Scientific Computing Research	428 304	443 566	465 593	+37 289	+8.7%
Basic Energy Sciences	1 644 767	1 698 424	1 862 411	+217 644	+13.2%
Biological and Environmental Research	592 433	613 287	625 347	+32 914	+5.6%
Fusion Energy Sciences Program	392 957	403 450	458 324	+65 367	+16.6%
High Energy Physics	770 533	795 701	776 521	+5 988	+0.8%
Nuclear Physics	534 642	550 737	569 938	+35 296	+6.6%
Workforce Development for Teachers and Scientist	18 500	18 613	16 500	-2 000	-10.8%
Science Laboratories Infrastructure	111 800	112 485	97 818	-13 982	-12.5%
Safeguards and Security	80 573	81 066	87 000	+6 427	+8.0%
Science Program Direction	185 000	186 132	193 300	+8 300	+4.5%
Small Business Innovation Research (SBIR)	175 471	0	0	-175 471	-100.0%
Total science	**4 934 980**	**4 903 461**	**5 152 752**		

Source: FY 2014 Department of Energy Budget Highlights.

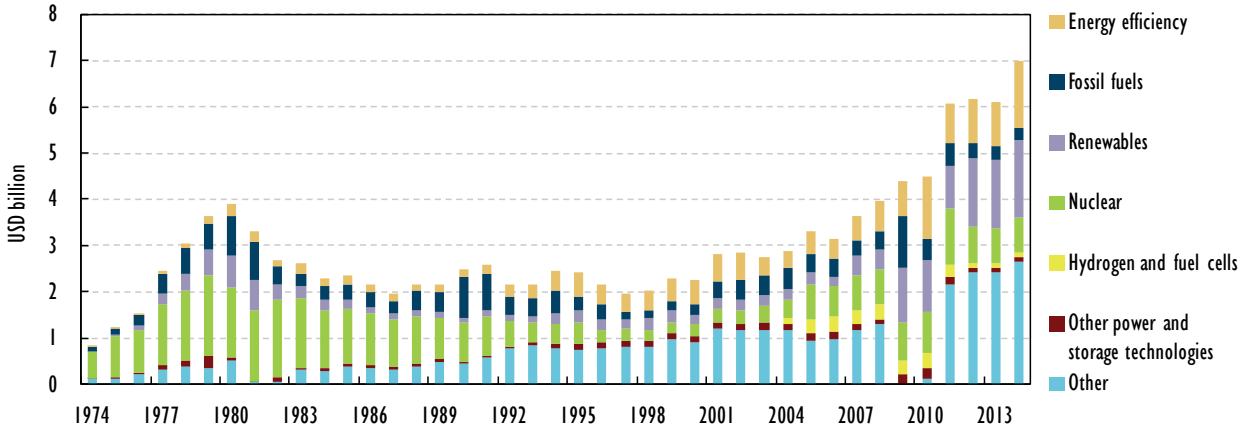
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Figure 11.1 Government spending on energy RD&D as a ratio of GDP in IEA member countries, 2012



Notes: data not available for the Czech Republic, Greece, Italy, Japan, Korea and Turkey.

Figure 11.2 Government RD&D spending on energy, 1974-2014



Note: data are estimated for 2013 and 2014.

INTERNATIONAL CO-OPERATION

The DOE works with a large number of foreign governments and international organisations to promote best practice policies and programmes to accelerate technology innovation and clean energy deployment. Through leadership in the Clean Energy Ministerial and the Energy and Climate Partnership of the Americas, DOE is cultivating an array of co-operative activities with countries that account for the vast majority of the world's energy use. With most of the growth in future energy use expected to occur in developing countries, DOE also supports strong strategic bilateral partnerships with both China and India (DOE, 2011). The United States also participates in 38 IEA Implementing Agreements, more than other IEA member country: in cross-cutting programmes, end-use technologies, fossil fuels, fusion power and renewable energy and hydrogen.

ASSESSMENT

Investments in energy RD&D make a major contribution to achieving national energy goals, including reducing GHG emissions and providing secure and reliable energy. The

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domestic energy innovation infrastructure is well developed and the United States continues to be one of the largest global funders of energy RD&D. The DOE's Strategic Plan provides a path to achieving national energy goals and demonstrates the government's firm commitment to basic research, development, demonstration and deployment of priority clean energy technologies. Establishing performance goals is laudable, such as reducing utility-scale energy storage costs by 30% by 2015 and bringing at least five commercial-scale CCS demonstrations on line by 2016. The government should continue to evaluate and report on the achievement of its targeted outcomes in a clear and transparent way.

The Quadrennial Technology Review is providing the platform to align energy technology and programme priorities to achieve national energy goals and guide the Department's priority-setting over a five-year horizon. The review makes a strong case for focusing on technologies that could be demonstrated on a commercial scale sooner and expected to be adopted by markets, while being cognisant of the contribution of fundamental energy science and research in this regard. The proposed approach to review and adjust programme plans to reflect evolving technology, policy changes and market developments is commendable. However, the effectiveness of the government's energy technology activities could be further strengthened through a framework that facilitates greater co-ordination and synergies across multiple governmental agencies that are involved in the energy sector. This could be an appropriate topic for a broader energy policy review.

