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Coal-fired Electricity Generation after Paris 2015 Climate Agreement

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Tiivistelmä

Kivihiilen käyttö sähköntuotannossa on maailmanlaajuisesti yksi suurimmista CO_2-päästöjen aiheuttajista vastaten noin viidesosaa globaaleista kasvihuonekaasupäästöistä. Näin ollen, jotta Pariisin ilmastosopimuksen mukainen 2°C tavoite - joka vaatii mahdollisimman nopeaa päästöjen laskua – saavutetaan, maat etsivät keinoja vähentää mm. sähköntuotantosektorin päästöjä. Paine löytää kivihiilelle korvaavia, vähäpäästöisempiä vaihtoehtoja kasvaa jatkuvasti.

Tässä diplomityössä tutkitaan kivihiilen roolia – mennyttä, nykyistä, ja tulevaa – sähköntuotannossa kolmessa merkittävässä kehittyneessä maassa, joista jokaisella on pitkät perinteet kivihiilen valmistuksessa ja käytössä. Nämä maat ovat USA, Kanada ja Yhdistynyt Kuningaskunta (UK). Työssä selvitetään poliittiset rakenteet ja markkinoiden tilat, jotta ymmärretään, kunkin maan sähköntuotannon kehityksen syyt. Lisäksi tutkimus tarjoaa näkemyksiä kivihiilen tulevaisuudesta kansallisten ennusteiden ja julkistettujen poliittisten toimenpiteiden perusteella.

Kukin maa on asettanut - tai asettamassa - kunnianhimoisia tavoitteita rajoittaa sähköntuotannon kasvihuonekaasupäästöjä mm. vähentämällä kivihiilen roolia sähköntuotannossa – jos ei vielä tänään niin ainakin tulevaisuudessa. Esimerkiksi UK:lla ja Kanadalla on kummallakin CO_2 päästöintensiteettiraja kivihiilipolttoiselle sähköntuotannolle taaten, että uutta kivihiilikapasiteettia ei rakenneta ilman hiilidioksidin talteenottoa ja varastointia (CCS). US EPA on myös asettanut suunnitelman vähentää fossiilisen sähköntuotannon päästöjä (Clean Power Plan, CPP), joka tosin on tällä hetkellä jäädytettynä haasteiden kuulemisten ajaksi (vähintään kahdeksi vuodeksi).

Suorien säädösten lisäksi myös muut tekijät ajavat alas CO_2 intensiteetiltään korkeapäästöistä sähköntuotantoa. Muutosta edesauttavat erityisesti markkinat eli hintakilpailu kivihiilen ja vaihtoehtoisten polttoaineiden välillä. Erityisesti ”puhtaammasta” maakaasusta on tullut kivihiilelle haastaja. Esimerkiksi USA:n ja Kanadan markkinoilla maakaasun hinta on tullut valtavasti alas 2000-luvulla vilkastuneen liuskekaasutuotannon seurauksena (shale gas boom). Toki myös alati tiukentuvat rajoitteet muille kuin kasvihuonekaasupäästöille, kuten NO_x ja SO_2, voivat johtaa ennenaikaisiin kivihiilivoimaloiden sulkemisiin.

Toisin sanoen, kivihiilen erityisesti viime aikoina heikentynyt markkina-asema on haurastanut sen tulevaisuuden asemaa sähköntuotannon polttoaineena. Esimerkiksi, jotta kivihiilivoimala pääsisi maakaasupolttoisen voimalan tasolle vaatisi se ainakin osittaista (n.50%) hiilidioksidin talteenottoa. Käytettävissä olevat CCS-tekniikat ovat tosin vielä varsin kalliita eikä niiden toimintaa olla todistettu riittävästi suuressa mittakaavassa. Toki projektien kannattavuutta on pystytty parantamaan esimerkiksi talteen otetun hiilidioksidin hyödyntämisessä öljyntuotannossa, mutta edelleen ne ovat silti hyvin riippuvaisia valtion avustuksista.

Avainsanat Kivihiili, sähköntuotanto, CCS, CO_2, päästöt, päästökauppa, ilmastosopimus, ilmastonmuutos, USA, Kanada, Iso-Britannia, EU

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Abstract

Coal-fired electricity generation is still a major, increasing source of the global greenhouse gas (GHG) emissions accounting for approximately one-fifth of the total GHG emissions. Concurrently, in order to meet the Paris Agreement target to limit global warming "well below 2°C" - which calls for reduction of the global GHG emissions as soon as possible - nations worldwide are pursuing to limit GHG emissions from, inter alia, energy sector. Therefore, the pressure to replace coal with less carbon-intensive fuels is increasing.

This thesis observes the role – past, current and future - of coal-fired electricity generation in three developed countries that have had long traditions in coal production and consumption; i.e. the United States of America (USA), Canada and the United Kingdom (UK). The policy framework and market conditions are reviewed to understand the position of coal in national electricity generation mixes. Additionally, future projections are provided based on national energy outlooks and policy announcements.

Each observed nation has or is about to implement ambitious targets to reduce GHG emissions from the electricity sector, thus also limiting coal's share in their generation mixes - if not today, at least in the future. For instance, the United Kingdom (UK) and Canada have both recently implemented carbon dioxide (CO_2) emission performance standards on coal-fired generating units, ensuring that new coal-fired capacity will not be built without partial carbon capture and storage (CCS) system. The US Environmental Protection Agency has also finalized the rule on fossil fuel-fired generating units in 2015, referred to as the Clean Power Plan (CPP). This plan has been, however, halted by the Supreme Court in early 2016 for at least two years before its final decision on the rule.

In addition to direct regulations on the CO_2, there are other factors driving nations towards less carbon intensive generation mixes. Most notably, market conditions and competition between generation fuels are encouraging shift from coal to natural gas (NG)-fired electricity generation in particular. That is, NG market prices have been historically low during 2010s, particularly in the USA and Canada, due to the shale gas boom which started in the 2000s. Also tightened limits on hazardous air pollutants such as NO_x and SO_2 emissions are encouraging early retirements of coal-fired units.

Furthermore, decreased competitiveness of coal as a generation fuel has weakened its future prospects. For instance, in order to meet the carbon intensity of a modern NG-fired power plant, a coal-fired unit would need to have at least partial, c. 50%, CCS. Available technologies are still, however, rather expensive and operations have not yet been proven reliable enough on a large scale compared to the widely used NG-fired technologies. While CCS projects may receive additional funding by selling by-products from the CO_2 capture process, they are still reliant on government support.

Keywords Coal, electricity generation, CCS, CO_2, GHG, emissions, emission trading, Climate Agreement, climate change, USA, Canada, UK, EU

Preface

This master's thesis has been carried out between 1 November 2015 and 30 May 2016 for the department of Mechanical Engineering (former department of Energy Technology) at Aalto University School of Engineering.

The topic is highly interesting and timely as nations around the world have recently, in December 2015, adopted the historical Paris Climate Agreement and have been introducing their national action plans to mitigate the climate change and reduce greenhouse gas emissions from, inter alia, the electricity sector. Accordingly, the purpose of the paper is to provide up to date information of the topic for those who work among the field as the policy environment and market conditions are constantly changing.

The supervisor of the thesis was Sanna Syri, professor of Energy Technology and Energy Economics at Aalto University and the deputy head of the Mechanical Engineering department. Advisors were Mikko Wahlroos and Samuel Cross, doctoral researchers at the particular department.

I sincerely thank Sanna Syri for giving me this interesting opportunity and advising me throughout the process. I am willing to thank my advisors, Mikko Wahlroos and Samuel Cross, as well for supporting me with their guidance and encouraging attitude during the project. I would also like to thank the rest of the faculty for warmly welcoming me to be a part of the group.

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CPP Rate-Based Goals (EPA 2016)
CPP Mass Goals (EPA 2016)
CPP Mass Goals with New Source Complement (EPA 2016)

Abbreviations

$\$_{CAN}$	Canadian Dollar (€1.143 as of 8 May 2016 (ECB 2016))
$\$_{US}$	US Dollar (€1.142 as of 8 May 2016 (ECB 2016))
AB	Assembly Bill
AEO	Annual Energy Outlook
AESO	Alberta Electric System Operator
ARB	California Air Resources Board
ARP	Acid Rain Program
BAT	Best Available Techniques
BGR	Bundesanstalt für Geowissenschaften und Rohstoffe (The Federal Institute for Geosciences and Natural Resources)
BSER	Best System for Emission Reduction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAP	Climate Action Plan
CCC	Committee on Climate Change
CCEMA	Alberta Climate Change and Emission Management Act
CCEMC	Climate Change and Emission Management Corporation
CCGT	Combined Cycle Gas Turbine
CCME	Canadian Council of Ministers of the Environment
CCPI	Clean Coal Power Initiative
CCR	Cost Containment Reserve
CCS	Carbon Capture and Storage
CEIP	Clean Energy Intensive Program
CEPA	Canadian Environmental Protection Act
CFD	Contracts for Difference
CHP	Combined Heat and Power
CLL	Climate Change Levy
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPF	Carbon Price Floor
CPP	Clean Power Plan
CPS	Carbon Price Support
CSAPR	Cross-State Air Pollution Rule
DECC	Department of Energy and Climate Change
Defra	Department for Environment and Rural Affairs
DOE	U.S. Department of Energy
ECCC	Environment and Climate Change Canada
EERS	Energy Efficiency Resource Standards
EGU	Electricity Generating Unit
EIA	U.S. Energy Information Administration
ELV	Emission limit value
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPC	Emission Performance Credit
EPS	Emission Performance Standard
ERC	Emission Rate Credit
ETS	Emission Trading Scheme
EU	European Union

FBC	Fluidized Bed Combustion
FEED	Front End Engineering and Design
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GTCC	Gas Turbine Combined Cycle
HAP	Hazardous Air Pollutant
IEA	International Energy Agency
IED	Industrial Emissions Directive
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized cost of electricity
LCPD	Large Combustion Plants Directive
LUEC	Levelized Unit Electricity Cost
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxic Standards
NAAQS	National Ambient Air Quality Standards
NBP	NO_x Budget Trading Program
NCV	Net Calorific Value
NEB	National Energy Board of Canada
NER	New Entrants Reserve
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standard
O_3	Ozone
OECD	Organisation for Economic Cooperation and Development
PC	Pulverized Coal
PM	Particulate Matter
RES	Renewable Electricity Standard
RGGI	Regional Greenhouse Gas Initiative
RO	Renewables Obligation
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SCPC	Supercritical Pulverized Coal
SGRR	Specified Gas Reporting Regulation
SIP	State Implementation Plan
SO_2	Sulphure Dioxide
TCEP	Texas Clean Energy Project
UK	the United Kingdom
UNECE	United Nations Economic Commission for Europe
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
USA	the United States of America
USC	Ultra-supercritical
WCI	Western Climate Initiative

1 Introduction

1.1 Coal-fired Electricity Generation and Climate Change

On December 2015, after intense negotiations, nearly 200 nations worldwide adopted the historical Paris Climate Agreement to limit global warming "well below" 2 °C and "pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels" (UNFCCC 2015a). In order to meet such goal, it requires rapid reduction of the global greenhouse gas (GHG) emissions as Figure 1 indicates. However, despite ambitious targets, GHG emissions, a major portion of which is carbon dioxide (CO_2), show a rather increasing trend.

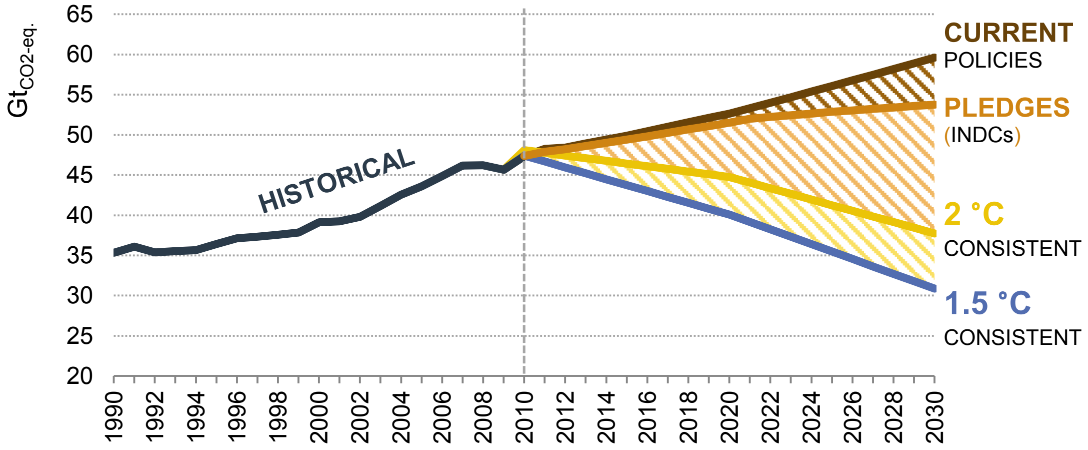

Figure 1 – Historical and projected GHG emissions (CAT 2015)

Coal-fired electricity generation has a significant contribution to the total fossil fuel combustion related CO_2 emissions and is a major source of CO_2 emissions from electricity sector as shown in Figure 2. In 2010, CO_2 emissions from fossil fuel com0bustion accounted for approximately 63% of the total worldwide GHG emissions of which one-third originated from coal-fired generation; In other words, CO_2 emissions from coal-fired power plants corresponded to nearly one-fifth of the overall global GHG emissions. This makes coal generation a crucial link what it comes to mitigating the climate change.

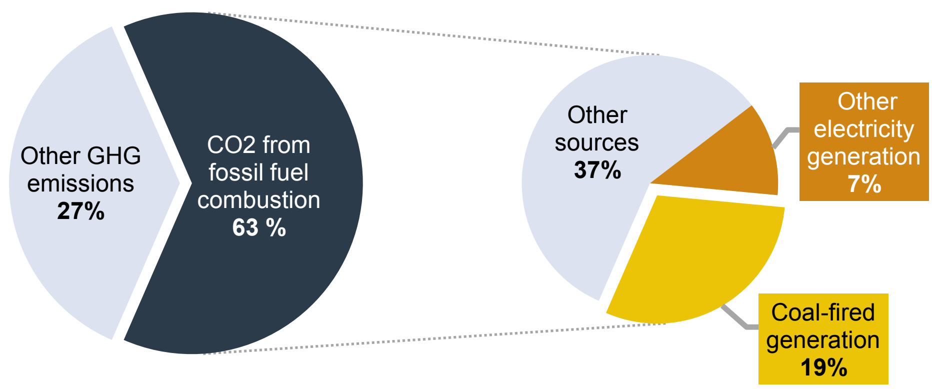

Figure 2 - Sources of global GHG emissions of 47.3 Gt$_{CO2\text{-}eq.}$ in 2010 (CAT 2015; IEA 2015a; IEA 2015c)

In addition to their already high contribution to the global GHG emissions, coal-fired electricity generation related emissions are actually further increasing. Figure 3 represents the trend of CO_2 emissions from fossil fuel combustion and electricity generation during 1990-2013. In the beginning of the period, CO_2 emissions from coal-fired electricity generating plants accounted for 24% of the total CO_2 emissions form fossil fuel combustion or 65% of the overall electricity sector CO_2 emissions. By 2013, coal-fired electricity generation was responsible for over 30 % of the total CO_2 emissions from fossil fuel combustion or 72% of emissions from electricity generation. Consequently, emissions from coal-fired generation nearly doubled from 5.0 Gt_{CO2} to 9.9 Gt_{CO2} during the period while total emissions from fossil fuel combustion increased by 56% from 20.6 Gt_{CO2} to 32.2 Gt_{CO2}.

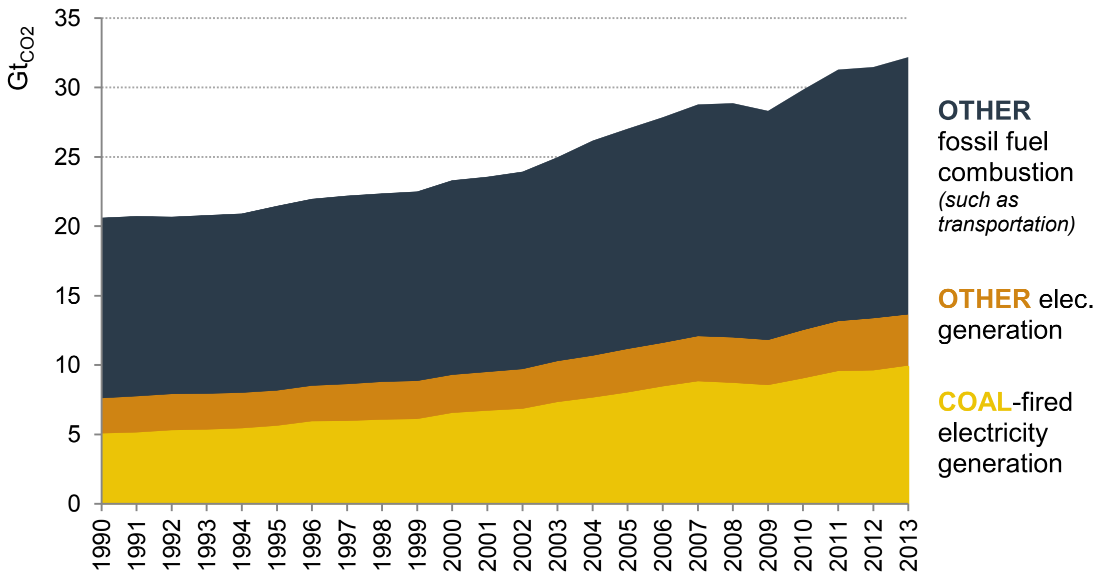

Figure 3 – Development of global CO_2 emissions from fossil fuel combustion (IEA 2015b; IEA 2015c)

Contribution of the electricity sector to the global GHG emissions has been expanding due to increased use of coal in electricity generation (IEA 2015f). However, its relative share from the total global electricity supply has increased only slightly between 1990 and 2013; from around 37% to approximately 41 %, as can be seen from Figure 4. Still, electricity generated from coal more than doubled during this period from 4400 TWh_{elec} to 9600 TWh_{elec}. This is a main concern from the perspective of the Paris Agreement (Section 3.1.2) and efforts mitigating the climate change as the coal remains the most CO_2 intensive fuel (i.e. emitted grams of CO_2 per kWh electricity generated) of commonly used fuels by the power sector (IEA 2015a p.35). By comparison, the particular number for coal ranges from 875 to 1035 g_{CO2}/ kWh_{elec}, depending on coal rank used, while for natural gas and fuel oil the same factor is 400 and 675 g_{CO2}/ kWh_{elec}, respectively (See Section 2.1).

Despite its high contribution to the global GHG emissions, coal is widely used, as it remains an exceedingly competitive fuel: it is an inexpensive, abundant and secure source of energy (IEA 2014c p.172). Thereby, for electricity providers, it might appear a significantly hard mission to resign entirely from the use of coal in a market based electricity generation without external incentives. Actually, as IEA states (IEA 2014c), global coal-use is expected to further increase during the following decades.

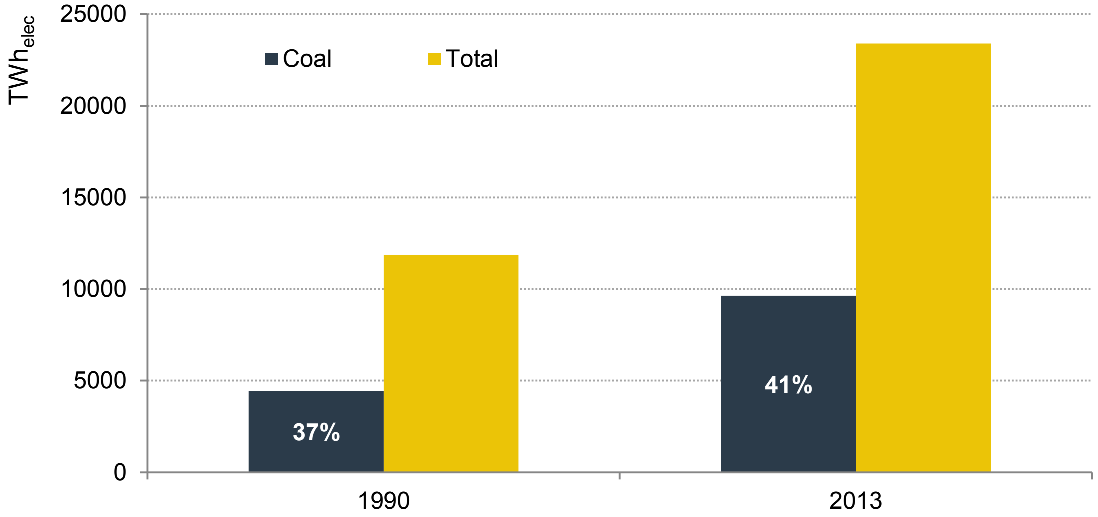

Figure 4 - Total world electricity generation and generation from coal in 1990 and 2013 (IEA 2015f)

1.2 Research Questions

As the pressure to act against global warming is increasing, countries initiate their national plans to kick in global efforts. Consequently, the purpose of this paper is to find out how coal-fired electricity generation has developed in three important developed countries, the United States of America (USA), Canada and the United Kingdom (UK). The aim is to review both internationally and nationally implemented and planned actions to mitigate the climate change particularly on the perspective of the electricity sector. Therefore, the objective is also to find out how particular countries will decrease GHG emissions from coal-fired electricity generation under prevalent market conditions. For instance, is it, on any circumstances, reasonable for a coal-fired electricity generating plant equipped with a carbon capture and storage (CCS) system to enter the market and generate electricity?

Accordingly, the following research questions are carried out:

i. How and why coal use in electricity generation has developed so far and what are the future perspectives in the reference countries?
ii. How countries are going to respond to the climate challenge and cut their GHG emissions as coal remains the major source of primary energy?

By analyzing the historical data and national projection of the future development of coal use, answers to the following questions are derived:

iii. What are the effective policies to contribute less GHG intensive electricity generation?
iv. Could a coal-fired, carbon capturing and storing electricity generating plant, on any circumstances, enter the market?

Although the three nations have long expertise in coal use and production, the sizes of markets and shares of coal in electricity generation mixes vary notably. The general situation in particular countries will be presented in the following subsection.

1.3 Current Situation in Reference Countries

United States clearly dominates the coal use for electricity generation in the studied countries as presented in the Figure 5. It used to have a significant contribution to the total global coal-fired electricity generation during the past decades (compare Figure 4 and Figure 5). Its role has, however, recently narrowed due to increased global use of coal for power generation. In 1990, almost 1,700 TWh of electricity in the USA was generated from coal which accounted for over one-third of the total coal-fired electricity generated worldwide and approximately 14% of the overall global electricity generation, whereas in 2013, while coal-fired electricity generation remained nearly unchanged in the USA, coal-fired generation corresponded to less than 10% of the total global electricity generation and less than 20% of the global coal-fired generation.

Compared to the USA, the UK and Canada are small players in terms of coal-fired electricity generation (see Figure 5), since their combined generation in 1990 and 2013 accounted for only 17% and 11.5%, respectively, to the US coal-fired generation. Additionally, coal use in electricity generation showed a decreasing trend; in the UK and Canada, coal generation fell 36% and 21%, respectively, by 2013 compared to the 1990 levels.

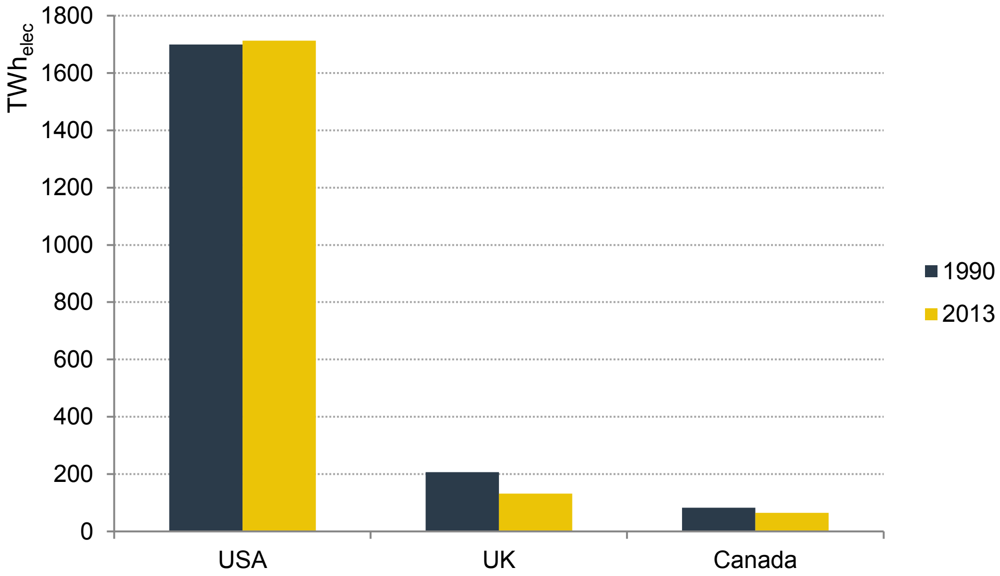

Figure 5 - Coal-fired electricity generation in reference countries in 1990 and 2013 (IEA 2015f)

However, if compared to the national electricity generation mixes (see Figure 6), the UK, instead, holds the first place in coal-fired generation, as close to 65% of the domestic electricity generation originated from coal-fired plants in 1990. At the same time, coal-fired generation accounted for 53% of the total electricity generated in the USA. Canada, unlike others, had over 60% of its electricity generated with hydropower while coal accounted for less than 20%. Nonetheless, a radical change has happened since then, as coal's share has dropped in each country; in the USA to 39.8%, in the UK to 36.7% and in Canada to 10% by 2013. These changes follow a common trend; the decrease in coal generation has been mainly compensated with NG-fired generation increasing its share from 12% to 27% in the USA, from 2% to 27% in the UK and from 2% to 10% in Canada. Also renewables are taking shares from coal (and oil), particularly in the UK where, for instance, wind generation grew from 0% to 8% within 13 years.

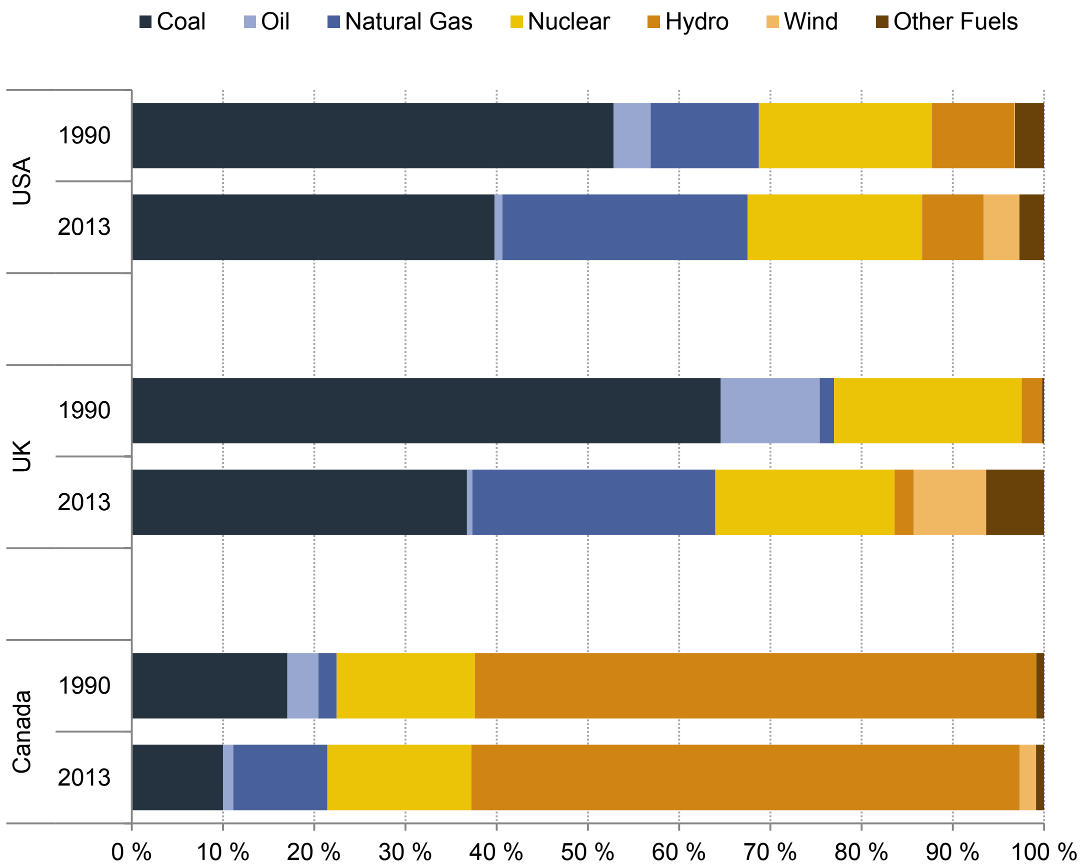

Figure 6 - Generation mixes of the reference countries in 1990 and 2013 (IEA 2015f)

Consequently, coal-fired generation has been responsible for the most CO_2 emissions from electricity generation in each country, as presented in Figure 7. However, coal's shares of the total emissions from electricity generation have decreased by 2013. At the same time overall electricity sector emissions have increased in the USA and Canada. In turn, the UK has managed to turn both, coal-fired generation originated and overall electricity sector emissions to a downward trajectory.

In terms of emission intensity factors (i.e. grams of emitted CO_2 per kWh of generated electricity), coal-fired generation is most efficient in the UK with 923 g_{CO2}/kWh_{elec} factor in 2013. It is followed by the USA with 928 g_{CO2}/kWh_{elec} which has remained nearly unchanged from the 1990 level. Coal-fired plants in Canada, instead, showing a further increasing trend, emit the most CO_2 in terms of electricity generated; its factor has grown from 980 to 1033 g_{CO2}/kWh_{elec} during 1990-2013. However, to get the overall picture, it is reasonable to compare the intensity factors of the overall generation as well. It turns out, as the generation mixes already hinted, that Canada generates the cleanest electricity (in terms of CO_2 emission intensity) of the three countries with 161 g_{CO2}/kWh_{el} factor for its overall generation mix in 2013. Nevertheless, the USA and particularly the UK are on the way to less carbon intensive generation mixes as the USA has decreased the factor from 590 to 494 g_{CO2}/kWh_{elec} and the UK from 682 to 472 g_{CO2}/kWh_{elec} within 13 years.

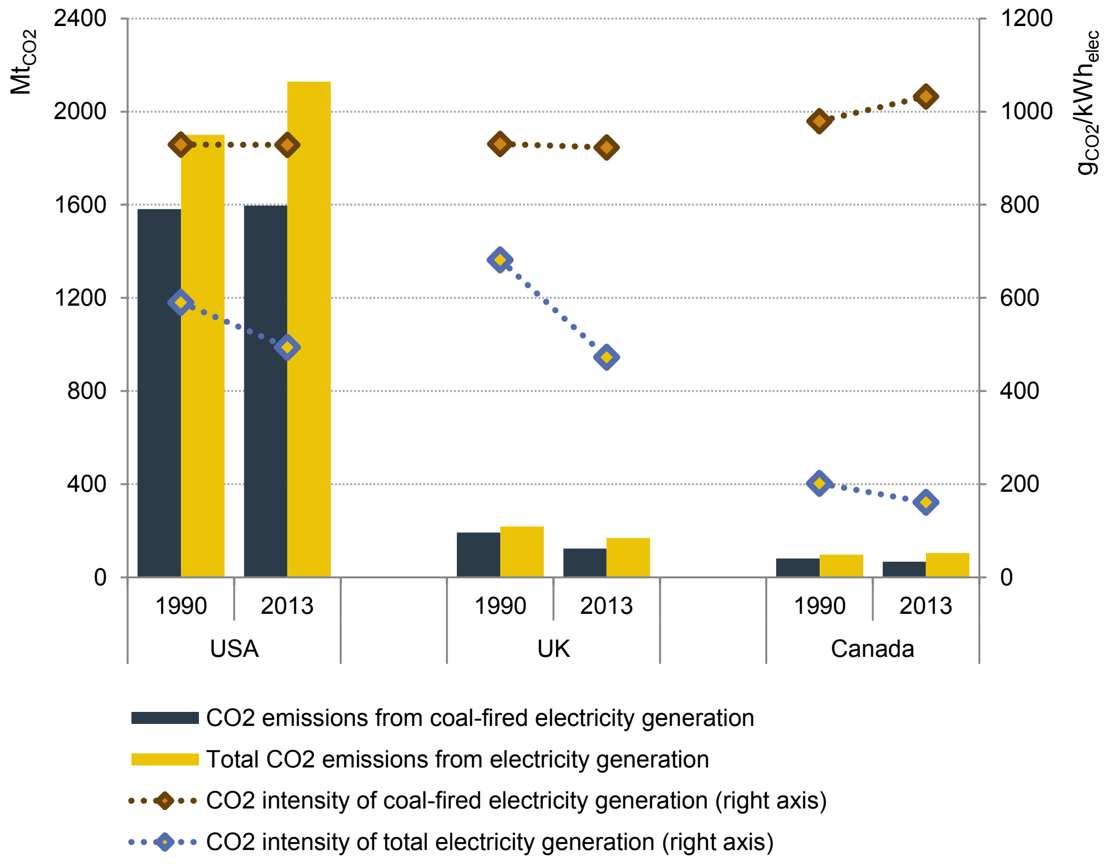

Figure 7 CO_2 emissions from total electricity generation and from coal-fired electricity generation in 1990 and 2013 together with CO_2 intensity of coal-fired generation (IEA 2015c; 2015f)

1.4 Structure

The reasons behind the shifts and future prospects will be provided later in this paper. There are numerous reasons affecting the national generation mixes. Among the most significant ones is the policy environment which will be presented in Section 3 on international (3.1) and federal/national level (3.2, 3.3, 3.4 and 3.5) as well as, on regional level (3.4) in the case of the USA and Canada. Legislation and regulations have an effect on market conditions which, in turn, define which fuels and generation technologies are competitive enough to enter and remain on the market. Available technologies together with definition of coal as a generation fuel are presented in Section 2.

The main analysis of the situation in the reference countries is proceeded separately in Sections 4 (the USA), 5 (Canada) and 6 (the UK). The analysis includes observation of historical and current data of electricity generation (4.1 and 4.2; 5.1 and 5.2; 6.1), national coal production and consumption (4.3; 5.3 and 6.4) as well as development of fuel prices (4.4; 5.5 and 6.5). This study aims to find reasons behind the development of particular factors as well. Furthermore, national projections (4.8; 5.7 and 6.6) and ongoing coal-fired power plant projects are reviewed (4.6; 4.7; 5.6 and 6.3) to understand the future prospects of coal-fired generation in particular countries.

Finally, Section 7 will conclude the study and presents proposals for further research.

1.5 Sources and Limitations

The data used is, at first hand, retrieved from official national databases and agencies. That is, in case of the USA information relied on mainly originates from U.S. Energy Information Administration (EIA), the U.S. Environment Protection Agency (EPA) and the U.S. Department of Energy (DOE). The Canadian data is mostly from Statistics Canada's socioeconomic database, CANSIM whereas the information related to the UK is primarily from the Department of Energy and Climate Change (DECC) and from the European Commission. The study also uses data provided by the International Energy Agency (IEA), particularly in case official national data is limitedly available but also when countries are compared concurrently (e.g. in the Introduction) as national level datasets are often categorized differently. For this reason, also the technology grouping (Section 2.2) follows the IEA's method. If necessary, units are, as well, equivalently converted with the IEA's unit converter (available at *https://www.iea.org/statistics/resources/unitconverter/*). Accordingly, the main objective is to rely on trusted, peer-reviewed publications but occasionally, for instance, to get the latest information of ever-changing projects, also local news and email contacts are used.

There is a number of factors that constrain the study. Mainly, the topic is exceedingly wide. Thus, some significant restrictions and generalizations have been made. That is, particularly in the USA case, the time and the scope of the work do not leave space for entire state-by-state observation. Therefore, analysis is made on very general, nation-wide and on multi-state level which is essential to mind.

Also, it is unmanageable to capture every detailed factor behind the market conditions and development in coal-fired generation. For instance, while there are measures that directly affects to coal-fired units, it is difficult to trace every single regulation that implicitly affects to the national generation mix or fuel prices. Thus, the study pursues to include only the most crucial elements behind the situation.

Furthermore, it is important to take into account that, as mentioned before, environment is constantly changing. For instance, some listed projects defined as "ongoing" or "about to commence operation soon" during the writing, may have faced setbacks since then; in worst case even cancelled. This actually realized during the study when unexpectedly the UK Government cancelled the funding for its CCS commercialization competition in late 2015 (see section 6.3.1). Following also applies to fuel prices as they may vary notably within a short period of time which, in turn, affects to national projections as well. Ergo, information provided here may quickly, to some extent, become obsolete.

2 Technical Background

The purpose of this section is to define coal (Section 2.1) and to provide general information of available coal-fired electricity generation methods (Section 2.2). It also describes ways of controlling GHG emissions from existing and new coal-fired generation units in (Section 2.3). The projections of generation cost are, however, presented separately for each country, the USA, Canada and the UK in Sections 4.8, 5.7 and 6.6, respectively. This is due to, inter alia, varying market conditions and policy environment of each country, making national generation costs diverging from one another.

2.1 Coal definition

Coal, a solid fossil fuel, refers to a range of combustible sedimentary rock materials mostly consisting of carbon and is often divided into two main categories which both themselves divided into two subcategories (IEA 2014a):

i. Hard Coal (high and medium rank coal)
    a. Anthracite
    b. Bituminous coal
        i. Coking coal
        ii. Other bituminous coal
ii. Brown Coal (low rank coal)
    a. Sub-bituminous coal
    b. Lignite

The division between categories depends mainly on the calorific value, volatile matter content and fixed carbon content together with caking and coking properties of the matter. The relative value of the coals within a particular category depends on the degree of moisture and ash content and contamination by Sulphur, chlorine, phosphorous and certain trace elements. However, classification often varies on both national and international level systems and may sometimes be based, instead of inherent values, rather to the final use of the coal. (IEA 2014a)

The IEA (2014a p.I.13) adopts The International Coal Classification of the Economic Commission for Europe (UNECE) as the basis for defining hard coal and brown coal: hard coal, considered as a high and medium rank coal has a gross calorific value not less than 24 GJ/t (~6.7 kWh_{fuel}/kg_{fuel}) on ash-free but moisture basis with a mean random reflectance of vitrinite of at least 0.6. Instead, coal is considered as a low rank brown coal if it is having a caloric value less than given 24 GJ/t (~6.7 kWh_{fuel}/kg_{fuel}) with a mean random reflectance of vitrinite of less than 0.6.

Coals commonly used for steam generating, labeled as steam coal (or thermal coal), consist of anthracite, bituminous coal (other than coking coal) and sub-bituminous coal. Though, anthracite-fired electricity generation has a minor effect to the total generation in OECD countries and is occasionally categorized separately (IEA 2015a p.35). In 2012, steam coal accounted over 80% of the total coal used for electricity and heat generation worldwide, as Figure 8 represents. Virtually, the rest of coal-fired electricity and heat was provided with the lower rank coal; lignite. Generally, 65% of coal consumed globally was used for electricity and heat generation. (IEA 2014a).

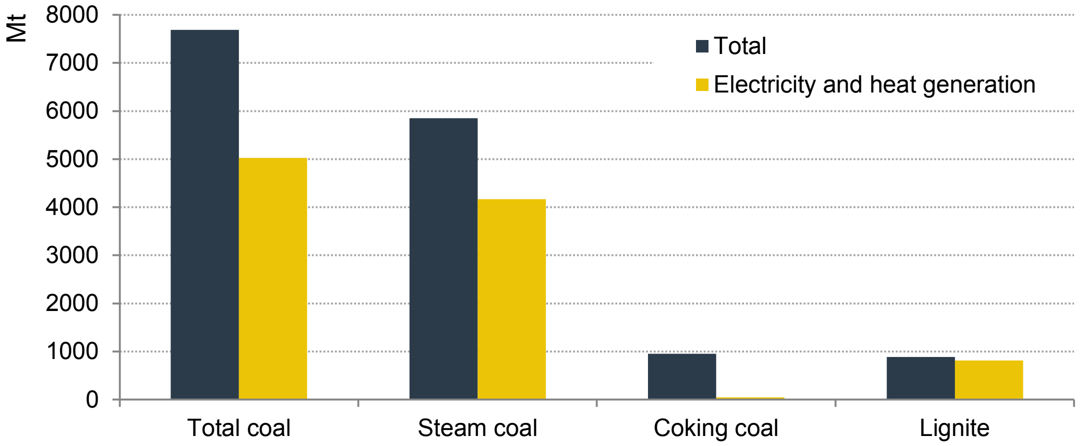

Figure 8 – Annual world coal consumption in 2012 (IEA 2014a, Table 5.7a)

According to the guidelines of Intergovernmental Panel on Climate Change (IPCC) (2006 vol.2) anthracite has the second highest default net calorific value (NCV) (7.4 kWh_{fuel}/kg_{fuel}) of the coal ranks after coking coal (subcategory of bituminous coal) with the NCV of 7.8 kWh_{fuel}/kg_{fuel} (see Figure 9). Other bituminous has the third highest NCV of 7.2 kWh_{fuel}/kg_{fuel}. Brown coal ranks, sub-bituminous and especially lignite have significantly lower NCVs than that of hard coal ranks; 5.3 and 3.3 kWh_{fuel}/kg_{fuel}, respectively. NCV for steam coal (average of anthracite, other bituminous and sub-bituminous NCVs) equals 6.6 kWh_{fuel}/kg_{fuel}. Compared to other fossil fuels, steam coal has notably lower energy content: NCV of natural gas (13.3 kWh_{fuel}/kg_{fuel}) is over two times higher and crude oil NCV (11.8 kWh_{fuel}/kg_{fuel}) nearly 80% higher than the presented average value for steam coal.

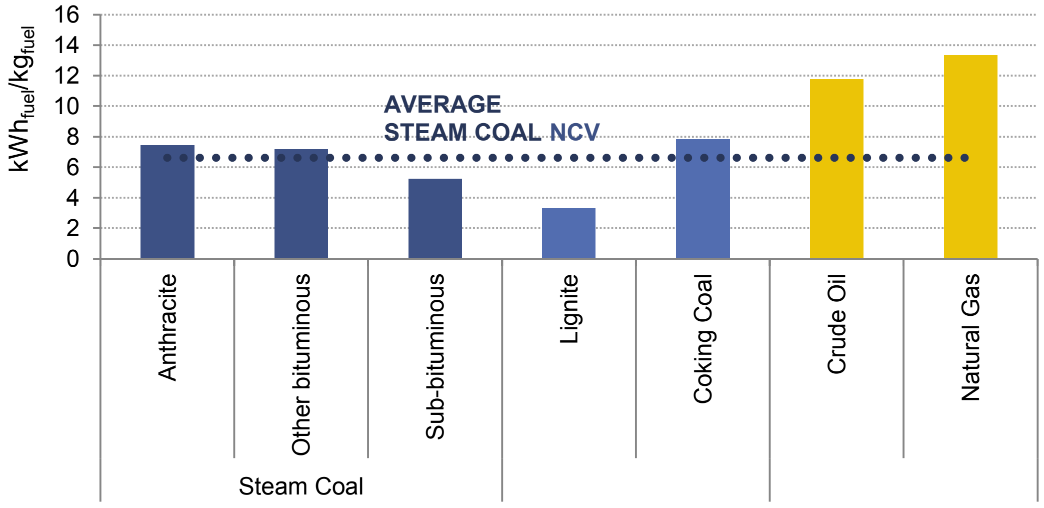

Figure 9 – Net calorific values (NCVs) of coal ranks, natural gas and crude oil (IPCC 2006 vol.2, table 2.2)

Correspondingly, default CO_2 emission factors for coal (i.e. the amount of CO_2 emitted by combusting fuel with the energy content of 1 kWh) indicates higher emission intensity during stationary combustion than natural gas and crude oil as presented in Figure 14. Emission factor for steam coal (i.e. average value of anthracite, other bituminous, sub-bituminous) remains over 70% higher than factor for natural gas and around 30% higher than crude oil emission factor. CO_2 emission factors among coal ranks vary marginally between 341 and 364 g_{CO2}/kWh_{fuel}. (IPCC 2006 vol.2).