The 2009 American Recovery and Reinvestment Act provided an unprecedented opportunity to significantly advance clean energy innovation across the United States economy. The short-term, large-scale funding infusion of more than USD 30 billion has enabled the support of extensive projects in renewable energy, energy efficiency, advanced vehicles and fuels, grid modernisation, small modular reactors and carbon capture and storage. Expanding and accelerating the research mission of the national laboratory system is also important given their critical role across the energy innovation spectrum, particularly in basic science and applied research. New funding mechanisms such as the Energy Innovation Hubs and Advanced Research Projects Agency – Energy (ARPA-E) is forging key partnerships with academia, industry and other institutions necessary to ensure that commercialisation opportunities are recognised as early as possible in the development cycle. The government is well positioned over the coming years to leverage the learning from its massive clean energy investments through the Recovery Act to significantly advance critical clean energy technologies along the innovation chain.

Besides the technology push programmes that are reducing the risk and cost of technology for investors, the federal government is also encouraging the uptake of technologies that are cost-competitive without subsidies through technology-pull incentives such as energy efficiency standards and vehicle efficiency regulations. However, the important question remains with respect to the speed and extent to which the more expensive clean energy technologies such as CCS can be deployed in the absence of a stronger market signal.

It is evident that states and local governments are actively pursuing solutions appropriate to their needs and circumstances. In many instances, they are playing a critical role in creating technology-pull incentives through regulatory measures, renewable portfolio standards, energy efficiency resource standards and other initiatives. This situation has been advantageous for the federal government as such policies and programmes broadly support the realisation of national energy goals. However, the government should leverage more fully and strategically its convenor and integrator role to provide greater coherence to a fragmented policy and regulatory environment, particularly in the electricity sector, among states, local governments, utilities, private investors and grid operators.

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The Budget Request process is to a large extent dependent on Congressional approval and goals, which may be different from those of the Administration. Securing the approval of adequate funding to support robust energy R&D programmes is further complicated in the current environment of fiscal and budget austerity. The recent DOE initiatives to articulate strategic goals, establish longer-term priorities and enable greater oversight of outcomes should help to convince Congress of the funding needs for energy programmes. The government should continue to develop approaches with Congress to secure a stable, long-term funding environment which would help meet energy technology goals and avoid negative impacts on programme stability.

RECOMMENDATIONS

The government of the United States should:

- *More closely link the technology review process with sector-wide policy reviews, such as the Quadrennial Technology Review, in order to establish clear and transparent research and development priorities and involve other concerned federal agencies.*
- *Maintain the commitment to invest in energy research, development and demonstration and, as appropriate, increase funding requests to achieve ambitious national energy goals.*
- *Develop innovative approaches that involve industry more closely to ensure that energy research and development results and advancements can be quickly commercialised.*

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PART II
ANNEXES

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ANNEX A: ORGANISATION OF THE REVIEW

REVIEW CRITERIA

The Shared Goals, which were adopted by the IEA Ministers at their 4 June 1993 meeting in Paris, provide the evaluation criteria for the in-depth reviews (IDRs) conducted by the IEA. The Shared Goals are presented in Annex C.

REVIEW TEAM

The in-depth review team visited Washington, D.C. from 17 June 2013 to 24 June 2014. During the visit, the review team met with government officials, representatives from ministries and government agencies, energy producers and suppliers, interest groups and various other organisations and stakeholders. This report was drafted on the basis of the information obtained in these meetings, the government response to the IEA energy policy questionnaire and information from many other sources. The team is grateful for the co-operation and hospitality of the many people it met during the visit. Thanks to their openness and candour, the review visit was highly productive.

In particular, the team wishes to express its gratitude to Mr. Jonathan Elkind, Acting Assistant Secretary for International Affairs, Department of Energy, Dr. Phyllis Yoshida, Deputy Assistant Secretary (Asia, Europe and the Americas), Office of International Affairs and Mr. Bob Cekuta, Principal Deputy Assistant Secretary, Energy Governance and Access, Department of State for their personal engagement with the team and to their staff for providing the team with detailed briefing on energy policy in the United States. The IDR team also wishes to thank Mr. Jud Virden, Associate Laboratory Director, Pacific Northwest National Laboratory, Richland, Washington, for hosting the IDR team. The willingness of all participants to share information and their gracious hospitality contributed in no small way to a successful and productive visit.

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The members of the review team were:

- Team Leader – Mr. Martin Hoffman, Deputy Secretary, Department of Resources, Energy and Tourism, Australia.
- Ms Gill Campbell, Assistant Director, EU Energy Policy, Department of Energy and Climate Change, United Kingdom.
- Mr. Sigurd Lauge Pedersen, Senior Advisor, Danish Energy Agency, Denmark.
- Mr. Charles-Antoine Louet, Head of Department, Nuclear Industry, Directorate General for Energy and Climate Change, France.
- Mr. Satender Singh, Senior Policy Advisor, Natural Resources Canada, Canada.