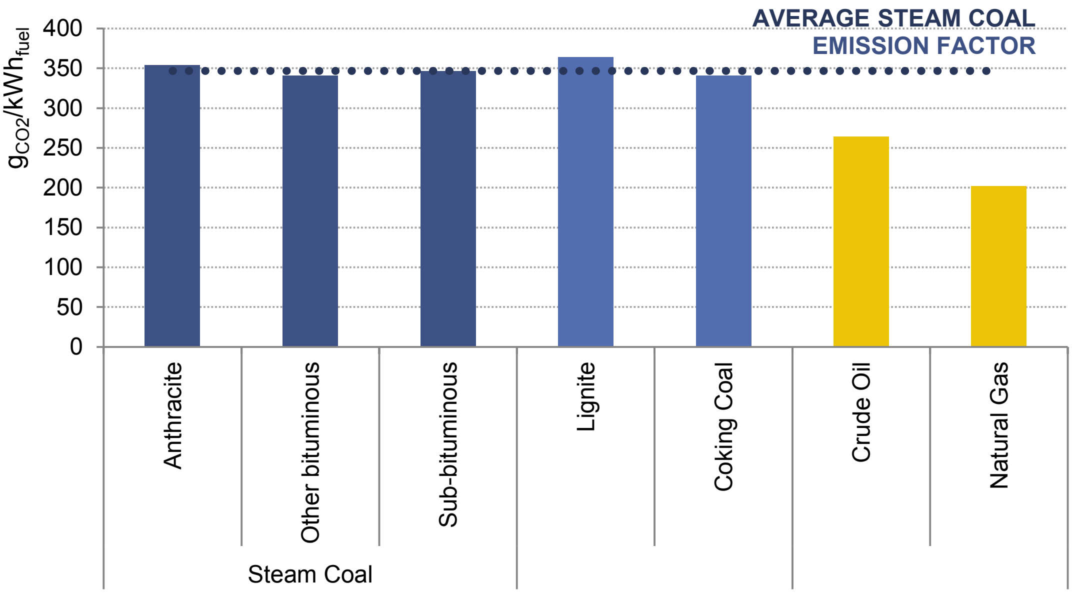

Figure 10 Default CO_2 emission factors for coal ranks, natural gas and crude oil (IPCC 2006 vol.2, Table 2.2)

CO_2 emission factor for steam coal on electricity output basis, i.e. the mass of emitted CO_2 per 1 kWh of electricity generated by combusting the fuel, indicates even greater contrast with natural gas as an average steam coal emission factor in OECD countries during period of 2009-2013 reached 915 g_{CO2}/kWh_{elec} that is over twice as much as value of 400 g_{CO2}/kWh_{elec} for natural gas. Still, emission factor for crude oil indicated 30% lower value compared to the factor for steam coal and, once again, the lowest coal rank, lignite, showed the highest emission rates with the value of 1035 g_{CO2}/kWh_{elec}. Given values should be taken, though, as indicative as they are sensitive to the quality of underlying data such as plant efficiencies, NCV of the fuel used etc. (IEA 2015a p.37)

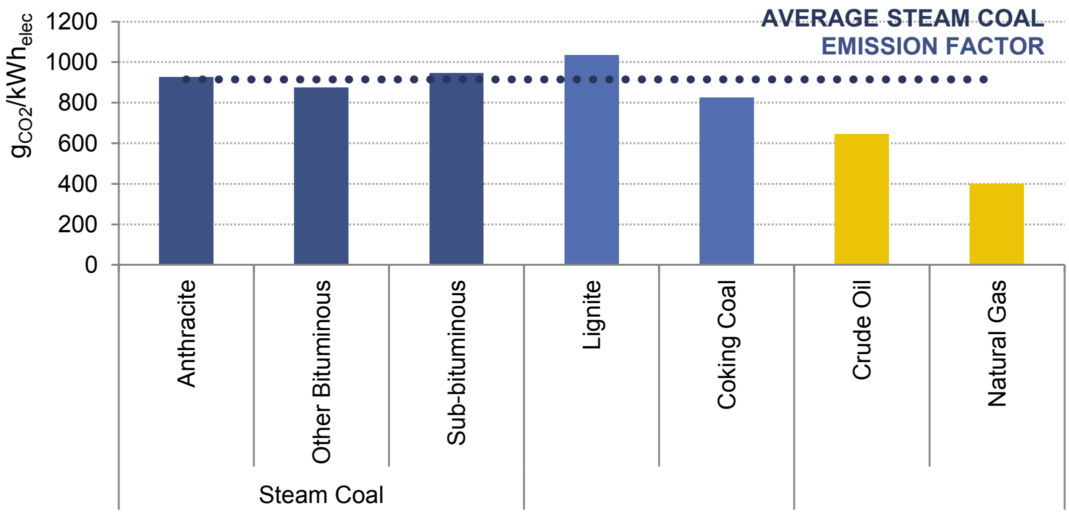

Figure 11 – Indicative CO_2 emission factors for fossil fuel-fired electricity generation in OECD countries by fuel based on electricity generation from 2009 to 2013 (IEA 2015a p.37)

Although, coal has relatively low energy content and high emission factor compared to other fossil fuels, it remains an abundant source of energy: proved recoverable worldwide coal reserves in 2012 accounted 1 052 133 Mt of which 43% is located in OECD countries; 74 591 Mt in OECD Europe, 263 824 Mt in OECD Americas and 113 497 Mt in OECD Asia Oceania, as stated by the IEA (2014a p.47). With estimated 2013 overall world production of 7823 Mt proved reserves equal over 134 years' production. According to the Federal Institute for Geosciences and Natural Resources of Germany (BGR 2014 p.64) coal reserves are, on energy basis, 20% higher than crude oil, natural gas and uranium reserves combined as presented in Figure 12. Furthermore, BGR expects overall coal resources correspond over 20-fold the amount of proven reserves so far. It is, however, worth of mention that there are other estimates of fuel resources as well.

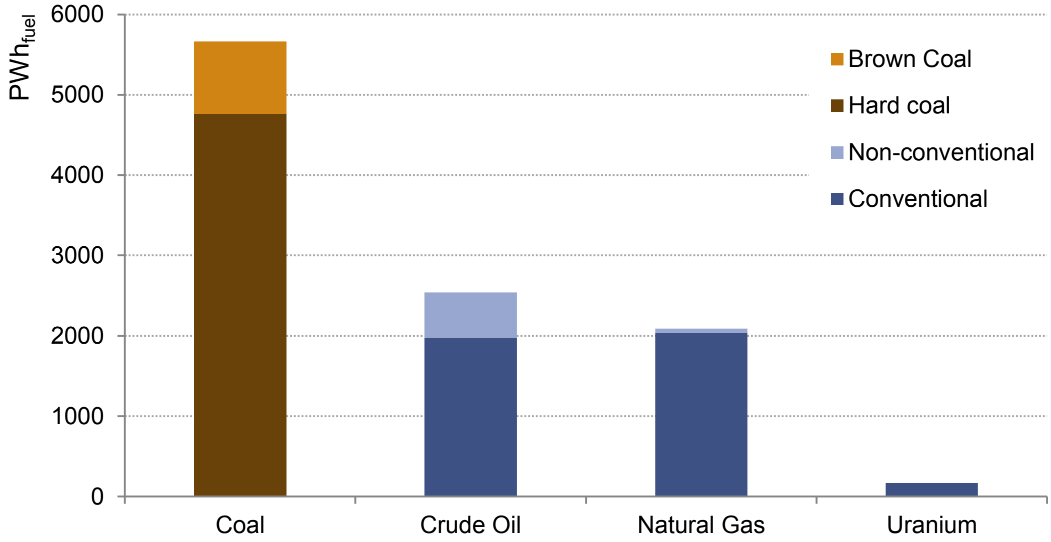

Figure 12 – Worldwide reserves of certain fossil fuels (BGR 2014 p.64)

2.2 Coal-fired Electricity Generation Technologies

Coal as a source of electricity generation fuel has various benefits which have long made it a desirable fuel. As being practiced since the late 19th century, conventional coal-fired generation provides reliable, matured and well understood option for producers of electricity. Furthermore, coal reserves are more distributed than those of NG and oil making its availability less prone to geopolitical uncertainties. Consequently, coal prices have been historically lower and less volatile than that of oil and NG. Additionally, coal-fired generation plants (particularly in the USA) are usually located either adjacent to, or within easy transportation from, a coal mine, thus enabling secure and long-term fuel supply arrangements. (Speight 2013 chap.11.2)

In conventional coal-fired power plant, like in any other condensing plant, the fuel (i.e. in this case coal) is fired in the boiler which turns the energy of the fuel into heat (see Figure 13). This heat released is used to produce high pressure and temperature steam by heating the feed water flowing through the pipes in the boiler. The resulting steam flows through a series of steam turbines that spin an electrical generator to produce electricity. The exhaust steam from the turbines is cooled, condensed back in water, and returned to the boiler to start the process over. This forms the steam cycle (or Rankine cycle) of the plant. The cycle, however, is able to turn only a limited amount of fuel energy content into electricity; usually over a half of the fuel's thermal energy is unexploited due to multiple energy conversion segments in the cycle. Conventional coal-fired plants are highly complex and have been usually designed for baseload operations. (Speight 2013 chap.11.2)

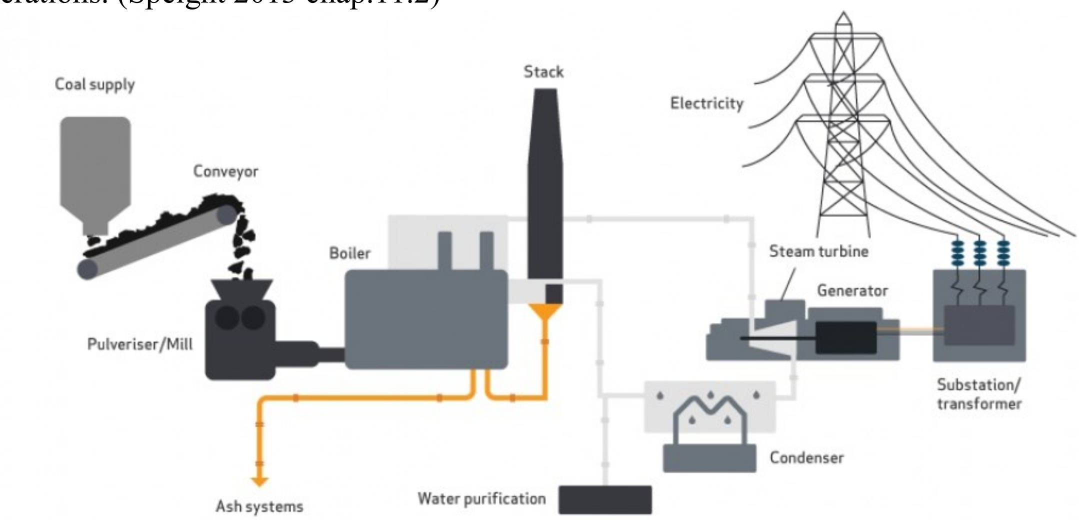

Figure 13 – Schematic diagram of pulverized coal-fired power plant (retrieved from http://www.worldcoal.org/coal/uses-coal/coal-electricity [4.5.2016])

U.S. Environmental Protection Agency (EPA) (2010a) lists five basic coal firing methods for coal-fired generation:

i. Stoker-firing,
ii. Pulverized coal (PC) combustion,
iii. Cyclone-firing,
iv. Fluidized-bed combustion (FBC)
v. Coal gasification (e.g. Integrated Gasification Combined Cycle, IGCC)

These processes, used by the electricity sector, vary significantly in performance, maturity level and utility rate. Stoker-fired system represents the most aged technology having its origins on the late 1800s and has negligible contribution to the electricity generating capacity today due to comparatively superior performance and benefits of more recent technologies. PC stands for most widely used process within the electricity sector whereas FBC and coal gasification technologies are still emerging ones. Considerable part of cyclone-firing boilers is still functioning, though FBC is superseding aforementioned technology due to higher performance, improved fuel flexibility and lower emission rates of the latter. (EPA 2010a)

According to the International Energy Agency (IEA) (2014b p.15) pulverized coal combustion accounts for over 90% of the total electricity generation capacity worldwide. Hence, coal-fired power plant capacity used globally can be generally categorized mainly by steam conditions of the PC boilers and the level of associated CO_2 emissions. By this, four technology groups are derived (IEA 2015h):

i. Subcritical
ii. Supercritical
iii. Advanced
   a. Ultra-supercritical (USC)
   b. Integrated Gasification Combined Cycle (IGCC)
   c. Combined Heat and Power (CHP)
iv. CCS-fitted

Of these, subcritical technology is considered as the most commonly used coal power plant type, though being at the same time the least efficient option among modern coal-fired generating technologies. In current subcritical units' steam cycle, water flowing through the boiler, is typically heated up to 540 °C to produce steam at a pressure of 17.9 MPa, i.e. below the critical pressure of water (22.1 MPa). Subcritical plants usually reach net thermal efficiency of 38%. Although subcritical steam cycle is not considered as an advanced technology it may be incorporated with such generating system (e.g. CHP) (IEA 2013a p.28; 2013b p.16)

In a supercritical unit, steam, with the temperature of around 565 °C, is pressurized above the critical pressure of water, to about 24.0 MPa. Thereby, water-steam separation is required only during start-up and shut-down. Supercritical units are typically designed to reach efficiencies of 42% to 43% and are more economical at large scale electricity generation (usually capacity greater than 500 MW) due to greater capital costs of components required to operate on higher steam pressures and temperatures. (IEA 2013a p.28; 2013b p.16)

Advanced technology category includes the most efficient PC unit available today: ultra-supercritical (USC) steam cycle plant. It is similar to the supercritical plant but operates even higher temperatures and pressures reaching thermal efficiencies of 45%. (IEA 2013b p.16) Main steam (i.e. steam entering to the high pressure turbine) in such a unit has a temperature of around 600°C and pressure greater than 30 MPa. (IEA 2013a p.28)

In addition, the IEA includes combined heat and power (CHP) and integrated gasification combined cycle (IGCC) coal-fired power plants to the advanced technology category. These technologies are described in Sections 2.3.1 and 2.3.4. Information related to the fourth category, CCS, is provided in Section 2.3.3.

2.3 GHG Emission Control in a Coal-Fired Power Plant

As the major of the electricity generated worldwide is provided by coal-fired power plant today and presumably in the future (IEA 2015h p.331), it is essential to concentrate on ways to reduce GHG emissions from existing and newly build coal-fired electricity generating units. Currently there is a number of control measures available or under development. In general, there are three basic approaches to reduce GHG emissions from coal-fired units;

i. improving plant efficiency
ii. co-firing other, less carbon intensive fuels (particularly biomass if considered as low carbon option)
iii. separating CO_2 for long-term storage using carbon capture and storage (CCS) technology

While efficiency improvement measures may result in cost savings due to decreased fuel consumption, CCS technologies may significantly increase both operating and capital costs as a result of expensive technology and decreased plant efficiency as mentioned in Section 2.3.3. In contrast, efficiency improvement measures may provide only marginal decrease in emissions whereas utilizing CCS technology can result up to 90% reduction in CO_2 emissions released to atmosphere. Thus, efficiency improvement may be a “first-step”, but if pursued to achieve emission limitations required under the Paris Agreement target (Sec 3.1.2) implementing CCS becomes vital.

Surely, taking the first-step is essential as well. At present, the average efficiency of global coal-fired electricity generation (i.e. coal fleet efficiency) is considerably less than what could be achieved with the modern technology as presented in Figure 14. Average coal fleet efficiencies in OECD countries and in the rest of the world reach respectively ratios of 37 % and 33% while with available technology (e.g. USC) the reachable efficiency is, as mentioned above, up to 45%. Due to the relatively inefficient generation, the average CO_2 intensity factor of global coal- fired electricity generation approaches emission intensity of a modern subcritical unit (880 g_{CO2}/kWh_{elec}) while for the new USC unit the factor would be 16% lower (i.e. 740 g_{CO2}/kWh_{elec}). (IEA 2015c)

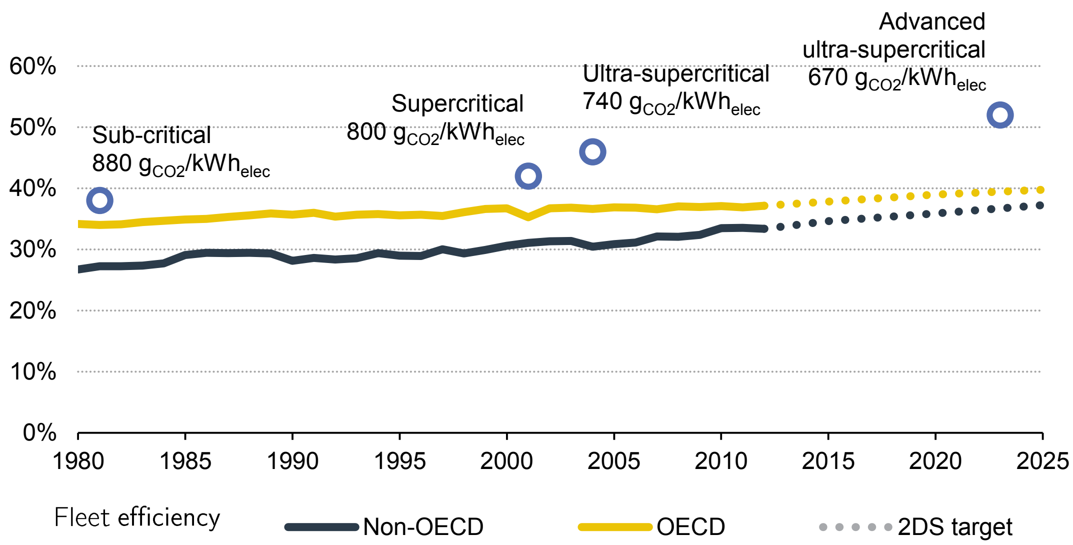

Figure 14 - Average coal fleet efficiencies and PC technologies introduced since 1980. “2DS target” stands for IEA’s scenario model where the aim to limit a global temperature rise to 2°C is achieved. Though, it also assumes that non CCS-fitted capacity is increasingly replaced with less carbon intensive options. (IEA 2015g)

The high emission factor and the gap between the achievable efficiency and the current coal fleet efficiency can be attributed to the high proportion of old technology in use; subcritical units account for 65% of the total worldwide coal-fired capacity of nearly 2000 GW (see Figure 15) whereas supercritical and advanced plants have significantly smaller shares of the total capacity; 21% and 14% respectively. Though, the IEA (2015h p.331) expects the aggregated share of advanced and supercritical units to increase up to 55% by 2040 as a result of capacity additions and retirements. Furthermore, in 2014, plants associated with emission control technology, particularly with CCS, had virtually meaningless contribution to the worldwide capacity. However, the IEA anticipates such capacity to increase from the level of 0.1 GW up to 63 GW by 2040. This existing 0.1 GW with CCS consist of world's first large-scale CCS-fitted coal-fired generation unit, Boundary Dam unit 3, in Canada (see Section 5.6.1)

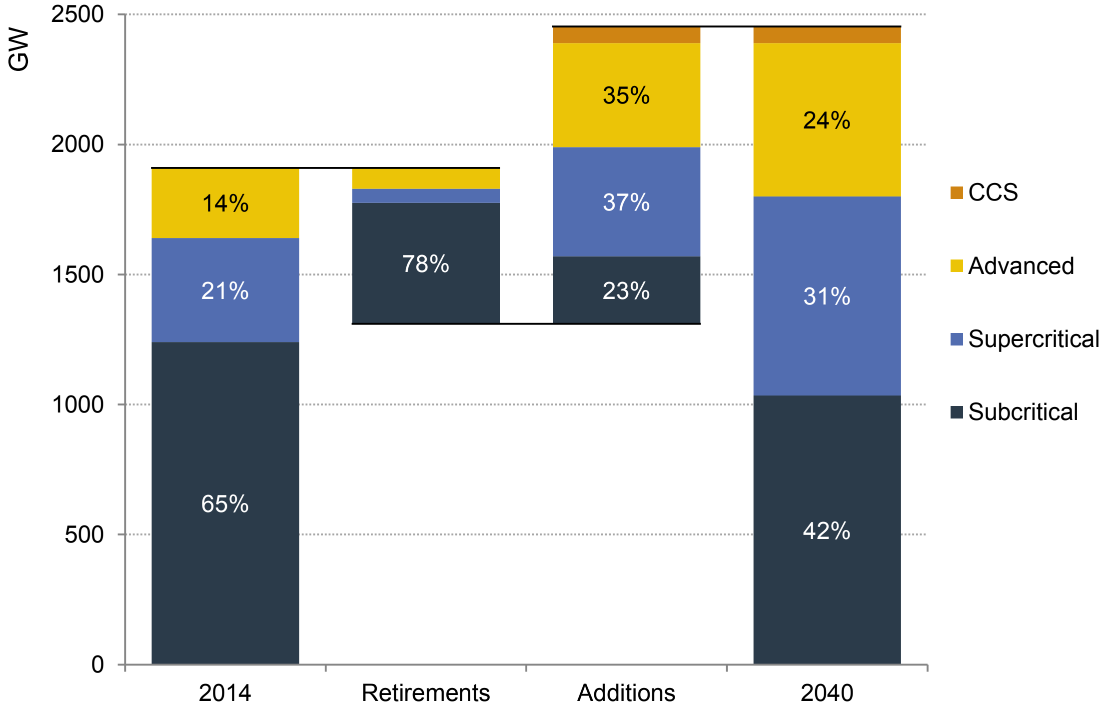

Figure 15 – Global coal-fired capacity by technology (IEA 2015h p.331)

Consequently, what it comes to new units, utilizing aforementioned, the most efficient, state-of-art technology is essential to achieve less carbon intensive generation. There are, however, various methods available to increase efficiency of existing units as well. In fact, it is common to extend life of a coal-fired power plant from 25-35 years up to 40 years, and sometimes even up to 50 years. Life extension usually includes refurbishing boiler parts, upgrading the turbines and adding flue gas cleaning to meet new emission regulations. Whilst coal-fired plant designs are usually conservative nature making the extension possible, the potential to improve an existing unit normally requires an exhaustive examination of the major functions (e.g. the combustion process and the steam cycle) (IEA 2014b p.18,19).

Table 1 below summarizes several available efficiency improvement methods for existing units. Values are however, based on site-specific circumstances and thus it is unlikely that all of the presented improvements could be implemented at every plant. Still, the table provides indicative values of potential for thermal efficiency improvement. (IEA 2014b p.19)

Table 1 - Potential efficiency improvements from measures to increase the efficiency of existing coal-fired power plants; from IEA (2014b p.19) based on NETL data (NETL 2008 p.4)

Power plant improvements	**Potential efficiency increase (percentage points)**
Air preheaters (optimise)	0.2 to 1.5
Ash removal system (replace)	0.1
Boiler (increase air heater surface)	2.1
Combustion system (optimise)	0.2 to 0.84
Condenser (optimise)	0.7 to 2.4
Cooling system performance (upgrade)	0.2 to 1.0
Feedwater heaters (optimise)	0.2 to 2.0
Flue gas moisture recovery	0.3 to 0.7
Flue gas heat recovery	0.3 to 1.5
Coal drying (installation)	0.1 to 1.7
Process controls (installation/improvement)	0.2 to 2.0
Reduction of slag and furnace fouling	0.4
Soot blower optimisation	0.1 to 0.7
Steam leaks (reduce)	1.1
Steam turbine (refurbish)	0.8 to 2.6

While some energy losses from coal-fired generating units may be reduced by utilizing presented methods, by far the largest loss results from the heat rejected from steam cycle to the cooling water. The use of combined heat and power (CHP) generation has therefore received renewed interest in the light of requirements to improve energy efficiency and reduce specific CO_2 emissions (e.g. included in the new EU Strategy on Heating and Cooling). (IEA 2010 p.59; European Commission 2016j). The following Section 2.3.1 provides more information about CHP generation.

The CHP, however, is limitedly applicable and may require huge infrastructure to supply the produced heat. Instead, combusting biomass alongside coal, referred as co-firing, could provide a rapidly exploitable option to decrease specific CO_2 emissions of the plant. This, of course, includes the assumption that biomass is considered as carbon neutral fuel as it incorporates CO_2 during its growing period. Biomass co-firing is described in Section 2.3.2.

Again, CCS technology enables the greatest potential to reduce GHG emissions from coal-fired power plants which may be incorporated with other control measures as well. Current post- and oxy-combustion technologies allow retrofitting with existing PC units, whereas pre-combustion method is only applicable to IGCC plants. Section 2.3.3 provides more information of the CCS while Section 2.3.4 concentrates on IGCC technology.

2.3.1 Combined Heat and Power

Combined heat and power generation (or cogeneration) is a mature and widely used technology in certain locations, such as in Finland, where the yearly demand for heat is high enough (e.g. due to long and severe winters) (IEA 2013c). In a conventional coal-fired unit significant amounts of energy released by coal combustion are lost during the steam condensation due to heat transfer into cooling water. However, in a CHP plant the otherwise wasted heat is used to produce steam for industrial purposes or to supply heat to a district heating network. (EPA 2010a p.34). Thus the overall plant efficiency increases up to 75-80% or, in some cases, even up to 90% of fuel source is converted into useful energy (IEA 2008 p.10). Though applying CHP requires typically higher temperatures of cooling water hence steam is extracted at an elevated pressure and temperature from an intermediate stage of the steam turbine. This results in a decreased production of electricity but, in turn, higher overall efficiency than if electricity and steam were generated separately. (EPA 2010a p.34)

CHP plant usually incorporates turbines which are specially designed to provide flexibility in operation, so that they can be run solely to provide power or to provide a consistent and secure supply of steam. For instance, in case of district heating, heating may be required only seasonally while an industrial plant may need a steady supply of steam throughout the year. (IEA CCC 2016). In any case, CHP system will be designed to meet the heat demand of the user since it costs less to transport surplus electricity than surplus heat from a CHP plant. Thus, CHP can be viewed mainly as a source of heat, with electricity as a by-product. (EPA 2010a p.34).

Consequently, the heat demand is also the biggest constraint preventing the wider use of CHP systems. (IEA CCC 2016). The construction of the necessary infrastructure for heat distribution (i.e. district heating network) involves high capital cost, thus the high requirements for heating (and cooling) is required (at least 5000 h/year). In addition, a ratio of electricity to fuel costs is recommended to be at least 2.5:1 to ensure profitable operation. (IEA 2008 p.11)

2.3.2 Biomass Co-firing

Combusting biomass together with coal in electricity generating units provides a cost effective and developed option compared to the other prominent GHG emission reduction technologies (e.g. CO_2 sequestration). It is a retrofit solution, hence widely adaptable among usual existing coal-fired plants. (Basu et al. 2011)

Co-firing technologies, as listed by Basu et al. (2011), can be generally categorized under three types:

i. direct co-firing,
ii. in-direct co-firing and
iii. gasification co-firing,

All of which have their advantages and deficits. While direct co-firing indicated the highest level of internal rate of return, external co-firing options (i.e. in-direct and gasification) were free from uncertainties occurred in the case of direct firing, such as fouling and corrosion of superheater tubes.

Issues with biomass co-firing are primarily related to dissimilar features of biomass and coal; coal is generally denser than biomass, it has a lower moisture content and does not degrade over time. Biomass, in turn, contains more volatile matter making it more likely to self-ignite.

Biomass may cause corrosion due to contained concentrations of chloride and contribute sulfate formation on boiler surface as a result of alkali content. (EPA 2010b)

Biomass co-firing leads to decrease of boiler and plant efficiency approximately 2 and 1 percentage points, respectively. However, biomass with high moisture, chlorine and alkali content, may lead to even greater efficiency losses over time. (EPA 2010a; Basu et al. 2011)

During 2010s the UK has demonstrated the prospects of co-firing biomass alongside coal in large-scale ultimately fully converting part of its largest coal-fired plant, Drax, in biomass. More information is provided in Section 6.2.

2.3.3 Carbon Capture and Storage

In general, carbon capture and storage (CCS), also known as "carbon capture and sequestration", involves the separation and capture of CO_2 from flue gas (or syngas in case of IGCC). It is a three-step process including (EPA 2015g p.2):

i. Capture of CO_2 from electric generating units (or other industrial processes)
ii. Compression and transport of the captured CO_2 (usually in pipelines)
iii. Underground (or undersea) injection and geologic storing of the CO_2 into deep underground rock formations

Again, capture processes applicable to coal-fired generation can be divided into three approaches based on which point of the generation process the capture takes place (i.e. before, during or after fuel combustion) (EPA 2015g p.4; IEA 2013a p.39):

i. Post-combustion
ii. Pre-combustion
iii. Oxy-combustion

Of these, post- and pre-combustion capture processes typically use solvent (solid sorbents) and membrane-based technologies for separating and capturing CO_2. Solid sorbents are used to separate CO_2 through chemical adsorption, physical adsorption, or a combination of the two effects. Membrane-based capture, instead, uses permeable or semi-permeable materials that allow for the selective transport/separation of CO_2. (EPA 2010a p.25)

Amines and chilled ammonia are typically the most cost-effective solvents used in solvent-based post-combustion capture as they have been already in commercial use for scrubbing CO_2 in industrial processes. Though, the scale of capture processes in industrial applications has not been as large as required in power generation, thus challenges in scaling up may occur. (EPA 2010a p.25; Chung et al. 2011)

In the post-combustion process, in accordance with the name, the CO_2 is separated after fuel is combusted from resulting flue gas (i.e. mostly mixture of N_2 and CO_2). Whereas in case of pre-combustion, the separation takes place before fuel is combusted from coal derived syngas which mainly consist of carbon oxides and hydrogen. This, however, requires gasification and is applicable to IGCC plant (described in Sec. 2.3.4). (EPA 2015g p.11; IEA 2013a p.40). The post-combustion process, instead, can be fitted with new or existing PC fired units and offers the greatest near-term potential for reducing power sector CO_2 emissions. (EPA 2015g p.9; Chung et al. 2011)

In the oxy-combustion process, the separation of CO_2 practically mostly takes places during the combustion. Namely, fuel is combusted by using high-purity oxygen (O_2) rather than air. Using purified oxygen helps to eliminate unwanted byproducts present in air and, thus, produces highly concentrated CO_2 stream (c. 60% partial pressure) instead of typical N_2 rich flue gas. However, some purification is still required but not with the same extent as with conventional coal combustion. On the other hand, there are a few key challenges with oxy-combustion including the capital cost and energy consumption for cryogenic air separation unit. Additionally, currently available boiler materials cannot withstand the high temperatures resulting from coal combustion in pure oxygen; hence it is necessary to partly recycle produced flue gas. As a result, the economic benefit of oxy-combustion compared to amine-based scrubbing systems is limited. (EPA 2015g p.17)

In spite of the technology used to capture CO_2, it needs to be transported and permanently stored to prevent it from dissolving to atmosphere. Transporting it via pipeline to the storage is currently considered as most feasible option. To transport CO_2 cost-effectively it is pressurized to supercritical fluid which may, though, require as much as 8% of the plant's net power output. It may also add $\$_{US}$ 150 million capital cost. Additionally, storing of the captured CO_2 still involves significant issues such as public fear on the topic. Also the suitable storage sites, e.g. deep saline formations, are limitedly available. In turn, storing provides an opportunity for additional incomes for power producers (and oil producers) as captured CO_2 can be used for Enhanced oil recovery (EOR) operations. It is a technique which involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil to make it more amenable for recovery. (EPA 2015g p.24). Currently, all large-scale coal-fired CCS plant projects in the USA and Canada are associated with EOR operations as described in 4.6 and 5.6.

In addition to concern related to the storing of the captured CO_2, the main issue with CCS is that the currently available technology is costly. According to the IEA (IEA 2013a p.22; 2011) the cost of electricity from a new coal power plant with CO_2 capture is estimated to be from 40 to 89% higher than a new coal plant without CO_2 capture – even without including the costs of transporting and storing the captured CO_2. Furthermore, the estimate was based on assumption that technology used is matured and represented "n-th-of-kind" (NOAK) costs whereas costs of capture and power from initial first-of-a-kind (FOAK) plants are typically significantly greater. CCS systems usually result in over 20% relative decrease in net efficiency which, in addition to increased capital costs, causes greater operating costs due to decreased output. CCS-fitted plants are also more complex and less reliable and flexible than conventional units.

To date, large-scale applications of CCS with coal-fired generation have been very limited; first large-scale unit was commissioned in 2014 in Canada (Boundary Dam unit 3, see Sec 5.6.1). However, there are also several ongoing projects in the USA which are about to commission operations soon (Sec. 4.6). Consequently, in order to make the technology more available and less expensive, it would require further applications of the technology. This would result to cost savings due to increased competition and experience gained from "learning by doing" together with increased economies of scale in design and production as order volumes rise. (IEA 2013a p.22)

2.3.4 Integrated Gasification Combined Cycle

IGCC technology has been developed to generate electricity from coal in a power plant that has environmental benefits of a NG-fired plant and performance of a combined cycle. In general, coal is gasified (e.g. via FBC) with oxygen (or air) which results in formation of synthesis gas (or syngas) consisting mainly of hydrogen and carbon monoxide. The formed syngas is then cooled, cleaned and fired in gas turbine. The combustion process produces hot exhaust that is, instead of releasing it directly to the atmosphere, it is passed from the gas turbine to the heat recovery steam generator. In which, the excess heat produces steam that drives a steam turbine forming a similar steam cycle as described above. Power is produced from both gas- and steam turbines. IGCC enables removing of the emission-forming constituents from the syngas prior to combustion and thus IGCC plant can meet extremely stringent emissions standard. (Speight 2013 chap.11.6.2)

The efficiency of the IGCC plant (without CCS) is comparable to a state-of-art PC unit. In addition to environmental benefits over conventional coal-fired units (e.g. reduced water consumption and improved control of air pollutants), the IGCC plant provides greater fuel flexibility (e.g. capacity to use wider range of coal ranks). However, IGCC technology includes higher complexity and greater construction costs compared to the conventional SCPC unit. (Speight 2013 chap.11.6.2). It is still emerging technology and, for instance, in the USA which still heavily relies on coal, there are presently only two operating large-scale coal IGCC power plants (described in Section 4.1).

The IGCC technology allows CO_2 capturing with pre-combustion technology as mentioned above (2.3.3). Today, the USA has two large-scale demonstration project of such coal power plant which are about to commence operation during in 2016 and 2019. Additionally, there is one planned similar project located in the UK. More information about the projects is provided in Sections 4.6 and 6.3.

3 The Policy Framework

Policies affecting coal-fired generation vary according to the nation. There are, however, international ambitious actions to reduce GHG emissions from inter alia the energy sector which intend to contribute implementation of national level measures as well – partly even succeeding in that. Both national and international level legislations that are significant in the perspective of coal-fired generation are presented in this section; first, international framework in Section 3.1 including Kyoto Protocol and the recent Paris Agreement, then national and regional level legislations starting from the USA and Canada (Sections 3.2, 3.3 and 3.4) ending with the EU and the UK level legislation (Sec. 3.5 and 3.6).

3.1 United Nations Framework Convention on Climate Change

The United Nations Framework Convention on Climate Change (UNFCCC) was adopted in 1992 as a framework for international cooperation to combat climate change. The intention was to limit average global temperature increases and the resulting climate change, and to cope with inevitable impacts. To date, there are 197 members or "Parties" to the UNFCCC of which 196 are states and one regional economic integration organization. These Parties include the USA, the UK and Canada. (UNFCCC 2016a)

There are two key milestones achieved under the UNFCCC; the Kyoto Protocol and the Paris Agreement that operationalize the Convention and commit nations to take steps to reduce global GHG emissions. The first of which, the Kyoto Protocol, covers the period of 2008-2020 and is described in Section 3.1.1 right below. The latter, the Paris Agreement, is a continuation of the Protocol, albeit being a separate agreement with rather different approaches. It covers the period after 2020, and is further observed in Section 3.1.2.

3.1.1 The Kyoto Protocol

Since 1995, Parties have met at annual negotiations, called "Conference of Parties" (COP), to strengthen the global response to climate change. At the third COP, 1997, countries adopted the Kyoto Protocol (KP) which set legally binding emission reduction targets on developed country Parties included in Annex B. The KP came into force on 16 February 2005 and committed 37 Parties to reduce GHG emissions to an average of 5% against 1990 levels during the first commitment period (2008-2012). The 15 member states of the EU in 1997 (including the UK) took 8% reduction target which was redistributed among themselves. The EU states jointly ratified the protocol in 2002. However, for the USA reduction target was set to 7% whereas for Canada it was set to 6%. Though, the USA has never ratified the KP while Canada has once ratified it in 2002 but withdrew from the treaty in 2011. (UNFCCC 2016c)

For the second commitment period of the KP, 2013-2020, Parties have committed to reduce GHG emissions by at least 18% below 1990 level (UNFCCC 2016c). Though the EU countries, together with Iceland, have decided to jointly meet 20% GHG emission reduction compared to 1990 level. This is in line with the EU's own 20-20-20 target and is achieved through both; EU ETS (Sec. 3.5.1) and national emission actions for sectors outside the ETS. (European Commission 2016g). In addition to six included GHGs in the first period - Carbon dioxide (CO_2), Methane (CH_4), Nitrous oxide (N_2O), Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs), Sulphur hexafluoride (SF_6) - also nitrogen trifluoride (NF_3) will be now covered. Nonetheless, the second commitment period of the Protocol, known as Doha Amendment, has still not came into effect as it requires instruments of acceptance by at least three fourths of the Parties to the

KP (i.e. at least 144). As of 21 April 2016, 64 countries have ratified the Doha Amendment. (UNFCCC 2016c)

According to the UNFCCC (2016c), the Kyoto Protocol intended to create a global carbon market by introducing three market-based mechanisms; Emission Trading, the Clean Development Mechanism (CDM) and the Joint Implementation (JI). Consequently, the KP allowed Annex B Party to trade any excess emissions, counted as "assigned amount units" (AAUs) with other Annex B Party that was over its targets. CDM and JI were both project-based mechanisms that "feed" the carbon market. They allowed Annex B Parties to partly meet their emission targets by investing sustainable development projects (CDM) or emission reduction projects (JI) outside their own borders; either in developing countries (CDM) or in other Annex B countries (JI). These mechanisms provided the investor with emission reduction units (ERUs) in case of JI and certified emission reductions (CERs) from CDM; each delivered unit equal to one ton of CO_2. Also removal units (RMU) were issued on the basis of land use, land-use change and forestry (LULUCF) activities.

It has turned out, however, that there is a huge surplus of AAUs from the first Kyoto period on the market. Thus, the amount of how much can be carried to the second period will be limited. Some Parties including the EU have declared not to purchase these surplus AUUs to prevent undermining incentives to meet emissions targets in the second period. (European Commission 2016g)

Notwithstanding, the EU as a whole as well as the UK itself were both successful in complying with the 2008-2012 reduction targets. The UK's individual reduction commitment was 12.5% below the base year and was achieved with emissions being reduced by 27% by 2011. Whereas the EU-15 has achieved an overall cut of 11.7% domestically without counting the additional reductions coming from carbon sinks (LULUCF) and international credits - i.e. the EU's joint reduction target of 8% was over-achieved exceeded. (CCC 2016; European Commission 2016g)

3.1.2 Paris 2015 Climate Agreement

After intensive negotiations that took place throughout 2012-2015, the Parties' efforts culminated at the COP 21 as the historical Paris Climate Agreement was adopted on 12 December 2015 (UNFCCC 2016d). According to the Article 2 (UN 2015) of the Agreement, Parties aim to strengthen the global response to the climate change through three key actions:

i. Holding the increase in the global average temperature "well below" 2°C above the pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C
ii. Increasing abilities to adapt to the impacts of climate change and foster climate resilience and low GHG emissions development
iii. Making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development.

In order to achieve the temperature goal, set out in the Article 2, it would require global peaking of GHG as soon as possible. In contrast to the KP, the Paris Agreement binds all Parties to undertake and communicate ambitious efforts to achieving such goal. Though, Parties recognize that peaking will take longer for developing country Parties and that support for the effective implementation is needed. Accordingly, each Party shall prepare, communicate and maintain successive nationally determined contributions that it intends to achieve. (UN 2015)

To assess the collective progress towards achieving the purpose of the Agreement, Parties shall periodically take a stock of the implementation referred as "global stocktake". The first stocktake undertakes in 2023 and every five years thereafter. The outcome of the stocktake shall inform Parties in updating and enhancing their actions. (UN 2015)

As of 29 April, 2016, Parties have submitted 162 pledges of national actions referred as "Intended Nationally Determined Contributions" (INDCs). However, UNFCCC's synthesis report (2015b) on INDCs indicates that, whilst covering the most of the global emissions, the aggregated effect of current INDCs is not enough to achieve the ultimate 2°C target. Nonetheless, developed countries including the USA, Canada and the UK as a member of the EU have submitted ambitious plans to reduce domestic emissions. (UNFCCC 2016b)

The USA intends to reduce its GHG emissions first by 17% below the 2005 levels in 2020 and further 26%-28% below 2005 levels in 2025. It refers to regulatory actions it has completed or about to complete including finalization of regulations to cut carbon pollution from new and existing power plants (aka Clean Power Plan, described in Section 3.2.2). Canada is similarly using 2005 as a base year in its pledge to reduce emissions by 30% in 2030. It also intends to cut power sector emissions, for instance, by accelerating phase-out of coal-fired generation (presumably referring to the new performance standard described in Section 3.3.1). Instead, the EU with its member States has even more ambitious target as the States have committed to jointly achieve at least 40% domestic reduction in GHG emissions by 2030 compared to 1990. The EU notifies that its goal follows the longer-term objective to reduce its emissions by 80-95% by 2050 compared to 1990 level. (UNFCCC 2016b). The UK alone actually already has a legally binding target to achieve 80% emission reduction by 2050 from 1990 levels (i.e. the Climate Change Act, see Section 3.2.1).

The Paris Agreement was opened for signature on 22 April 2016 in New York when 174 States and the EU signed the Agreement. It shall enter into force after at least 55 Parties accounting in total for at least 55% of the total global GHG emissions have deposited their instruments of ratification. However, as of 27 April 2016, only 15 Parties have ratified the agreement accounting in total for 0.03% of the total global GHG emissions. (UNFCCC 2016d)

3.2 U.S. Federal Legislation

The USA has a long tradition to regulate adverse emissions from fossil-fuel combustion (e.g. NO_x, SO_2, CO, and more recently on mercury). The Clean Air Act (CAA), which purpose is to protect public health and welfare, was established in 1970 and later amended in 1977 and 1990. It regulates harmful emissions form stationary and mobile pollution sources and has reached several milestones including the formation of world's first of its kind emission trading scheme for NO_x and SO_2 emissions that is seen as a forerunner for other market based emission reducing systems including the EU ETS (Section 3.5.1). More information about the CAA is presented in the following Section 3.2.1.

Concerns related to climate change have recently increased as 14 of the warmest 15 years in the USA have occurred during 2000-2015. As a result, the US Supreme Court has found GHGs air pollutants covered by the CAA. Consequently, under the CAA section 111(d) and with support of President Obama, the US Environmental Protection Agency (EPA) finalized its Clean Power Plan (CPP) which regulates carbon pollution (i.e. CO_2) from fossil-fuel-fired electricity generation units. The ultimate target is to reduce utility power sector emissions by 32 percent from 2005 levels by 2030. Plan comprises an instant rule for newly build units and a rule for existing units with final targets for 2030. The CPP is observed in Section 3.2.2.

The EPA required states to submit their initial plans or "State Plans" regarding the implementation of the rule or alternatively demand extension for the deadline of September 6, 2016 (EPA 2015c). However, the Plan faced a setback in 9th February 2016 when the Supreme Court decided to put it into halt until the challenges against the rule are heard. Hence, the EPA's request is not valid until further notice and the status of the plan remains uncertain.

3.2.1 Clean Air Act

The US Congress established the Clean Air Act (CAA) in 1970 and made key amendments in 1977 and 1990 (EPA 2015m). It is a federal law that regulates inter alia air emissions from stationary (e.g. power plants) and mobile sources in order to protect public health and welfare. The law required US Environmental Protection Agency (EPA), founded at the same year as the act, to establish four major regulatory programs (Bernosky 2011 p.57):

i. National Ambient Air Quality Standards (NAAQS)
ii. State Implementation Plans (SIPs)
iii. New Source Performance Standards (NSPS)
iv. National Emission Standards for Hazardous Air Pollutants (NESHAPs)

The EPA has established NAAQS for six "criteria pollutants" (EPA 2015h):

i. Carbon monoxide (CO)
ii. Lead
iii. Nitrogen oxides (NO_x)
iv. Particulate matter (10 µm in diameter and smaller)
v. Particulate matter (2.5 µm in diameter and smaller)
vi. Ozone (O_3)
vii. Sulfur dioxide (SO_2)

The Act authorizes the EPA to add additional pollutants and revise existing standards if necessary. Current emission limits for each criteria pollutant are presented in Table 2. CAA classifies standards into two types: primary standards provide public health protection whereas secondary standards protect public welfare. In order to monitor the implementation of new or revised standards, the Act calls for each state to submit their SIPs, applicable to appropriate industrial sources in the state, to the EPA. This way states demonstrate they have capacity to attain, maintain, and enforce statutory requirements. EPA must then review these plans and act to approve or disapprove each element of the plans. (EPA 2015h; 2015l; 2015m).

Besides pollutants regulated under NAAQS, the EPA controls other hazardous air pollutants (HAP) such as benzene, ethylene oxide, mercury compound and radionuclides, known to cause cancer or other serious health effects, under the NESHAP program. EPA monitors compliance of subjected facilities by several ways including inspections, report reviews and initial performance tests. (Bernosky 2011 p.58; EPA 2015i).

The CAA necessitates specific standards, NSPS, for new and modified major stationary pollution sources. Facility is considered "a major source" of pollution if it emits or has a potential to emit 9 tonnes per year or more of a hazardous air pollutant or 23 tons per year or more of a combination of hazardous air pollutants. Such a unit may be required to install the best emission control equipment possible recognized as maximum achievable control technology (MACT). Typically, NSPS apply to industrial facilities such as power plants and factories often limiting criteria pollutants but possibly applying to other pollutants (e.g. greenhouse gases) as well. (Bernosky 2011 p.58; EPA 2013)

Table 2 - National Ambient Air Quality Standards (EPA 2015h)

Pollutant [final rule cite]	**Primary/ Secondary**	**Averaging Time**	**Level**	**Form**
Carbon Monoxide [76 FR 54294, Aug 31, 2011]	primary	8-hour	9 ppm	Not to be exceeded more than once per year
		1-hour	35 ppm	
Lead [73 FR 66964, Nov 12, 2008]	primary and secondary	Rolling 3 month average	0.15 μg/m³	Not to be exceeded
Nitrogen Dioxide [75 FR 6474, Feb 9, 2010] [61 FR 52852, Oct 8, 1996]	primary	1-hour	100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
	primary and secondary	Annual	53 ppb	Annual Mean
Ozone [73 FR 16436, Mar 27, 2008]	primary and secondary	8-hour	0.075 ppm	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years
Particle Pollution Dec 14, 2012	$PM_{2.5}$ primary	Annual	12 μg/m³	annual mean, averaged over 3 years
	secondary	Annual	15 μg/m³	annual mean, averaged over 3 years
	primary and secondary	24-hour	35 μg/m³	98th percentile, averaged over 3 years
	PM_{10} primary and secondary	24-hour	150 μg/m³	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide [75 FR 35520, Jun 22, 2010] [38 FR 25678, Sept 14, 1973]	primary	1-hour	75 ppb	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
	secondary	3-hour	0.5 ppm	Not to be exceeded more than once per year

Although the CAA can be mainly considered as a traditional rate-based regulatory system, the Amendments of 1990 led to establish of the Acid Rain Program (ARP), which is considered as the world's first large-scale market-based environmental initiative (Schmalensee and Stavins 2012). The purpose of the program was to reduce primary precursor of acid rain, SO_2 (and later also NO_x) by emission allowance trading. It was implemented with two phases: the first began in 1995 affecting the largest coal-fired electricity generating units in 21 eastern and Midwestern states and the second entered into force in 2005 including smaller generating units and wider number of states. The final 2010 SO_2 cap was set at 8.95 million tons (8.12 metric tons), about half of the emissions from the power sector in 1980. (EPA 2015j; EPA 2015a)

Since 2003 the ARP has been extended with three sequential rules: during 2003-2008 NO_x Budget Trading Program (NBP), during 2009-2015 the Clean Air Interstate Rule (CAIR), and since 2015 Cross-State Air Pollution Rule (CSAPR), which purpose was to add a cap for NO_x

emissions and further restrict the SO_2 emission cap. The current rule, CSAPR, includes three separate cap-and-trade programs: SO_2 annual trading program, NO_x annual trading program and the NO_x ozone season trading program helping states to achieve NAAQS. States that are included in the CSAPR are presented in Figure 16. Currently there are 28 states affected by the rule, all of which are from southern and eastern side of the nation. 20 states are under all three trading programs, 3 states under fine particle control (annual SO_2 and NO_x) and 5 states controlling ozone season NO_x only under the rule. (EPA 2015j)

Whilst Acid Rain Program can be seen as a forerunner of a market-based environmental initiative and contributor of later international programs (e.g. EU emission trading scheme) Schmalensee and Stavins (2012) claims the Government has ironically lead virtually the closure of the original SO_2 allowance market with latter attempts to restrict the emission cap and moved the program towards traditional command-and-control approach. Additionally, at least a part of the program's celebrated success was due not to allowance trading but the earlier deregulations of US railroads. This increased the competitiveness of "cleaner" low-sulphur coal by lowering rail transport costs within the country.

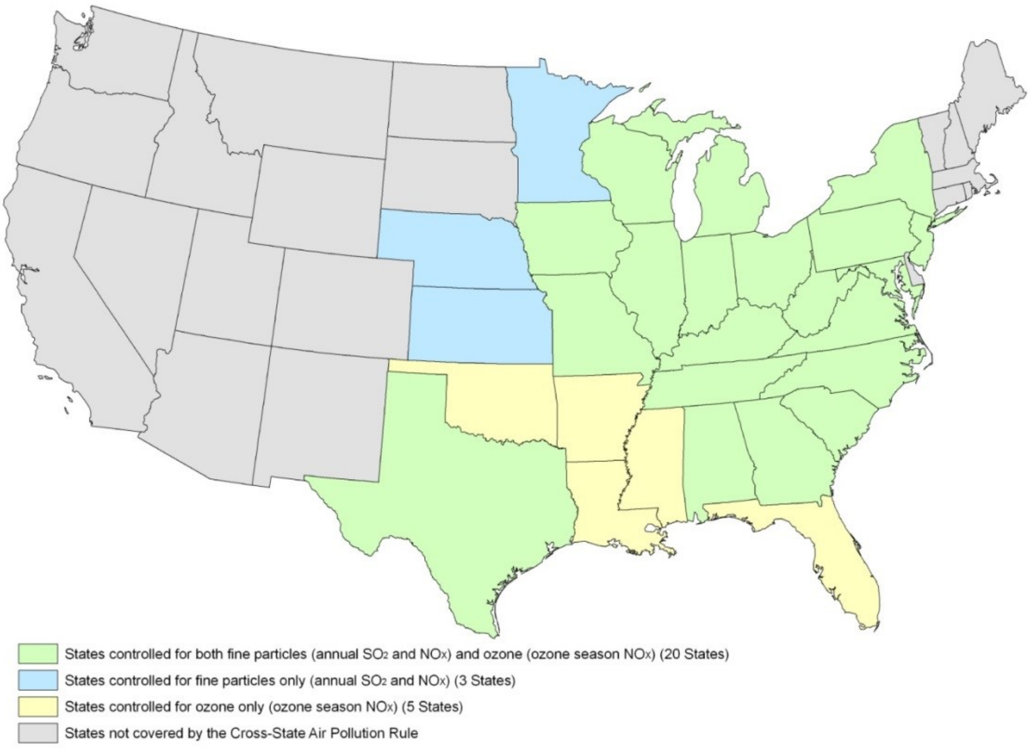

Figure 16 States that are included in Cross-State Air Pollution Rule (EPA 2015a)

3.2.2 Clean Power Plan

Two years after 2007, when the Supreme Court had founded that the greenhouse gases are air pollutants covered by the Clean Air Act, the EPA determined that "the current and projected concentrations of the six key well-mixed greenhouse gases, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6), in the atmosphere threaten the public health and welfare of current and future generations." (EPA 2015d)

While 1970, when the base for the CAA was implemented, air pollution from fossil fuel combustion caused direct and visible threat, a dense smog in U.S. cities and industrial centers (Bernosky 2011). Today rather vicarious and invisible risk sprouts due to the vast GHG emissions; according to the Agency, 2014 was the hottest year in recorded history and 14 of the 15 warmest years on record have all occurred in the first 15 years of this century (EPA 2015f).

Based on the 2009 pledge, under which USA committed to reduce its GHG emission in the range of 17 percent below 2005 levels by 2020, President Obama presented the Climate Action Plan (CAP) in 2013 to meet the 2020 goal. One key part of the plan was to deploy clean energy and cut carbon pollution from power plants. (Executive Office of the President 2013). Finally, in 2015, President Obama and the EPA announced the finalized Clean Power Plan (CPP), a first-ever rule that would cut the carbon emissions from power plants within the U.S. (EPA 2015b). However, the CPP is not EPA's first attempt to put a nationwide price on carbon as just five years prior to the finalized CPP in 2010, US Senate abandoned American Clean Energy and Security Act of 2009 that included economy-wide cap-and-trade system to cut CO_2 emissions from electricity sector (Schmalensee and Stavins 2012 p.7).

The goal of the CPP is to achieve CO_2 emission reductions from the utility power sector of approximately 32 percent from 2005 levels by 2030. At the same time, coal and natural gas are expected to remain major sources of electricity in the USA with coal providing 27 percent and NG 33 percent of 2030 the total projected generation (Federal Register 2015b p.5)

The EPA finalized the CPP on August 3, 2015. Under the authority of the CAA section 111 the Plan consisted of two rules which aim to reduce carbon pollution (expressed as CO_2) from electricity generating units (EPA 2015k):

i. Final Clean Power Plan for Existing Power Plants and
ii. Final Carbon Pollution Standards for New, Modified and Reconstructed Power Plants.

Hence, two different approaches are implemented depending on whether a power plant preexists or is a newly constructed, "modified" or "reconstructed" unit (terms classified in the CAA). Latter standard applies directly units that construction commenced after January 8, 2014, and reconstruction or modification after June 18, 2014, the date of publication of the proposed standards. The EPA established particular standard of performance, see Table 3, based on achievable emission limitation through the application of "the best system of emission reduction" (BSER) that is demonstrated for each type of generating unit: new, modified or reconstructed utility boiler and IGCC, and new or reconstructed stationary combustion turbines. Though, it is allowed to use other technology than recommended BSER, as long as the standard is met. (Federal Register 2015a p.64512)

Table 3 - GHG emission standards for newly constructed, reconstructed and modified steam generating units or IGCC facilities (Federal Register 2015a p.64512)

Affected EGU	**CO_2 Emission standard**
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg_{CO2}/MWh of gross energy output (1,400 lb_{CO2}/MWh).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg_{CO2} per MWh of gross energy output (2,000 lb_{CO2}/MWh).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg_{CO2} per MWh of gross energy output (1,800 lb_{CO2}/MWh).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: 1. 820 kg_{CO2}/MWh-gross for units with a base load rating greater than 2,100 GJ/h; or 2. 920 kg_{CO2}/MWh-gross for units with a base load rating of 2,100 GJ/h or less.
Newly Constructed and Reconstructed Fossil Fuel-Fired Stationary Combustion Turbines.	1. 450 kg_{CO2}/MWh-gross or 470 kg_{CO2}/MWh-net (1,000 lb_{CO2}/MWh-g or 1,030 lb_{CO2}/MWh-n) for base load natural gas-fired units. 2. 190 kg_{CO2}/MWh-heat input (lb_{CO2}/MMBtu) for non-base load natural gas-fired units. 3. 190 to 250 kg_{CO2}/MWh-heat input (120 to 160 lb_{CO2}/MMBtu) for multi-fuel-fired units.

For fossil-fuel fired steam generating unit the EPA finds highly efficient super critical pulverized coal (SCPC) plant with partial CCS indicating the BSER. According to the Agency (Federal Register 2015a p.64513), a newly constructed supercritical lignite-fired unit would require approximately 16 percent CO_2 emission capturing rate in order to meet the performance standard. Instead, for utility boiler burning sub-bituminous coal or dried lignite the CO_2 emission capturing rate of 23 percent is needed to meet the target. Though, it is not necessary to use CCS. The standard could be met as well, for instance, by co-firing natural gas in a modern SCPC or IGCC plant.

In the Final Rule the EPA gives an estimated capital costs for a new SCPC unit without carbon emission control and a new SCPC unit with partial CCS meeting the final standard of performance relying on research conducted by U.S. Department of Energy (DOE) and National Energy Technology Laboratory (NETL) (Federal Register 2015a p.52). Estimated capital costs comparison is presented in Table 4. Incremental costs for a modern SCPC unit to meet the performance standard would be, by estimation, 21-22 percent for capital costs (Federal Register 2015a p.52; DOE/NETL 2015 p.18). By comparison, meeting the required emission limits with SCPC unit by co-firing natural gas would not lead to an increase of capital costs over the uncontrolled SCPC unit. In turn, compliant natural gas co-firing IGCC unit would indicate total overnight costs of 3,036$\$_{US}/kW_{elec}$, an approximately 21.1% increase over the uncontrolled SCPC unit. (Federal Register 2015a p.64560)

Table 4 - Comparison of estimated capital costs for a new SCPC and a new SCPC meeting the final Standard of performance (Federal Register 2015a p.52; DOE/NETL 2015 p.18)

	Total overnight costs [2011$/kW]	**Total as-spent capital** [2011$/kW]
SCPC – no CCS	2,507	2,842
SCPC – 16% partial CCS	3,042	3,458
Incremental cost increase	21.3%	21.7%

The Environmental Protection Agency, in its Final Clean Power Plan for Existing Power Plants, announces multiple final goals for 2030 including CO_2 state-level goals and subcategory-specific emission performance rates. Similar to the standards for new, modified and reconstructed power plants, final goals can be achieved in affected EGUs by utilizing the BSER which for particular rule comprises three building blocks:

i. Improving heat rate at affected coal-fired steam EGUs.
ii. Substituting increased generation from lower-emitting existing natural gas combined cycle units for generation from higher emitting affected steam generating units.
iii. Substituting increased generation from new zero-emitting renewable energy generating capacity for generation from affected fossil fuel-fired generating units.

These building blocks are available for all affected EGUs either through direct investment or operating shifts or through emission trading. (Federal Register 2015b p.64667)

Instead of initiating a single step target for existing EGUs the EPA introduced 2030 goals that are achieved through an 8-year interim period of 2022-2029 which is separated into three steps, 2022-2024, 2025-2027, and 2028-2029. Each step is associated with step specific interim CO_2 performance rate. Both emission performance rates for the two subcategories of affected EGUs and state-level goals, expressed as a rate and as a mass, are included into interim targets. States may choose whether to follow step specific goals, or reach the interim targets as an average, as long as the state's goal is met over the 8-year period. (Federal Register 2015b p.64667)

Similar as for the newly constructed, reconstructed and modified units today, the EPA establishes CO_2 emission performance rate targets for two subcategories of affected existing EGUs. For fossil fuel-fired steam generating unit, the agency finalizes a performance rate of 590 kg_{CO2}/MWh_{elec} (1,305 lb_{CO2}/MWh). Stationary combustion turbines would instead require a performance rate of 350 kg_{CO2}/MWh_{elec} (771 lb_{CO2}/MWh). Rate-based CO_2 goals are considered as a weighted aggregate of the emission performance rates for the state's EGUs. Consequently, as stated in the rule, "affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state, must achieve the equivalent of the CO_2 emission performance rates, expressed via the state-specific rate- and mass based goals, by 2030." (Federal Register 2015b p.64667)

In addition, the EPA (2015b) provides a Clean Energy Incentive Program (CEIP) to reward early investments in renewable energy generation and demand-side energy efficiency measures that generate carbon-free electricity or reduce end-use energy demand during 2020 and/or 2021. The CEIP is established also to address stakeholders' concerns that the CPP could shift investment away from zero-emitting technologies such as solar and wind power. Incentives will be provided in the form of allowances or Emission Rate Credits (ERCs) for entities that are able to implement renewable energy production on the short-term and will be additionally recognized from energy efficiency investments that are implemented in low-income communities.

Since the publication of the final rule, the EPA's Clean Power Plan has encountered opposition and legal challenges as, inter alia, 27 states are suing the plan (E&E 2016). Though, at least 19 states have instead announced their support for the plan. Opponents' arguments include concerns about how transition from low-cost generation could eventually lead to increased consumers' expenditures. Applicable carbon trading may, in turn, keep polluting coal plants online in low-income and minority communities, areas where the air quality is already compromised. By the deadline in January, 2016, comments about the plan for the EPA yielding hundreds of pages of feedback included also other concerns about the trading; how to prevent the country dividing into a patch work of different trading systems which could result in higher costs, instead of reducing expenditures through a flexible market based approach as initially planned. According to the rule, parties are allowed to trade emissions in case they have chosen the same pathways (that are either mass based or rate based approaches) which eventually may lead to several incompatible trading systems. The role of existing cap-and-trade programs, such as RGGI (see Section 3.4.1), also remain unclear. (Holden and Harball 2016)

Furthermore, as Hogan (2015) points out, while the ambitious EPA's rule provides flexible pathways for states to limit their CO_2 emissions, it poses major concerns on the competitive, RTO (aka regional transmission organization) operated electricity markets which cover approximately 70% of the US electricity load. As the CPP will most likely not provide explicit and evenly distributed price on carbon, it could mesh well with the necessary electricity market design.

Supreme Court's decision (by votes 5-4) to halt greenhouse gas rules for power plants in 9th February 2016 increased concerns about the future of the Clean Power Plan and hence president Obama's action to mitigate the climate change and meet the targets of Paris Climate Agreement. The EPA will not be able to enforce states to either submit their emission reduction plans or request two-year extension by 6th September 2016 while a federal appeals court is hearing the challenges against to the rule. Thus, the Supreme Court could consider the case in the nine-month term that starts, at the earliest, in October. Despite the setback, the EPA is still confident with its' plan and continues to provide assistance for states that are willing to structure their plans to cut emissions. (Stohr and Dlouhy 2016; Reilly and Bravender 2016; Holden et al. 2016).

3.3 Measures of Canadian Federal Government

Federal government of Canada has implemented a performance standard for new and "end-of-life" coal-fired generation units that affects to plans on new capacity additions and presumably will increase renewable sources' contribution to the nationwide generation mix (described below 3.3.1). Additionally, Canadian government has provided other guidelines, standards and protocols on electricity sector emissions (Sec. 3.3.2).

3.3.1 Performance Standard for Coal-fired Units

Canada has enforced recently a strict rule for new coal-fired electricity generating units that has started commercial operation after June 2015. That is, Coal-Fired Electricity Generation Regulations, proposed in 2011 and adopted under the Canadian Environmental Protection Act (CEPA) came into effect on July 1st, 2015. In addition to new units, it covers "end-of-life coal units", generally coal-fired generating units that are 50 years of age. (ECCC 2013a)

Regulation is based on a performance standard i.e. limit for gram of emitted carbon dioxide per kWh electricity generated. The standard is set at the emissions intensity level of Natural Gas Combined Cycle (NGCC) technology and is fixed at 420 g_{CO2}/kWh_{elec} which is only 40% of the CO_2 emission intensity of coal-fired generation in Canada, 2013 (see Section 3.3.1) and less than 60% of the emission intensity of a modern super-critical coal unit (see Section 2.2). (Government of Canada 2015e)

Regulations, however, provide several exceptions: Firstly, affected unit may receive a temporary exemption from the performance standard until the end of 2024 if it incorporates technology for CCS and reaches predefined yearly regulated construction milestones between 2020 and 2024. Secondly, if a company owns several coal units it may use substitution i.e. swap performance standards of similar sized existing units. Owners are also allowed to swap standard of a unit retired ahead of its end-of-life with one or many units for the leftover time as long as units are in the same province and the total potential electricity production over the period being swapped is equivalent. Thirdly, in case of disruption or a significant risk of disruption to the electricity supply the minister may grant a temporary exemption for disruption mediating coal unit. Until the end of 2030 some affected units may be kept as a standby unit with reduced operation (9% or less of its capacity factor) to provide transition flexibility for new electricity generation. (ECCC 2013a)

As Jean Piette (2011) noted, after proposal in 2011, the regulations received critics regarding the pace of shift provided by the policy. As the standard generally applies only to end-of-life and new generating units, instead of all existing plants, two-thirds of operating coal capacity will not fall under the regulations until 2020 and nine of Canada's 51 coal plants (in 2011) could continue to operate until 2030. Furthermore, critics argued that the implementation time since the publication of the proposal was too long giving the power providers time to increase their coal capacity before the enforcement of the standard.

Albeit some provinces are expected to rely heavily on natural gas, the regulation is expected to encourage development of CCS systems and use of biomass by establishing new generating units or repowering existing or retired coal units on biomass. Additionally, it may increase interest to renewable alternatives such as wind and solar and enhance nation-wide electricity markets as provinces with an abundance of hydroelectric and renewable capability increase their exports to coal-reliant jurisdictions. (Piette 2011)

Section 10 of CEPA provides option to sign an equivalency agreement with province or territory in case federal rules are considered as overlapping with province or territory level regulations (i.e. the regional regulation provides effect that is equal or more effective than the federal regulation). By February 23, 2016, only Nova Scotia has signed such agreement considering particular emission standard for coal-fired units as it has implemented own GHG regulations to cut emissions from the electricity sector (see Section 3.4.5).

3.3.2 Other Federal Emission Initiatives

Prior to the implementation of the CO_2 performance standard for coal-fired units, Environment and Climate Change Canada (ECCC), a department of Federal Government, has initiated several emission control instruments under the authority of the CEPA, 1999. Such instruments include (ECCC 2013b):

i. New Source Emission Guidelines for Thermal Electricity Generation (original issued in 1981, revisions published in 1993 and 2003)
ii. National Emission Guideline for Stationary Combustion Turbines (published in 1992 by the Canadian Council of Ministers of the Environment, CCME)
iii. Canadian-Wide Standards for Mercury Emissions from Coal-fired Electric Power Generation Plants (endorsed in 2006 by the CCME)
iv. The Environmental Codes of Practice for Steam Electric Power Generation (revision published in 2003)
    a. Siting Phase (1987)
    b. Design Phase (1985)
    c. Construction Phase (1989)
    d. Operation Phase (1992)
    e. Decommissioning Phase (1992)
v. Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation (published in 1993, revised in 2005)

The Guidelines provide advice on emissions standards to regulatory authorities including emission limits for SO_2, NO_x and total particulate matter (PM) together with opacity limits and provisions for Continuous Emission Monitoring. In consequence of revised CEPA 1999 Guidelines (Canada Gazette, Part I, 2003), emission limits were stringent and the form of the limits was changed from input-based emission limit (i.e. allowable emissions per unit of heat energy input) to output-based limits (i.e. allowable emissions per unit of electricity output). ECCC expects such approach to encourage more efficient generation technology and operations. (ECCC 2013b)

(IEA CCC 2015) Canada-wide Standards for Mercury Emissions is a result of intergovernmental political commitment by federal, provincial and territorial Ministers to address key environmental protection and health risk issues. Consequently, CCME, in association with ECCC, set the mercury standard for the largest single man-made source for mercury emissions in Canada i.e. the power generation sector. Standard consists of two sets of targets;

i. provincial caps (kg/y) on mercury emissions from existing coal-fired electric power generation plants to be achieved by 2010; and
ii. capture rates or emission limits for new plants, based on best available technology economically achievable since the CWS inception in 2006.

3.4 Regional Emission Regulations in North America

In addition to nationwide legislations in the USA and Canada, U.S. states and Canadian provinces have implemented independent, regional-level emission regulations as a part of regional initiatives to mitigate the climate change. Methods vary from market or tax based systems to extreme ban of emitting coal-fired generation as was the case in Ontario, Canada (see 3.4.6).

At present, there are two GHG related emission trading schemes (ETS) operating within Canada and USA; California-Québec ETS (3.4.2) and RGGI (3.4.1) in the northeastern USA. Though, other regional regulations may have features of emission trading as well, e.g. Alberta's GHG regulation. However, both programs are on early stages as both have operated relatively a short time; first allowance actions were held in 2008 (RGGI) and 2012 (California-Québec). The role of existing ETSs remains uncertain in case the CPP, at some point, realizes as the Plan may have overlapping emission trading features.

3.4.1 The Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI), the first mandatory market based regulatory program in the USA to reduce GHG emissions, has been running since 2009 (Hibbard et al. 2015). Currently nine member states from the eastern parts of the USA, which seek in cooperation to cap and reduce CO_2 emissions from the power sector consist of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont (RGGI 2015). CO_2 emissions from particular states accounted 4% of the total emissions from the electric power sector in the USA in 2012. (EIA 2014)

RGGI cap-and-trade approach includes following six mechanisms (RGGI 2015):

i. A multi-state CO_2 emissions budget ("cap")
ii. Requirements for fossil fuel-fired electric power generators
iii. Allocating CO_2 allowances
iv. Investing proceeds
v. Allowing offsets
vi. An emissions and allowance tracking system

Accordingly, each member state has defined its annual state-level emission budgets or CO_2 emission cap. These determine how many emission allowances will be issued by each state yearly. One allowance represents a limited authorization to emit one short ton (c. 0.907 metric ton) of CO_2 from a regulated source. The total amount of scheduled allowances comprises the multi-state CO_2 emission budget. According to the budget, these allowances are then distributed through regional CO_2 allowance auctions conducted quarterly by non-profit corporation, RGGI Inc. accordance with the statutory and/or regulatory authority of each state. Proceeds from the auctions are returned to states and invested in consumer benefit programs related with energy efficiency, renewable energy, direct energy bill assistance and other GHG reduction programs. By the end of 2015, auctions have resulted in total proceeds of nearly $\$_{US}$ 2.4 billion (RGGI 2015; Hibbard et al. 2015 p.16)

Compliance of affected or "regulated" sources, generally including all fossil fuel-fired electricity generating plants with capacity of equal or greater than 25 MW, is conducted at the end of each three-year control period; every affected source must retire a number of allowances equal to the total tons of CO_2 emissions from the source over the three-year compliance period or "Interim Control Period". First compliance period situated during 2009-2011, the second 2012-2014 and current, the third 2015-2017. (Hibbard et al. 2015 p.15)

RGGI gives some flexibility for power plants to comply emission limits as regulated power plants are allowed to compensate limited amount of required emission allowances with CO_2 offset allowances which represent a project-based greenhouse gas emission reduction outside of the capped electricity sector. For each control period, the use of CO_2 offset allowances is restricted to 3.3 percent of affected source's CO_2 compliance obligation. (RGGI 2015)

Based on the assumption made in 2005, multi-state emission cap was originally designed to stabilize CO_2 emissions about 4% above of 2000-2002 levels during the period of 2009-2014, then requiring gradual reductions to achieve 10% decrease from 2009 cap level by 2019 (Ramseur 2015 p.4). As illustrated in Figure 17, emissions from the region were actually approximately 35% below the initial cap in 2009 which lead to tightening of the cap by 45% in 2015 (EIA 2014). States decided to sustain the initial plan to gradually reduce emission cap by 2.5% each year from 2015 through 2020 (Hibbard et al. 2015 p.15).

In 2012, an additional adjustment was made from cap of 170 Mt_{CO2} to 150 Mt_{CO2} as the original member state, New Jersey, exited the program. Then governor in the office, republican Chris Christie, with other conservative opponents, justified the exit by stating RGGI being inefficient, unjust tax on business and the cost would ultimately be passed on consumers. Christie claimed New Jersey achieves emission reduction even without the "failed" program as power producers were taking advantage of cheap prices for natural gas which is less polluting than fuels like coal. However, carbon market experts pointed out that such emission reduction might not be long-lasting as an economic recovery could cause emissions to soar again. Furthermore, some opponents of the governor's decision ascribed exit as a political move to gain more support for upcoming presidential race. (Navarro 2011)

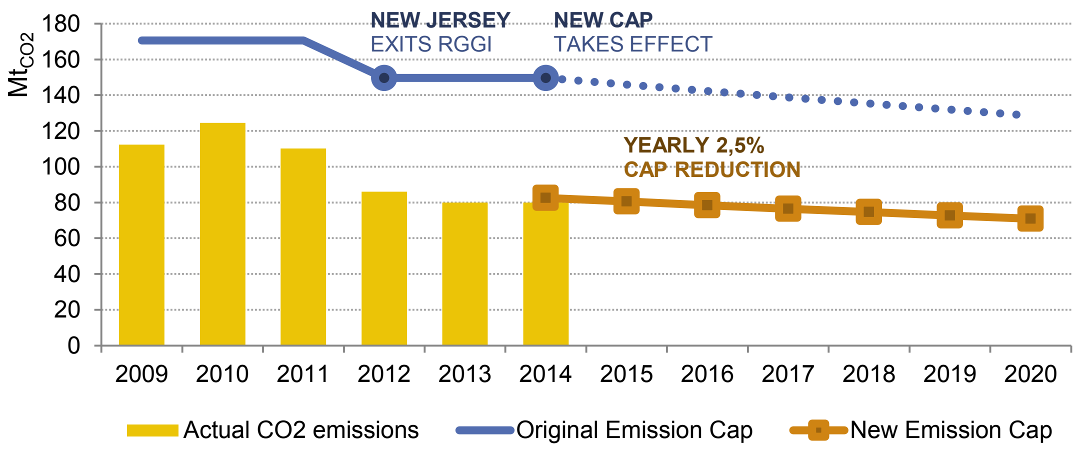

Figure 17 – Actual CO_2 emission from the RGGI region, original and adjusted emission caps (RGGI 2015; EIA 2014)

Since September 2008, RGGI Inc. has arranged 30 auctions having nearly 800 million allowances sold in total. As presented in the Figure 18, during the first compliance period, after a brief peaking in the beginning, the clearing price showed stable price level of around 2.1 $\$_{US}/t_{CO2}$. After 2012 Program Review and annunciation of the cap reduction, the number of offered allowances have matched the demand, hence the prices have indicated rather increasing trend reaching the all-time highest price of 8.28 $\$_{US}/t_{CO2}$ in the 30th auction. (RGGI 2015; EIA 2014)

The RGGI states have also established a Cost Containment Reserve (CCR) of CO_2 allowances creating a fixed additional supply of allowances. Participants have predefined certain trigger prices and quantities of these extra allowances on the market for each calendar year. Additional allowances are available for sale only if the allowance prices exceed the distinct levels that are \$4, \$6, \$8 and \$10 for the years 2014, 2015, 2016 and 2017, respectively. After 2017 the release price will be rising by 2.5 percent each year. The CCR allowance quantity for 2014 was 5 million allowances and 10 million CO_2 allowances each year thereafter. (RGGI 2015)

New York, Maryland and Massachusetts, in particular order, have the major shares of the total allocated allowances. In 2015, 77% of all over 66.8 million allocated allowances, equal to 66.6 million metric tons of CO_2 emissions, was distributed between above-mentioned states; 39%, 22% and 16% to New York, Maryland and Massachusetts, respectively. The number of allocated allowances is less than the budgeted emission cap due to adjustments for banked allowances. (RGGI 2015)

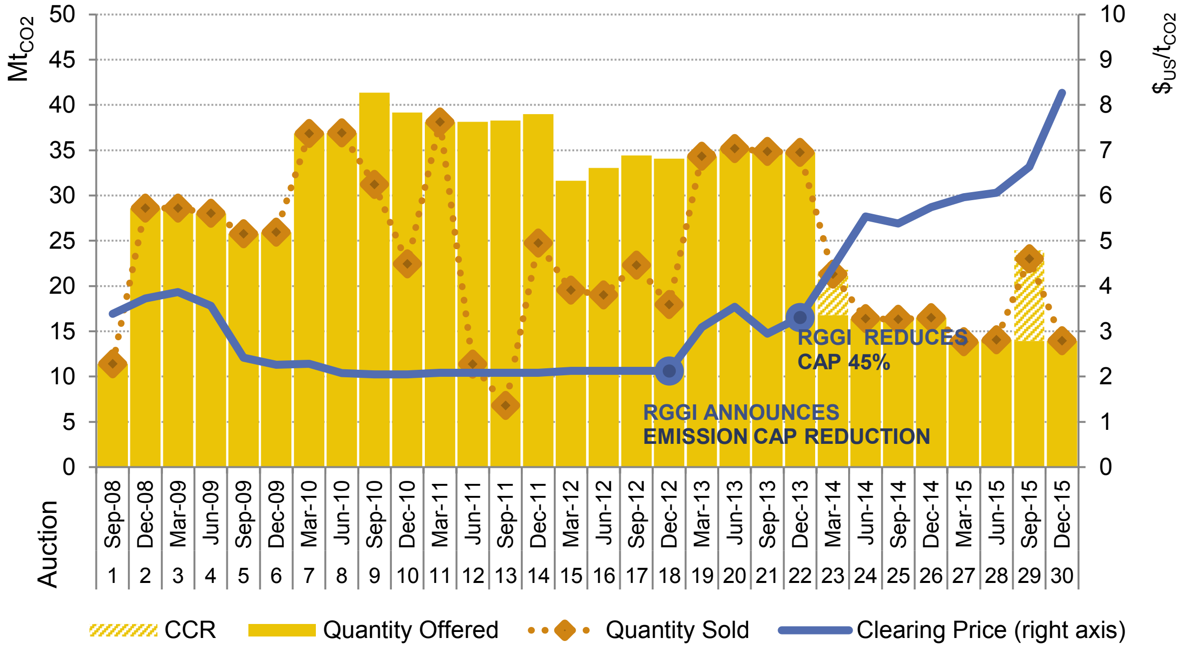

Figure 18 – RGGI CO_2 Allowance auction clearing price and quantity of offered (including Cost Containment Reserve, CCR) and sold allowances; Units converted to metric tons of CO_2 (RGGI 2015; EIA 2014)

3.4.2 California-Québec Emission Trading Scheme

At present, linked cap-and-trade systems between California and Québec form the largest carbon market in North America that is, additionally, the first ETS designed to be operated by subnational authorities of different nations (EDF et al. 2015b). California and Québec both are on national level significant GHG emitters as California was the second largest GHG emitter in the USA with the amount of 459 $Mt_{CO2\text{-}eq.}$ in 2013 (cf. US annual CO_2 emissions of 5 279 Mt) and Québec on the third place of Canada's corresponding list with the 2013 GHG emissions of 83 $Mt_{CO2\text{-}eq.}$ while total GHG emissions of Canada was 726 $Mt_{CO2\text{-}eq.}$ (ECCC 2015; EIA 2015h).

California-Québec ETS is a result of Western Climate Initiative (WCI) in which California joined 2007 and Québec 2008 (EDF et al. 2015b; 2015a). Other members currently consist of British Columbia, Ontario and Manitoba (WCI 2013). The main goal of the initiative was to reduce GHG emissions by 15% from 2005 levels by 2020 which was mainly intended to achieve by establishing a market based cap-and-trade program among the member states covering nearly 90% of the GHG emissions in WCI states and provinces by 2015. However, only two WCI members, above-mentioned California and Québec, have established emission trading systems so far. Though, Ontario have recently announced its intention to also launch an ETS by 2017. (Garside 2015)

California and Québec have both their state and province level targets to mitigate the climate change that have led to legislative procedures to adopt cap-and-trade regulations and other supporting guidelines such as mandatory GHG reporting. Global Warming Solutions Act, also known as Assembly Bill 32 (AB 32) signed into law in 2006 required California Air Resources Board (ARB) to develop regulations, such as market mechanisms, to reduce GHG emissions from California to 1990 levels by 2020. Similarly, in 2006 Québec initiated its First Climate Action Plan leading to implementation of a levy based on the carbon content of fossil fuels. The Plan was followed by a new GHG emission reduction target (20% below 1990 levels by 2020) in 2009 and, during the same year, Québec adopted its Environmental Quality Act authorizing the government to implement an ETS. (EDF et al. 2015a; 2015b)

Québec has been officially linked with California cap-and-trade system since 2014. A year earlier California and Québec started first, individual compliance periods lasting from 2013 to 2014. The second compliance period started in 2015 and will last until the end of 2017. Following, the third period runs correspondingly three years from 2018 to 2020. Each period consists of annual allowance budgets (see Figure 19 and Figure 20) which are mainly allocated with affected entities via quarterly arranged auctions for both, current allowances and future allowances purchasable three years in advance. (EDF et al. 2015a; 2015b)

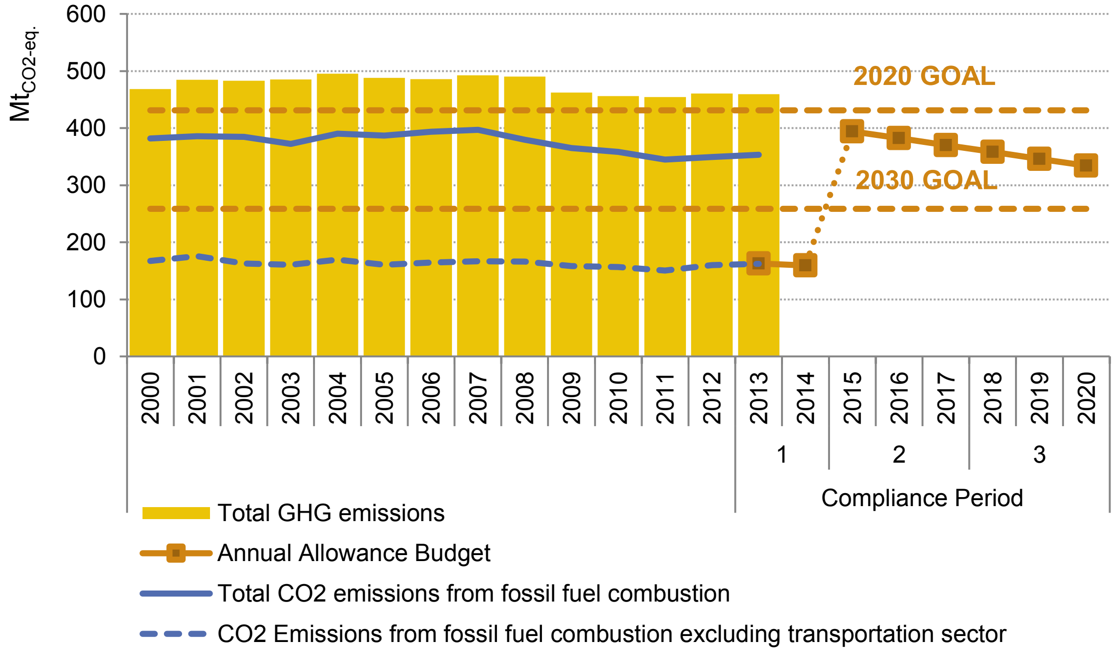

Figure 19 – GHG emissions in California, emission level goals for 2020 and 2030, and annual allowance budgets for 2013 to 2020 (ARB 2015; EIA 2015h; Thomson Reuters 2016)

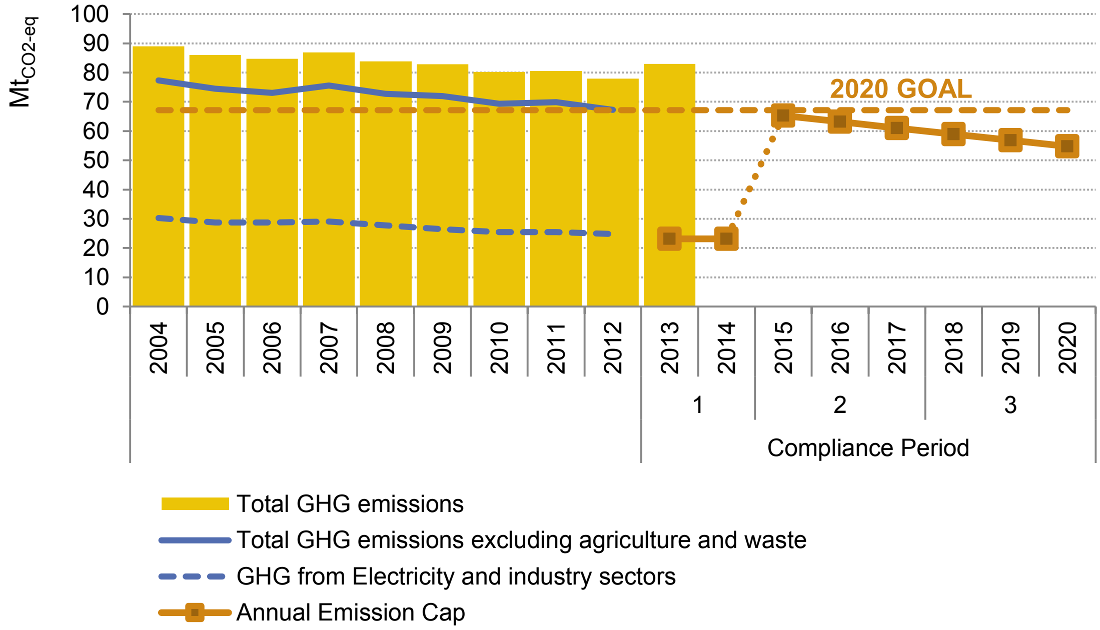

Figure 20 – GHG emissions in Québec, emission level goal for the year 2020 and annual emission caps for 2013 to 2020 (Government of Québec 2012a; 2012b; 2015; ECCC 2015)

Annual allowance budget of 162.4 $Mt_{CO2\text{-}eq}$ for California in 2013 accounted roughly for 35% of the total GHG emissions from the region and was approximately equal to CO_2 emissions from the fossil fuel combustion excluding transportation sector, which was not at that time included in the cap-and-trade system (EIA 2015h; Thomson Reuters 2016). Later, after the linkage of the two systems, regional administrations expanded the scope to include, besides facilities such as heavy industry and first delivers of electricity (including imports) that emit equal or more than 25,000 $t_{CO2\text{-}eq}$ GHG emissions a year, fossil transportation fuels and retail sales of natural gas (EDF et al. 2015a). Hence, Californian allowance budget was adjusted to 394.5 $Mt_{CO2\text{-}eq}$ (i.e. around 85% of total 2013 GHG emissions (ARB 2015)) for 2015 gradually decreasing 12 $Mt_{CO2\text{-}eq}$ yearly thereafter (Thomson Reuters 2016).

Again, for Québec, the annual allowance budget of 23 $Mt_{CO2\text{-}eq}$ for the first compliance year accounted less than 30 % of the total GHG emissions of the year in question. Similarly, as in the case of California, the annual budget was increased in 2015 up to 65.3 $Mt_{CO2\text{-}eq}$ accounting nearly 79% of the 2013 emissions to meet the expansion of the cap-and-trade system (Government of Québec 2012b). In 2016 and thereafter, the allowance budget gradually decreases by 2.1 $Mt_{CO2\text{-}eq}$ per year. With the current allowance budget of 63.2 $Mt_{CO2\text{-}eq}$ Québec's share of the total budget of 447.2 $Mt_{CO2\text{-}eq}$ is approximately 14% meaning it will be the price taker. That is, Californian entities will have a greater impact to the auction prices due to the greater allowance volume.

Allowance price have showed moderate upward trend on the both markets, in California and Quebec, since the first joint auction was held in November 2014 as Figure 21 and Figure 22 demonstrate. For entities in California, which are forced to buy allowances only in US dollars the price was $\$_{US}$11.9 for an allowance (equal to 1 $Mt_{CO2\text{-}eq}$ of GHG emissions) which has increased slightly to $\$_{US}$ 12.7 per allowance or $\$_{US}$ 0.6 above the 2015 floor price by the last auction in November 2015 (ARB 2016; EDF et al. 2015a p.13). Price of the future allowances remained parallel to the current allowance price during 2014 and 2015. In the Québec market, where entities are allowed to buy either in Canadian or US dollars (exchange rate adjusted day ahead) the first joint auction allowance price set to $\$_{CAN}$ 13.4 per $Mt_{CO2\text{-}eq}$ (in Canadian dollars) presented relatively greater increase to 17 $\$_{CAN}$ /$Mt_{CO2\text{-}eq}$ by the last auction which can be attributed to the fluctuation in US dollar and Canadian dollar exchange rates (Government of Québec 2016).

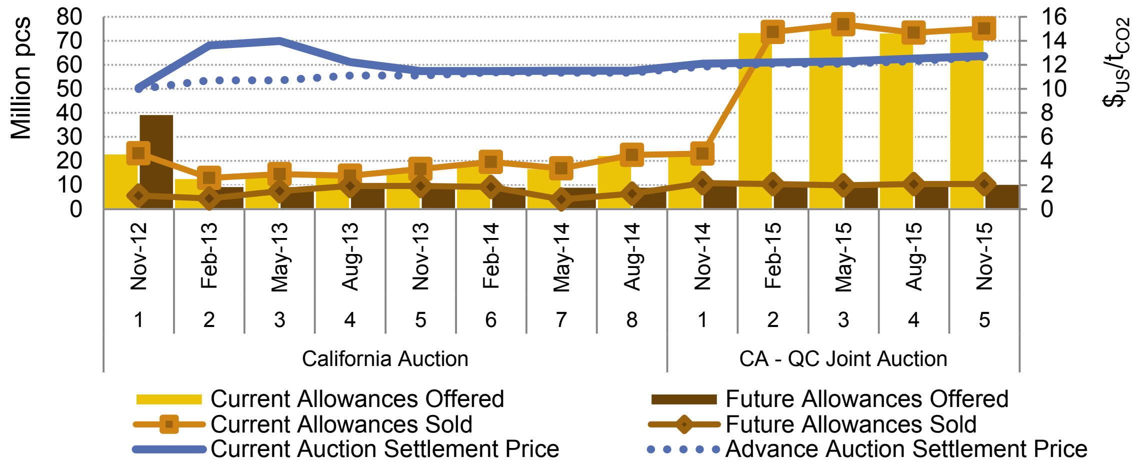

Figure 21 – Results of emission allowance auctions under Californian cap-and-trade program. Future allowances are offered three years advance to the compliance year. (ARB 2016)

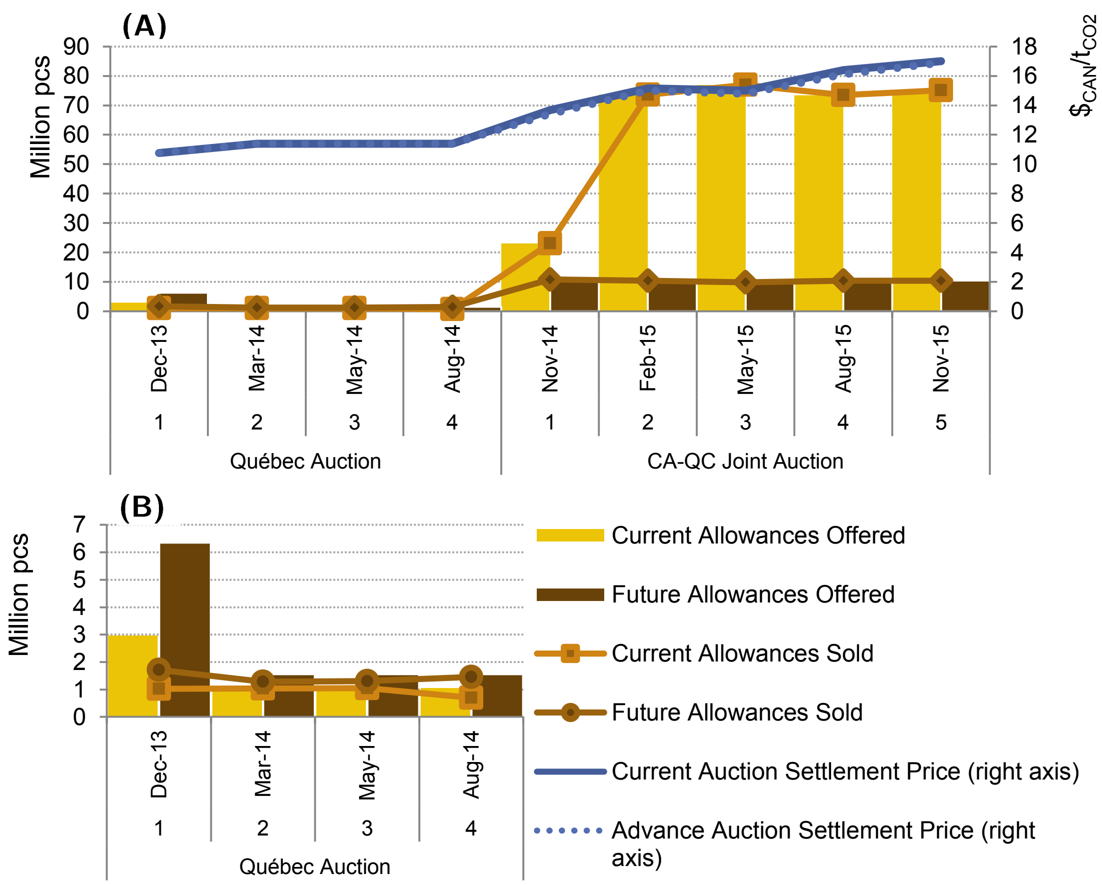

Figure 22 - Results of emission allowance auctions under Québec cap-and-trade program (Government of Québec 2016) Note that Part B represents scaled version of "Quebec Auction" series in part A.