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- Mr. Oliver Bornkamm, Deputy Head of Division, International Energy Policy, Federal Ministry of Economics and Technology, Germany.
- Mr. Ron Cameron, Head of Division, Nuclear Development, Nuclear Energy Agency.
- Mr. Kijune Kim, Head of Division, Country Studies Division, IEA.
- Mr. Manuel Baritaud, Senior Analyst (Electricity), IEA.
- Mr. Grayson Heffner, Senior Analyst (Energy Efficiency), IEA.
- Mr. Kieran McNamara, Desk Officer, Country Studies Division, IEA.

The review was conducted under the direction of Mr. Didier Houssin, Director of Sustainable Energy Policy and Technology, IEA. Kieran McNamara managed the review and is the author of the report with the exception of Chapter 3 on Electricity, which was drafted with Manuel Bauritaud and Matthew Wittenstein; Chapter 4 on Nuclear Energy, which was drafted by Ron Cameron; Chapter 7 on Energy Efficiency, which was drafted with Grayson Heffner; and, Chapter 8 on Oil, which was drafted with Andrew Robertson. Michael Waldron made a substantial contribution to the Renewable Energy chapter.

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ORGANISATIONS VISITED

Alliance to Save Energy

American Council for an Energy-Efficient Economy (ACEEE)

BGE (a subsidiary of Exelon Corporation)

Chevron

Duke Energy

Edison Electric Institute (EEI)

Electric Reliability Council of Texas (ERCOT)

Electric Power Research Institute- EPRI

Federal Energy Regulatory Commission (FERC)

National Association of Regulatory Utility Commissioners (NARUC)

National Grid

Nuclear Energy Institute (NEI)

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Pacific Northwest National Laboratory (PNNL)

Pepco

PJM Interconnection (PJM)

United States Department of Energy

United States Department of State

United States Energy Information Administration

United States Chamber of Commerce's Institute for 21st Century Energy

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ANNEX B:
ENERGY BALANCES
AND KEY STATISTICAL DATA

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Unit: Mtoe

SUPPLY		1973	2011	2012	2013E	2020	2030	2040
TOTAL PRODUCTION		**1456**	**1785**	**1806**	**1859**	**2211**	**2341**	**2413**
Coal		333	536	495	479	521	543	543
Peat		-	-	-	-	-	-	-
Oil		535	361	407	461	588	536	496
Natural gas		503	531	559	565	676	799	872
Biofuels and waste[1]		37	94	89	91	135	150	159
Nuclear		23	214	209	214	215	216	224
Hydro		23	28	24	23	25	26	26
Wind		-	10	12	15	19	19	22
Geothermal		2	9	9	9	26	45	62
Solar/other		-	2	2	3	6	7	10
TOTAL NET IMPORTS[2]		**282**	**410**	**338**	**291**	**111**	**59**	**69**
Coal	Exports	31	63	74	68	75	86	92
	Imports	1	8	6	5	1	1	1
	Net imports	-30	-55	-68	-63	-74	-85	-91
Oil	Exports	11	142	149	166	151	165	184
	Imports	315	608	552	522	412	454	507
	Int'l marine and aviation bunkers	-15	-48	-37	-37	-38	-37	-37
	Net imports	289	418	366	319	223	251	286
Natural Gas	Exports	2	35	37	36	98	158	184
	Imports	24	81	73	67	54	46	52
	Net imports	22	46	36	31	-43	-112	-132
Electricity	Exports	0	1	1	1	1	1	1
	Imports	1	4	5	5	4	4	4
	Net imports	1	3	4	5	3	3	3
TOTAL STOCK CHANGES		**-8**	**-3**	**-4**	**36**	**-**	**-**	**-**
TOTAL SUPPLY (TPES)[3]		**1730**	**2191**	**2141**	**2187**	**2322**	**2400**	**2482**
Coal		311	479	425	435	447	457	451
Peat		-	-	-	-	-	-	-
Oil		817	786	771	785	812	787	782
Natural gas		515	569	596	607	633	687	740
Biofuels and waste[1]		37	91	89	91	137	153	162
Nuclear		23	214	209	214	215	216	224
Hydro		23	28	24	23	25	26	26
Wind		-	10	12	15	19	19	22
Geothermal		2	9	9	9	26	45	62
Solar/other		-	2	2	3	6	7	10
Electricity trade[4]		1	3	4	5	3	3	3
Shares in TPES (%)								
Coal		*18.0*	*21.9*	*19.9*	*19.9*	*19.2*	*19.1*	*18.2*
Peat		-	-	-	-	-	-	-
Oil		*47.3*	*35.9*	*36.0*	*35.9*	*34.9*	*32.8*	*31.5*
Natural gas		*29.7*	*25.9*	*27.8*	*27.8*	*27.2*	*28.6*	*29.8*
Biofuels and waste[1]		*2.2*	*4.2*	*4.1*	*4.2*	*5.9*	*6.4*	*6.5*
Nuclear		*1.3*	*9.8*	*9.8*	*9.8*	*9.3*	*9.0*	*9.0*
Hydro		*1.3*	*1.3*	*1.1*	*1.1*	*1.1*	*1.1*	*1.0*
Wind		-	*0.5*	*0.6*	*0.7*	*0.8*	*0.8*	*0.9*
Geothermal		*0.1*	*0.4*	*0.4*	*0.4*	*1.1*	*1.9*	*2.5*
Solar/other		-	*0.1*	*0.1*	*0.1*	*0.2*	*0.3*	*0.4*
Electricity trade[4]		*0.1*	*0.1*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*

0 is negligible, - is nil, .. is not available, x is not applicable. Please note: rounding may cause totals to differ from the sum of the elements.