Compliance of the affected entities is monitored a year after the compliance period ends when the "true up" occurs meaning each entity must retire the amount of allowances equal to their emissions during that period, which are not already covered with the annual compliance obligations (at least 30% of the previous year GHG emissions). System allows flexibility for compliance including offsets, allowance price containment reserve and limited allowance banking. Offsets, credits achieved via support of mainly environmental initiatives to, for instance, reduce GHG emissions, are limited to cover no more than 8% of company's compliance obligation for each compliance period. (EDF et al. 2015a; 2015b)

3.4.3 Other US State Level Regulations

In addition to aforementioned schemes, various US states have also initiated other regional regulations to reduce GHG from the power sector including CO_2 emissions performance standards, renewable portfolio standards (RPS) and energy efficiency resource standards (EERS) that reduce CO_2 emissions by altering the generation mix and reducing energy demand. (EPA 2014)

CO_2 emission performance standard applies either directly to electricity generating units or to the local electricity distributing company. This depends on the sector structure; in some states utilities are vertically integrated meaning that one company is responsible for electricity generation, transmission, and distribution over a given service territory. In this case state has authority regulate these utilities. Instead, in states where the electric power industry has been restructured - i.e. ownership of electric generation assets has been decoupled from transmission and distribution assets - public utility authors have authority to regulate only the electricity distribution utilities. States have implemented three types of performance standards that affect directly generating units and or local distribution companies (EPA 2014):

i. Standard based on emissions per electricity generated that enforces generating units limit their specific emissions to predefined level
ii. Standard for local distributors that sets an emission rate on purchased electricity
iii. Requirement for new coal-fired generating units to implement partial CCS system with specific capturing rate. By far, six US states - California, New York, Oregon, Washington, Illinois and Montana – have implemented an individual emission standard on CO_2 emissions.

To date, according to the EPA (2014), 27 states have implemented EERS that applies to retail distributors of electricity and/or natural gas. Such standard sets multiyear target for energy savings that utilities meet through various approaches including customer energy efficiency programs, peak demand reductions and combined heat and power. As a result, an EERS affects to fossil fuel-fired generating units by reducing electricity purchases from such units.

(EPA 2014) Another regulation that indirectly affect to fossil-fuel-fired power plants, RPS or renewable electricity standard (RES), forces retail electricity suppliers to supply a minimum share or amount of their electricity load with electricity generated with renewable sources thus reducing the utilization of fossil-fuel-fired electricity generating units. By far 29 states and Washington, DC have adopted mandatory RPSs with varying designs and an additional 9 have voluntary renewable energy goals. Additionally, states have performance-based incentives and finance mechanisms for renewable energy including feed-in tariffs and other payments or tax incentives. Currently 18 states have state-wide performance-based policies, and in several other states utilities have adopted programs based on performance-based incentives.

3.4.4 Alberta GHG regulations

Alberta, a province of Canada that is well-endowed with natural resources including coal, minerals, natural gas and oil, has created a unique, first of its kind system in North America to reduce GHG emissions of large scale emitters and create price for carbon pollution. Showing increasing trend in annual GHG emissions since 1990 and having the largest contribution to the total emissions in Canada (in 2013 38% share with the amount of 267 $Mt_{CO2\text{-}eq}$) Alberta have initiated its Climate Change and Emissions Management Act (CCEMA) to manage increasing GHG emissions (EDF et al. 2015c; ECCC 2015). The following year after CCEMA was passed in 2003 it developed a mandatory reporting program, Specified Gas Reporting Regulation (SGRR), which currently requires facilities that emit 50,000 $t_{CO2\text{-}eq}$ or more of greenhouse gases to submit annual reports on their emissions (EDF et al. 2015c p.2; AEP 2015).

SGRR was followed by SGER, being in effect since 2007, that requires facilities that emit 100,000 $t_{CO2\text{-}eq}$ or more of greenhouse gases a year to, instead of an absolute cap for aggregate emissions, reduce their emissions intensity (Government of Alberta 2012). Facilities commissioned 2015 and before are enforced to reduce their intensity 2% a year compared to the baseline intensity (average intensity of the first three years) starting from the fourth year of commercial operation in order to meet the 12% reduction target over a six-year period. For facilities commencing year 2016, the emission intensity reduction target is set to 15% for the six-year compliance period whereas facilities with commencing year of 2017 are constrained to limit their emission intensity of the 9^{th} year commercial operation to 80% of the baseline emission intensity.

According to the Alberta Environment and Parks (AEP 2016), a ministry of the Government of Alberta, the affected entities have four ways to meet their intensity reduction targets:

i. Make improvements to their operations (i.e. reduce on-site emissions)
ii. Use Emission Performance Credits (EPC)
iii. Purchase Alberta-based carbon offset credits
iv. Contribute to the Climate Change and Emissions Management Fund

EPC and offset credit are both market based mechanisms. Credits are equal to 1 $Mt_{CO2\text{-}eq}$ and are generated by regulated facilities that have reduced below their reduction target (EPCs) or by facilities and sectors not subject to the Regulation that are able to reduce their greenhouse gas emissions (offset credits). Credits are registered to the Alberta Emission Performance Credit Registry and the Alberta Emission Offset Registry, operated by CSA Group, where they can be purchased by regulated facilities in order to meet their targets.(CSA Group 2016)

Besides on-site emission reduction and carbon credit purchase, covered companies are permitted to pay a fixed fee for Climate Change and Emissions Management Fund to compensate their emissions. In 2016 the fee equals \$20 per emitted $t_{CO2\text{-}eq}$ (in Canadian dollars) and \$30 per emitted $t_{CO2\text{-}eq}$. in 2017. The money collected by the government of Alberta into the fund may only be invested through the non-profit Climate Change and Emissions Management Corporation (CCEMC) on accepted initiatives and projects associated with GHG emissions reduction and Alberta's ability to adapt to climate change. (AEP 2016)

According to the ministry (AEP 2016), since 2007, together with the result of total prevented GHG emissions of 61 $Mt_{CO2\text{-}eq}$ approximately $\$_{CAN}$ 577 million has been paid into the fund of which $\$_{CAN}$ 350 million has been invested into 109 clean energy and adaptation projects as Figure 23 indicates. Offset projects constitutes the major share, 40%, of the total prevented emissions. "Cogeneration recognition" has the portion of 36% as CHP plants receive recognition for the performance in their compliance calculation compared to a stand-alone alternative of an 80% efficient boiler and a natural gas combined cycle electricity plant. Thus, facility improvement accounts the rest, 24% of the total emissions prevented. With such measures prevention equals roughly 7.6 $Mt_{CO2\text{-}eq}$ annual emissions on average i.e. 2.8% share of the total Alberta's 2013 GHG emissions.

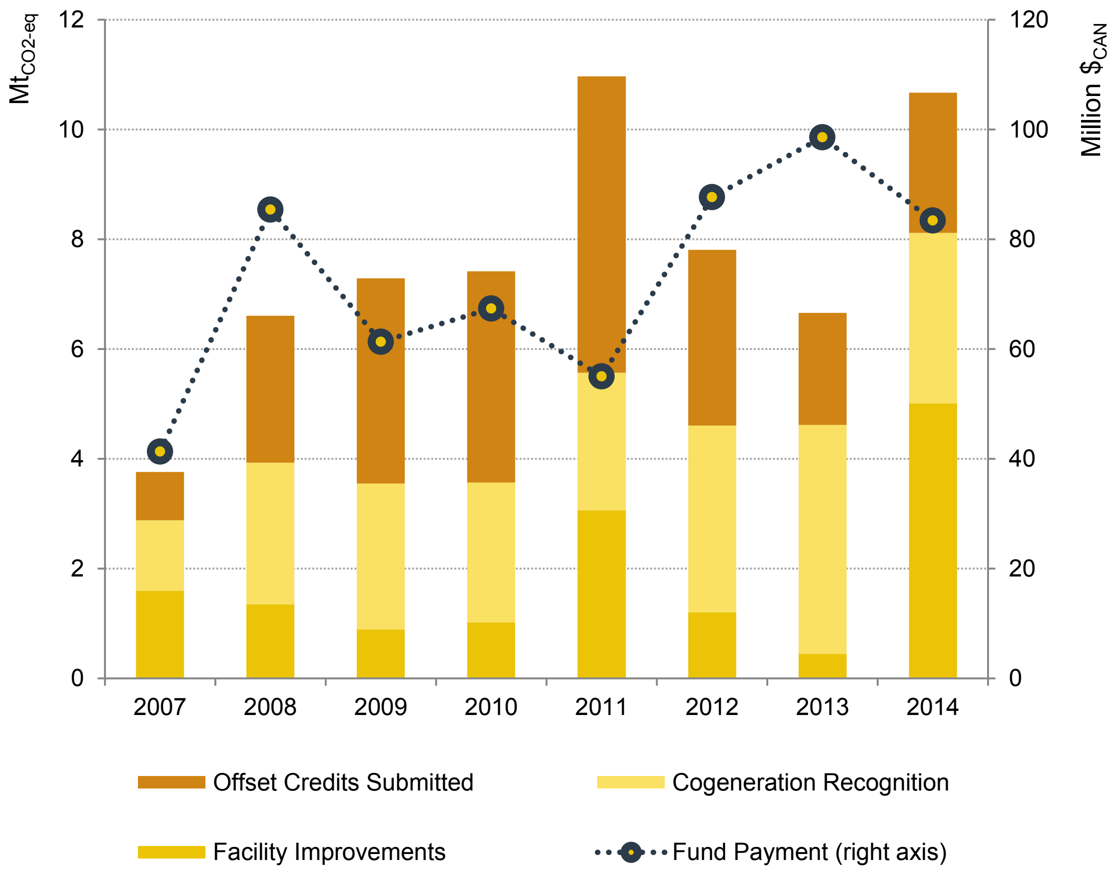

Figure 23 – Payments into Climate Change and Emissions Management Fund and GHG emissions prevented through offsets, facility improvements and cogeneration recognition (AEP 2016)

In addition to its current carbon price system, Alberta is developing additional policies to mitigate the climate change. Based on recommendations put forward by the Climate Change Advisory Panel, the government of Alberta (2016) recently introduced its new strategy on climate change, Climate Leadership Plan which focuses, inter alia, on phasing out coal-generated electricity and developing more renewable energy. Under the plan retirement of coal-fired power plants is accelerated so that "there will be no pollution from coal-fired electricity generation by 2030". Two-thirds of the existing coal-fired capacity will be replaced by renewable energy and the rest by natural gas. Such a shift will be fostered by carbon price for coal-fired generators of $\$_{CAN}$ 30 per ton of emitted CO_2 (planned implementation in 2018) and by incentives offered for renewable generation.

3.4.5 Nova Scotia's Greenhouse Gas Emissions Regulations

Nova Scotia, a Canadian province that heavily relies on coal-fired electricity generation, has implemented regulation for GHG emissions from the electricity sector as a part of its' Environment Act 1994-95. GHG regulations, i.e. gradually tightening cap for GHG emissions from electric power producers, came into effect on 2009 and were amended in 2013 to provide caps for period of 2021-2030. Caps are presented in Figure 24. (Government of Nova Scotia 2013)

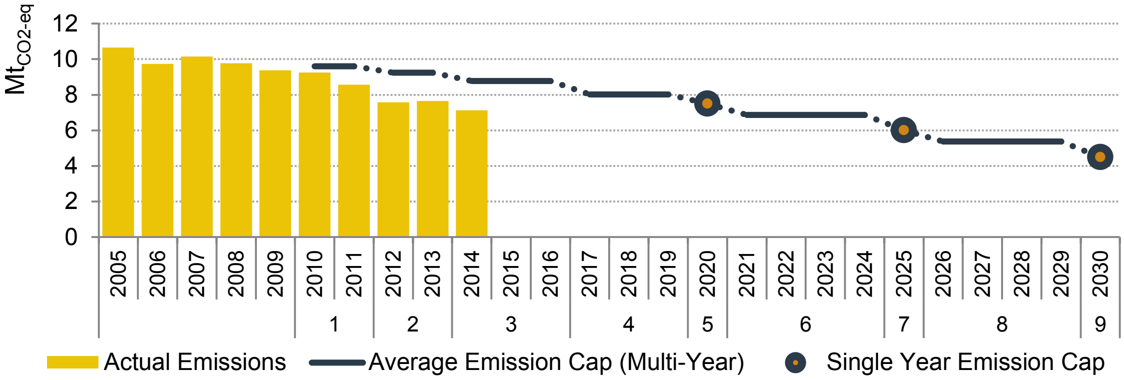

Figure 24 – Actual electricity sector GHG emissions and emission caps for electricity sector in Nova Scotia by compliance period (Government of Nova Scotia 2013; Nova Scotia Power 2016)

On May 26, 2014, Environment ministers of Canada and the province of Nova Scotia signed an equivalency agreement, a.k.a. "An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from the Electricity Producers in Nova Scotia" that liberates coal-fired generation units in Nova Scotia to comply with the federal performance standard. The agreement came into force on July 1, 2015 and terminates on December 31, 2019 "or may be terminated earlier by either Party giving the other at least three months' notice". "The Parties" (i.e. Canada and Nova Scotia) commit to initiate its renewal in case the effect of Nova Scotia's regulation for 2021-2030 is still considered equivalent to the effect on greenhouse gas emissions levels that would result from the application of the federal regulation. The agreement was signed under the authority of the Section 10 in the CEPA 1999 which purpose is to minimize the duplication of federal and provincial or territorial level environmental regulations. (ECCC 2014)

3.4.6 Ontario's Coal Phase-out

The province of Ontario has successfully phased out coal-fired generation by the April, 2014. Still, in 2003, coal accounted for 25% or nearly 8 GW_{elec} of the existing generation capacity in the region (see Figure 25). Elimination of the coal-fired generation in phased approach originates to 2001 when the province announced its intention to close the remaining four-unit Lakeview generation station. Two years later, Ontario committed to eliminate all of its coal-fired generation driven by the concern about public health, environment, climate change, and prospects for Ontario-based green energy. As a result, the operation in Lakeview was ceased in 2005. Later, in 2010, phasing out started in the Nanticoke (3.94 GW_{elec}), that was the largest coal-fired plant in the Northern America at the time. It was ultimately shut down at the same year, 2013, as the Lambton generation station was entirely retired. Atitokan and Thunder Bay generation stations are being converted to biomass in which coal use ceased in 2012 and 2014, respectively. Also repowering of 4 Nanticoke generation units with biomass is under consideration. (Ministry of Energy 2015; Harris et al. 2015 p.14)

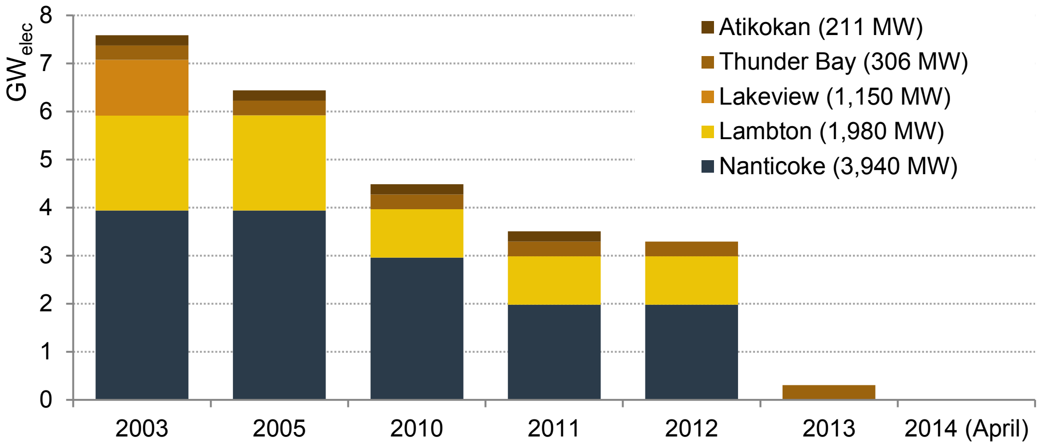

Figure 25 – Phase-out of coal-fired generation capacity in Ontario (Ministry of Energy 2015)

Normally, major energy policy reforms such as fossil fuel phase-out would require supporting mechanisms to mitigate negative impacts of the transition and solutions to cover energy needs caused by the restructuring (Harris et al. 2015). However, this was not the case in Ontario. Rosenbloom and Meadowcroft (2014 p.676) list four elements that largely facilitated the phase-out. First, coal had already a limited contribution to the generation mix (i.e. the abovementioned 25% of existing capacity in 2003). At the initial year of the reform (2005), the total 159 TWh$_{elec}$ of the electricity was generated mainly by nuclear power (49%), hydro power (22%) and coal (19%). At the time NG-fired generation accounted for 6% and renewables only 3% of the total electricity generated. However, as a result of the policies, shares of nuclear, hydro, NG and renewables (mostly wind but also biomass and solar) increased up to 61%, 25%, 7% and 7%, respectively by 2014 when the total electricity generation accounted for 157 TWh$_{elec}$. (Government of Canada 2016b; 2015d)

Secondly, there was no coal production in Ontario, hence the limited impact on job markets. Third, growth in demand was slower than expected, so that new projects did not feed rapidly into retail power prices. Finally, natural gas has become a more abundant and affordable source alongside coal. (Meadowcroft 2014 p.676). Additionally, the Government of Ontario owned fossil fuel-fired generation plants in Ontario through the Ontario Power Generation company, which absorbed the costs of coal plants' shutdowns without opposition (Harris et al. 2015).

Nonetheless, Ontario's reform resulted significant reduction in four major pollutants from the electricity sector; during 2005-2015, annual GHG emissions decreased by 87% (from 32.9 Mt$_{CO2\text{-}eq}$ to 4.25 Mt$_{CO2\text{-}eq}$) while NO_x, SO_x and mercury emissions decreased by 86%, 99.6% and 100%, respectively (Ministry of Energy 2015). However, Ontario Power Generation assures that, by time of the reform launch, its' generation units were already among the cleanest power generators in the North America (Harris et al. 2015). Additionally, it could have address mercury, SO_x, NO_x, and PM emissions from generation, thus increase air quality and prevent harmful health impacts, cost-effectively with existing technology.

3.5 The EU Regulations

As a member of the European Union (EU), the UK takes part in EU actions to mitigate climate change. For instance, the EU has committed to 2020 target (aka 20-20-20 Target) that consists of three goals: The first of which is to reduce emissions by 20% on 1990 levels; the second is to provide 20% of its total energy from renewables and; the third is to increase energy efficiency by 20% from 2007 levels. EU members are also pursuing to reach 80-95% GHG emission reduction by 2050. (CCC 2016)

The EU has introduced several initiatives to achieve emission reductions of which most significant on the perspective of fossil fuel-fired power plants is the EU Emission Trading System (EU ETS). It is a cap-and-trade system for high emitting industry and intends to create a price on carbon emissions. For more information about the EU ETS, see following Section 3.5.1.

In addition to actions reducing GHG emissions, the EU has also implemented directives to limit other harmful emissions from polluting installations including the industrial emissions directive (IED). It significantly affects future prospects of UK's aged coal-fired plants by strictly limiting NO_x, SO_2 and dust emission. Subsequent Section 3.5.2 provides further information of the IED.

3.5.1 The EU Emission trading system

The EU emission trading system (ETS) is European Union's key tool to reduce industrial GHG emissions from more than 11 000 power stations and industrial plants located in 31 European countries (European Commission 2016i). To reduce the emissions in a cost-effective way, the system functions on the "cap-and-trade" basis - likewise the abovementioned schemes including the US Acid Rain Program (Sec. 3.2.1), RGGI (Sec. 3.4.1) and California-Quebéc ETS (Sec. 3.4.2.). The EU ETS is, however, considered as world's first international company-level cap-and-trade system.

As the cap-and-trade systems generally function, the EU ETS forms an overall limit or "cap" of GHG emissions of all participants in the system. The legislation creates allowances which entitles the holder to emit GHG emissions equivalent to the global warming potential of 1 ton of CO_2 equivalent ($t_{CO2\text{-}eq.}$). The predefined cap determines the number of allowances available in the whole system during each period. Allowances are annually distributed mainly through auctions and for free to certain participants. At the end of each year participants must return the equivalent amount of allowances for every emitted ton of CO_2-eq. during the year. In case the participant has insufficient amount of allowances it needs to either buy more allowances on the market - through auctions or from other participants – or reduce its annual emissions. Significant fines are imposed for non-complying participants (i.e. € per emitted ton of CO_2-eq) to ensure the system operation.

The EU ETS was launched in 2005 and implemented through several phases; currently the system is on the third phase. First of which was a three-year pilot period during 2005-2007 and covered only CO_2 emissions from power generators and energy-intensive industrial sectors. The most of the emission allowances were given to businesses free of charge although the penalty for non-compliance was 40 €/t_{CO2}. Even though the phase one established a price for carbon, the price of allowances fell practically to zero in 2007. This was due to a sizable allowance surplus and the fact that phase one allowances were not valid in phase two (i.e. 2008 onwards). (European Commission 2016c)

For the second phase of the EU ETS, which coincided with the first commitment period of the Kyoto Protocol (2008-2012) (see Sec 3.1.1), the European commission tightened the emission cap to some 6,5% below the 2005 level. However, still 90% of the allowances were given away for free while the penalty grew to 100 €/t_{CO2}. Several member states, including the UK, held auctions. Albeit the national caps were adjusted for phase two based on verified emissions data gathered during the pilot phase, they greatly exceeded the actual demand. Main reason for this was the unforeseen economic crisis that began in late 2008 depressing emissions throughout the period. The great margin between the cap and the allowance demand caused a large and growing surplus of unused allowances weighing down the carbon price. (European Commission 2016c)

Current, the third phase was launched in 2013 and runs to 2020 (i.e. the second commitment period of Kyoto protocol) until the phase four or the Paris Agreement period (2021-2030) begins (see Sec 3.1.2). Main theme for the phase three was harmonization of the system. For instance, instead of allocating free allowances on the basis of national criteria, allocation is made under the EU-wide benchmarks of emissions performance (European Commission 2016i). As a result, since 2013 power generation sector has been subject to 100% auctioning (European Commission 2016e p.24). In fact, the allowance auctioning became the default allocation method; the share of auctioned allowances progressively increases each year starting from around 40% in 2013 (European Commission 2016i). Also, a single, EU-wide emission cap was implemented replacing previous national level caps. It started from 2084.3 $Mt_{CO2\text{-}eq.}$ in 2013 and linearly declines to 1816.5 $Mt_{CO2\text{-}eq.}$ by 2020 so that in 2020 emissions from fixed installations will be 21% lower than in 2005. (European Commission 2016e p.18)

The phase three introduced the New Entrants Reserve (NER) and "NER 300" program to fund deployment of renewable energy and CCS related projects. The NER 300 is funded from the sales of 300 million earmarked allowances (European Commission 2016f). The funds from these sales are then distributed to projects selected through two rounds of calls for proposals. One of the funded projects was White Rose CCS project (see Section 6.3.2) located in the UK with maximum NER 300 funding of 300 million euros (European Commission 2014).

Today, EU ETS covers roughly 45% of the emissions EU's GHG emissions (European Commission 2016c). It covers heavy-energy using installations including power stations and other combustion plants with equal or higher than 20 MW thermal rated input (European Commission 2016e p.20). Additionally, as of 2012, all emissions from flights arriving at or departing from any airport situated in any EU ETS participating country (i.e. EU member states and Norway, Iceland and Liechtenstein) were included in the system (European Commission 2016e p.89).

In accordance with Article 10(2) of the EU ETS directive, 88% of the total allowances that can be auctioned are distributed to member states based on their phase one GHG emissions. 10% of the auctioning rights are distributed to the least wealthy EU member states. The remaining 2% provides "Kyoto bonus" for member states which by 2005 had reduced their greenhouse gas emissions by at least 20% of levels in their Kyoto Protocol base year or period. Auctions take place on a common transitional auction platform (i.e. European Energy Exchange, EEX) appointed through a joint procurement procedure. However, states may choose to "opt-out" from the common platform and have their separate platforms as Germany, Poland and the UK have done. However, EEX currently provides a platform, though separate from the common one, for German and Polish auctions. For the UK, the platform is the ICE Futures Europe (ICE). (European Commission 2016e pp.29–31; 2016d)

So far the ETS haven't been able to create a significant, sustaining price on carbon (see Figure 26). The main reason is the huge surplus of the allowances in circulation; the surplus for phase three is expected remain around 2 billion allowances. The possibility to bank allowances combined with the lower than expected demand during the phase two resulted from year to year growing surpluses. To address the persisting surplus, European Commissions postpones or "back-loads" 900 million allowances during 2014-2016 as an immediate measure. As a long-term solution, the EU ETS will be reformed including establishment of a market stability reserve (MSR) as of 2018. The 900 million backloaded allowances - together with remaining allowances that are unallocated by at the end of the current trading phase (2020) - will be placed in the reserve. (European Commission 2016h; 2015)

Short-term measures seemed to be addressing the problem as the allowance price rose from the below 3 €/$t_{CO2\text{-}eq.}$ in 2013 to over 8 €/$t_{CO2\text{-}eq.}$ by the end of 2015 as presented in Figure 26. However, suddenly, during the beginning of 2016, the price plunged again settling to around 5 €/$t_{CO2\text{-}eq.}$ by the end of March 2016. According to Garside and Szabo (2016) many market participants suspect that speculative short-selling has been responsible for the decline. On the other hand, warm December and low electricity prices may have put generators on the sellside to unwind forward hedges they no longer need. Besides, some European industrial sectors that hold large allowance surpluses are looking to monetize the units to raise cash as the fears of another economic slowdown are arising. However, once the bottom is hit (i.e. possibly the c. 5 €/$t_{CO2\text{-}eq.}$) the price may resume upward path, as the recent market data indicates (Garside and Szabo 2016; Garside 2016).

Figure 26 – Development of EU ETS carbon price during phase three (EEX 2016)

3.5.2 EU Industrial Emissions Directive

Industrial emissions directive (IED) - or Directive 2010/75/EU of the European Parliament and the Council - enforces member states to regulate pollutant emissions from industrial installations. It recasted 7 previously existing directives including the large combustion plants directive (LCPD), i.e. Directive 2001/80/EC which had very similar properties as the subsequent, tightened IED. The IED came into force on 6 January 2011 and had to be transposed by 7 January 2013. The main purpose of the directive is to protect human health and the environment across the EU particularly through application of Best Available Techniques (BAT). (European Commission 2016b)

Chapter III (with Annex V) of the IED establishes provisions for certain pollutant emissions also known as emission limit values (ELV) (see Table 5) from large combustion plants (i.e. rated thermal input ≥ 50 MW) (European Parliament and European Council 2010 Annex V; European Commission 2016a). These "minimum requirements" have replaced that of in the LCPD since 1 January 2016. To facilitate the implementation, Chapter III of the IED provides four flexible mechanisms for plants meeting the specified conditions. These mechanisms and conditions are listed in Table 6.

Table 5 –Emission limit values for coal combustion as of 12 April 2016 (European Parliament and European Council 2010 Annex V)

Total rated thermal input (MW)	**Emissions (mg/nM³)**		
	SO_2	**NO_x**	**Dust**
50-100	400	300[a]	30
100-300	250	200	25
> 300	200	200	20

[a] 450 in case of pulverized lignite combustion

Table 6 – Flexible mechanisms under the IED (European Commission 2016a)

Mechanism	**Article**	**Time Frame**	**Scope**	**Condition**
Transitional National Plan (TNP)	32	1 January 2016 – 30 June 2020	Plants which were granted the first permit before 27 Novermber 2002[a]	The plants have to be part of a plan that sets ceiling for maximum total annual emissions for all of the plants covered by the TNP.
Limited life time derogation (LLD)	33	1 January 2016 – 31 December 2023	Plants that had not been granted an exemption (Article 4(4) of Directive 2001/80/EC)	The operator commits not to operate the plant more than 17 500 operating hours and after 2023.
Small isolated systems	34	1 January 2016 – 31 December 2019	Combustion plants that were on 6 January 2011 part of a system with a consumption less than 3000 GWh in the year 1996 and less than 5% of annual consumption is obtained through interconnection with other system	
District heating plants	35	1 January 2016 - 31 December 2022	Plants with total rated thermal input of ≤ 200 MW or less if first permit was granted before 27 November 2002[a].	

[a] or the operator of the plant had submitted a complete application for a permit before that date, provided that it was put into operation no later than 27 November 2003

Consequently, by paraphrasing Gross et al. (2014), UK coal power plants that are operating after 31 December 2015 have three options to comply with the directive:

i. Enter into Transitional National Plan (TNP) and - together with other plants entered into TNP - jointly comply with the declining total emission ceiling during 2016-2020 and become fully IED compliant by 2020; or
ii. participate in limited life time derogation (LLD) retiring after 17 500 h of operation or by the end of 2023, whichever is reached first; or
iii. Initially fully comply with the conditions determined under the directive.

To comply with conditions presented in Table 5, the UK coal plants need to be most likely retrofitted with some form of abatement technology as they are fairly old in age (see Section 6.2). However, this increases capital and operating costs of the generation units and may additionally decrease the plant efficiency. These are major factors which generator operators need to take into account when choosing between the IED comply options. For instance, to meet the ELV for NO_x emissions coal plant would need to utilize selective catalytic reduction (SCR) technology or a hybridization of this with selective non-catalytic reduction (Hybrid SCR/SNCR) which would result in increased operating and capital costs as presented in Table 7. (Gross et al. 2014)

Table 7 – Estimated capital and operating costs of NO_X abatement options (PB 2014)

Technology	Cost estimate	Capital costs	Operating costs	
		£/kW	**£/MW/yr**	**£/MWh**
SCR	low	100	1 345 and	0.2
SCR	medium	130	1 345 and	0.25
SCR	high	200	1 345 and	0.5
Hybrid SCR/SNCR	low	86.7	8 517	
Hybrid SCR/SNCR	medium	97.5	8 517	

3.6 The UK Legislation

Since 1995, when the UK signed up to the Kyoto Protocol (Section 3.1.1) it has taken several steps to limit GHG emissions including legally binding targets for now and for the future. A framework to develop economically credible emissions reduction path was established in the Climate Change Act, 2008. The Act included four main actions (CCC 2016):

i. Introducing 2050 Target to reduce UK GHG emissions by at least 80% in 2050 from 1990 levels
ii. Setting up legally binding "Carbon Budgets" i.e. a cap on the amount of GHG emissions emitted in the UK over five-year periods (currently on second period, 2013-2017)
iii. Establishing the Committee on Climate Change (CCC) to advise the Government on emissions targets and report to Parliament on progress made reducing GHG emissions.
iv. Implementing a National Adaptation Plan which requires the Government to inter alia assess the UK's risks from climate change and prepare a strategy to address them.

Under the Act there are two key government departments in the center of setting the climate policy. First, the Department for Energy and Climate Change (DECC) leads on the policy to reduce emissions and is also responsible for delivering secure energy and drive ambitious action on climate change. Second, the Department for Environment and Rural Affairs (Defra) leads on domestic adaption policy and is responsible for developing a National Adaptation Programme. (CCC 2016)

Already set Carbon Budgets and projected emissions are shown in Figure 27. To achieve such goals and ultimately the 2050 target, the CCC gives recommendations for sector specific budgets and estimates of cost-effective paths. For power sector it recommends that carbon intensity of generation should decrease from around 450 g_{CO2}/kWh_{elec} in 2014 to 200-250 g_{CO2}/kWh_{elec} in 2020 and to below 100 g_{CO2}/kWh_{elec} in 2030. It could be delivered by a range of different mixes of low-carbon generation (e.g. renewables, nuclear and CCS fitted plants) and through the increased role of demand side and the flexibility of the system. (CCC 2015 p.16). However, the latest emission projections indicate that further actions are required to meet the fourth budget by 2027.

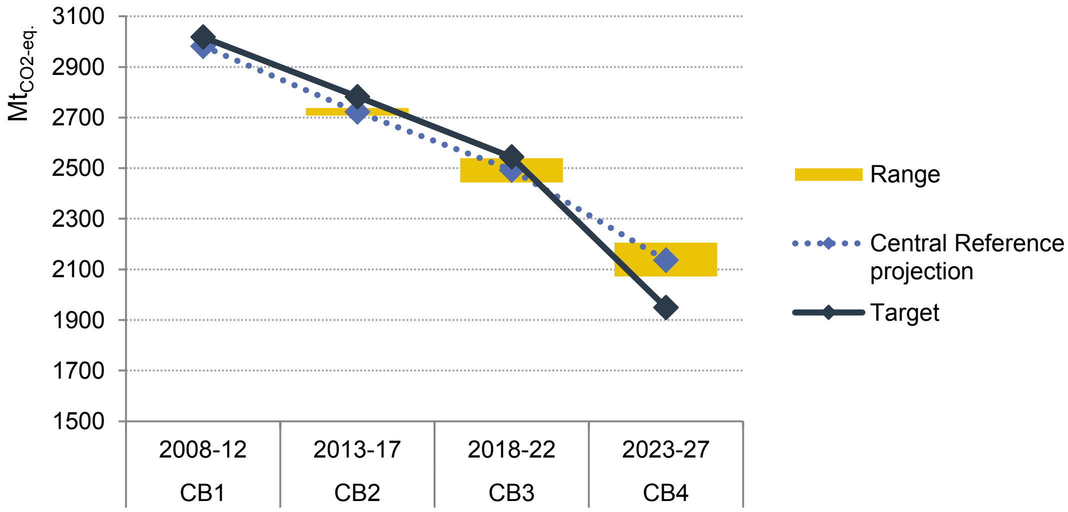

Figure 27 – Carbon budgets and estimated (and actual for CB1) emissions for each budget period (DECC 2015j)

On the other hand, the UK has already implemented measures to promote low carbon generation and limit GHG emissions from the power sector. These include Renewables Obligation (RO) and, more recent, Electricity Market Reform (EMR). The EMR has further two key elements, the Capacity Market (CM) and Contracts for Difference (CFD), and additionally two supporting mechanisms, Emission Performance Standard (EPS) and Carbon Price Floor (CPF). These combined has had a major contribution to the UK's generation mix to date and in the future. Renewables Obligation is described in Section 3.6.1 below, whereas the EMR and the related elements in the two subsequent Sections 3.6.2 and 3.6.3.

3.6.1 Renewables Obligation

The department of Energy and Climate Change (DECC) introduced Renewables Obligation (RO) scheme in 2002 aiming to intensify large-scale renewable electricity generation in the UK (DECC 2015b). The scheme will be replaced for new capacity by newer supporting mechanism, contract for difference (CFD), as a part of the electricity market reform (EMR) by April, 2017 (see Section 3.6.3). However, the RO provides a full lifetime support (20 years) for accredited electricity generation up to 2037.

The RO ensures that specified proportion, or "obligation", of supplied electricity is generated from renewable sources by following method (as Figure 28 illustrates): Office of the Gas and Electricity Markets (Ofgem) issues Renewables Obligation Certificates (ROCs) to electricity generators relating to the amount of eligible renewable electricity they generate on monthly basis. As a result, generators receive, in addition to whole sale electricity price, a premium from the ROCs they sell to electricity suppliers. Secondly, suppliers must hold predefined amount of obligations ("obligation level") annually which is verified by Ofgem. Suppliers who do not present enough ROCs to meet their obligation pay a penalty, or "buy-out price" (determined as £ per missing ROC). Ofgem then re-distributes the money collected buy–out (and late payment) funds to suppliers who presented enough ROCs on pro-rata basis. (DECC 2015b)

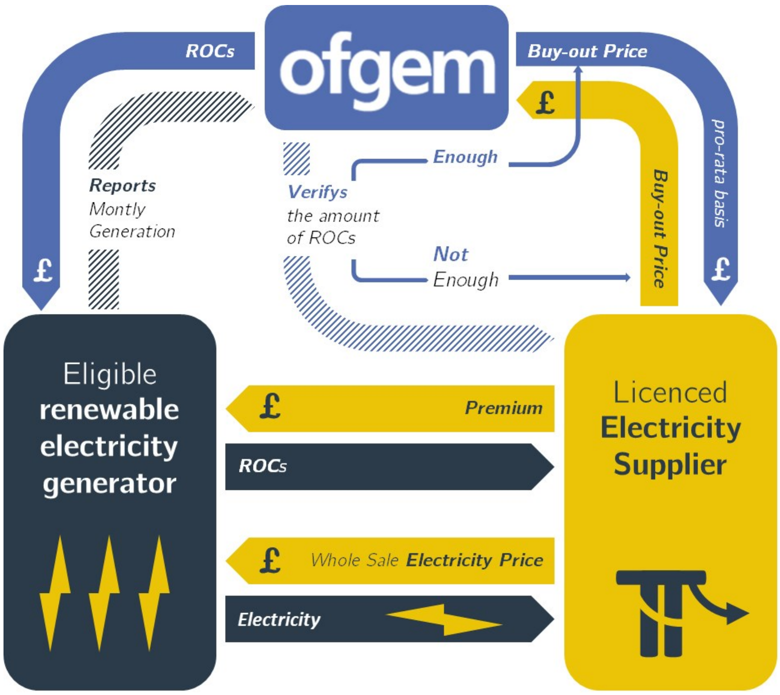

Figure 28 –Illustration of the RO scheme operation

ROCs are tradable commodities that have no fixed price whereas the buy-out prices together with obligation levels for each obligation period (1 April – 31 March) are determined a year in advance (Figure 29). Obligation level defines the necessary amount of ROCs required to supply one MWh of electricity, thus the obligation for each supplier is calculated by multiplying the total annual supply to customers in the UK (MWh) by the obligation level (ROCs per MWh). (DECC 2015b)

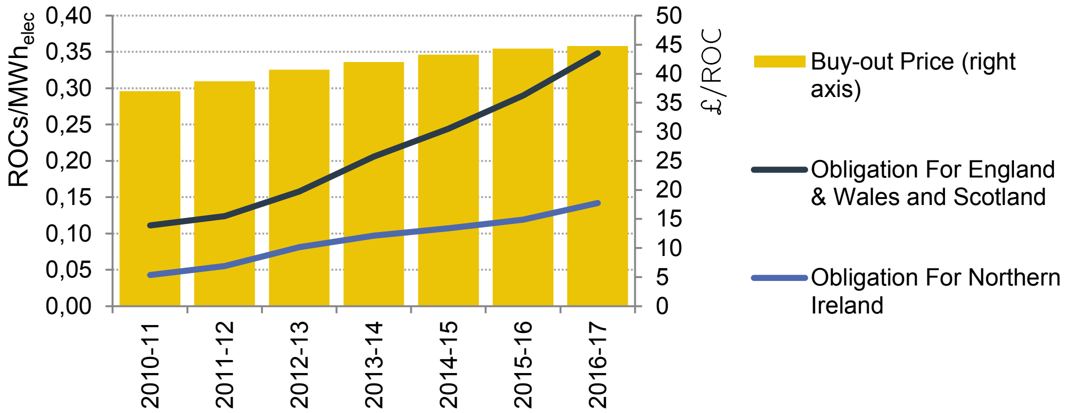

Figure 29 Buy-out price and obligations by obligation period (1 April – 31 March) (Ofgem 2016)

The DECC (2015d p.27) have created bands (i.e. ROCs issued per eligible MWh electricity generated) to support the full or partial conversion of coal-fired power stations to generate renewable energy from biomass. Generators are allowed to use a unit-by-unit approach and change bands from month to month by changing the proportion of biomass used in each month. Bands for biomass co-firing units are presented in Table 8. The DECC assumes that the lower percentage co-firing involves lower risk and lower investment requirements than at higher percentage conversion. This is taken into account in the banding.

Table 8 – RO bands for biomass co-firing and conversion (DECC 2015d p.27)

Band	**Description**[a]	**Support level (ROC/MWh)**
Low-range co-firing of biomass	Less than 50% biomass co-fired in a unit	0.5 (from April 2015)
Mid-range co-firing of biomass (other than bioliquids)	50% - less than 85% biomass co-fired in a unit	0.6
High-range co-firing of biomass (other than bioliquids)	85% - less than 100% biomass co-fired in a unit	0.9 (from April 2014)
Biomass conversion unit or station	Electricity generated by a unit using 100% biomass	1.0

[a] In each case up to 10% fossil fuel can be used in a unit for permitted ancillary purposes without affecting the eligibility of that unit for the band

3.6.2 Electricity Market Reform

The Electricity Market Reform (EMR) is a national program intending to promote investments in low carbon electricity generation while securing sufficient generation capacity and providing affordable electricity for consumers (DECC 2014b). The program was implemented in 2014 under the Energy Act 2013 and is a result of the UK Government's response to challenges facing the electricity sector (e.g. closure of old capacity, growing electricity demand and intentions to meet national carbon and renewable targets). The EMR consists of several mechanisms of which two key elements are

i. Contracts for Difference (CFD) and
ii. Capacity Market

Purpose of the CFD scheme is to provide long-term stable electricity price for low carbon electricity generators thus ensure constant revenues and reduced investment risks (DECC 2014b). It is a private law contract between a low carbon electricity generator and the Government-owned company called Low Carbon Contracts Company (LCCC). The CFD replaces the phasing out, aforementioned RO scheme by April 2017 (Baker 2015). The contract provides constant revenues via levy-funded, two-way feed-in tariff for generating companies as the level of the tariff is determined by the difference of pre-agreed price level ("strike price") and the average market price for electricity ("the reference price"). The reference price is calculated differently for intermittent and baseload generators as shown in Figure 30 and Figure 31. Being a two-way tariff, in case the reference price for electricity is greater than the predetermined strike price, generator has to pay back the difference (i.e. return money back to consumers). (DECC 2011 p.41).

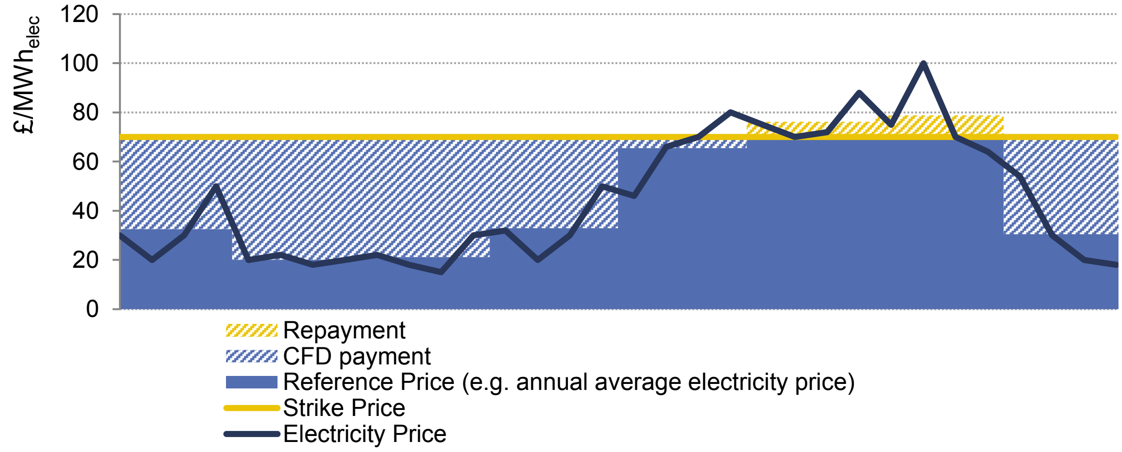

Figure 30- The operation of an baseload Feed-in Tariff with CFD (DECC 2011 p.41)

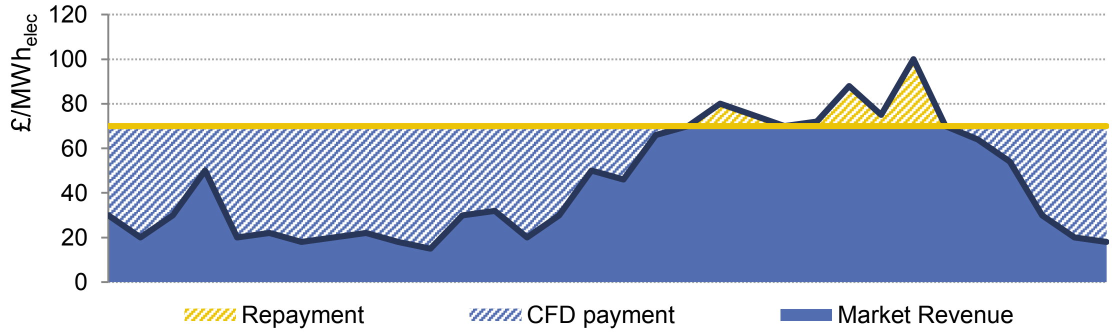

Figure 31 - The operation of an intermittent Feed-in Tariff with CFD (DECC 2011 p.41)

Strike prices for each eligible technologies are determined in EMR Delivery Plan (DECC 2013b p.37) for the first plan period of 2014/15-2018/19. In the CFD allocation response technologies are broadly divided into two groups; “Group 1” or “established” and “Group 2” or “less established”. Technologies within groups are described in Table 9. Such grouping provides that less established technologies will not be required to compete on price directly with Group 1 technologies (DECC 2014a p.15). Some generation technologies, however, remain unclassified which are listed under “other”. Prices for a number of these “other” technologies (e.g. nuclear, CCS) aren’t specified in the Delivery Plan and hence are determined case-by-case basis (DECC 2014a p.6).

Table 9 – Technology grouping for CFD budget (Baker 2015 p.137; DECC 2014a p.6)

Established	**Less Established**	**Other**
Onshore Wind (> 5 MW)	Offshore Wind	Nuclear
Solar PV (> 5 MW)	Wave	Biomass Conversion
Waste with CHP	Tidal Stream	CCS
Hydro Projects (> 5MW and <50MW)	Advanced Conversion Technology [a]	Large Hydro
Landfill Gas and Sewage Gas	Anaerobic Digestion	Tidal
	Dedicated Biomass with CHP	Scottish Island Onshore Wind
	Geothermal	

[a] Standard and advanced gasification and pyrolysis, including advanced bioliquids.

Consequently, coal-fired units with CCS may be eligible for support under the CFD, though with an uncertain, situation-dependent extent. Additionally, the CFD provides support for conversion of coal-fired or biomass co-firing units to “sustainable biomass” with a flat strike price of 105 £/MWh_{elec} throughout the first Delivery Plan period. However, the UK Government, in accordance with the UK Bioenergy Strategy, has decided to end payments to biomass conversions in 2027 which results in the shorter contract term. (DECC 2013b).

While the CFD scheme purpose is to encourage investments in new low carbon generation, the Capacity Market mechanism intends to ensure a secure electricity supply, even at times of peak demand (e.g. cold winter’s evenings), by incentivizing sufficient reliable capacity (both supply and demand side). That is, each chosen capacity providers are given a steady payment for keeping capacity available, but then again, providers are penalized if they fail to deliver energy when needed. The Capacity Market functions alongside the electricity market - which is where most participants earn the majority of their revenues – and the capacity is purchased by National Grid on behalf of suppliers. Capacity providers are chosen through capacity auctions that are held four years ahead of each delivery year. (DECC 2014b).

Following three types of capacity are eligible to participate in capacity auctions and receive capacity payments (DECC 2014b p.94):

i. New and existing generation capacity (including CHP)
ii. Demand side response (DSR) (including embedded generation)
iii. Electricity storage

However, there are several restrictions related to eligible capacity which prevent capacity receiving support through another schemes - including RO, CFDs or UK CCS Commercialization Program (Sec. 6.3.1) - to enter in the Capacity Market mechanism (DECC 2014b p.94).

Results of the first and second capacity auctions, arranged in 2014 and 2015, are presented in Figure 32. After the CCGT capacity with 45% share or 22.2 GW, capacity labelled as "coal/biomass" contributes the second largest share, 19% or 9.2 GW of the contracted capacity delivered during 2018/19. Of this awarded coal/biomass capacity, 3.1 GW received a three-year contract (EDF's West Burton and Cottam stations). Though, one-third or 4,5 GW of the total participated coal and biomass-fired capacity exited the first auction above the clearing price of 19.40 £/kW/y (National Grid 2015b). As only 5% or 2.6 GW of the awarded capacity for 2018/19 comes from newly build units, Capacity Market mechanism has raised concerns that it provides subsidies to old and polluting power stations instead of contributing to investments in new, low carbon generation capacity, thus slowing decarbonisation of the UK (Hope 2014; Sandbag 2015; Tsagas 2015).

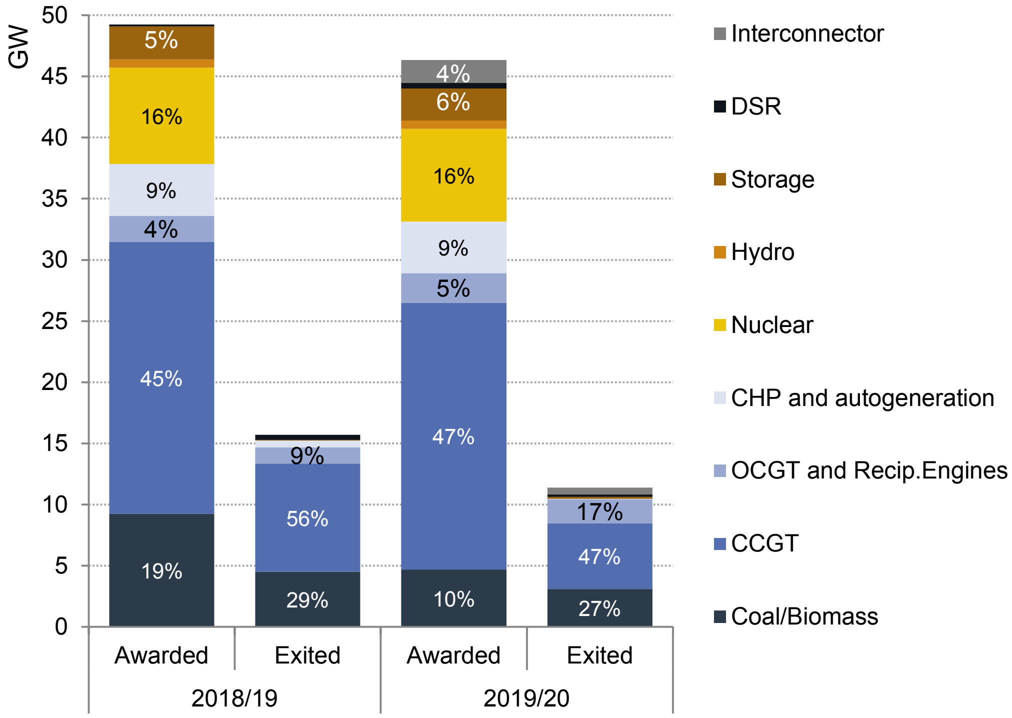

Figure 32 – Results of 2014 and 2015 capacity auctions by delivery period (National Grid 2015b; 2015c)

For the 2019/20 period, in addition to already contracted 3.1 GW, nearly 4.5 GW of coal/biomass labelled capacity was awarded in the 2015 auction with the clearing price of 18 £/kW/y. This capacity accounted for 10% of the total newly contracted capacity. However, roughly 40% or 3.1 GW of participated coal and biomass-fired capacity failed to get contracts. Once again, NG-fired capacity holds the largest share as CCGT capacity accounted for 47% or 21.8 GW of capacity contracted in the 2015 auction. In turn, nearly half or 5.3 GW of the exited capacity was also labelled as CCGT. That is, nearly 20% of the participated CCGT capacity was not contracted for 2019/20. More precise information about the awarded coal-fired capacity is presented in Section 6.2.

3.6.3 EMR supporting measures

In addition to package of reforms to encourage market liquidity and new entrants, Government energy market measures that work alongside with the EMR include (DECC 2014b):

i. Carbon Price Floor (CPF)
ii. Emission Performance Standard (EPS)

The CPF which came into effect on 1 April 2013 is made up of EU ETS emission allowance price and the topping up, UK-only carbon price support (CPS) rate of Climate Change Levy (CCL) (HM Revenue & Customs 2014). Its purpose is to help meeting national decarbonisation targets – for which the UK Government considered EU ETS alone would be inefficient and unpredictable (HM Revenue & Customs 2011). The CPF mechanism intends to provide clear, predefined cap (floor) for carbon price for each annual period (from April to March) according which the CPS rate is adjusted.

The CPF was planned to start from 16 £/t_{CO2} and then linearly increase to 30 £/t_{CO2} by 2020 and ultimately rising to 70 £/t_{CO2} by 2030 as presented in Figure 33. However, price of the allowances in the EU ETS market turned out to be subsequently lower than expected, thus the Government decided to froze the CPS to 18 £/t_{CO2} level for the rest of the 2010s despite it might not be enough to follow the targeted price trajectory. The threat was that with the planned trajectory of the CPF and further increasing share of the UK-only CPS rate, the UK firms would face significantly higher energy prices than those of competitors abroad. Increasing carbon price could have also caused substantially risen household energy bills. (HM Revenue & Customs 2014)

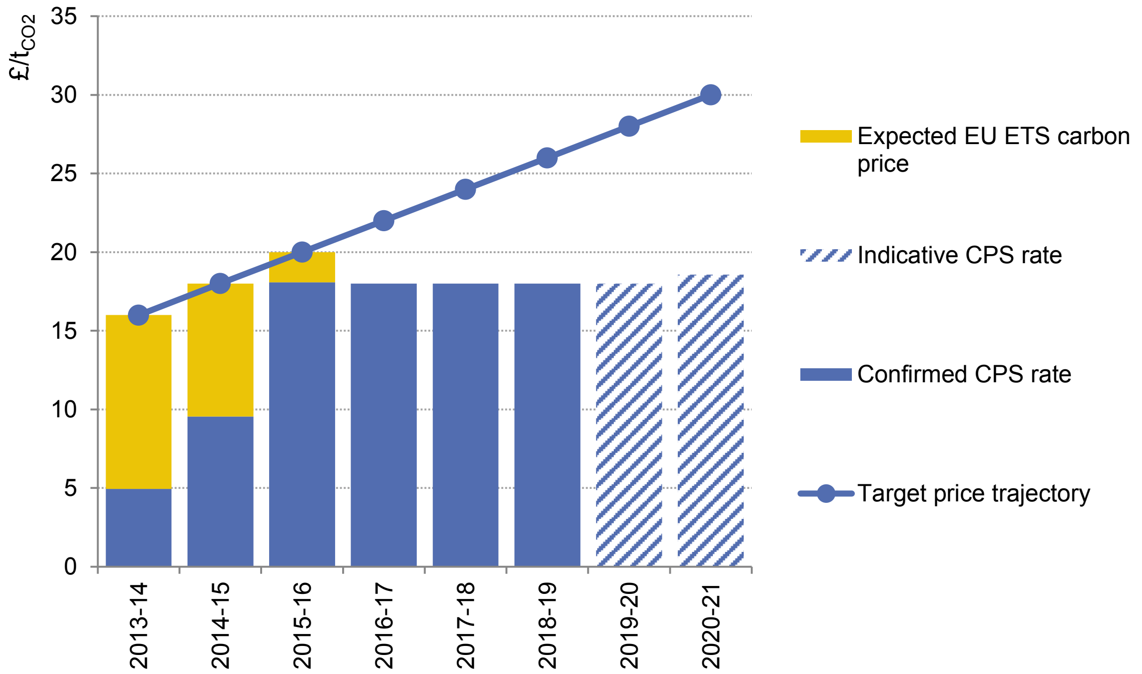

Figure 33 – Illustration of the UK Carbon Price Floor mechanism. The carbon price for UK electricity generators consist of market based EU ETS allowance price and the UK-only CPS rate of the CLL which is set two years in advance according to the desired price and prevalent allowance price (HM Revenue & Customs 2011; 2016)

In addition to EU ETS allowance prices, generator must pay fuel specified CPS rates in case they use fossil fuels listed in Table 10 for electricity generation. Generally, CPS applies to all generation fossil fuels including coal. Generator becomes liable for the rates when gas passes through the meter at the generating station; or when liquefied petroleum gas, coal and other solid fossil fuels are delivered through the entrance gate at the generating station (HM Revenue & Customs 2015). Rates for each fuel which are provided two years in advance are derived from the difference of target carbon price (i.e. the CPF) and the EU ETS market carbon price multiplied with the emission factor of the relevant fuel (HM Revenue & Customs 2011 p.16).

Table 10 - CPS rates for fuels used in electricity generation. Fuel specific rates are based on carbon content of each fuel to achieve predetermined CPS rate per t_{CO2} (i.e. 18 £/t_{CO2} for 2016-20 and 18.57 £/t_{CO2} for 2020-21) (HM Revenue & Customs 2016 p.214)

Fuel	**Capped rate**	**Indicative Capped rate**		**Unit**
	1.4.2016 - 31.3.2019	1.4.2019 - 31.3.2020	1.4.2020 - 31.3.2021	
Natural gas	0.00331	0.00331	0.00342	£/kWh_{fuel}
Liquefied petroleum gas	0.0528	0.0528	0.05447	£/kg_{fuel}
Coal and other taxable solid fossil fuels	1.5479	1.5479	1.5849	£/GJ_{gross}
Gas oil; rebated bio blend; and kerosene	0.04916	0.04916	0.05054	£/$litre_{fuel}$
Fuel oil; other heavy oil and rebated light oil	0.05711	0.05711	0.05874	£/$litre_{fuel}$

DECC expected (2014d) that the combined effect of increasing low carbon generation, rising carbon prices and planning restrictions in the National Policy Statement (NPS) would make coal plants progressively less profitable over time. Nonetheless, the emission performance standard (EPS) was introduced in the Energy Act 2013 setting emission limits to new fossil fuel generating units. The EPS is planned to act as backstop to prevent the deployment of new unabated coal plant in the event of a change to current policy which could make market conditions more favorable to new unabated coal capacity.

The EPS set annual CO_2 emission limit to new fossil fuel-fired generation plants (capacity above 50 MW) which is equivalent to 450g_{CO2}/kWh_{elec} for plants operating at baseload (annual load factor of 85%). Practically this limit ensures that new coal plants are able to operate at baseload only by using CCS. The EPS also applies to existing units that "significantly extend their life, by replacement or installation of a main boiler, for a period consistent with that of a new plant". (DECC 2014d)

4 Coal-Fired Generation in the USA

4.1 Nationwide Electricity Generation

Coal-fired electricity generation in the USA has constantly increased since the 1970s together with the total electricity generation until the financial crisis hit in the late 2000s (see Figure 34). The coal-fired generation peak, in the absolute terms, was achieved in 2005 when it reached nearly 2000 TWh_{elec} satisfying over a half of the total generation required particular year. The net change since then by 2014 indicates 21% decrease settling the generation to the 1990 level; 1520 TWh_{elec}. The steepest decline occurred between 2009 and 2012 when the net change, after a short recovery in 2010, reached 24% from 2008 level.

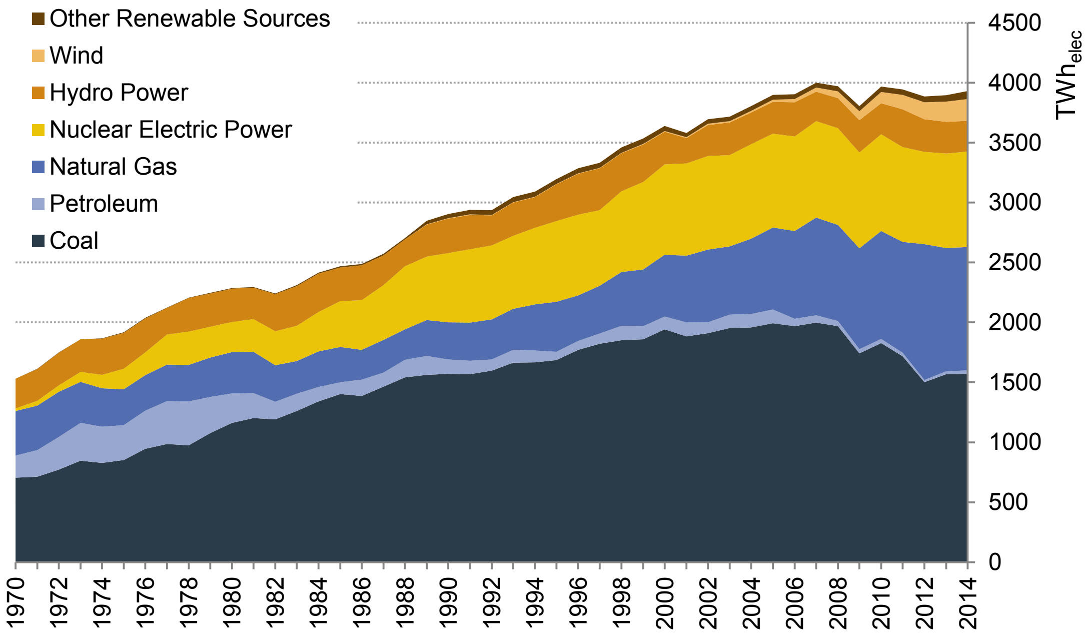

Figure 34 Annual electricity net generation in the United States by fuel (EIA 2015g)

US electricity generation has closely followed the growth trend of the economy until 2011 as Figure 35 indicates. As the global economy faced financial crisis in 2008, until then constantly growing US gross domestic product (GDP) began to decline which hit the electricity demand as well as forcing electricity providers to withdraw some of their generation capacity, especially that of coal-fired. What was formerly the main compensator for growing demand, now faced the brunt. As the economy began to show recovering after 2009 so did the amount of coal-fired generation but soon after, in 2011, while the GDP maintained its' growing trend, coal generation started its descent again leading to resign of 85 large-scale coal-fired units during 2011-2014 corresponding overall nameplate capacity of over 18 GW (EIA 2015b). Coal-fired generation is expected to further decrease as during 2015, when EPA's Mercury and Air Toxics Standards (MATS) came into effect, over 100 coal-fired generation units or approximately 13.7 GW were closed (i.e. c. 4.4% of the overall existing coal-fired capacity of 311 GW in 2014; described below in Table 11) (EIA 2016b). Most of these retired units were built between 1950 and 1970 with an average age of 54 years and average capacity of 133 MW. After the retirements the existing coal fleet has an average age of 38 years (Operating coal-fired generation units are further observed below)

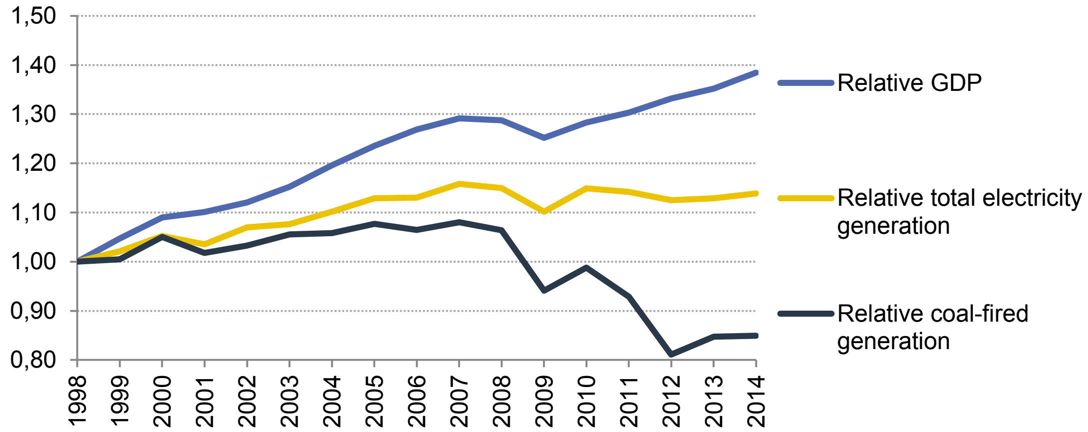

Figure 35 – Relative GDP, total electricity generation and coal-fired generation; base year: 1998 (EIA 2015g; BEA 2016)

As showed in Figure 36 coal power has dominated the US electricity generation over the decades having the maximum share of 57% in 1987. The share has decreased since then, with an increased trend after 2008, descending on 40% by 2014. Recently, since early 1990s, when efficient combined cycle technology became more common, natural gas-fired electricity generation has intensely expanded its share from 11% in 1990 to 26% in 2014 while peaking in 2012 with the share of 29% (EIA 2012). During the period, expansion of the domestic natural gas pipeline network decreased uncertainties around natural gas availability, and the natural gas production rapidly increased due to utilization of shale gas formations. Share of renewable fuels (including hydro power) in generation mix has, instead, remained between a narrow band of 8% and 13% whereas nuclear power has kept its 20% share over the period. Currently petroleum-fired generation has a negligible contribution to the total electricity generation. (EIA 2015g)

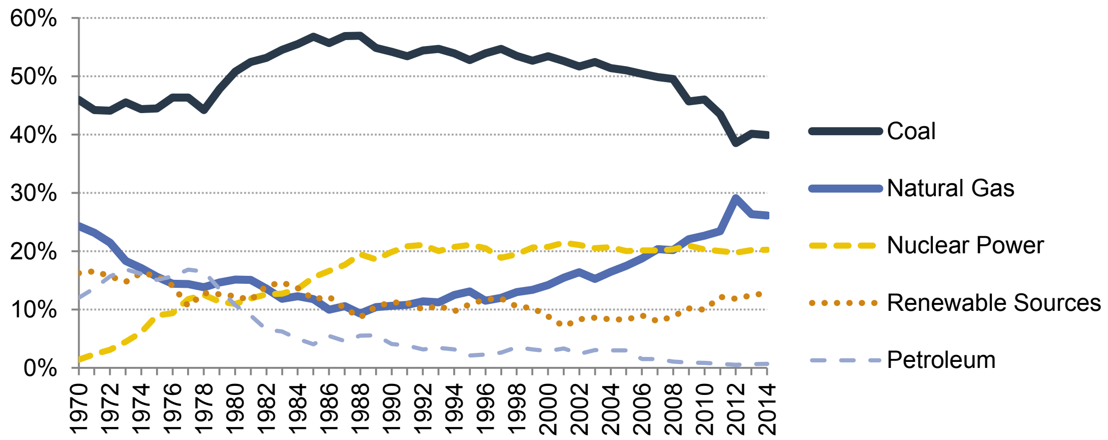

Figure 36 – Shares of major generation fuels of the total electricity generation by year (EIA 2015g)

Albeit coal share in the US generation mix has declined during the last decades the monthly generation profiles appears to have a common trend regardless of the year as presented in Figure 37. Generation peaks are reached at the end of the summer (July and August) and by the beginning of the following year (December and January) while April and November are usually months when the coal-fired generation is at its minimum level. In 2014, peak generation of 156

TWh$_{elec}$, achieved in January, was 44% higher than the minimum monthly generation of the year; 109 TWh$_{elec}$ in April. This requires flexibility from the existing capacity and indicates that coal-fired power plants hold an important role to accommodate the seasonal fluctuation in electricity demand.

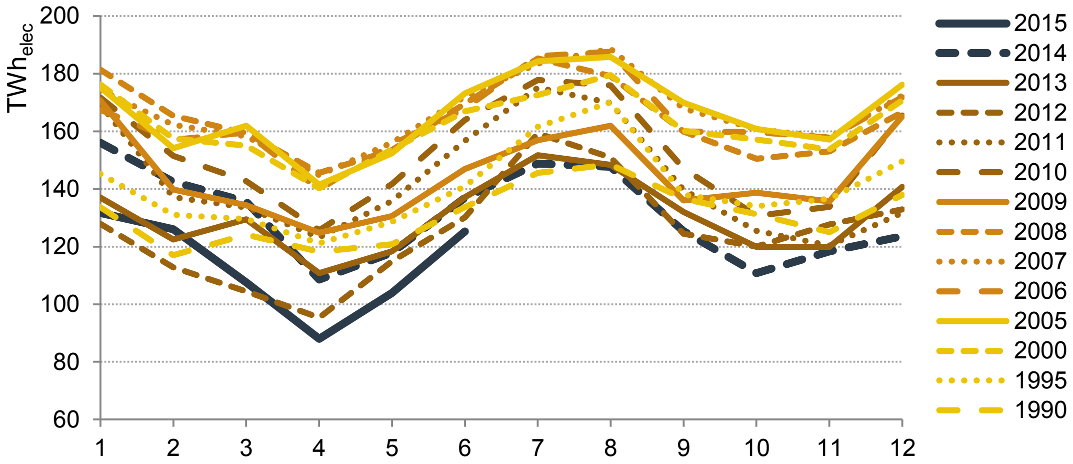

Figure 37 – Monthly coal-fired electricity generation by year (EIA 2015g)

Seasonal generation profile is explained with natural temperature changes during the year which usually take place at same time of each year. The number of heating and cooling degree days, i.e. daily average temperature's difference from the base temperature of 65 °F (18.3 °C), is approximately proportional to the amount of energy that would be needed to heat or cool a building in a certain location (EPA 2015e). Figure 38 and Figure 39 provide data of average monthly heating and cooling degree days during the 2010s in North America. The degree day peaks occurs simultaneously with the peaks of coal-fired generation described above (Figure 37); Energy demand for cooling is often highest during July and August whereas most heating is usually needed during December and January. However, according to the 2014 National Climate Assessment (US GCRP 2014) warmer winters will decrease energy demands for heating, but correspondingly increased summer temperatures will increase electricity use causing higher summer peak loads.

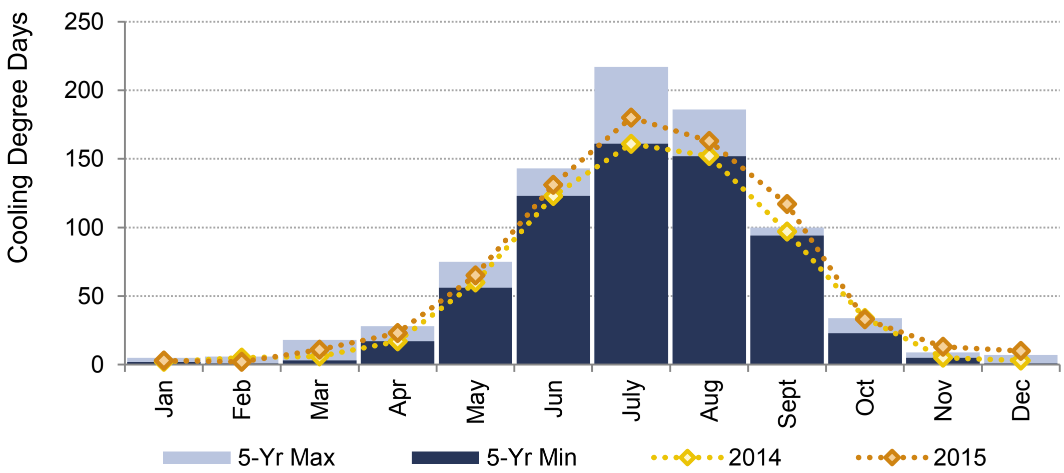

Figure 38 – Cooling degree days in North America (CGA 2016, Chapter 2.1)

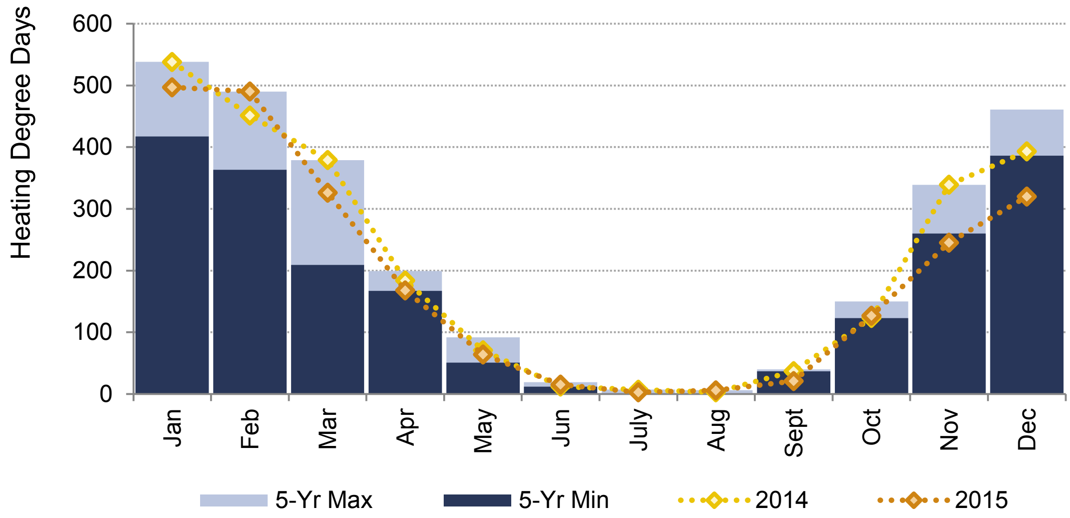

Figure 39 – Heating degree days in the USA (CGA 2016, Chapter 2)

Even though, over 4% of the older, existing coal-fired capacity was retired in 2015, as mentioned above (Sec. 4.1), observing the annual generation data for 2014 gives a directive picture of the current operating capacity. As shown in the Figure 40, which is compiled from the data provided by the EIA (2015b) form 860 (i.e. operating data of US generating units larger or equal of 1 MW_{elec}), existing large-scale coal-fired electricity generation capacity (units ≥100 MW_{elec}) is provided with rather aged technology; units commissioned during 1990-2014 corresponds less than 10% of the total large-scale capacity of 300 GW in 2014 (the overall coal-fired capacity equals 311 GW), whereas plants commissioned during the 1970s and 1980s account for almost 65% of the capacity in service. Thus, capacity build before 1970 still constructs nearly one-fourth of the existing capacity. Years 1973 and 1980 hold the largest annual capacity shares as units commissioned in 1973 and 1980 respectively forms 16.6 GW and 16 GW or 5.5% and 5.3% of the existing capacity.

During the proposal year of the CPP, 2014, only one large-scale coal-fired unit was commissioned (EIA 2015b). In November 1, 2014, Spiritwood commissioned Spiritwood Station (North Dakota) which is a coal-fired CHP unit with a gross generating capacity of 106 MW. It supplies steam to the Blue Flint Ethanol bio-refinery for process energy and to dry distillers grains. With current level of the steam supply, unit reaches 60 % operating efficiency but it has a potential to reach 66% efficiency with additional steam users (Larson 2015).

According to the EIA generation data (2015b), subcritical technology have clearly dominated the coal fleet over the decades having the 2014 share of 64% of the existing large-scale coal-fired generating capacity (excluding CHP plants) while supercritical units correspond one-third of the capacity and the rest 3.6% fall under the category of advanced, including CHP, IGCC and ultra-supercritical units (as categorized in the Section 2.2). Furthermore, out of the 21 GW operating capacity, build during 2000-2014, 44% is generated with the subcritical technology whereas only 4.4% is considered as advanced.

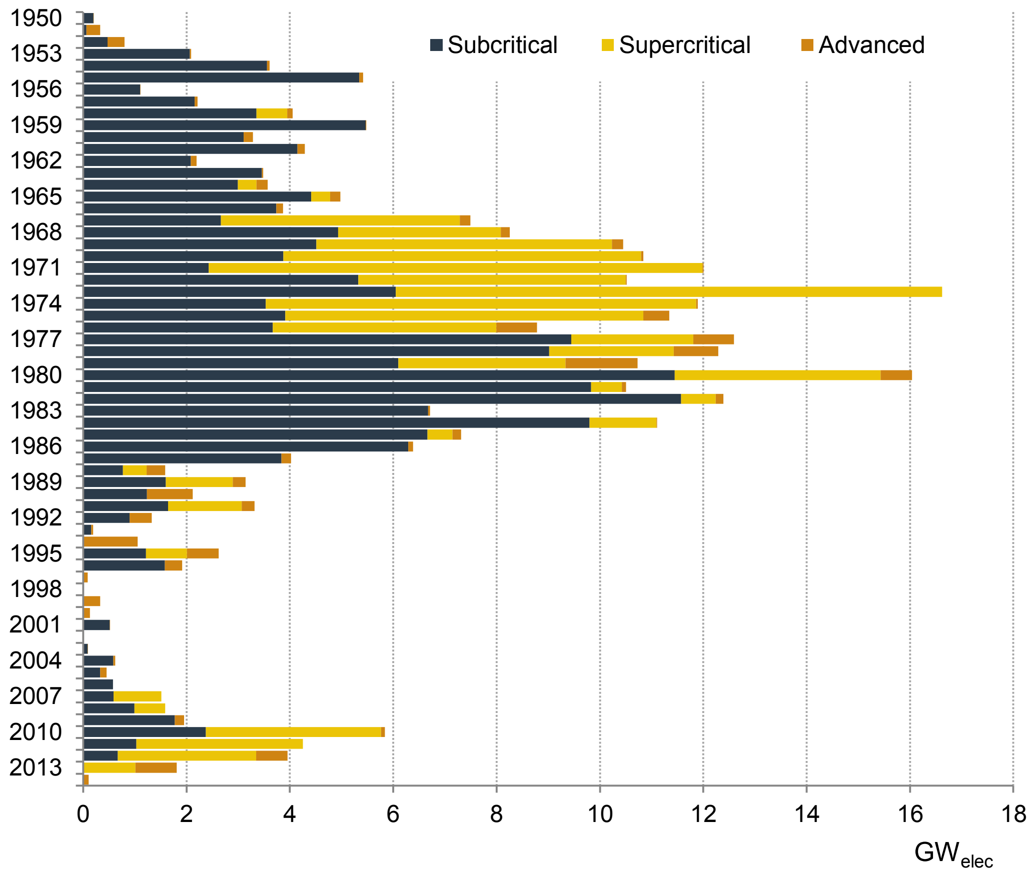

Figure 40 – Existing large-scale, ≥100 MW$_{elec}$, coal-fired capacity by commission year and plant type in 2014 (EIA 2015b); see Section 2.2 for more info about the plant types

As presented in Table 11 the number of existing large-scale coal-fired generators in the USA, 2014, equals 666 of which 622 are based on PC-firing technology corresponding over 95% of large-scale coal-fired generation capacity. Secondly, 33 of the generating units, accounting 3.3% of the total capacity, generate combined heat and power, thus, having a minor contribution to the total capacity. Generating units capable of co-firing various fuels simultaneously, such as coal and natural gas or multiple coal rank, exist the amount of 147 with an aggregate capacity of 55.2 GW$_{elec}$, thus having nearly one-fifth share of total capacity.

The largest single operating coal-fired electricity generating unit in the USA, 2014, utilizes supercritical and pulverized coal combustion technology reaching the nameplate capacity of 1426 MW$_{elec}$ (EIA 2015b). The largest and currently only large-scale, ultra-supercritical coal plant provides maximum 609 MW of electricity whereas largest subcritical unit reaches 957 MW$_{elec}$ generation capacity. Currently, there are only 5 large-scale generating units associated with IGCC of which the largest one produced capacity of 332 MW$_{elec}$. Three of the operating coal-fired IGCC units are part of Edward Sport power plant in Indiana, forming a total nameplate capacity of 805 MW$_{elec}$ making it the largest IGCC plant in the United States. Since its commissioning in 2013, it has had operating issues preventing it to reach scheduled generating capacity and proposed emission levels (Lundin 2014; Human 2014). $3.3 billion plant has also offended customers as the owner, Duke Energy, has tried to include the swollen construction expenses to customer bills to make operation profitable (Russel 2016).

Table 11 – Summary of existing large scale, ≥100 MW_{elec} coal-fired capacity in 2014 (EIA 2015b)

	Total capacity	Share	Number of generating units	Average Unit Size	Largest unit
	GW_{elec}			MW_{elec}	MW_{elec}
Status					
Operating	298.5	99.7 %	661	452	1426
Standby	0.602	0.2 %	3	201	205
OS[a]	0.435	0.1 %	2	218	218
Total	**300**	**100 %**	**666**	**450**	
Steam properties[b]					
Subcritical	201.4	67.2 %	536	376	957
Supercritical	97.5	32.6 %	129	756	1426
Ultra-supercritical	0.6	0.2 %	1	609	609
Firing Technology					
Fluidized Bed	5.3	1.8 %	20	264	668
Pulverized Coal	285.2	95.2 %	622	458	1426
Other	9.1	3.0 %	24	378	893
Additional features					
Co-firing	55.2	18.4 %	147	376	957
CHP	9.0	3.0 %	33	273	765
IGCC	1.1	0.4 %	5	226	332

[a] Out of service, *not* expected to be operating next calendar year

[b] Here listed entities (supercritical and ultra-supercritical) include units that could be otherwise, like in Figure 5.5, labelled as advanced units

4.2 Regional Level Electricity Generation

Electricity generation mixes vary notably among the different regions within the USA, as can be seen from Figure 42. To make it clear to follow, US census regions and divisions are presented in Figure 41. States in Midwest and South are the most dependent on coal whereas West and Northeast divisions have on aggregate significantly smaller share of coal-fired generation in their portfolio. However, the overall trend is clear; coal's role in electricity generation is diminishing nation-wide.

According to the EIA data (2015d), Midwest states, responsible of one-fourth of the total US electricity generation, generated 71% of their electricity with coal-fired plants in, both, 2002 and 2008 and, in 2014, 61% of the generated electricity was originated from coal-fired units accounting 15% of the total US electricity generation and 39% of the total nationwide coal-fired generation. East North Central states of Midwest faced 6% decline in the total electricity generation between 2008 and 2014 which was compensated with reductions in coal power and, partially, by switching coal to NG and renewable energy sources. In turn, while overall generation in West North Central increased by 16% since 2002, coal-fired generation remained close to the

2002 level. Increase in the electricity demand was mainly satisfied with renewable generation expanding its share from 5% to 19% by 2014.

States in the South region, generating almost 50% of the total electricity in the USA satisfied half of the region's electricity demand with coal-fired plants in 2002. Though, coal's share in electricity generation mix has decreased since then settling to 38% by 2014. Such shift can be least attributed to the states of West South Central division, such as Texas, as their absolute coal-fired generation has remained, roughly, on constant level over the period, while South Atlantic states (e.g. Florida and Georgia), the most electricity generating division in the US, have, on aggregate, significantly put aside their coal-fired capacity as the coal-fired generation in 2014 indicated over 30% decrease from 2008 level. Meanwhile, natural gas increased its share in electricity mix by over 80%. Similarly, East South Central division decreased coal-fired generation by 20% between 2008 and 2014 more than doubling the NG-fired generation. Noteworthy, however, is the fact that states of West South Central have faced continuous, increasing trend in the electricity demand over the period, unlike East South Central and South Pacific divisions on aggregate, which has been compensated with, especially, renewable sources and already high share of NG-fired generation. (EIA 2015d)

Regions of the Northeast and the West provide, in turn, rather different generation profile as the EIA information (2015d) indicates. Together, regions contribute one-fourth of the total electricity generated in the USA and are responsible for 15% of the total US coal-fired generation which is mainly due to coal dependent aggregate generation mix of the Mountain division states (e.g. Arizona and Wyoming) in the West as over a half of the generation is provided with coal. Such area has abundant coal reserves which partly explain the intensive coal use as described in Section 4.3. Pacific division of the West, instead, generated only 3% of the total electricity with coal-fired capacity and, additionally, over half of the division's generation was fulfilled with renewable sources. As mentioned in Section 3.4.2, California which is a part of the Pacific division and a member of Western Climate Initiate, have implemented its Global Warming Solutions Act (Assembly Bill 32) to reduce GHG emissions leading to formation of California-Quebec emission trading scheme under which major electricity providers operate. Policy environment in California presumably have had an impact leading to nearly resign of coal-fired generation within the area.

Northeastern states have undergone a significant shift since 2008 as aggregate coal-fired generation has nearly phased out having 4% share of the total electricity generated in 2014; 30% less than in 2008. Such a shift has expanded the shares of NG-fired, nuclear power and renewable generation to 40%, 31% and 21%, respectively. The policy environment in the region is, in this case as well, favorable for less carbon intensive electricity generation as seven out of nine states within the Northeast region, such as New York, are part of the Regional Greenhouse Gas Initiative, a market based regulatory program, to reduce GHG emissions among large scale emitters (see Section 3.4.1), which has been functioning since 2009. Annual emissions within the area, however, remained five first operating years of the program well below the predetermined cap, which was, thus, tightened in 2014 as showed in the Figure 17. Thereby, in addition to practiced policies within the region, the shift to less carbon intensive electricity generation may be attributed to external market mechanisms as natural gas has become more competitive during recent years as described in Section 4.4.

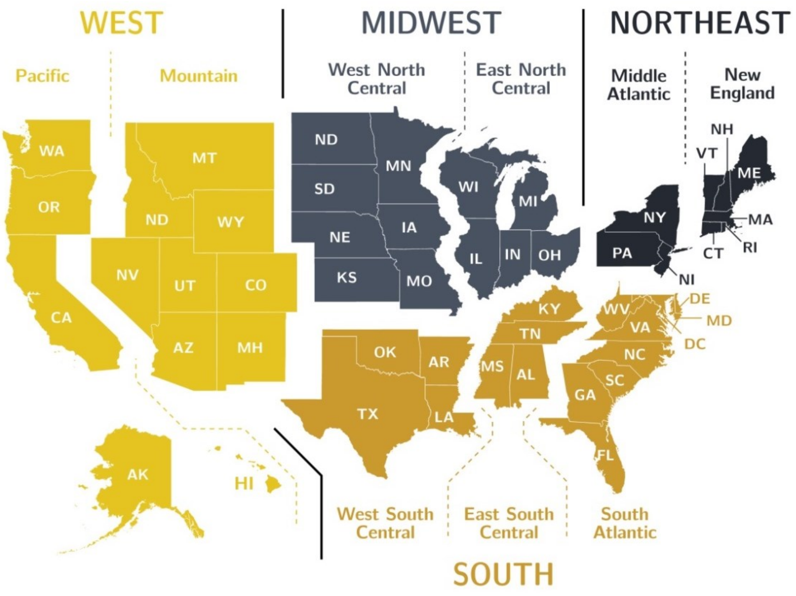

Figure 41 – US Census regions (West, Midwest, Northeast and South) and divisions; modified from EIA version: https://www.eia.gov/consumption/commercial/maps.cfm [1.2.2016]

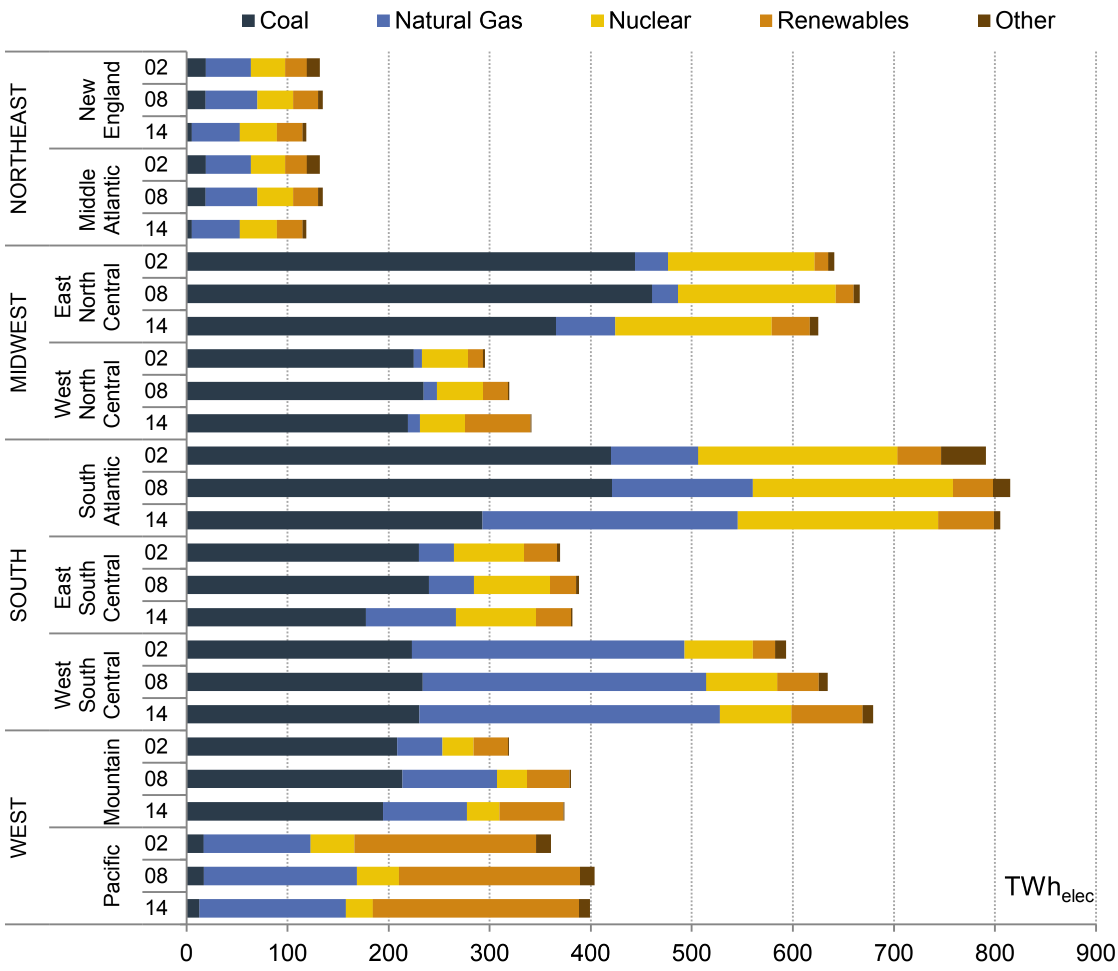

Figure 42 - Net generation from electricity plants by census division and years 2002, 2008 and 2014 (EIA 2015d)

4.3 US Coal Production and Consumption

United States is a major coal producer on global level. 2013 the ultimately largest producer, China, with a share of approximately 46% of the total world coal production (7822.8 Mt), was followed by the USA with 11% share (IEA 2014a p.44). As a major producer, USA is mostly self-sufficient in coal use as imports accounted only 1.2% of the total available coal for domestic consumption (832 Mt) in 2014 (EIA 2015g). Consequently, USA is a net exporter as 10% of the produced coal was exported in 2014, of which over a half to Europe where main importers were Netherlands (13% of total US coal exports), United Kingdom (10%) and Italy (6%) (EIA 2016a). Additionally, USA exports within the North America; 11% of the nation's total exports to Canada and Mexico, 6% and 5% respectively. Brazil, South Korea and Japan are important US coal importers as well having shares of 8%, 9% and 5% of the total US coal exports, respectively. Though, exports have declined since 2012 over 20% due to decreased international coal demand (EIA 2016c).