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Unit: Mtoe

DEMAND							
FINAL CONSUMPTION	**1973**	**2011**	**2012**	**2013E**	**2020**	**2030**	**2040**
TFC	**1315**	**1487**	**1433**	**..**	**1562**	**1578**	**1607**
Coal	74	25	22	..	23	23	23
Peat	-	-	-	..	-	-	-
Oil	693	747	719	..	758	733	725
Natural gas	367	312	296	..	352	361	368
Biofuels and waste[1]	37	71	66	..	82	86	91
Geothermal	-	0	0	..	1	1	1
Solar/other	-	1	1	..	2	3	3
Electricity	143	325	321	..	343	372	397
Heat	-	7	7	..	..	..	..
Shares in TFC (%)							
Coal	*5.6*	*1.7*	*1.5*	..	*1.5*	*1.5*	*1.4*
Peat	-	-	-	..	-	-	-
Oil	*52.7*	*50.2*	*50.2*	..	*48.6*	*46.4*	*45.1*
Natural gas	*27.9*	*20.9*	*20.7*	..	*22.5*	*22.9*	*22.9*
Biofuels and waste[1]	*2.8*	*4.8*	*4.6*	..	*5.3*	*5.5*	*5.6*
Geothermal	-	-	-	..	*0.0*	*0.0*	-
Solar/other[2]	-	*0.0*	*0.0*	..	*0.0*	*0.0*	*0.2*
Electricity	*10.9*	*21.8*	*22.4*	..	*21.9*	*23.6*	*24.7*
Heat	-	*0.4*	*0.5*	..	..	..	..
TOTAL INDUSTRY[5]	**483**	**399**	**353**	**..**	**505**	**539**	**542**
Coal	60	23	21	..	23	22	22
Peat	-	-	-	..	-	-	-
Oil	161	153	111	..	177	193	193
Natural gas	177	112	115	..	169	176	176
Biofuels and waste[1]	29	32	27	..	35	38	42
Geothermal	-	0	0	..	-	-	-
Solar/other	-	-	-	..	-	-	-
Electricity	56	73	73	..	102	109	109
Heat	-	5	5	..	..	..	..
Shares in total industry (%)							
Coal	*12.5*	*5.8*	*6.0*	..	*4.5*	*4.1*	*4.0*
Peat	-	-	-	..	-	-	-
Oil	*33.4*	*38.3*	*31.5*	..	*35.1*	*35.8*	*35.5*
Natural gas	*36.7*	*28.2*	*32.7*	..	*33.4*	*32.6*	*32.5*
Biofuels and waste[1]	*5.9*	*8.0*	*7.7*	..	*6.9*	*7.1*	*7.8*
Geothermal	-	-	-	..	-	-	-
Solar/other	-	-	-	..	-	-	-
Electricity	*11.5*	*18.4*	*20.6*	..	*20.2*	*20.3*	*20.2*
Heat	-	*1.3*	*1.5*	..	..	..	..
TRANSPORT[4]	**414**	**589**	**597**	**..**	**596**	**565**	**575**
OTHER[7]	**419**	**499**	**483**	**..**	**460**	**474**	**490**
Coal	14	1	1	..	1	1	1
Peat	-	-	-	..	-	-	-
Oil	135	48	55	..	39	36	34
Natural gas	173	183	163	..	164	160	153
Biofuels and waste[1]	9	13	13	..	13	12	12
Geothermal	-	0	0	..	1	1	1
Solar/other	-	1	1	..	2	3	3
Electricity	87	251	247	..	240	262	286
Heat	-	1	1	..	..	..	..
Shares in other (%)							
Coal	*3.3*	*0.3*	*0.2*	..	*0.2*	*0.2*	*0.2*
Peat	-	-	-	..	-	-	-
Oil	*32.4*	*9.7*	*11.4*	..	*8.5*	*7.6*	*7.0*
Natural gas	*41.3*	*36.6*	*33.9*	..	*35.7*	*33.7*	*31.2*
Biofuels and waste[1]	*2.1*	*2.6*	*2.7*	..	*2.8*	*2.6*	*2.4*
Geothermal	-	-	-	..	*0.0*	*0.0*	*0.1*
Solar/other	-	*0.3*	*0.3*	..	*0.5*	*0.6*	*0.6*
Electricity	*20.9*	*50.3*	*51.2*	..	*52.2*	*55.2*	*58.5*
Heat	-	*0.3*	*0.3*	..	..	..	..