US coal production closely follows electricity sector demand as 2014 over 90% of the total domestically available coal was consumed by electric power producers (see Figure 43 and Figure 44). Total domestic consumption reached its peak in 2007 and a year later did the coal production. Both have decreased since those years; total consumption by 19% since 2007 and production by 15% since 2008. EIA (2016c) expects US coal production, in fact, to further decrease in short-term due to low natural gas prices, decreasing international demand and contribution of environmental regulations. Thus, estimated 2015 aggregate production equals 816 Mt (900 M short tons) which is 10% less than 2014 level of 907 Mt, being the largest decline ever recorded.

The United States have five major coal basins, regions that produce coal, which are presented in Figure 45: (i) Powder River Basin, (ii) Illinois Basin, (iii) Northern and (iv) Central Appalachia Basins, and (v) Uinta Basin. The largest producing region, Powder River Basin, located in Mountain division, within the states of Wyoming and Montana, accounted 41% of the total US production in 2013. Though, the EIA (2016c) assumes that annual production from the region, together with the Northern Appalachian Basin and the Uinta Basin, in 2015 was 10% to 20% below their corresponding regional annual average levels over 2010-14 while Central Appalachian Basin faced the largest decline as production in 2015, by estimate, was 40% below its annual average level over 2010-14. Nonetheless, estimated coal production from the Illinois Basin in 2015 was 8% higher than production levels over 2010-14.

Due to fact that the coal reserves are unevenly distributed within the country, as Figure 45 shows, some regions provide higher supply of coal than others, which have presumably lead to cheaper coal for consumers on abundant areas as producers gain cost benefit due to size of output (i.e. economies of scale), and again transportation costs for nearby consumers remain low compared to customers far from the sources. Such divisions including Mountain, West and East North Central, clearly rely more on coal in their generation mix as presented above in the Figure 42. In 2014, transportations costs accounted for 39% of the total delivered cost of coal for electric power sector in 2014, the highest percentage since 2008 when the EIA start publishing the transportation rate data (EIA 2016f).

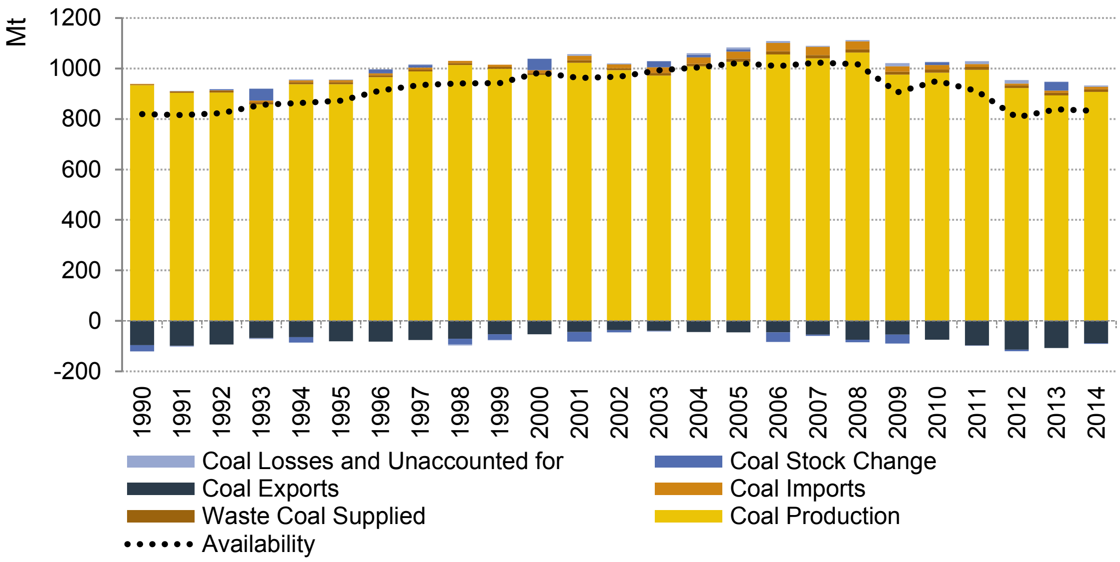

Figure 43 – US coal supply (EIA 2015g)

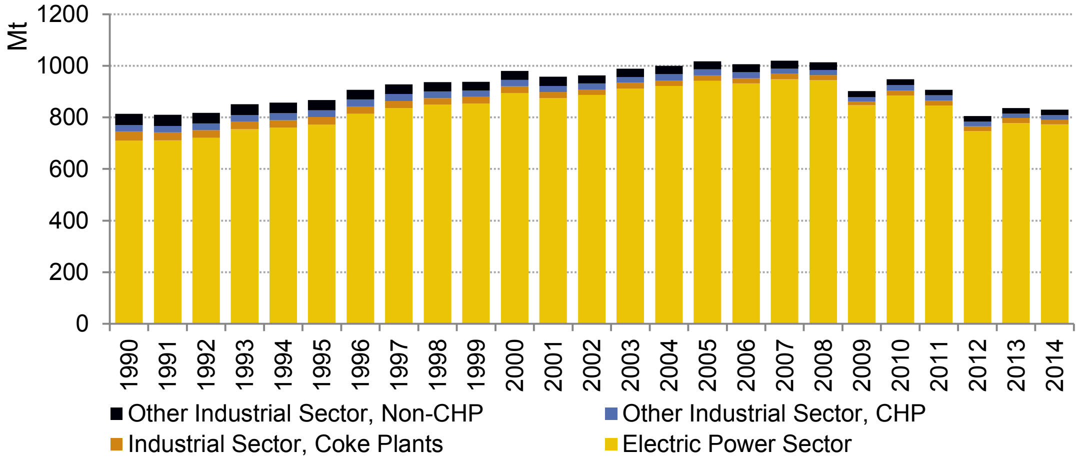

Figure 44 – US domestic coal consumption by sector. (EIA 2015g)

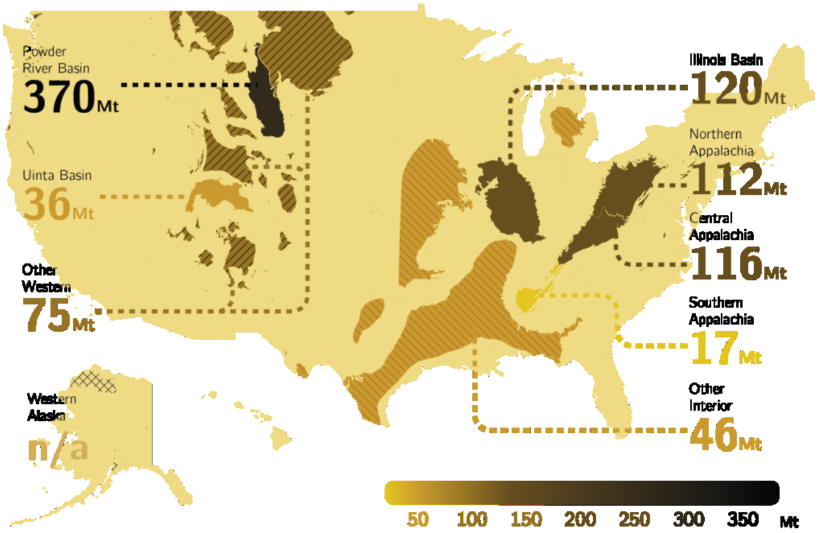

Figure 45 – Aggregate US coal production by coal basin in 2013; compiled from the data available at: http://www.eia.gov/beta/coal/data/browser/ [30.1.2016]

4.4 Generation Fuel Prices in the USA

Cost of coal delivered to electricity generating plants is on average stable and cheap due to abundant domestic production (see Section 4.3). Since 2001, price have fluctuated between 4.5 and 8.6 $\$_{US}/MWh_{fuel}$ settling approximately to 7.5 $\$_{US}/MWh_{fuel}$ by the end of 2015. In its reference case were the CPP (Sec. 3.2.2) is not effective, EIA expects (2015c) that coal maintains its stable price having a constant yearly growth of 1% which is primarily a result from declines in coal mining productivity in several key supply regions, e.g. Central Appalachia and Wyoming's Powder River Basin. However, in the case CPP becomes effective, the EIA estimates (2015a) (based on the EPA's proposed plan in 2014) that the delivered coal prices fall 13% below the baseline (i.e. reference case) by 2030 as the electricity sector switches to less emitting generating sources.

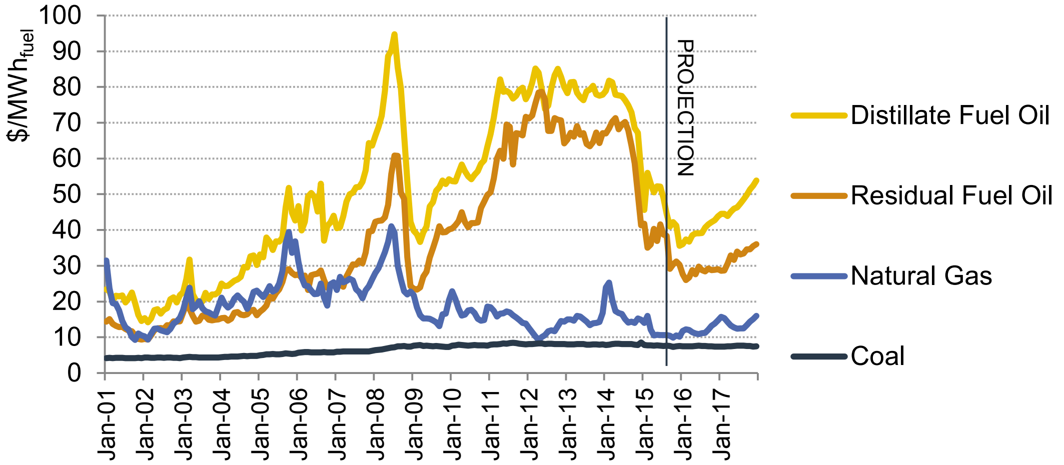

Figure 46 – Average, energy equivalent cost of fossil fuels delivered to electricity generating units (EIA 2016g)

Contrary to the coal, cost of other fossil generation fuels – natural gas, distillate and residual fuel oils - indicates greater uncertainty. For instance, since 2001, the average price of delivered natural gas have varied roughly between 9 and 41 $\$_{US}/MWh_{fuel}$. Though after peaking in 2008, unlike prices of delivered oil, cost of natural gas have indicated relatively moderate fluctuation remaining between 9 and 25 $\$_{US}/MWh_{fuel}$ and settling to 10 - 11 $\$_{US}/MWh_{fuel}$ by the end of 2015.

Before, price of natural gas had closely followed the oil price (see Figure 46) due to burner tip competition between NG and oil together with linked production processes of the fuels. However, as Wang et al. (2014) notes, the recent development in US natural gas production is decoupling its price from the crude oil price which will have, in addition to an encouraging effect on the domestic consumption, presumably far-reaching impacts on the global NG market as well. High crude oil prices and development of shale gas production technologies encouraged companies to invest with increasing extent in natural gas production capacity during the 2000s. This led to the shale gas boom as Figure 47 highlights; between 2007 and 2014 natural gas withdrawals from shale gas formations increased by nearly 7-fold. By the end of 2014, shale gas accounted for 44% of the total US natural gas gross withdrawals. While during the period of 2007-2014 total marketed US natural gas production increased by 34%, domestic consumption faced only 19% growth which led to record low natural gas prices by the early 2010s (EIA 2016h).

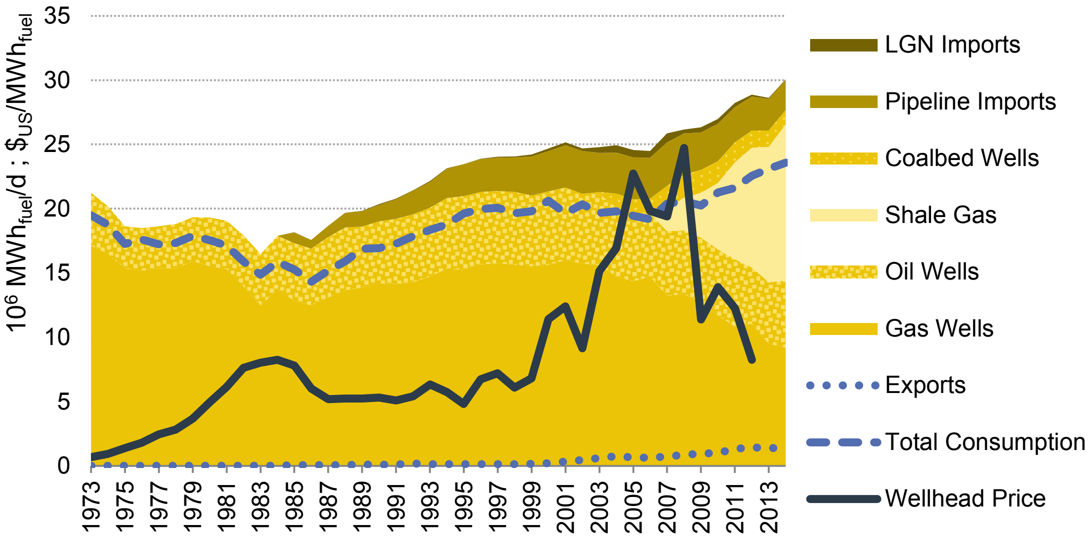

Figure 47 – US natural gas supply and demand; and nominal annual wellhead prices (EIA 2016h)

According to long-term outlook (i.e. Annual Energy Outlook or AEO) provided by the EIA (2015c), cost of delivered natural gas to electricity sector will face an average annual increase of 2.4% during the period of 2013-2040 (i.e. 90% increase from the 2013 level) which is mainly due to increasing utilization of more expensive unconventional gas resources to satisfy the growing demand. Price development is projected rather similar also in the case of the CPP (EIA 2015a). However, the natural gas price is very sensitive for assumptions as, for instance, in the scenario of more abundant than estimated US tight oil and natural gas resources and higher gains from developing production technology, the price may further decrease on near-term and hardly exceed the current price level by the end of the period (2015c).

To understand recently increased natural gas demand on electricity sector it is essential to observe the fuel costs in the terms of the potential electricity generation. As Figure 48 presents, cost difference between natural gas and coal shows rather different when the generation efficiencies of coal-fired and NG-fired units are taken into account. Since 2011, modern combined cycle gas turbine (CCGT) unit with 60% efficiency have faced, on average and on generation basis, 34 months out of 58 cheaper fuel costs than average US coal-fired unit with an operating efficiency of 33%. In turn, a modern pulverized coal-fired plant may have encountered cheaper fuel costs than an average NG-fired unit over the period.

However, it is also essential to recognize that costs are based on monthly average nationwide fuel prices that, in real case, vary according to the region and fuel quality. Such regional differences have presumably made NG-fired generation profitable even more often in some regions than the nationwide average price suggests. For instance, in November, 2015 average spot price of Central Appalachian coal was as high as 21.46 $\$_{US}$/MWh$_{fuel}$ while Powder River Basin coal price was only 5.15 $\$_{US}$/MWh$_{fuel}$ (EIA 2015a) whilst natural gas was sold in Henry Hub and Transco Zone 6 NY for 17.21 $\$_{US}$/MWh$_{fuel}$ and 14.9 $\$_{US}$/MWh$_{fuel}$, respectively. See Figure 62 in Section 5.4 for more information about near-term NG spot price development.

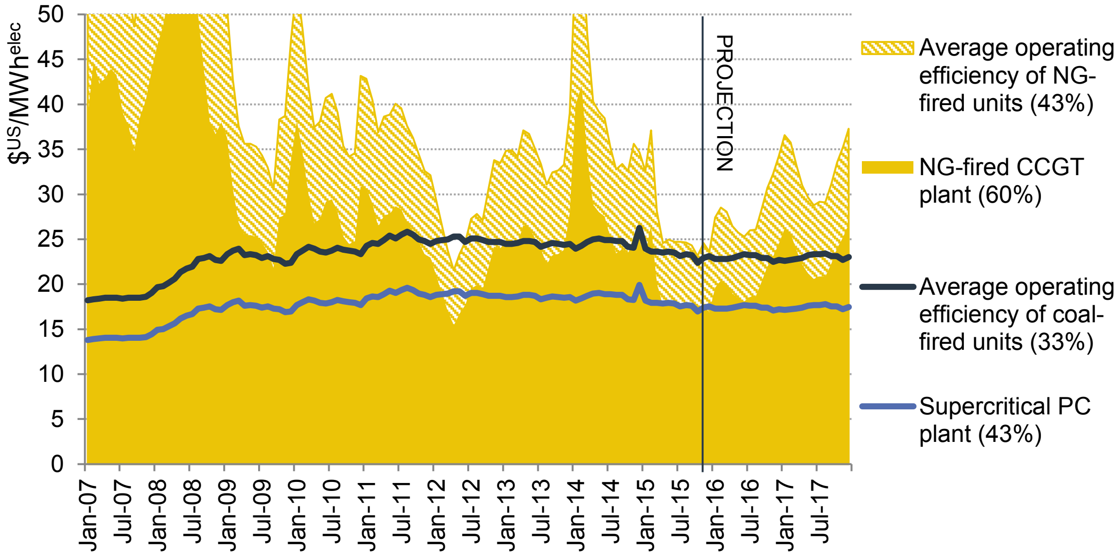

Figure 48 – Average costs, based on electricity generated, of natural gas and coal delivered to electricity generating units (EIA 2015e, Table 8.1; IEA 2015e; EIA 2016g)

4.5 Electricity Prices in the USA

Electricity prices among different US divisions follow the varying trend of generation mixes. In general, average electricity price in divisions with limited fossil generation (especially that of coal-fired) appear higher than the national average while the case is opposite with highly coal reliant divisions; average price remains below national average. Average division-level electricity prices are presented in Figure 49.

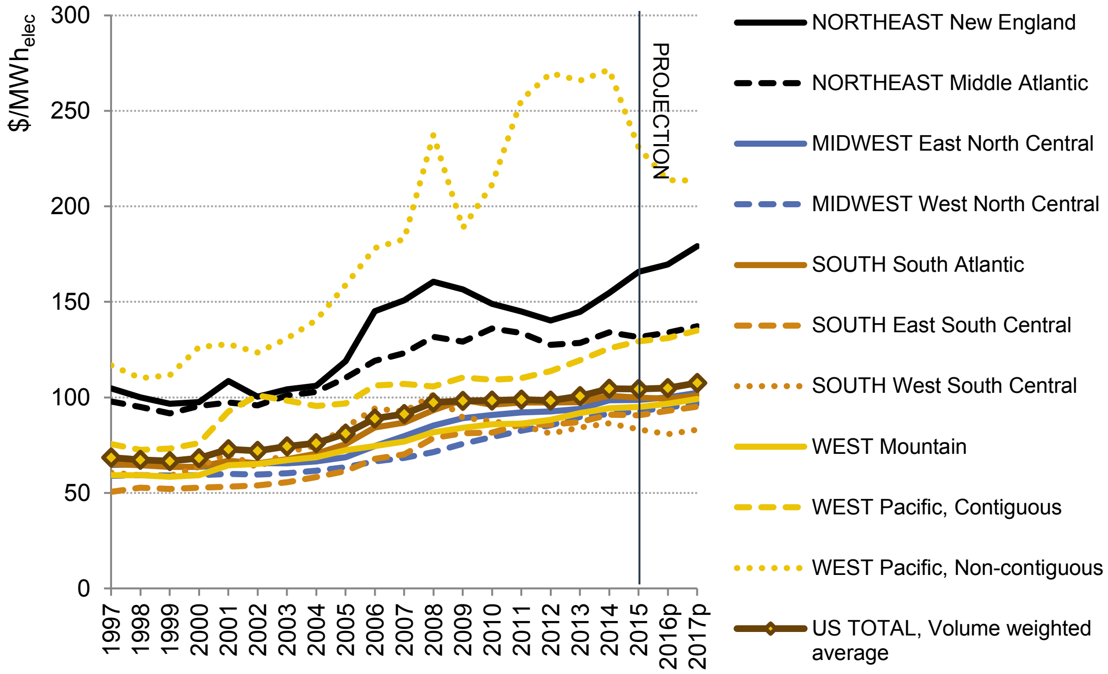

Figure 49 – Annual average retail electricity prices by census division with projections for 2016 and 2017 (EIA 2016g)

Four divisions located in West and Northeast regions, have higher electricity price than the weighted average over the 2000s and the 2010s. Electricity prices are highest on non-contiguous parts of the Pacific division (i.e. Hawaii and Alaska); in 2015 over twice as much as the average US price. Though, volumes within such areas are presumably so small that they have a negligible contribution to the overall generation volume.

The rest of the four divisions with higher-than-average price share several common features; since 2002, coal's share in divisions' generation mixes remained below 15% while, in 2014, less than 5% of the electricity generated was provided with coal-fired units (described in Section 4.2). Additionally, states within the divisions have carried out individual, regional or state level emission regulations. For example, both of the two existing regional GHG emission trading schemes in the USA, i.e. RGGI and California-Quebec, operate either within Middle Atlantic and New England divisions of the Northeast region or within the Pacific division of the West region (see Sections 3.4.2 and 3.4.1). RGGI operates mainly in the Northeast region of which two divisions show the second and the third highest retail electricity prices within the country; in New England annual price reached 165.8 $\$_{US}/MWh_{elec}$ in 2015, i.e. 59% higher than the US average price of 104.3 $\$_{US}/MWh_{elec}$, whereas price in Middle Atlantic settled to 131.6 $\$_{US}/MWh_{elec}$ or 26% above the national average. Contagious parts of the Pacific division of the West, area where the California-Quebec ETS partly operates, indicated slightly lesser price of 129.3 $\$_{US}/MWh_{elec}$ or 24% above the average.

In the remaining six divisions –East and West North Central, East and West South Central, South Atlantic and Mountain - the average retail price for electricity was below the national average. In 2015 on average, the cheapest electricity price occurred in the West South Central states (Texas, Arkansas, Louisiana and Oklahoma) with rate of 83.3 $\$_{US}/MWh_{elec}$ or 20% below the US average. In 2014, fossil-fuel generation provided 78% share of the division's generation mix, which is the highest division-level fossil-fuel generation share in the US (see Figure 42). Fossil fuels (i.e. basically coal and natural gas) had also a significant role in other lower-than-average electricity price divisions dominating the generation mixes with shares from 68% to 74%.

4.6 Large-Scale Coal Power Plant CCS Projects

As of 4 May 2016, there are three coal-fired power plant CCS project in the USA (GCCSI 2016; MIT 2016) which are summarized in Table 12 below. Two of which, Kemper County and Petra Nova projects, are under construction and about to commission operation soon, during 2016-2017. The third, Texas Clean Energy project, is under planning and construction is about to commission during 2016. The plant is anticipated to be ready in 2019. Each project is awarded under DOE's Clean Coal Power Initiative. Also, the captured CO_2 from each unit are about to be used for EOR operations in nearby oil fields.

Table 12 – Coal-fired Power Plant CCS projects in the USA

	Project		
	Kemper Country IGCC	***Petra Nova CCS Project***	***Texas Clean Energy Project***
Leader	Southern	NRG Energy / JX Nippon	Summit Power
Location	Mississippi	Texas	Texas
Size (MW)	582 (net)	240 (gross)	405 (gross)
Generation Method	IGCC	PC	IGCC
Capture Process	Pre	Post	Pre
CO_2 Fate	EOR[b]	EOR	EOR
CO_2	65% (3Mt/y)	90% (1.6Mt/y)	90% (2-3Mt/y)
Initial Budget (billion)	\$2.4 billion	\$1 billion	\$1.727 billion
Actual Budget (billion)	\$6.6 billion	-	\$4 billion
CCPI[a] funding (million)	\$0.270	\$0.167	0.345 [c, d]
Status	Construction 99% Complete	Construction 70% Complete	Financial closing in 2016, groundbreaking thereafter
Planned Commissioning	2nd half of 2016	early 2017	2019

[a] Clean Coal Power Initiative

[b] Enhanced Oil Recovery

[c] Reduces from \$450 million due to the expiration of unused funds

[d] Additionally granted with \$811 million in federal investment tax credits

[e] Engineering, Procurement, and Construction

4.6.1 Kemper County IGCC

Kemper County IGCC plant is a demonstrative project and financially supported with \$270 million by US Department of Energy (DOE) under the Clean Coal Power Initiative (CCPI) (DOE 2016b). The plant is expected to start its operation during 2016. According to the DOE, as of 4 May 2016, construction is approximately 99% complete and commissioning activities of various subsystems are underway. Southern Company, a developer, in co-operation with KBR and DOE, of the Transport Integrated Gasification (TRIG™) technology used in the project, and the owner and the operator of the plant through its subsidiary, Mississippi Power, is currently evaluating the startup date of the complex which is about to take place on the second half of 2016. Since August 2014, it has operated the combined cycle part of the unit with natural gas. (DOE 2016b; Chediak 2016)

The Kemper County facility will operate with low-rank coal, lignite, mined from the near located Mississippi Power owned coal reserves. This arrangement is expected to virtually eliminate transportation risk and provide low-cost fuel (4.3 – 5.1 $\$_{US}/MWh_{fuel}$) for over the 40-year life. (Mississippi Power 2015; GCCSI 2016). The plant will have a peak net output capacity of 582 MW_{elec} when coupling coal derived syngas-fired combustion turbines with NG-fired duct burners in the heat recovery steam generator. It will achieve 524 MW_{elec} net generating capacity when operated syngas-only. CO_2 emissions from the operation will be partially, with capturing rate of 65% or over 3 Mt annually, segregated with pre-combustion technology and then transported via pipeline to two off takers for use in EOR operations at depleted oil production fields in Mississippi. (DOE 2016b)

The flagship project of large-scale coal gasification and pre-combustion sequestration plant has encountered several challenges since the cooperative agreement was launched in 2006 including regulatory issues and, more recently, concerns with equipment such as pipe thickness, length, quantity and metallurgy (MIT 2016; DOE 2016b). Decisions during the planning phase such as running gasifier with air instead of oxygen or choice of an inland location instead of coast have had an significant impact on the budget which has currently ballooned to \$6.49 billion, over three times to the projected \$2.4 billion (Swartz and Rahim 2015; Chediak 2016). Though, Mississippi Power expects the budget to expand even more, up to \$6.6 billion, as in February, 2016, the company is pushing back the already delayed projected completion date by two months to August, 2016, saying it needs to reline pipes that control gas heated to 1,800 degrees. (Amy 2016). Once the project is fully operational, the company expects to generate at least \$50 million additional income annually by selling captured CO_2 and other marketable by-products including 135 000 t of sulphuric acid and 20 000 t ammonia yearly. (Mississippi Power 2015; GCCSI 2016)

Keeping in the mind the Kemp project is first-of-its kind where such, separately designed technologies are scaled and combined into a large complex, Jeff Phillips, a senior program manager at the Electric Power Research Institute Inc., expects the next plant of Kemper's type to cost 10 to 15 percent less and subsequent plants even less (Swartz and Rahim 2015). Pioneer project has already aroused global interest including South Korean energy company Alps Energy that signed a letter with Southern Company to evaluate the deployment of the company's proprietary coal gasification technology at the new, 1,000 MW power plant (Southern Co. 2015).

4.6.2 Petra Nova CCS Project

On the third round of the CCPI, 2010, the US DOE chose Petra Nova CCS project in Texas to represent a demonstrative project of a commercial coal-fired power plant integrated with a large-scale post-combustion CCS system and, thus, is supporting the total budget of $1 billion with $167 million. The project is owned by the Petra Nova Parish Holdings, LLC, a 50/50 joint venture between NRG Energy and JX Nippon Oil & Gas Exploration. (DOE 2016a)

CSS is integrated to an existing W.A. Parish power plant (i.e. one of the largest single source of the CO_2 emissions in the USA), with a 240 MW slip-stream from 610 MW coal-fired unit (MIT 2016). The project utilizes KM-CDR amine scrubbing CO_2 process developed by Mitsubishi Heavy Industries and the Kansai Electric Power Company with the CO_2 capturing rate of 90%, or 1.6 Mt annually. When the carbon capturing starts, it will be piped for EOR operations at mature oil fields in the Gulf Coast region, at the beginning to Hilcorp's West Ranch Oil Field, which is expected to hold approximately 60 million barrels of oil recoverable from EOR operations.

In contrast to most CCS projects, NGR has taken a novel approach when structuring the project. Usually projects sell the captured CO_2 for EOR with a fraction of the value it generates for the oil field owner. For the Petra Nova project, selling the captured CO_2 may have secured 10-35 $\$_{US}/t_{CO2}$ income for the supplier while the West Ranch oil field could have produced additional $150-300 worth of oil for each ton of CO_2 delivered to the third party. Therefore, NGR planned to secure a greater share of that value and decided to build and own the CO_2 delivery pipeline and take a 50 percent equity stake in the West Ranch oil field itself. (Jenkins 2015 p.8)

As a result of purchasing a direct stake in the West Ranch field NGR brought in the first partner, Hilcorp, the oil producing company and the original owner of the field. While working on the front-end engineering and design for the project, partners NGR, Hilcorp and MHI soon realized that original plan for 60 MW CCS project was insufficiently sized to make project financially attractive. Thus NGR decided to quadruple the size and turn the project into a joint venture with JX Nippon, an experienced Japanese oil company. (Jenkins 2015 p.8)

According to the DOE (2016a, 2016d), as of March 2016, construction activities are nearly 70% complete and the project is on track for completion around the end of 2016. It is expected to be operational in early 2017. If project turns out to be successful and repeated again, NGR is looking for ways to take 20-30% out of the costs away which could possibly render government support unnecessary for future (Jenkins 2015 p.6).

4.6.3 Texas Clean Energy Project

Under Round 3 of the CCPI, the DOE awarded $450 million to Summit Power Group's Texas Clean Energy Project (TCEP) (DOE 2016c); a 405 MW_{gross} coal-fired IGCC plant integrated with CCS system that will provide commercial output capacity of 245 MW_{elec}. Plant will utilize pre-combustion, acid-gas capture technology provided by Linde Rectisol to capture 90%, or 2-3 Mt annually, of the produced CO_2 from the facility. The IGCC part will use Siemens commercial gasification and power block technologies. In addition to CPPI award, the project has been further granted with $811 million in federal investment tax credits for clean power projects. The DOE funding, in turn, was reduced in September 2015 by approximately $104 million to $345 million due to the expiration of unused funds (MIT 2016; Blum 2015; DOE 2016c)

(Blum 2015) On December 2015, Summit signed the engineering and construction contracts with China Huanqiu Contracting & Engineering Corp. and Montreal-based SNC-Lavalin Engineers & Constructors Inc. whereby the construction is planned to begin in the late 2016 in West Texas. Project has faced, similarly as many other CCS projects, skyrocketing project costs that brought it into a halt in 2013. Oil boom between 2013 and 2015 contributed to labor shortages and higher construction costs, while the surplus of cheap natural gas from shale has disadvantaged coal. However, recently plunging oil prices brought down construction costs and freed up a lot of skilled labor constraining expected construction costs below \$3 billion. Hence, the initial total budget of \$1.727 billion has swelled up to almost \$4 billion in total. (MIT 2016; Blum 2015)

Projected commissioning of the plant is during 2019. Thereafter it will sell captured CO_2 for EOR in the surrounding Permian Basin. Additionally, it will also produce other valuable commercial products, including urea (for fertilizer), argon gas, sulfuric acid, and an inert non-leachable slag suited to cement making, road building, and roofing materials. Plant is linked with NG pipe network which provides start-up, backup and maintenance fuel for the facility. (MIT 2016)

Summit Power has, besides the TCEP plant, other IGCC/CCS projects internationally including Caledonia Clean Energy Project, a 570 MW coal-fired CO_2 sequestrating plant in United Kingdom; see Section 6.3.3. (Summit Power 2016)

4.7 Proposed Conventional Steam Coal Units

In addition to CCS related projects, there are several conventional coal-fired units under planning or construction in the USA. However, besides economic issues, the EPA's rule for new fossil fuel-fired units (Section 3.2.2) has heightened uncertainty around the projects; i.e. whether or not the units are affected by the rule.

4.7.1 Two Elk Generating Station

Two Elk Generating Station was proposed in 1996, and was planned to be a 300 MW, low-quality-coal-fired power plant (Tempest 2014; Storrow 2015a). Afterwards North American Power Group, the company behind the Two Elk, have also proposed biomass and natural gas combusting units but today Two Elk is pursuing only unit 1 which have received a permit to burn coal and natural gas. (Storrow 2015b)

(Storrow 2015a) On August 2015, after 19 years of delays, the plant failed to receive the ninth permit extension from the Wyoming Industrial Siting Council, the state board that oversees industrial projects. The Wyoming Department of Environmental Quality is also investigating, if, already two times temporarily revoked, air quality permit is still valid as since the project proposal only a little construction has been done. In addition, the Department of Justice is seeking the return of \$5.7 million in stimulus funds for carbon capture research, claiming it was spent on unauthorized costs. On top of that, a Campbell County judge issued a default notice in 2015 against Two Elk for failing to pay \$207,000 in property taxes.

Despite the construction delays the EPA (Federal Register 2015b p.64543) considers plant as an existing unit i.e. its' construction began before January 8, 2014 and hence will not be subject to the performance standard for new units, which requires partial CCS for regular coal-fired generating units to meet the standard (see Section 3.2.2). In its' final rule the EPA states "we accordingly continue to rely on developer statements that this facility has commenced construction and would not be a new source for purposes of this proceeding".

4.7.2 Plant Washington & Holcomb 2 Unit

In addition to Two Elk Station there are two active, though uncertain, conventional coal-fired generating unit proposals; Super-critical pulverized coal plants in Georgia and Kansas with generating capacities of 850 MW and 895 MW, respectively (Sunflower Electric Power 2016; P4G 2016). As project developers convinced the EPA that both plants were under construction by the publication of the proposed CPP, the EPA suggested special treatment for such plants due to special circumstances - perhaps by announcing a standard less stringent than that applied to other new sources or consider them as existing units. (Cummings 2015)

Despite the assurances of developers, they failed to explicitly characterize the construction status of the projects: "- as with the Holcomb expansion project, the EPA is unaware of any physical construction that has taken place at the proposed Plant Washington site and a recent audit of the project described it as 'dormant' ". Hence, in its final rule, the EPA considers it is likely that "these units may never actually be fully built and operated" and thus is not promulgating a standard of performance at this time because such action "may prove to be unnecessary". The EPA also refers to other regulatory issues occurred due to construction delays that most likely increase uncertainty of the projects fate. (Federal Register 2015b p.64543)

4.8 Projections

Based on the business-as-usual trend projection in the Annual Energy Outlook 2015 (AEO2015) (i.e the reference case; see Table 13 for definition), the EIA estimates (2015c) that coal-fired generation together with nuclear energy remain fairly flat through the outlook period of 2013-2040 (see Figure 50). Already high utilization rates at existing units and high capital costs and long lead times for new units mitigate growth in nuclear and coal-fired generation. As a consequence, the expected average annual growth in electricity demand is compensated with increased natural gas-fired and renewable generation of which natural gas-fired generation contributes 60%.

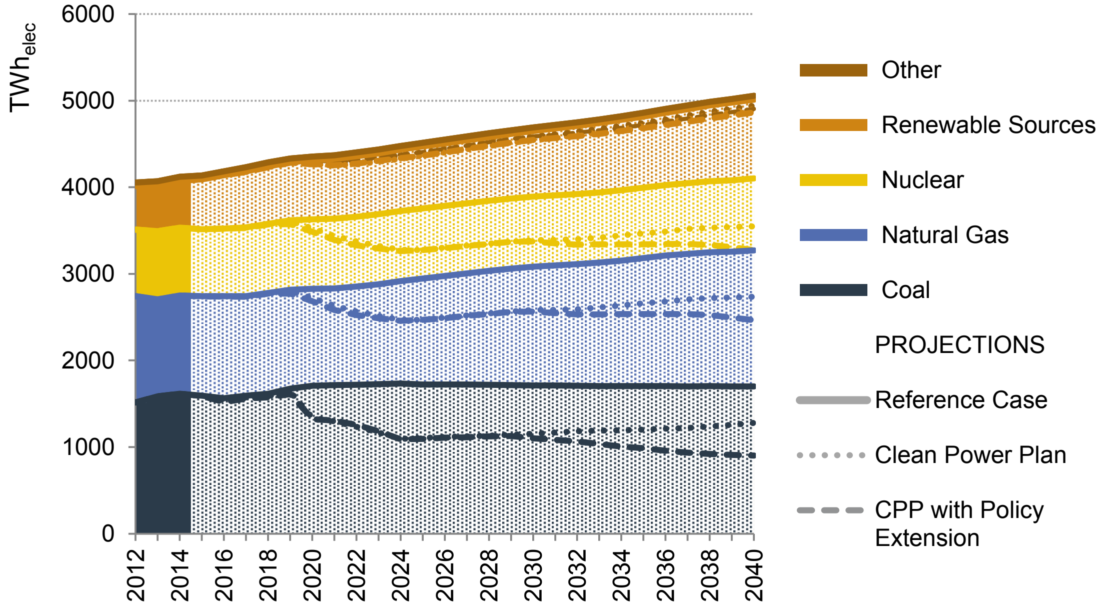

Figure 50 – Projected electricity generation by fuel (EIA 2015c; EIA 2015a)

With such an expectation, the share of coal-fired generation drops from 39% to 34% by 2040. Likewise, nuclear energy share falls from 19% to 16%. Natural gas and renewables, in turn, increase their shares from 27% and 13% to 31% and 18%, respectively. However, especially the amount natural gas-fired generation is highly case sensitive as in the scenario of high oil price, natural gas diminishes part of its generation share settling to 23% by 2040. On the contrary, from all provided scenarios, notable increase in coal-fired generation occurs only in the high oil price scenario. (EIA 2015c)

Besides the traditional Annual Energy Outlook, the EIA analyzes (2015a) the impacts of the proposed CPP. Despite the fact that the analysis is based on the EPA's proposed CPP in 2014 and the finalized interim period is planned for 2022-2030 instead of proposed 2020-2030, it gives an indicative estimate of the situation (see Section 3.2.2 for further information of the finalized CPP). The EIA provides analysis through several scenarios including base policy and policy extension cases (see Table 13 for definitions). In either case, coal-fired generation declines to 30% below the AEO2015 reference case generation by 2023. In the policy extension case, coal generation continues to fall after the CPP final target year of 2030, representing 53% of the reference case generation or 904 TWh_{elec} in 2040 as capacity factor of existing units continues to decline. In case CPP is not followed by further, tightened GHG emission regulations, the coal-fired generation is expected to face a moderate increase due to growing capacity factor of existing coal-fired generation units reaching 1278 TWh_{elec} annual generation by 2040.

Table 13 – Description of EIA reference case and Clean Power Plan cases (EIA 2015a)

Case	**Description**
Reference (AEO)	EIA's AEO2015Reference case. AEO2015 presents annual projections of energy supply, demand, and prices through 2040. The Reference case is generally based on federal, state, and local laws and regulations as of October 2014.
Base Policy (CPP)	The Base Policy case models the proposed Clean Power Plan using the AEO2015 Reference case as the underlying baseline.
Policy Extension (CPPEXT)	The Policy Extension case extends CO_2 reduction targets beyond 2030, in order to reduce CO_2 emissions from the power sector by 45% below 2005 levels in 2040, using the AEO2015 Reference case as the baseline.

Re-dispatching coal-fired generation to NG-fired generation provides an initial compliance strategy. Though, by 2025, renewable generation contributes more to electricity generation reaching over 1100 TWh_{elec} by 2030 which is over 50% higher than in the reference case. In both CPP cases, renewable generation continue its growth beyond 2030 to meet the tightening goals or to maintain goals under expanding electricity demand. However, the impact analysis expects fossil fuel prices (e.g. natural gas price) to increase during the outlook period making renewables most attractive compliance mechanism. Hence, for instance, in the presence of lower than expected natural gas prices, renewable generation may represent notably reduced generation shares.

The extent of the US coal fleet depends mostly on the degree of the unit retirements as projected new generation unit additions remain exceedingly low. In both CPP cases, baseline policy and policy extension, the reliance of fossil fuel generation diminishes trough the outlook period (see Figure 51). Coal-fired generation capacity faces the greatest burden, as in both cases the retirements presents over 90 GW or over 30% of the existing coal-fired capacity by 2040. Although, even in the reference case, which does not take implementation of the CPP into account, the largest retirements occur particularly for coal generation resulting in 13% or 40 GW decrease in the existing coal-fired capacity by 2040. Furthermore, regardless of the case, projected coal-fired capacity additions remain diminutive as planned and unplanned additions account for less than 0.5% of the projected coal-fired capacities in 2040. It reflects the high capital costs of coal-fired units and uncertainty around the future of emission regulations.

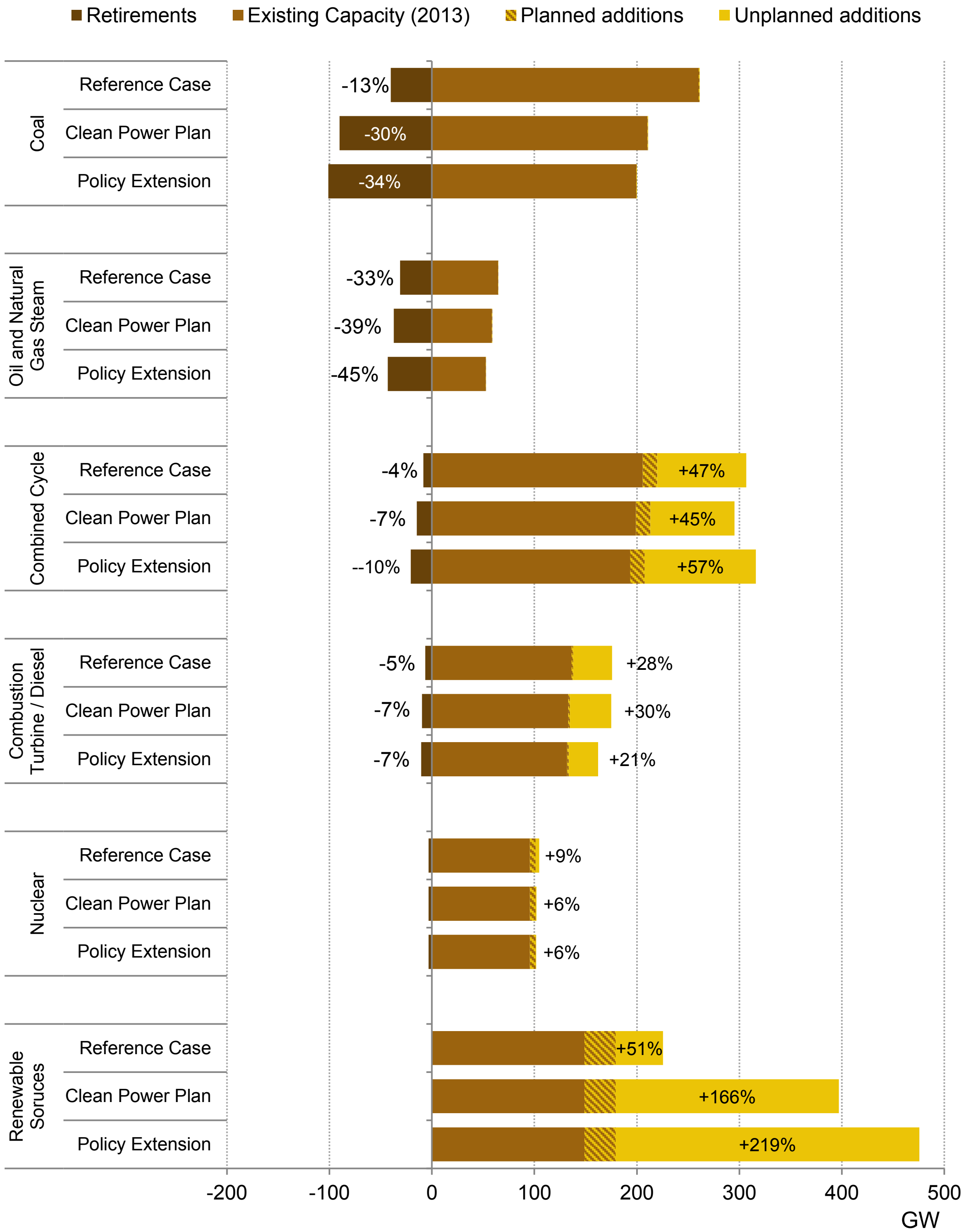

Figure 51 – Projected cumulative generation capacity additions, retirements and existing capacity (which does not retire) during 2014-2040 (EIA 2015a)

On short term, during 2015-2019, nearly 100 GW of new generation capacity (summer capacity) is added, the most of which comes from natural gas, wind and solar power; 57%, 22%, 14%, respectively as Figure 52 presents. According to the data (EIA 2016d), only a few coal-fired additions with cumulative capacity of 0.7 GW are planned for the period (presumably, takes projects mentioned in Sections 4.6 and 4.7 into account). Out of the nearly 40 GW of retiring capacity, in turn, coal accounts for 73% or 29 GW.

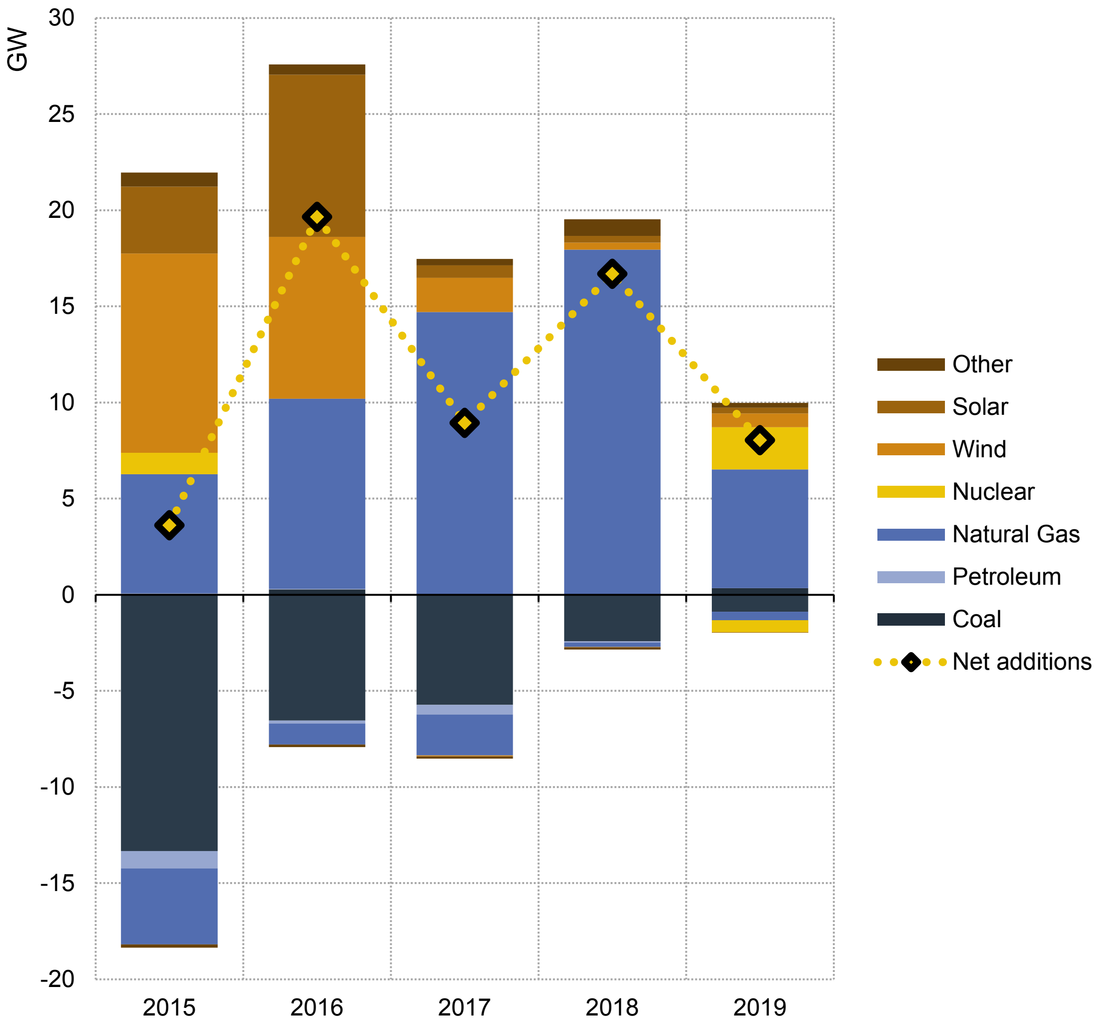

Figure 52 – Planned capacity changes by energy source as of December 31, 2014 (EIA 2016d)

Additionally, as a part of its annual outlook (AEO), the EIA provides cost projections for available power plant types (EIA 2015f). Average values of projected levelized costs of electricity (LCOE) for plants entering in service 2020 are presented in Figure 53. It is, however, important to note that while LCOE is a convenient summary measure, numerous technological and regional characteristics affect the actual costs and the plant investment decisions (e.g. utilization rate and the existing resource mix). Still, presented numbers can be used as to compare overall competiveness of different generating technologies.

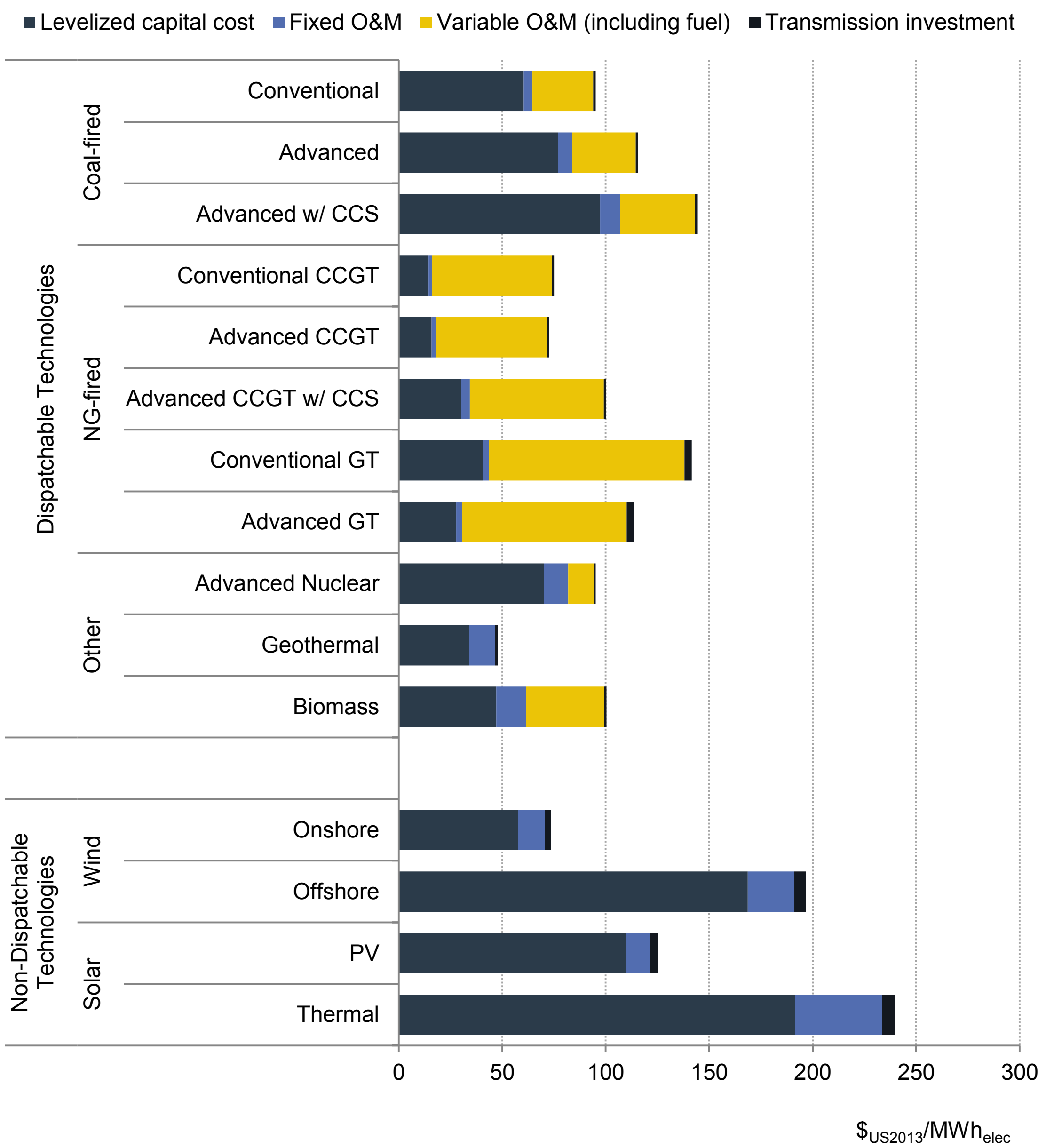

Figure 53 - U.S. average levelized costs for plants entering service in 2020 (EIA 2015f)

As Figure 53 indicates, NG-fired CCGT generation (without CCS) is the most competitive option of the fossil fuel-fired units; 72.7-75.1 $\$_{US}$/MWh$_{elec}$. This is due to significantly lower capital costs than any other presented generation type. In turn, variable costs hold the greatest share accounting for at least 65 % of the total LCOE which makes costs sensitive to fuel price fluctuations. Furthermore, the data confirms that the future prospects for new coal power are very limited on the overall US scale. With levelized cost of 95.2 – 115.7 $\$_{US}$/MWh$_{elec}$ (depending on technology), of which at least 60% are due to capital costs, coal generation remains among the top of the dispatchable technology list. In addition, if coal plants are about to equip CCS, the cost bounces to 144.4 $\$_{US}$/MWh$_{elec}$ which is double the cost of advanced CCGT and approximately 50% higher than costs of nuclear, biomass or CCGT with CCS.

5 Coal-Fired Generation in Canada

5.1 Electricity Generation in Canada

Canada is an exemption among the studied countries as coal has only a minor role in the overall nationwide generation mix. As Figure 54 presents, in 2013 coal-fired generation accounted for only 10% (65.2 TWh) of the total 654 TWh electricity generated; slightly over a half of its' all-time peak of 118 TWh in 2001. Uniquely, due to enormous drainage basins in Canada, hydro power dominates the generation mix with approximately 60% portion of the total annual generation during 1990-2013. Natural gas-fired generation has notably increased its' share of 2 % or 9.7 TWh_{elec} in 1990 ultimately exceeding coal's share in 2012 with 69.5 TWh_{elec} generation (11% of the total); soon after wind power surpassed oil-fired generation in 2011 with 10.1. TWh_{elec}. (IEA 2015d)

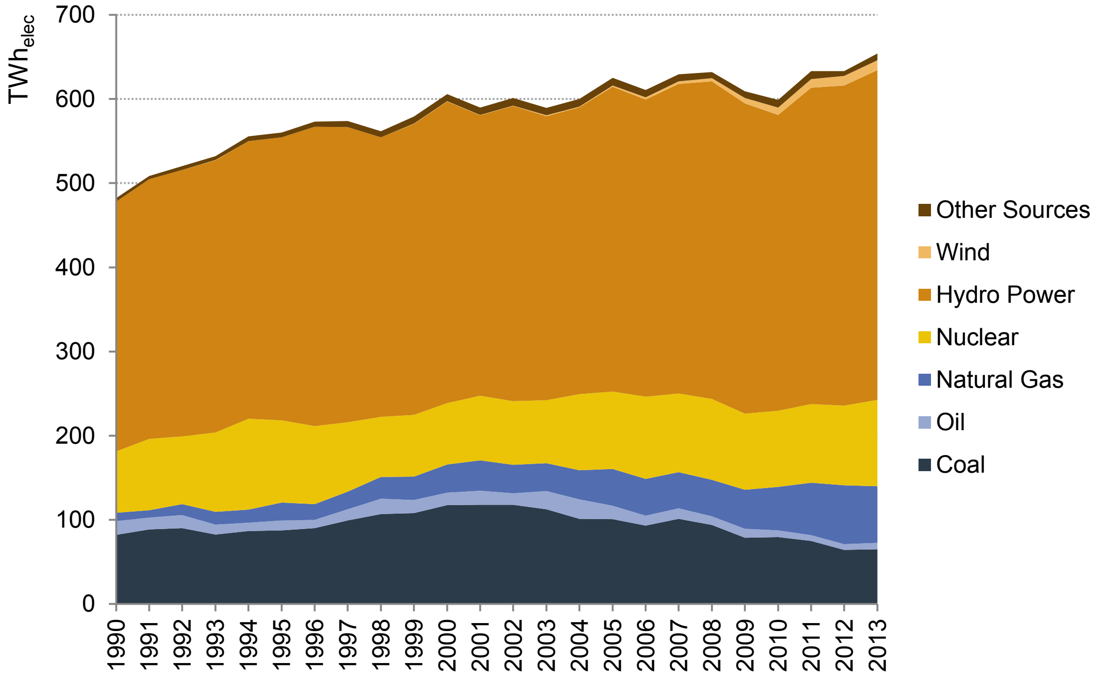

Figure 54 Electricity generation by fuel (IEA 2015d)

As Figure 63 shows, coal's share temporarily enlarged during 1998-2003 reaching 20% share in 2001. According to the World Nuclear Association (2016), between 1995-1998, former Ontario Hydro (today Ontario Power Generation and Bruce Power) laid up eight nuclear power units in Ontario to renew the generators and so extend those lifetimes. Four of the shutdown reactors were part of the Pickering station (515 MW_{elec} each) and the other half part of the Bruce station (750 MW_{elec} each); ergo a substantial amount of generation capacity (approximately 5000 MW_{elec} in total). After the refurbishment, four out of the eight units (Pickering A1 and A2; Bruce A3 and A4) were brought back online during 2003-2005 recovering share of nuclear power back to 15% with expense of coal and oil-fired power. Later, in 2012, both Bruce A1 and A2 were also restarted further increasing nuclear power capacity in Ontario. Pickering A2 and A3 were newer refurbished and restarted as it would have been uneconomical for the company. Consequently, shortage due to partial shutdown of the nuclear plants was temporarily satisfied with increased fossil generation.

While coal-fired generation has decreased since the peak in 2001 NG has maintained its' sustaining growth over the period. Due to low prices in the early 1990s NG appeared more affordable for consumers, thus making it competitive electricity generation fuel alongside coal (see Section 5.4 below). Tightened emission guidelines for thermal electricity generation published in 2003 and Ontario's phase-out of coal-fired generation since 2005 (see Section 3.4.6) followed by the proposal (and later implementation) of the performance standard for coal-fired units in 2011 (Section 3.3.1) primed substantial descent of coal-fired generation which ultimately shrank by 44% between 2001 and 2013 while the overall generation increased by 10%.

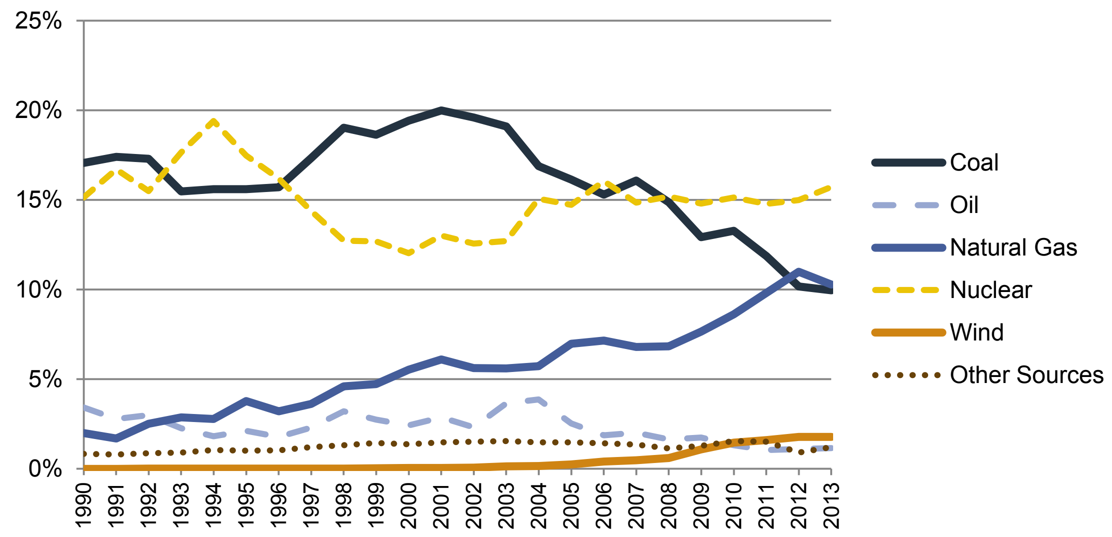

Figure 55 – Shares of generating fuels in Canadian generation mix (hydro power not included due to its' vast and relatively constant share) (IEA 2015d)

5.2 Province and Territorial Level Generation

Province level generation mixes reflect diversified distribution of natural resources and related industries around the country (see Figure 56); provinces with the most abundant coal resources - Alberta and Saskatchewan – consequently generates the most of the coal-fired electricity within the country (see Section 5.3). Former major coal producing provinces, Nova Scotia and New Brunswick, also still rely on coal-fired generation. Regions located around vast river systems including Quebec, Manitoba, British Columbia and Newfoundland satisfy the most of the electricity demand with flexible hydro power. Again, in the major uranium processing province, Ontario, nuclear power dominates the generation mix.

Furthermore, highly varying provincial generation mixes indicates the wide range of province level environmental policies within Canada of which pre-eminent is Ontario's decision phase out of coal-fired generation to cut GHG emissions and other pollutions leading to ultimately resign of province's coal-fired units by the end of 2014. Such reform limits provinces that rely on coal-fired generation to four; Alberta, Saskatchewan, Nova Scotia, New Brunswick with respective 2014 shares of 42.9 TWh_{elec}, 9.3 TWh_{elec}, 5.5 TWh_{elec} and 2.6 TWh_{elec} or 57%, 42%, 52% and 16% from respective total generation. Of those only Alberta, accounting for 71% of the total Canadian coal-fired generation, exceeded 2005 level coal-fired generation in 2014. However, coal's share from Albertan generation mix decreased by 10 percentage points during the period. In 2014, there was a fraction of 0.07 TWh_{elec} coal-fired generation in Manitoba but it has a meaningless contribution to the total generation accounting for only 0.2% of the province's generation mix.

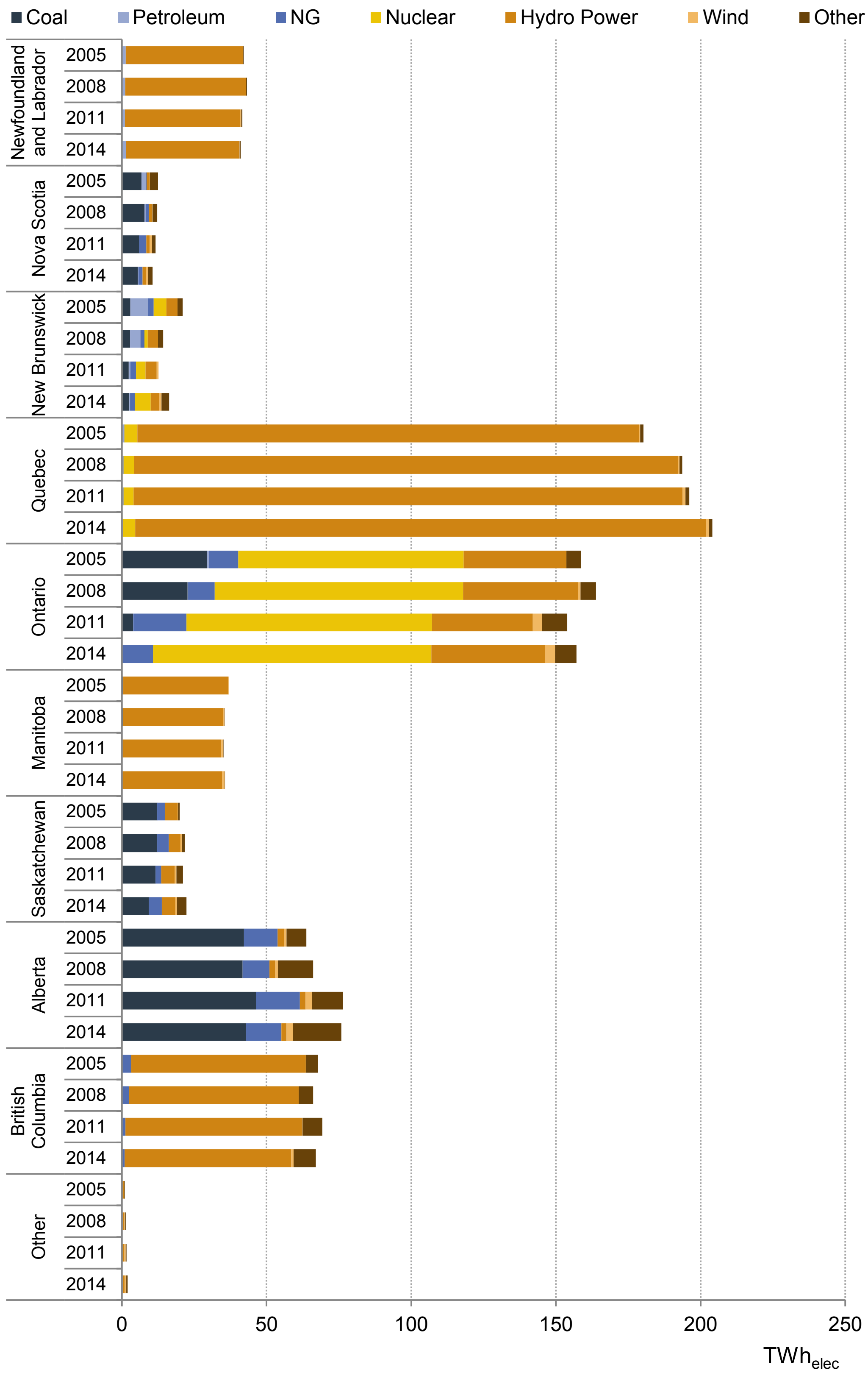

Figure 56 – Electricity generation in Canadian Provinces by generation type (Government of Canada 2016b; 2015d)

5.3 Coal Production and Consumption in Canada

Canada is world's 12th largest coal producer with 69 Mt production in 2013 or 1 % of the total 7 822.8 Mt worldwide production (Government of Canada 2015b; IEA 2014a p.44). As Figure 57 presents, major share of domestically produced coal ends up being exported; in 2013, 53% or 36.6 Mt of total produced Canadian coal was exported of which 90% was labelled as metallurgical, bituminous coal (i.e. coking coal) (Government of Canada 2015c). Imports, instead, accounted for 20% or 8Mt of the total domestically available coal in 2013. After a notable decline between 1997 and 2003 domestic, annual coal production has remained fairly stable fluctuating between 65 Mt and 69 Mt.

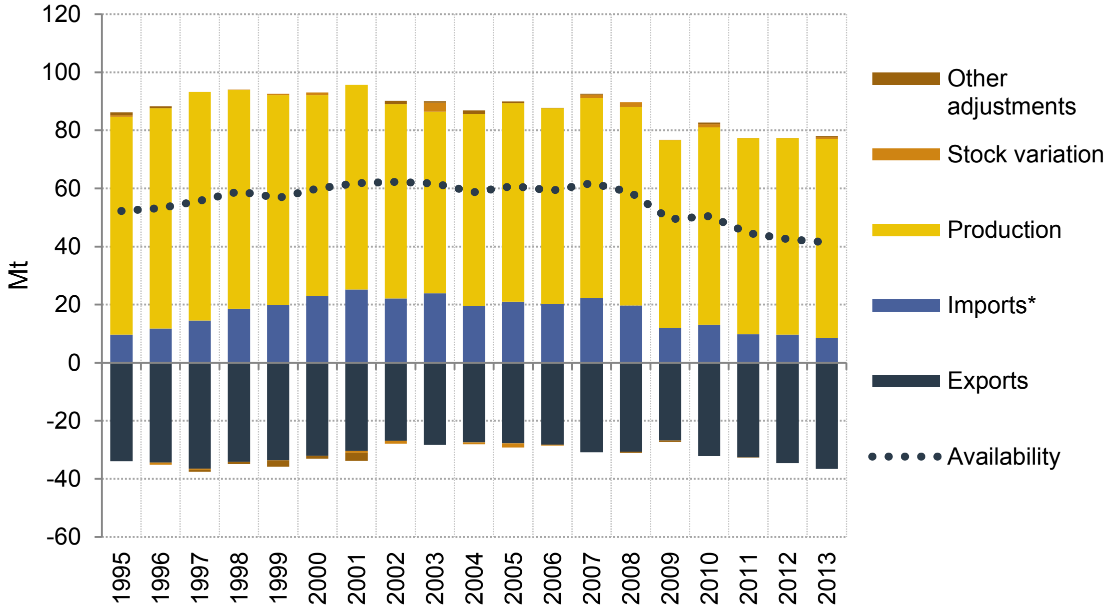

Figure 57 Coal supply (Government of Canada 2015b; Government of Canada 2015c)
**) Imports for year 2013 is derived from available data (Imports = Availability + Exports + Stock Variation - Production - Other adjustments)*

According to National Resources Canada (2015), Canada has seven coal-producing companies that operates 19 mines located in western Canada; British Columbia, Alberta and Saskatchewan. Coal is also mined in Nova Scotia and New Brunswick and, additionally, reserves and resources have been identified in Yukon, Ontario, Newfoundland and Labrador, the Northwest Territories, and Nunavut. At present, Canada holds 8.7 billion t of proved resources of coal-in-place equal to c. 100-year production.

As presented in Figure 58, British Columbia has the largest bituminous coking coal production capacity in Canada (30.8 Mt production in 2013) whereas most of the sub-bituminous and other bituminous coals are mined in Alberta (in 2013, 21.7 Mt and 3.8 Mt, respectively). Instead, mines in Saskatchewan produce mainly lignite (8.9 Mt in 2013). British Columbia exports the most of produced coal (in 2013, 96%) while in Saskatchewan low rank lignite is used within the province. 11% of Albertan coal was exported in 2013 consisting of bituminous coal ranks leaving sub-bituminous coal for indigenous consumption.

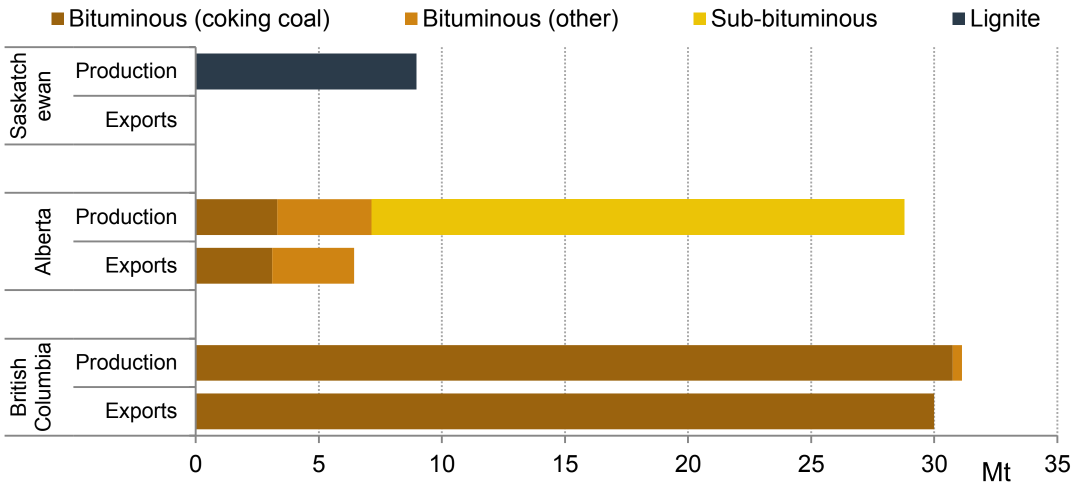

Figure 58 – 2013 coal production and exports by coal rank in major coal producing provinces (Government of Canada 2015c)

Generally, electricity sector is responsible for the major of domestic coal demand, i.e. 87% or 35.8 Mt of the total consumption in 2013, as shown in Figure 59. The remaining domestically consumed coal (i.e. other than used for electricity generation) is mainly transformed to coke and manufactured gases or used as an energy source for industrial processes, approximately 9% and 4% in 2013, respectively, from the total consumption. Consequently, as coal-fired generation faced an enduring decline since its peak in 2007 (see Figure 54) so did the domestic consumption; by 2013, 33% (20.3 Mt) fall to 41.4 Mt from 61.7 Mt peak in 2007. However, due to high share of high rank coal production, thus, important role of international trade for Canadian coal industry, domestic production as a whole hasn't followed the trend; declining domestic demand has led increase in net exports by 19.5 Mt during 2007-2013 (see Figure 57).

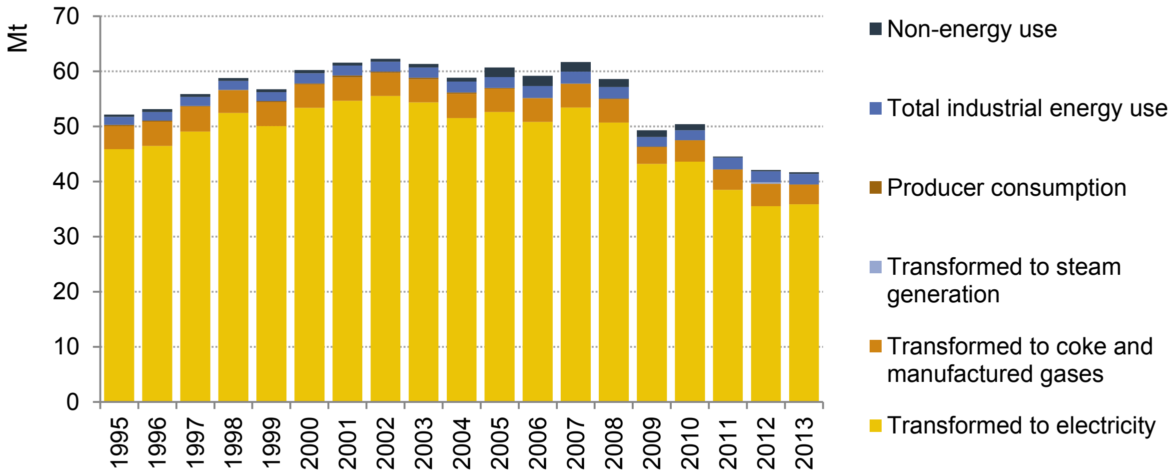

Figure 59 - Coal consumption by utilization type (Government of Canada 2015b)

Electricity sector's consumption of different coal ranks have declined unevenly leading to increased emission intensity of coal-fired generation (see Figure 60); share of consumed high rank bituminous coal has decreased from 18% to 9% between 2005 and 2014 while share of lower rank sub-bituminous coal have increased from 61% to 71%. Lignite consumption have maintained its' c. 20% share. This explains the 10% increase in emission intensity of Canadian coal-fired electricity generation from 2005 level of 940 g_{CO2}/kWh_{elec} to 1033 g_{CO2}/Wh_{elec} by 2013 as indicated by the IEA (2015c) statistics (see also Figure 7).

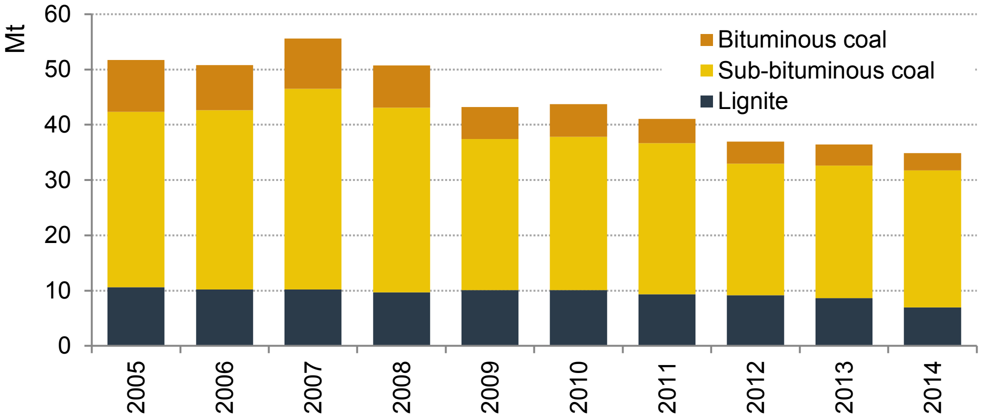

Figure 60 – Electricity sector coal consumption by coal rank (Government of Canada 2016a)

5.4 Generation Fuel Prices in Canada

As coal consumed by the electricity sector is mainly indigenous production, costs have remained relatively stable and low; within 4 and 5 $\$_{CAN}/MWh_{fuel}$ during 2001-2013. Coal is used as generation fuel mainly in provinces with own coal production, thus transportation costs remain minimal. In addition, some electricity generating companies such as TransAlta, own and operate coal mines (TransAlta 2016a). Such infrastructure presumably provides predictable and adjustable, hence, cost-competitive supply of coal for generation units.

From the observed generation fuels, average price of oil consumed for electricity generation have varied the most between 2000 and 2013 nearly quadrupling from $\$_{CAN}$ 19.1 to $\$_{CAN}$ 61.3 per MWh_{fuel}. After 2009, when the average price faced the sharpest increase of the period, domestic oil sands production exceeded conventional oil production (Natural Resources Canada 2014). Also, between 2010 and 2013 Canadian oil exports expanded by over a third. These may explain the rapidly grown expenses of oil-fired generation. Though, as showed in Figure 55, oil-fired generation has a minor, shrinking contribution to the total nationwide generation as it is only used during peak demand period or in areas where other generation options are not widely available (e.g. Yukon, NWT, and Nunavut) (NEB 2016a).

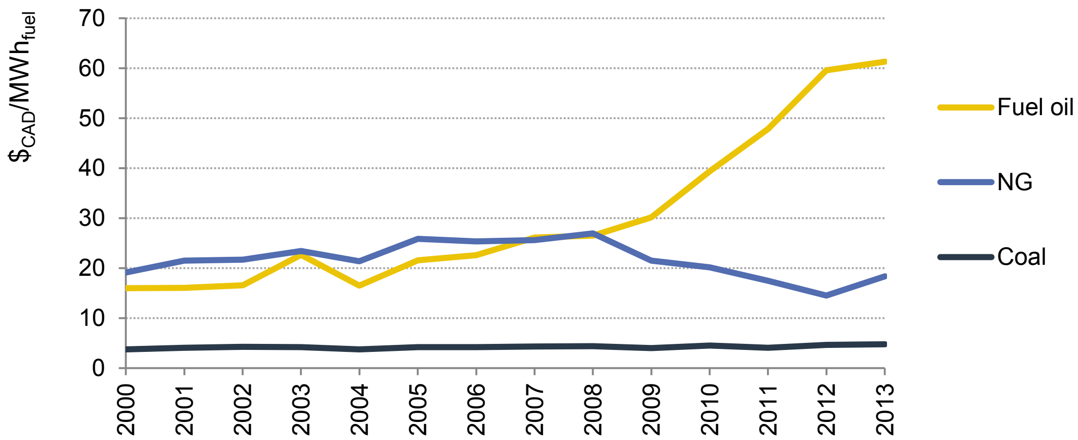

Figure 61 – Annual average prices of chosen fuels consumed for electricity generation (IEA 2016)

During 2000-2013, annual average price of natural gas - that is crucial for reforming, Canadian electricity sector - have remained relatively stable over the period; average price have fluctuated between the bottom of 14.5 $\$_{CAN}$/MWh$_{fuel}$ (2012) and the peak of 26.9 $\$_{CAN}$/MWh$_{fuel}$ (2008) settling to 18.4 $\$_{CAN}$/MWh$_{fuel}$ (2013), i.e. slightly under 2000 price of 19.1 $\$_{CAN}$/MWh$_{fuel}$. However, observing NG price only on yearly average basis does not bring up the volatile characteristics of US-Canada-wide NG market that sensitively correlates with multiple factors such as oil prices, weather conditions and global economic growth. Figure 62 provides such information by showing the near-term historical weekly spot price development of Henry Hub (i.e. a distribution hub on the NG pipeline system) and major events that affected to the price.

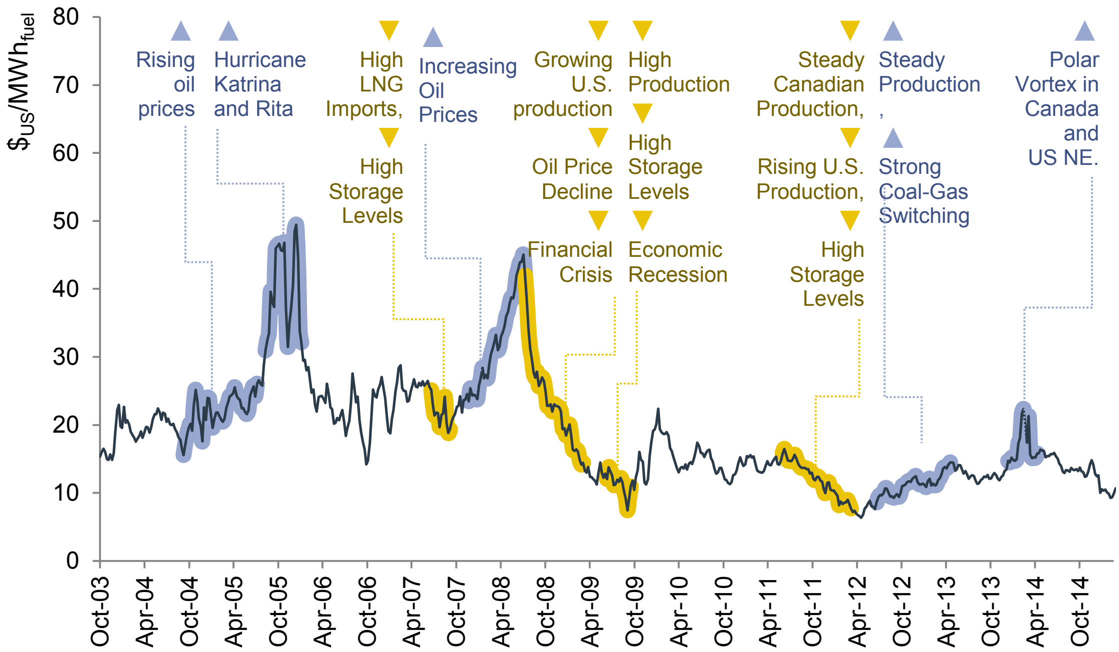

Figure 62 – Weekly Henry Hub natural gas spot prices and events affecting prices (EIA 2016e; NEB 2015a)

Long-term development of natural gas market and increased production can be attributed to 31 October, 1985, when the federal government and the gas producing provinces of British Columbia, Alberta and Saskatchewan signed the Agreement on Natural Gas Markets and Prices (or Halloween Agreement) which replaced government-controlled NG pricing and established open access for shippers on NG pipelines (see Figure 63). US market was further opened as the Agreement relaxed restrictions on exports from Canada. During the initial years following deregulation, increased competition, excess productive capacity in Canada and a general decline in global energy prices led to decline in NG price. Concurrently, new pipelines made markets in the USA more accessible to Canadian producers, hence, increasing NG production, exports and revenues; between 1986 and 1995 Canadian production more than doubled from 2.1 TWh$_{fuel}$/d to 4.3 TWh$_{fuel}$/d (NEB 2015b)

According to the National Energy Board of Canada or NEB (2015b) NG prices rapidly increased in the early 2000s as demand rose while combined Canadian and US production remained steady. Expected increasing price encouraged the development of liquefied natural gas import infrastructure. Though, rapid growth in NG production form shale and tight formations in Canada and the USA considerably increased supply and decreased prices.

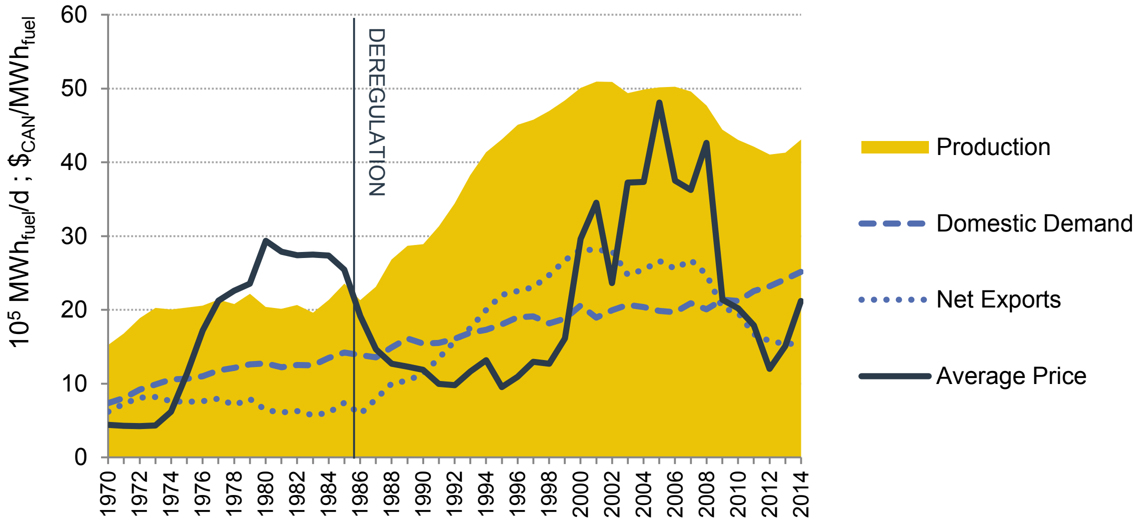

Figure 63 – Canadian natural gas disposition (10^5 MWh$_{fuel}$/d) and average historical prices in real (\$$_{CAN2014}$/MWh$_{fuel}$) (NEB 2015b)

5.5 Electricity Prices in Canada

Similarly, as generation mixes vary among the regions, so do electricity prices as Figure 64 presents. Generally, residents in provinces with high share of hydro power generation, especially Québec, Manitoba and British Columbia, benefit by relatively inexpensive and stable electricity prices. In contrast to the USA, prices in Canadian provinces that rely on coal-fired generation including Alberta, Saskatchewan and Nova Scotia, indicates highest rates. On average, residents in Charlottetown, Prince Edward Island, pays the most of their electricity compared to the rates in other major cities. Though, the province generates some wind and imports the bulk of its electricity from the mainland (Government of Canada 2015a; 2016b), hence, the price is prone to fluctuations.

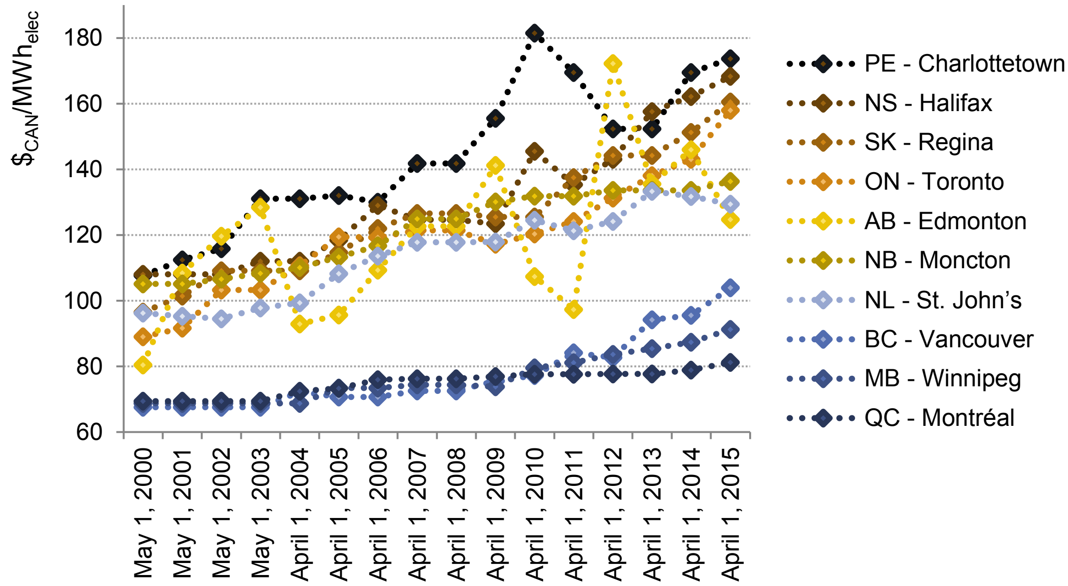

Figure 64 – Average residential electricity prices (including taxes) in major Canadian cities on certain days. Provinces providing over 80% of generated electricity with hydro power marked in tones of blue. (Hydro Québec 2016; Government of Canada 2016b)

Yearly snapshot of daily residential prices in Edmonton signals that electricity rates are rather volatile in Alberta where the electricity market has been deregulated since 1996. Hence, any customer (residential, commercial or industrial) may elect to purchase power from authorized retailers. Though, only few Albertan consumers purchase electricity under long-term contracts (Baker et al. 2011). Additionally, besides the energy-only, spot market known as the Power Pool, there is no capacity market that would provide stable returns for build generations, thus the lack makes backup reserve capacity expensive. Furthermore, Alberta's industry is highly concentrated on producing energy commodities e.g. oil sands, hence the electricity demand of the region is sensitive to any changes occurring in the global economy.