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Unit: Mtoe

DEMAND							
ENERGY TRANSFORMATION AND LOSSES	**1973**	**2011**	**2012**	**2013E**	**2020**	**2030**	**2040**
ELECTRICITY GENERATION[7]							
Input (Mtoe)	430	916	894	..	977	1058	1129
Output (Mtoe)	169	372	367	368	401	439	476
Output (TWh)	1966	4327	4271	4274	4665	5104	5530
Output Shares (%)							
Coal	*46.2*	*43.3*	*38.5*	*40.2*	*37.7*	*35.5*	*32.4*
Peat	-	-	-	-	-	-	-
Oil	*17.1*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*
Natural gas	*18.6*	*24.2*	*29.6*	*26.9*	*29.1*	*32.5*	*35.5*
Biofuels and waste[1]	-	*1.8*	*1.8*	*1.7*	*2.2*	*2.9*	*2.9*
Nuclear	*4.5*	*19.0*	*18.8*	*19.2*	*17.7*	*16.2*	*15.6*
Hydro	*13.5*	*7.4*	*6.5*	*6.3*	*6.3*	*5.9*	*5.5*
Wind	-	*2.8*	*3.3*	*4.0*	*4.7*	*4.4*	*4.6*
Geothermal	*0.1*	*0.4*	*0.4*	*0.4*	*0.6*	*1.0*	*1.3*
Solar/other	-	*0.2*	*0.3*	*0.4*	*0.8*	*1.0*	*1.6*
TOTAL LOSSES	**430**	**685**	**693**	**-2**	**753**	**811**	**861**
of which:							
Electricity and heat generation[8]	261	532	514	..	576	619	653
Other transformation	8	-15	18	-2	14	13	11
Own use and transmission/distribution losses[9]	161	169	161	..	164	179	196
Statistical Differences	**-15**	**18**	**15**	**..**	**7**	**12**	**15**
INDICATORS	**1973**	**2011**	**2012**	**2013E**	**2020**	**2030**	**2040**
GDP (billion 2005 USD)	4984.23	13846.78	14231.58	14498.62	17475.59	22152.94	28082.19
Population (millions)	211.94	312.04	314.28	316.80	314.28	334.96	381.31
TPES/GDP (toe/1000 USD)[10]	0.35	0.16	0.15	0.15	0.13	0.11	0.09
Energy production/TPES	0.84	0.81	0.84	0.85	0.95	0.98	0.97
Per capita TPES (toe/capita)	8.16	7.02	6.81	6.90	7.39	7.17	6.51
Oil supply/GDP (toe/1000 USD)[10]	0.16	0.06	0.05	0.05	0.05	0.04	0.03
TFC/GDP (toe/1000 USD)[10]	0.26	0.11	0.10	..	0.09	0.07	0.06
Per capita TFC (toe/capita)	6.21	4.77	4.56	..	4.97	4.71	4.21
Energy-related CO_2 emissions ($MtCO_2$)[11]	4697.7	5288.4	5074.1	-	5400.4	5470.5	5554.7
CO_2 emissions from bunkers ($MtCO_2$)[11]	45.2	148.2	112.1	-	117.1	114.0	112.5
GROWTH RATES (% per year)	**73-11**	**10-11**	**11-12**	**12-13**	**13-20**	**20-30**	**30-40**
TPES	0.6	-1.1	-2.3	2.2	0.9	0.3	0.3
Coal	2.6	-4.7	-11.3	2.4	0.4	0.2	-0.1
Peat	-	-	-	-	-	-	-
Oil	-0.2	-2.4	-1.9	1.7	0.5	-0.3	-0.1
Natural gas	0.6	2.3	4.7	2.0	0.6	0.8	0.7
Biofuels and waste[1]	5.4	2.3	-3.1	2.7	6.0	1.1	0.6
Nuclear	14.0	-2.1	-2.5	2.6	0.1	0.0	0.4
Hydro	1.1	22.7	-13.4	-2.6	1.1	0.2	0.1
Wind	-	27.0	17.4	19.5	3.8	0.1	1.3
Geothermal	8.6	1.7	1.3	2.8	16.7	5.6	3.2
Solar/other	-	13.3	17.7	8.8	11.6	1.8	4.2
TFC	0.3	-0.9	-3.7	..	..	0.1	0.2
Electricity consumption	2.2	-0.3	-1.3	..	..	0.8	0.7
Energy production	0.5	3.6	1.2	2.9	2.5	0.6	0.3
Net oil imports	1.0	-9.3	-12.2	-13.0	-5.0	1.2	1.3
GDP	2.7	1.8	2.8	1.9	2.7	2.4	2.4
TPES/GDP	-2.0	-2.9	-4.9	0.3	-1.8	-2.0	-2.0
TFC/GDP	-2.3	-2.7	-6.2	..	..	-2.3	-2.2

0 is negligible, - is nil, .. is not available, x is not applicable. Please note: rounding may cause totals to differ from the sum of the elements.

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Footnotes to energy balances and key statistical data

1. Biofuels and waste comprises solid biofuels, liquid biofuels, biogases, industrial waste and municipal waste. Data are often based on partial surveys and may not be comparable between countries.
2. In addition to coal, oil, natural gas and electricity, total net imports also include biofuels.
3. Excludes international marine bunkers and international aviation bunkers.
4. Total supply of electricity represents net trade. A negative number in the share of TPES indicates that exports are greater than imports.
5. Industry includes non-energy use.
6. Other includes residential, commercial and public services, agriculture/forestry, fishing and other non-specified.
7. Inputs to electricity generation include inputs to electricity and CHP plants. Output refers only to electricity generation.
8. Losses arising in the production of electricity and heat at main activity producer utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of approximately 33% for nuclear and solar thermal, 10% for geothermal and 100% for hydro, wind and solar photovoltaic.
9. Data on "losses" for forecast years often include large statistical differences covering differences between expected supply and demand and mostly do not reflect real expectations on transformation gains and losses.
10. Toe per thousand US dollars at 2005 prices and exchange rates.
11. "Energy-related CO_2 emissions" have been estimated using the IPCC Tier I Sectoral Approach from the *Revised 1996 IPCC Guidelines*. In accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2012 and applying this factor to forecast energy supply. Future coal emissions are based on product-specific supply projections and are calculated using the IPCC/OECD emission factors and methodology.

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ANNEX C: INTERNATIONAL ENERGY AGENCY "SHARED GOALS"

The member countries* of the International Energy Agency (IEA) seek to create conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and to the well-being of their people and of the environment. In formulating energy policies, the establishment of free and open markets is a fundamental point of departure, though energy security and environmental protection need to be given particular emphasis by governments. IEA countries recognise the significance of increasing global interdependence in energy. They therefore seek to promote the effective operation of international energy markets and encourage dialogue with all participants. In order to secure their objectives, member countries therefore aim to create a policy framework consistent with the following goals:

1. Diversity, efficiency and flexibility within the energy sector are basic conditions for longer-term energy security: the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable. Non-fossil fuels, particularly nuclear and hydro power, make a substantial contribution to the energy supply diversity of IEA countries as a group.

2. Energy systems should have **the ability to respond promptly and flexibly to energy emergencies.** In some cases this requires collective mechanisms and action: IEA countries co-operate through the Agency in responding jointly to oil supply emergencies.

3. The environmentally sustainable provision and use of energy are central to the achievement of these shared goals. Decision makers should seek to minimise the adverse environmental impacts of energy activities, just as environmental decisions should take account of the energy consequences. Government interventions should respect the Polluter Pays Principle where practicable.

4. More environmentally acceptable energy sources need to be encouraged and developed. Clean and efficient use of fossil fuels is essential. The development of economic non-fossil sources is also a priority. A number of IEA member countries wish to retain and improve the nuclear option for the future, at the highest available safety standards, because nuclear energy does not emit carbon dioxide. Renewable sources will also have an increasingly important contribution to make.

5. Improved energy efficiency can promote both environmental protection and energy security in a cost-effective manner. There are significant opportunities for greater energy efficiency at all stages of the energy cycle from production to consumption. Strong efforts by governments and all energy users are needed to realise these opportunities.

6. Continued **research, development and market deployment of new and improved energy technologies** make a critical contribution to achieving the objectives outlined above. Energy technology policies should complement broader energy policies. International co-operation in the development and dissemination of energy technologies, including industry participation and co-operation with non-member countries, should be encouraged.

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7. Undistorted energy prices enable markets to work efficiently. Energy prices should not be held artificially below the costs of supply to promote social or industrial goals. To the extent necessary and practicable, the environmental costs of energy production and use should be reflected in prices.

8. Free and open trade and a secure framework for investment contribute to efficient energy markets and energy security. Distortions to energy trade and investment should be avoided.

9. Co-operation among all energy market participants helps to improve information and understanding, and encourages the development of efficient, environmentally acceptable and flexible energy systems and markets worldwide. These are needed to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives.

(The Shared Goals were adopted by IEA Ministers at the meeting of 4 June 1993 Paris, France.)

* Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

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ANNEX D: GLOSSARY AND LIST OF ABBREVIATIONS

In this report, abbreviations and acronyms are substituted for a number of terms used within the International Energy Agency. While these terms generally have been written out on first mention, this glossary provides a quick and central reference for the abbreviations used.

AC	Alternating current
ACCCE	American Coalition for Clean Coal Electricity
ACEEE	American Council for an Energy-Efficient Economy
ACP	American Centrifuge Plant
AEO	*Annual Energy Outlook*
AMI	Advanced Metering Infrastructure
AMO	Advanced Manufacturing Office
ANWR	Arctic National Wildlife Refuge
APPA	American Public Power Association
ARRA	American Recovery and Reinvestment Act
ASM	Ancillary Services Market
AWEA	American Wind Energy Association
BECP	Building Energy Codes Program
BEG	Bureau of Economic Geology
BES	Basic Energy Sciences
BESC	United States Department of Energy BioEnergy Science Center
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BPA	Bonneville Power Administration
BPT	Best practice/established technologies
BRC	Bioenergy Research Centers
BSEE	Bureau of Safety and Environmental Enforcement
BWR	Boiling water reactor
CA	California
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CALNEV	Calnev Pipeline
CAP	Climate Action Plan
CASC	Capacity Allocating Service Company
CCGT	Combined-cycle gas turbines
CCPI	Clean Coal Power Initiative
CCPO	Climate Change Program Office
CCS	Carbon capture and storage
CCUS	Carbon capture, use and storage
CEBAF	Continuous Electron Beam Accelerator Facility
CEQ	Council on Environmental Quality
CERC	Clean Energy Research Center

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CES	Clean energy standard
CFL	Compact fluorescent lamps
CFTC	Commodity Futures Trading Commission
CHP	Combined heat and power
CIP	Critical Infrastructure Protection
CMI	Critical Materials Institute
CNG	Compressed natural gas
COL	Construction and operating licences
COU	Consumer-owned utilities
CPD	Customer Protection Division
CRISP	Cybersecurity Risk Information Sharing Project
CSAPR	Cross-State Air Pollution Rule
CSLF	Carbon Sequestration Leadership Forum
CSP	Concentrated solar power
CSWG	Cyber Security Working Group
DHS	Department of Homeland Security
DOE	Department of Energy
DOI	Department of Interior
DOT	Department of Transportation
EEI	Edison Electric Institute
EERE	Energy Efficiency and Renewable Energy
EERS	Energy efficiency resource standards
EFRC	Energy Frontier Research Centers
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIOC	Electricity Infrastructure Operations Center
EISA	Energy Independence and Security Act
EM	Environmental Management
ENN	ENN Energy Holdings Limited
ENR	United States Department of State Bureau of Energy Resources
EOR	Enhanced oil recovery
EPA	Environment Protection Agency
EPACT1992	Energy Policy Act of 1992
EPCA	Energy Policy and Conservation Act
ERCOT	Electric Reliability Council of Texas
ESCO	Energy service companies
ESF	Emergency Support Function
ESPC	Energy Savings Performance Contracts
ESPS	Existing Source Performance Standard
FAA	Federal Aviation Administration
FE	Fossil Energy
FEMA	Federal Emergency Management Agency
FEMP	Federal Energy Management Program
FERC	Federal Energy Regulatory Commission
FES	Fusion Energy Sciences
FID	Final investment decisions

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FIT	Feed-in tariffs
FOAK	First-of-a-kind
FPA	Federal Power Act
FPC	Federal Power Commission
FPGI	Future Power Grid Initiative
FRIB	Facility for Rare Isotope Beams
FTA	Free Trade Agreement
FTC	Federal Trade Commission
GAO	Government Accountability Office
GDP	Gross domestic product
GHG	Greenhouse gas
GLBRC	Great Lakes Bioenergy Research Center
GLE	General Electric's Global Laser Enrichment
GTO	Geothermal Technologies Office
HDV	Heavy-duty vehicles
HEU	Highly enriched uranium
HFC	Hydrofluorocarbon
HHI	Herfindahl-Hirschman Index
HLW	High-level waste
IA	Office of International Affairs
IDR	In-depth reviews
IEA	International Energy Agency
IECC	International Energy Conservation Code
IEP	International Energy Programme
IFNEC	International Forum for Nuclear Energy Cooperation
IGCC	Integrated gasification combined-cycle
IMM	Independent market monitors
IOU	Investor-Owned Utilities
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producers
IRS	Inland Revenue Service
ISL	In-situ-leach
ISO	Independent System Operator
ITC	Investment Tax Credit
JBEI	Joint BioEnergy Institute
JCAP	Joint Center for Artificial Photosynthesis
LBNL	Lawrence Berkeley National Laboratory
LCA	Libya Collective Action
LCFS	Low Carbon Fuel Standard Program
LCOE	Levelised cost of energy
LDC	Local distribution companies
LDV	Light-duty vehicles
LEU	Low-enriched uranium
LGP	Loan Guarantee Program

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LMP	Locational marginal pricing
LNG	Liquefied natural gas
LOLE	Loss of load expectation
LOLP	Loss of load probability
LPO	Loan Programs Office
LTO	Light tight oil
LULUCF	Land use, land-use change, and forests
LWR	light water reactor
MATS	Mercury and Air Toxics Standards
MDV	Medium-duty vehicle
MEPS	Minimum energy performance standards
MISO	Mid-continent Independent System Operator
MMS	Minerals Management Service
MOPR	Minimum offer price rule
MOU	Memorandum of understanding
MTHM	Metric tonnes of heavy metal
NACAP	North American Carbon Storage Atlas Partnership
NARUC	National Association of Regulatory Utility Commissioners
NASA	National Aeronautics and Space Administration
NASEO	National Association of State Energy Officials
NE	Nuclear Energy
NEHHOR	Northeast Home Heating Oil Reserve
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NERA	NERA Economic Consulting
NERC	North American Electric Reliability Corporation
NERSC	National Energy Research Scientific Computing Center
NESO	National Emergency Strategy Organisation
NGL	Natural gas liquids
NGNP	Next Generation Nuclear Plant
NGV	Natural gas vehicle
NHTSA	National Highway Traffic Safety Administration
NIETC	National interest electric transmission corridors
NIST	National Institute for Standards and Technology
NLOB	National Laboratory Operations Board
NLPC	National Laboratory Policy Council
NOPR	Notice of Proposed Rulemaking
NOX	Oxides of nitrogen
NPP	Nuclear power plants
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSF	National Science Foundation
NSPS	New Source Performance Standard
NSTX	National Spherical Torus Experiment (NSTX) at Princeton
NWPA	Nuclear Waste Policy Act
NYISO	New York ISO
NYSERDA	New York State Energy and Research Authority

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O&M	Operations and maintenance
OASIS	Open access same-time information system
OATT	Open Access Transmission Tariff
OCS	Outer Continental Shelf
OEM	Original equipment manufacturer
OFE	Office of Fossil Energy
OPS	Office of Pipeline Safety
ORNL	Oak Ridge National Laboratory
OSTP	Office of Science and Technology Policy
PJM	PJM Interconnection
PMA	Power Administration
PNNL	Pacific Northwest National Laboratory
POLR	Provider of last resort
POU	Publicly owned utilities
PPP	Purchasing power parity
PRB	Powder River Basin
PSC	Public Service Commission
PTC	Production Tax Credit
PUC	Public Utilities Commission
PUCT	Public Utilities Commission of Texas
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
PWR	Pressurised water reactor
QER	Quadrennial Energy Review
QTR	Quadrennial Technology Review
R&D	Research and development
RCSP	Regional Carbon Sequestration Partnerships
RD&D	Research development and deployment
RD&D	Research, development and demonstration
REAP	Rural Energy for America Program
REC	Renewable energy certificates
REP	Retail Electric Provider
RFS	Renewable Fuel Standard
RGGI	Regional Greenhouse Gas Initiative
RHIC	Relativistic Heavy Ion Collider
RIN	Renewable Identification Numbers
RMR	Reliability must-run
ROE	Returns on equity
RPM	Reliability pricing model
RPS	Renewable portfolio standard
RTO	Regional Transmission Organisations
SBIR	Small Business Innovation Research
SCC	Social cost of carbon
SEAB	Secretary Of Energy Advisory Board

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SEPA	Southeastern Power Administration
SETO	Solar Energy Technologies Office
SGC	Smart Grid Collaborative
SGDP	Smart Grid Demonstration Program
SGIG	Smart Grid Investment Grant
SIRTF	Severe Impact Resilience Task Force
SLAC	Stanford Linear Accelerator Center
SMD	Standard Market Design
SMR	Small modular reactors
SNF	Spent nuclear fuel
SPP	Southwest Power Pool
SPR	Strategic Petroleum Reserve
STEO	Short-Term Energy Outlook
STTR	Small Business Technology Transfer
SUV	Sports utility vehicle
SWPA	Southwestern Power Administration
SWU	Separative work units
T&D	Transmission and distribution
TCEP	Texas Clean Energy Project
TFC	Total final consumption
TIS	Texas Interconnected System
TLR	Transmission loading relief
TMI	Three Mile Island
TPES	Total Primary Energy Supply
TPS	Three pivotal supplier
TVA	Tennessee Valley Authority
UAN	Urea ammonium nitrate
UIC	Underground Injection Control
ULSD	Ultra-low sulphur diesel
UNFCCC	UN Framework Convention on Climate Change
URENCO	URENCO Group
USDA	United States Department of Agriculture
USEC	United States Enrichment Corporation
USGS	United States Geological Survey
VOST	Value of solar tariff
WAPA	Western Area Power Administration
WCI	Western Climate Initiative
WCS	Western Canadian Select
WECC	Western Electricity Co-ordinating Council
WIRES	WIRES is a non-profit group representing electric transmission owners
WTI	West Texas Intermediate

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International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

Tel: +33 (0)1 40 57 66 90
E-mail: books@iea.org



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Energy Policies of IEA Countries

The United States

Since the last IEA review of the United States was published in 2008, the country's energy policy landscape has fundamentally changed. In many aspects there have been significant improvements, and the country is in a strong position to deliver a reliable, affordable and environmentally sustainable energy system.

The most obvious change has been the renaissance of oil and gas production: the growth in unconventional gas production, alongside increased output of light tight oil, is making a substantial contribution to economic activity and competitiveness. Conversely, the expansion in energy production is also raising unease on environmental and safety grounds, concerns which must be addressed appropriately.

The U.S. natural gas boom has resulted in stable wholesale electricity prices, lower greenhouse gas emissions and greater system flexibility. The electricity system, however, is in need of significant investment if the country is to meet demand growth forecasts and strengthen its resilience to climate change. Renewable energy production is growing but the durability of federal tax incentives remains a persistent uncertainty.

At policy level, a number of strategic initiatives have created a new policy framework over the past six years. Among them, the Climate Action Plan has the potential to guide the U.S. economy away from its reliance on fossil fuels and towards a more sustainable energy system.

This review analyses the energy policy challenges facing the United States and provides recommendations for further policy improvements. It is intended to help guide the country towards a more secure, sustainable and affordable energy future.

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