Another province that have reformed its' electricity sector, since 2014 coal-free Ontario, have faced increasing, though more stable, trend in its electricity rates. Ontario's coal phase-out caused an increased pressure to pull up the electricity rates as it required massive investments for new generation capacity and electricity grid; by an estimate total capital costs in January 2013 approached $\$_{CAN}$18 billion (Gallant 2013). Additionally, government-decreed projects such as subsidies for new solar and wind generation and development of smart grid, added annual cost almost $\$_{CAN}$ 7.35 billion or $\$_{CAN}$ 1,530 for each 4.8 million ratepayer. Due to implemented rate increases by Ontario Energy Board, especially for on-peak hours, an average monthly household energy bill has increased by 30% since 2010 (CBC News 2015a). Provinces intention to partially privatize its' hydro power capacity raises concerns that electricity bills may even further increase during the following years. But then again, Ontario's trend seems to be in line with the overall national trend in electricity prices; rates have increased constantly even before the phase-out. Therefore, it might be too soon to conclude the actual burden of the phase-out.

5.6 Coal-fired Capacity Additions and CCS projects

Currently, there are not ongoing plans of conventional or CCS coal-fired unit additions in Canada as market conditions and tightening regulations increase concerns related to coal-fired plants. However, in 2014, world's first large-scale, CCS retrofitted coal-fired generation unit (110 MW_{net}) started its' operation in Saskatchewan. There was also planned a 1000 MW, 20% carbon capturing coal-fired unit in Alberta, but since 2012 its' status have remained uncertain and no proceeding has done since plans were finalized in 2011. Following subsections provide further information about the two projects.

According to the National Energy Board of Canada (2016, Lis N., email), the last conventional coal-fired unit was built in 2011 which is Keephills 3 with net generating capacity of 450 MW owned by TransAlta and located in Alberta. Additionally, in 2014, two existing TansAlta owned units, Sundance 1 & 2 in Alberta as well, where rebuilt and brought back online providing total net capacity of 600 MW which is at some sources considered as new generating capacity. The Board is not anticipating any new conventional coal-fired generation unit additions.

5.6.1 Boundary Dam CCS project in Saskatchewan

Unit 3 of the Boundary Dam Power Station is world's first commercial large-scale post-combustion CCS project (Stéphenne 2014). Conventional coal-fired generation unit was aging and subject to the new federal GHG regulation (see Section 3.3.1). Provincially owned SaskPower expected to extended unit's useful lifetime by 30 years by retrofitting Shell Cansolv's post-combustion, amine based CCS system. Project was justified with tightened federal regulations and with the fact that coal will provide locally produced, abundant and economical source of fuel. Additionally, it could make Saskatchewan, thus Canada in general, a world leader of CCS technology (SaskPower 2016b).

Retrofitted system was commissioned in October, 2014, and has been running with varying generating and capturing levels since then (MIT 2016). On full load operation it reaches gross generating capacity of 139 MW (110 MW_{net}) and 90% capturing rate. Scheduled capturing rate for CO_2 is 1 Mt_{CO2} annually, though by February, 2016, after 16 months of operation, only 0.63 Mt_{CO2} was captured (SaskPower 2016a). Encouraged by the 100% operation achievement in January, 2016 (see Figure 65), SaskPower is optimistic with the target for 2016 to capture 0.8 Mt_{CO2} and run approximately 85% of the time (in 2015 plant was online 56% of the time and 0.43 Mt_{CO2} was captured). Plant is expected to be fully operational by the end of 2016 (MIT 2016).

Project is funded by the SaskPower with $\$_{CAN}$1.11 billion and with $\$_{CAN}$240 million subsidy from Government of Canada (Natural Resources Canada 2016). In addition to electricity, the company will generate revenues by delivering 90% of the captured CO_2 to the Weyburn field for EOR via 66 km pipeline (MIT 2016). Rest of the captured CO_2 is delivered to the Aquistore project 2 km away. Other byproducts of the process including sulphuric acid and fly ash are also sold. SaskPower counts it will receive $\$_{CAN}25/t_{co2}$ from Cenovus Energy (Burton 2015). However, lower than expected volumes of delivered CO_2 has resulted $12 million penalties under the CO_2 supply contract.

SaskPower intends to expand CCS to existing Boundary Dam 4 and 5 generation units. However, it still needs to ensure the Unit 3 functions properly for entire year. Thus, it pushed back the deadline of the decision to 2017 instead of announcing the status of the expansion by 2016 (CBC News 2015b).

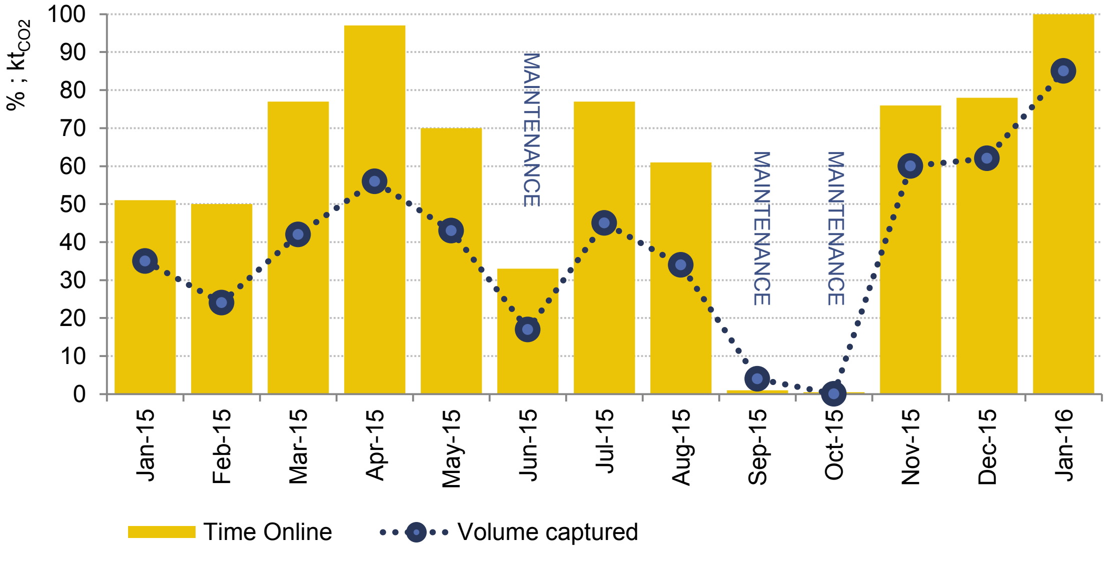

Figure 65 – Monthly operation data of Boundary Dam Unit 3 since January, 2015 (SaskPower 2016a)

5.6.2 Bow City CCS project in Alberta

Still in 2011, Bow City Power, in cooperation with Canslov (a subsidiary of Shell), planned to build a 1000 MW, supercritical coal-fired plant integrated with post-combustion CCS system (Canslov's amine scrubbing technology) for EOR operation via 51-100 km pipeline. Plant was planned to utilize coal from nearby mines, hence provide reliable and cost effective power for the community from 2017. Estimated cost was $\$_{CAN}$ 2.9 billion with planned capturing rate of 1 Mt_{CO2}/year or 20% of the total CO_2 emissions. (MIT 2016)

However, after Bow City Power made a significant effort to secure financing for the project the chancing market and regulatory conditions have made proceeding difficult. With an exception of finalizing the design of CCS in 2011, hardly any significant advancement has been done. Taking into account Alberta government's recently initiated program to phase out much if not all of it coal-fired capacity by 2030 (see Section 3.4.4). President and the CEO of Bow City Power (2016), Brian F. Bietz, states that "notwithstanding the commitment to make Bow City effectively 'clean as gas' the chances of the project proceeding continue to decline." Furthermore, "the presence of large gas supplies in Alberta coupled with the ongoing low price for gas makes proceeding even less likely in the foreseeable future as even coal's economic advantage is severely eroded until if and when gas prices were to increase again."

5.7 Projections

In its' report "Canada's Energy Future 2016", National Energy Board (NEB 2016a) estimates that electricity generation capacity increases during the projection period of 2014-2040 by 33 GW from 2014 capacity of 140 GW. Capacity additions will compensate retiring capacity and growing demand. As Figure 66 shows, projected capacity additions are mainly based on natural gas generation (40% of the capacity additions), wind (27%) and hydro/wave/tidal categorized generation (16%).

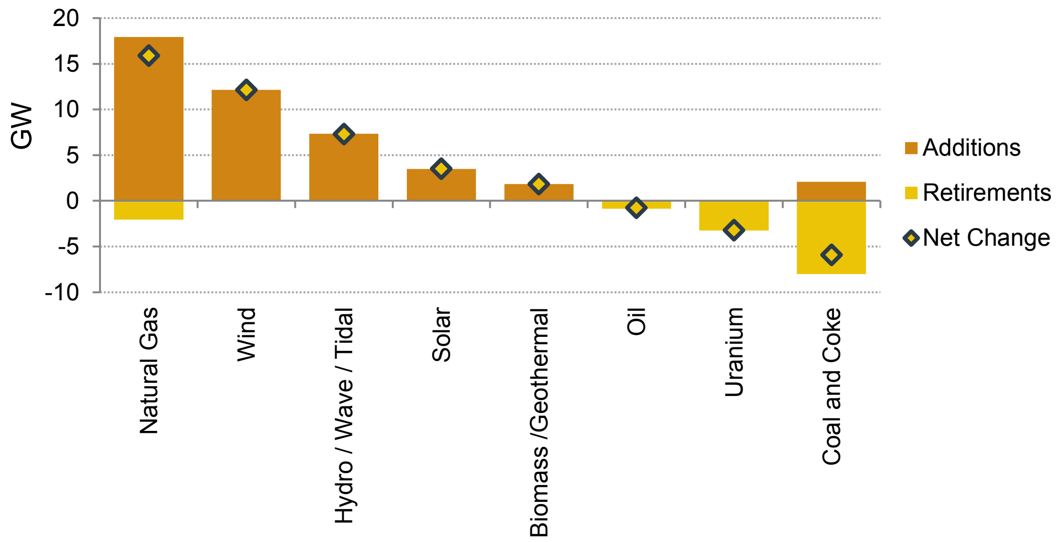

Figure 66 – Capacity additions and retirements during 2014-2040 (NEB 2016a)

Accordingly, the overall Canadian electricity generation will increase by approximately 21% by 2040; from 655 TWh_{elec} to 795 TWh_{elec} (see Figure 67). Growth in electricity demand is compensated with increased role of natural gas and renewable sources with an expense of coal, oil and nuclear power generation. By 2040, coal's generation share drops by a half from 2015 level whereas NG-fired generation, likewise non-hydro renewables, more than double the annual generation.

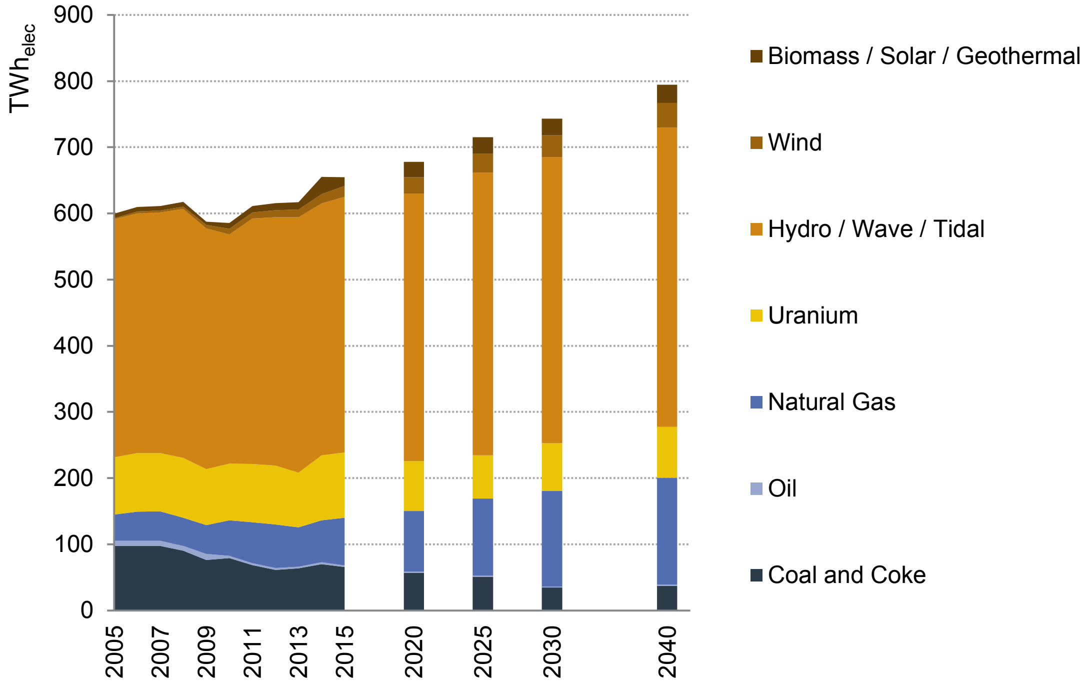

Figure 67 – Projected electricity generation by fuel (NEB 2016a)

Greater role of natural gas generation is driven by several factors including low NG prices, lower GHG emission intensity of NG-fired units compared to coal generation. Additionally, NG-fired plants benefit from shorter construction times and lower upfront capital costs than coal-fired or nuclear power units. Also, well-developed NG pipeline network, together with flexibility of NG-fired units (in the terms of unit size and start-up time) to meet short and long-term load changes, support the NG-fired capacity growth.

Coal-fired power plant retirements account for the largest share (56%) of the total retirements of 14 GW during the period. However, such number includes the retirements due to Ontario coal phase-out (see Section 3.4.6) during 2014, thus the rest 5.6 GW is expected to occur between 2015 and 2040 in Alberta, Saskatchewan, Manitoba and Nova Scotia driven by the tightened emission regulations for coal-fired units (see Sections 3.3.1 and 3.3.1).

NEB expects (2016a) coal capacity increase by approximately 2 GW during the outlook period of which 1.3 GW is associated with CCS. However in the outlook, it did not provide information about how the remaining non-CCS-fitted capacity would meet the new emission standard (Sec. 3.3.1). According to the market analyst of NEB (2016b), Natalia Lis, presented figures actually include following two conventional units that have commissioned prior to or during 2014, i.e. before the GHG regulation came into force in 2015:

i. 2011 - Keephills 3 - a new, non-CCS unit - 450 MW
ii. 2014 - Sundance 1 & 2 - repaired non-CCS units - 600 MW

In effect, NEB (2016b) does not anticipate any new conventional coal-fired units being built besides the aforementioned. Additionally, the Boundary Dam CCS-fitted unit (see Section 5.6.1) is included to the projected 1.3 GW CCS unit capacity additions. Consequently, the projected capacity additions with CCS excluding the existing Boundary Dam CCS unit equal 1.2 GW which is expected to be commissioned during 2022-2040.

However, Alberta Electric System Operator (AESO 2014), estimates in the "AESO 2014 Long-term Outlook" that given the current costs of CCS no new coal-fired plants will develop in Alberta (i.e. the province generates c. 70% of the total coal generation in Canada; see Section 5.2). Retiring coal-fired plants will be replaced with less costly technologies like combined cycle natural gas-fired generation. Figure 68 represents numbers - that are levelized unit electricity costs (LUEC) by generation type and scenario - behind the projections.

According to the outlook (AESO 2014), LUEC for coal-fired unit with CCS (237 $\$_{CAN}/MWh_{elec}$) greatly exceeds the price of the lower cost technologies such as natural gas combined cycle (NGCC) and wind with LUECs of 82 $\$_{CAN}/MWh_{elec}$ and 89 $\$_{CAN}/MWh_{elec}$, respectively. This is due to high capital and operating costs of CCS systems. Furthermore, CCS requires c. one-third of gross capacity output in auxiliary load increasing the overall cost of the unit. As a result, AESO sums it up as follows: "coal-fired generation with CCS is not likely to be developed in Alberta without significant capital subsidies, very high carbon costs, or both."

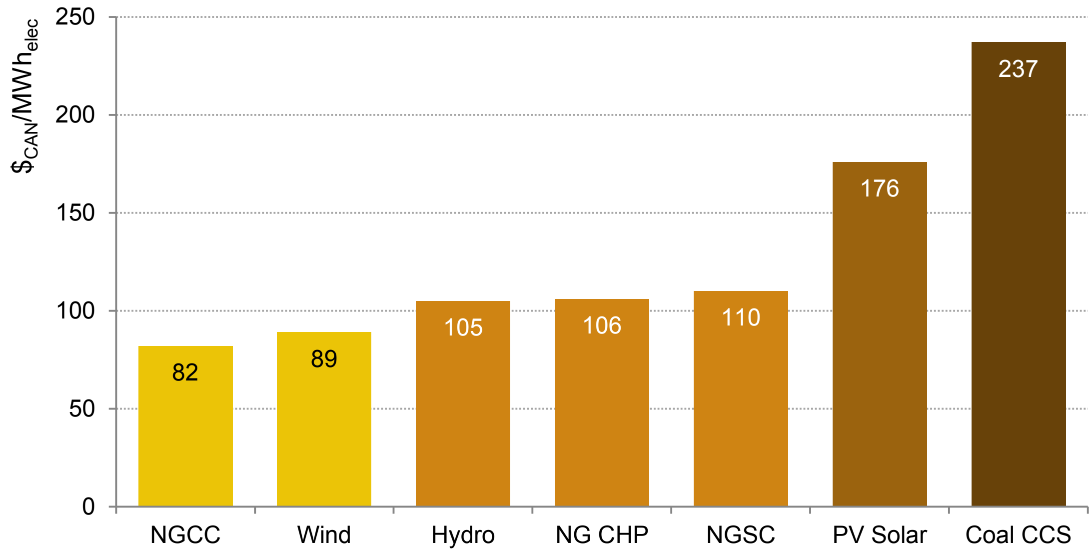

Figure 68 – Levelized unit electricity costs by generation method (AESO 2014)

In turn, TransAlta - a major power generating company partly owning 4640 MW of coal-fired capacity in Alberta (TransAlta 2016b) – hinted in 2015 that CCS might be an option. According to 21st report on sustainability of the company, TransAlta (2015) pursues to transform to less carbon intensive generation and lists several options including life-extension of coal-fired plants through CCS projects, conversion of coal to gas, or investing in additional renewable generation. Though, thus far it has not published any concrete proposals related to coal-fired CCS (NEB 2016b).

6 Coal-Fired Generation in the United Kingdom

6.1 Electricity Generation in the UK

Coal has an important - though significantly diminished – role in the UK generation mix. As Figure 69 and Figure 70 indicate, prior to the decent during the 1990s, coal accounted for roughly two-thirds or over 200 TWh_{elec} of the overall electricity supplied in the UK. By the 2000s, however, coal had already lost a half of its share mainly for NG-fired generation while the overall generation was still increasing. This period of rapid switch from coal-fired electricity generation to NG-fired generation is also known as "Dash for Gas". which was a result of privatization of the electricity sector and the liberalization of natural gas market during the 1990s (Pearson and Watson 2012).

Coal-fired generation faced a temporary recovery in 2012 resulting in nearly 40% or 143 TWhelec generation share due to increased NG costs as described in section 6.5. Coal has, though, since then followed the downward trend as the overall UK generation. The main reasons are outages at several coal-fired plants, series of plant retirements and biomass conversions during 2010s (see Section 6.2), lower overall electricity demand and changes in the relative prices of coal and gas (Section 6.5) (DECC 2015g p.46). Currently, coal-fired generation corresponds one-fourth or 76 TWhelec of the total generation. While NG-fired generation has settled to approximately 100 TWh after the decline from the peak of 176 TWh in 2008, renewables have notably increased their share since then. For instance, combined wind and solar generation increased nearly sevenfold from 7 TWh_{elec} to 36 TWh_{elec}. Also bioenergy labelled generation grew over threefold to 29 TWh_{elec} during 2008-2015 (DECC 2016b).

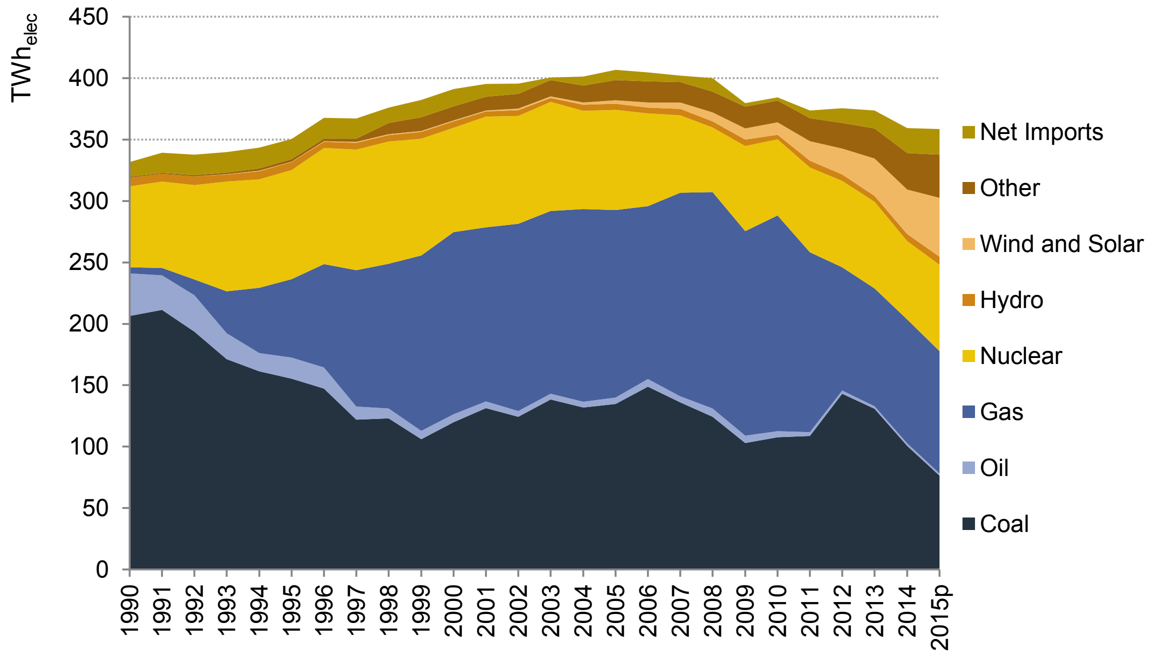

Figure 69 Electricity generation by fuel in the UK; years 1990-1997 from IEA statistics (2015f); 1998-2015 from DECC (2016b)

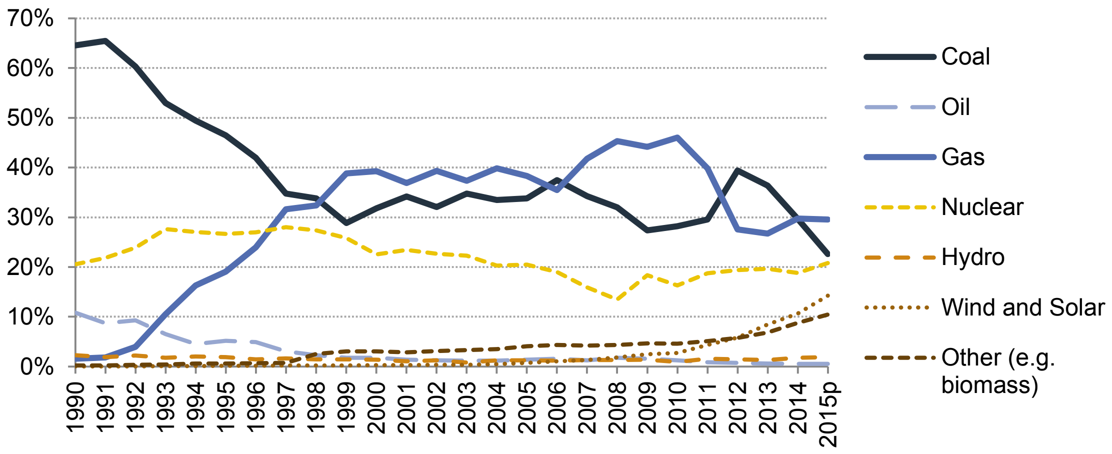

Figure 70 – Relative electricity generation by fuel in the UK; years 1990-1997 from IEA statistics (2015f); 1998-2015 from DECC (2016b)

As figure Figure 71 shows, coal-fired generation peaks during the coldest, winter time (i.e. quarters 4 and 1) which indicates coal still has an important role as an intermittent capacity to satisfy seasonal fluctuations in electricity demand. However, the quarterly peak of 30 TWhelec in 2015 was 40% lower than the maximum peak during 1998-2012 or, respectively, nearly 30% and 15% lower than in 2013 and 2014. The annual load factor for coal-fired plants in 2014 was 47% (DECC 2015c Table 5.9) meaning that over a half of the existing capacity was, on average, in reserve. This was 16% lower than during the generation peak year of 2012 (i.e. 57%) but, in turn, 19% higher than in 2011 (40%). Concurrently, the yearly minimum generation occurring during the third quarter is, respectively, 52% and 19% below the 2013 and 2014 levels. This indicates that coal decreasingly contributes to baseload capacity while other generating forms, NG and renewables, have been seizing shares from the generation mix.

In fact, due to increased costs on coal generators, operators are searching for higher value and thus moving from baseload and peak sales to look at particular half hourly periods or blocks. However, UK coal plants are fairly old (see Section 6.2 below) and were designed to operate explicitly on a baseload profile. Hence, those have previously considered being too inflexible to follow short-term demand profiles. As a result, some operators strive to keep the plants hot – even when it is not profitable. Still it is difficult for old coal units to compete with more flexible and efficient gas plants. (H. Evans 2016)

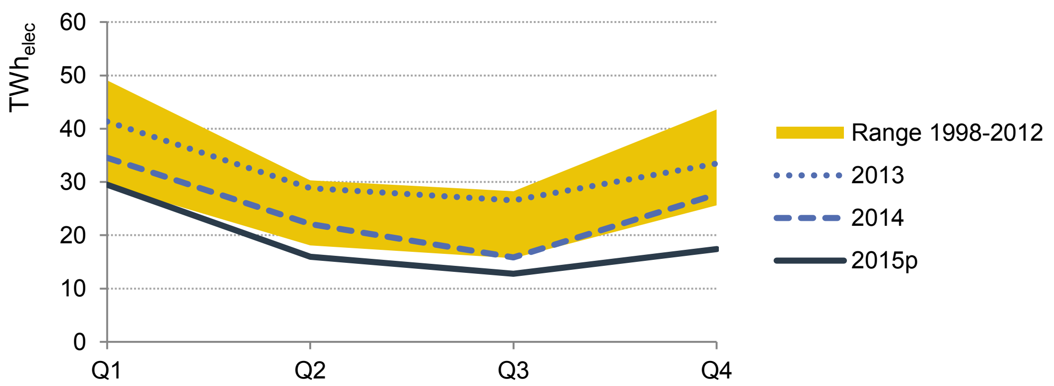

Figure 71 – Quarterly coal-fired generation in the UK (DECC 2016b)

6.2 Coal-fired Generation Capacity

Current status of UK coal-fired power stations is summarized in Table 14. At the beginning of 2016, UK coal-fired plants comprised 18.6 GW capacity which is roughly a quarter of the overall generation capacity in the UK (S. Evans 2016; DECC 2015c Table 5.10). However, already during March 2016 two sites – Longannet and Ferrybridge – with total capacity of 3.2 GW or 17% of the existing coal capacity were closed. Eggborough power station (1.9 GW) will also partially close during 2016 and Lynemouth (0.4 GW), in turn, plans to convert into biomass. Furthermore, Rugeley (1.0 GW) and Fiddler's Ferry (2.0 GW) have announced intentions to retire. Decisions are mainly justified with deteriorated market conditions due to fallen power prices and increased carbon costs (SSE 2016; Engie 2016). Surely, given tightening emission limits (the IED, see Section 3.5.2), the average unit age of 44 years, and relatively inefficient performance of the fleet (36% average efficiency) (DECC 2015c Table 5.9), market conditions will be far from improving for the existing capacity.

In addition to retirements in 2016, the UK has already faced a series of coal plant closures or conversions to biomass during 2010s. Within three years, 2012-2014, approximately 9.3 GW of existing coal-fired capacity was discharged. Three stations were partially or fully converted to run with biomass - Drax units 1-3 (1.3 GW), Ironbridge (0.9 GW) and Tillbury units 7-10 (0.8 GW) - resulting in 3 GW decrease in coal capacity (DECC 2014c; 2015c Table 5C). In tandem, approximately 6 GW of coal capacity was entirely retired as a result of EU's Large Combustion Plant Directive (LCPD) under which 6 plants (Cockenzie units 1-4; Didcot A; Ferry Bridge units 1-2; Kingsnorth; Tillbury units 7-10; Ironbridge) decided to "opt-out" and operate only 20 000 hours between 2008 and 2015 and then shut down (DECC 2014c). These opted out plants included the aforementioned Ironbridge and Tillbury that, despite the conversion, were required to shut down by the end of 2015.

Currently, as the LCPD is followed by the IED (Sec. 3.5.2) which affects coal-fired units that operate after 2015, existing units are under similar decision as during the effective time of the LCPD; generators may choose whether to comply with the IED (directly or through TNP) or opt-out and run a limited time (LLD). According to Evans (2016) at least Ratcliffe (2.0 GW) and Drax units 4-6 (1.9 GW) are compliant or are planning to comply with the IED whereas Cottam (2.0 GW) and West Burton (2.0 GW) are "exploring options". Additionally, Drax intends to convert more units into biomass. Aberthaw B, however, faces legal challenges over air pollution rules.

Under tightening emission regulations and deteriorating market conditions, capacity mechanism (Sec. 3.6.2) may provide relief for coal generator as a form of secured income. It replaces Supplemental Balancing Reserve (SBR) mechanism which provides 34 £/kW during 2016/17 for small amount of reserve capacity to operate when supplies are tight (S. Evans 2016). Fiddlers Ferry and Eggborough had received SBR contracts for winter 2016/17 corresponding part of their capacities. Presumably, at least the SBR contracted capacity remains operational for the 2016/17 period even if the rest of the contracted plants are closed. In turn, under the capacity mechanism, EDF's West Burton and Cottam received three year contracts for 3 GW starting in 2018/2019 as described in Figure 72. Further, Drax, Ratcliffe and Aberthaw were contracted for 2019/20 with total capacity of 4.4 GW. These three and one year contracts - with respective payments of 19.40 £/kW/y and 18£/kW/y for 2018/19 and 2019/20 contracts (Sec. 3.6.2) - probably ensure there will be at least 7.5 GW of coal-fired capacity available by the beginning of 2020s.

On the other hand, as contracts are mainly for one-year period at the time, it will not provide long-term certainty of stable incomes for generators. Thus, despite already received contracts, early, unplanned retirements may be seen. For instance, three out of four Fiddler's Ferry units already had a capacity market contract for 2018/19 (1.3 GW) which later failed to secure contract for 2019/2020 (Figure 72). As a result, the owner (SSE) may choose to rather cease commercial operation of the units and pay £33 million penalty for breaching its 2018/2019 agreement than face losses under the current market conditions (SSE 2016). However, as a consequence of the consultation on further reforms on the capacity market (DECC 2016a), the DECC is proposing to arrange supplementary capacity market auction for 2017/18 replacing the existing Contingency Balancing Reserve (CBR) scheme which also includes the abovementioned SBR mechanism. This may provide additional options for struggling coal-fired units.

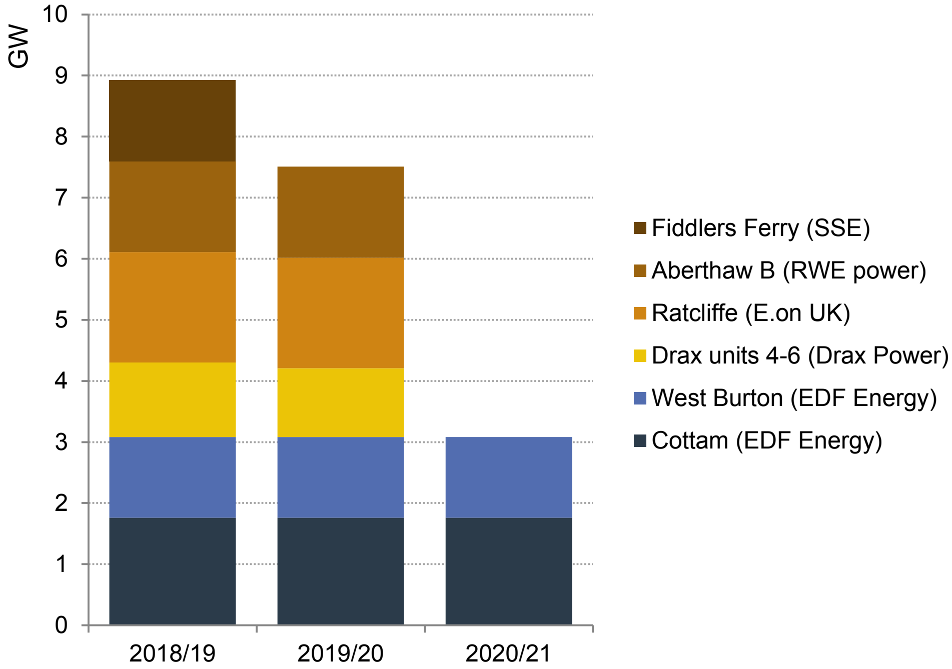

Figure 72 – Awarded coal-fired capacity under capacity market mechanism (auctions in 2014 and 2015) by plant and delivery period (National Grid 2015b; 2015c)

Table 14 – Status of coal-fired capacity in 2016 in the UK; from (S. Evans 2016) and (National Grid 2015b; 2015c)

Site/ ***Owner***	**Capacity (MW)**	**Age (years)**	**Status**	**Capacity market**	**SBR 2016/ 17**
Ratcliffe/ *E.on UK*	2,000	48	No plans to close[1]	Yes - *One year contracts for 2018/19 and 2019/20.*	No
Drax units 4-6/ *Drax Power*	1,935	30	No plans to close[2]	Yes (2 of 3 units) - *one year contracts for 2018/19 and 2019/20. Third unit did not bid.*	No
Cottam/ *EDF Energy*	2,008	47	No plans to close[3]	Yes - *Three year contract from 2018/19.*	No
West Burton/ *EDF Energy*	2,012	49	No plans to close[3]	Yes (3 of 4 units) - *Three year contract from 2018/19*	No
Eggborough/ *Eggborough Power*	1,960	49	Planning partial closure[4]	No	Yes *(775 MW)*
Rugeley/ *ENGIE*	1,006	44	Planning to close[5]	No	No
Lynemouth/ *Lynemouth Power*	420	44	Planning to convert to biomass[6]	No	No
Aberthaw B/ *RWE power*	1,586	45	No plans to close[7]	Yes - *One year contracts for 2018/19 and 2019/20*	No
Longannet/ *Scottish*	2,260	46	Closed *(March 2016)*	No	No
Ferrybridge C/ *SSE*	980	50	Closed *(March 2016)*	No	No
Fiddler's Ferry/ *SSE*	1,961	45	Not clear[8]	Yes (3 of 4 units) – *One year contract for 2018/19*	Yes *(1 of 4 units)*
Kilroot/ *AES*	520	35	No plans to close	N/A	No

1 Compliant with the EU Industrial Emissions Directive.
2 Plans to become compliant with EU IED. Hopes to convert more units to biomass
3 "Exploring options"
4 Announced plans to close from April 2016. Part of the plant will remain available during winter 16/17.
5 Closing early summer 2016.
6 Biomass conversion received EU State Aid approval in December.
7 Faces EU legal challenge over air pollution rules.
8 One unit contracted to SBR for winter 2016/17, another has National Grid "ancillary services" contract. Two other units to remain available.

6.3 Coal-fired Power Plant CCS projects in the UK

As mentioned in Section 3.6.3, new large-scale coal-fired capacity is liable to achieve the EPS which limits CO_2 emissions from baseload electricity generation to 450 kg_{CO2}/MWh_{elec}. This ensures new units are able to operate at baseload only by using CCS, thus it is unlikely that new coal-fired capacity will be built without any CCS system.

Currently, there are two large-scale coal-fired power plant CCS project proposals in the UK; White Rose CCS project and Caledonia Clean Power project (CCEP) (MIT 2016; GCCSI 2016; CCSA 2016). Statuses of the projects are described in following Sections 6.3.2 and 6.3.3. In 2012 introduced UK's CCS commercialization competition (see following Section; 6.3.1) gave a longed-for boost to CCS project proposals. However, it was cancelled in its current form just three years later which may have significant impact on proposed and chosen projects.

6.3.1 CCS Commercialization Competition

In November 2012, both abovementioned projects were shortlisted for UK's CCS commercialization competition which was published alongside with Government's CCS Roadmap in April 2012. Purpose was to make CCS technology competitive with other low carbon technologies in 2020s. The competition itself was meant to provide £1 billion capital funding, together with additional operational funding through the UK Electricity Market Reforms (see Section 3.6.2), to support the design, construction and operation of the UK's first commercial-scale CCS projects. On March 2013 Government announced two preferred bidders of which one was the White Rose project. The other announced bidder was NG-fired retrofit CCS project known as Peterhead project. Consequently, CCEP was appointed as reserve project. Subsequently in 2014, the White Rose was awarded multi-million pound contracts to undertake Front End Engineering and Design (FEED) studies. (DECC 2013c; 2015i)

However, in November 2015 just weeks before the final bids were to be submitted the Government announced that it will terminate the £1 billion competition funding. This decision was unexpected and came as a shock to the industry and investors. It may have long lasting, if not permanent, consequences to the investments in low carbon technology and relationship between the UK Government and the industry. For not to lose the work and investments achieved thus far and to secure the development of CCS in the future it is essential that Government comes up with a new, clear strategy for CCS promptly. (ECC Committee 2016). Thus far it is, though, uncertain what are the follow-up measures of stakeholders and what future prospects do the two chosen projects have.

6.3.2 White Rose and Yorkshire - Humber CCS pipeline projects

White Rose CCS project, or formerly known as UK Oxy CCS Project, is a plan to build a new 448 MW_{gross}, ultra-supercritical PC-fired plant with 90% CCS by utilizing GE's (formerly Alstom) oxy-fuel combustion technology (GCCSI 2016). The plant is to be delivered by Capture Power Limited which is a consortium of project sponsors i.e. GE, Drax and BOC (Capture Power 2016). Though, after fulfilled its work on FEED, Drax would not be investing further on the project and will withdraw its share from Capture Power. Drax justifies the decision with recently reduced renewable subsidies as 3 units of the existing Drax Power Station runs on biomass. However, as the new plant is to be built on land adjacent to the existing plant, Drax will continue to make the site, along with the infrastructure at the existing plant, available for the project. (CC Journal 2015)

If built, the planned c. 2£ billion plant will capture annually 2 Mt_{CO2} which then is to be transported via proposed 75 km Yorkshire and Humber CCS cross-county pipeline and a sub-sea pipeline into a permanent geological storage site (i.e. saline formation) beneath the North Sea (National Grid 2016; DECC 2015i; GCCSI 2016). Also EOR options are being investigated (MIT 2016). The pipeline is to be planned and operated by National Grid and its purpose is to provide shared infrastructure to major power stations and other industrial CCS projects in the region. Pipeline would utilize similar technology as the national high-pressure gas pipeline network, owned and operated by National Grid. (National Grid 2016; GCCSI 2016)

In addition to be a preferred bidder under the £1 billion CCS competition - that was recently terminated in its current form - the White Rose project was awarded up to 300 million euros (or c. £250 million) in July 2014 under EU's NER300 scheme (see Section 3.5.1). Despite the additional EU funding, current status of the project remains very uncertain. As a result of the Government's decision to scrap the competition funding, the CEO of Capture Power, Leigh Hackett, stated that "[i]t is too early to make any definitive decisions about the future of the White Rose CCS Project, however, it is difficult to imagine its continuation in the absence of crucial Government support" (Capture Power 2016). Furthermore, in April 2016, the Secretary of State decided (to refuse development consent for the Development. Namely the reason was insufficient funding and that the powers of compulsory acquisition sought by the applicant for the development cannot be granted. (DECC and Scott 2016). This decision, however, may be challenged but taken aforementioned Capture Power's statement into account it seems to be unlikely.

Although, White Rose project may have faced its end, National Grid is willing to continue the multi-user Yorkshire and Humber CCS pipeline project. The Secretary of State should provide a decision of whether the project will be granted with development consent by 19 May 2016 (National Grid 2016). In 18 February 2016, DECC requested and update or further clarification about the project. National Grid remains in its response, 2 March 2016, confident that whilst the status of the White Rose is weakened, it will not undermine the CCS pipeline project as the pipeline "had never been intended for the sole use of the White Rose project". Surely, the future development and use of the Yorkshire and Humber Pipeline cannot be fully assessed until the Government's revised strategy for CCS is made clear. According to the National Grid, granting the development consent for the project provides an opportunity to secure the best value for the UK in current work, and in the future development prospects. (National Grid and Green 2016)

6.3.3 Caledonia Clean Energy Project

Caledonia Clean Energy Project (CCEP), also known as Captain Clean energy project, is Summit Power Group's plan to build a 570 MW_{net} CCS coal-gasification (IGCC) power station to be located in Grangemouth, Scotland (DECC 2015a). The plant is to be developed as a "sister project" to Summit Power's government-backed Texas Clean Energy Project (TCEP) in the US (Sec. 4.6.3) (Slavin 2013; Summit Power and Kerr 2015). Such approach will result in "many advantages", according to the company. (Summit Power and Kerr 2015 p.4)

Similarly, as in the case of TCEP, the plant is about to turn the coal feedstock into a syngas and CO_2 by utilizing Siemens gasifiers. Produced hydrogen-rich syngas would be used to run combustion turbine in the plant whereas separated CO_2 would be transported via largely existing NG-pipeline network and store in the saline aquifer below a depleted gas field in the Central North Sea. Proposed, National Grid operated on-shore part of the pipeline would be approximately 280 km long whereas the redesigned offshore NG transmission pipeline would reach length of approximately 102 km and owned and operated by the CCEP. The separated, transported and stored CO_2 with planned 90% capturing rate would amount 3.8 Mt annually. (Summit Power and Tynan 2013; GCCSI 2016)

The project participated in both UK's CCS commercialization program and EU's NER300 program (Section 3.5.1) but was not granted under particular programs (MIT 2016). However, Summit Power remains confident that the project can proceed without direct funding from the UK government in case "tariff support is made attractive enough" (Slavin 2013; Summit Power and Kerr 2015). Surely, the CFD (see Sec. 3.6.2), which is issued on case by case basis for CCS projects, may provide notable subsidy for the project. For instance, in 2015 the Government and EDF finalized the CFD for Hinckley Point C, which is a planned, 3.4 GW nuclear power plant. The Government will provide inflation linked strike price of 92.50 £/MWh_{elec} for 35 years for the generator. (Bounds 2015; DECC 2015e). This may give a point of reference for eligible CCS projects as nuclear power and CCS fitted generation are grouped similarly under the CFD scheme as "other technology" (see Table 9).

Notwithstanding, 27 March 2015 UK Government announced it will provide, together with Scottish Government, £4.2 million for industrial research and feasibility work for the CCEP project. The funding, £1.7 million from the DECC and £2.5 million from the Scottish Government, allows Summit Power to undertake £6 million budgeted, detailed studies over an 18 month period to advance the engineering design of the project and detect possible risks (DECC 2015a; Summit Power and Kerr 2015). The findings of the work will be then shared across industry and academia aiming to increase understanding about development and deployment of CCS at commercial scale. (DECC 2015a). Project commission is presently slated for 2022 after which plant would potentially operate 30 years. (GCCSI 2016). Summit Power's long term goal is that CCEP would act as an anchor for sustained effort to develop an entire integrated system consisting of e.g. clustered CCS projects, common CO_2 pipeline and offshore infrastructure, jointly creating CO_2 for EOR sector. (Summit Power and Kerr 2015)

6.4 The UK Coal Production and Consumption

The post-war culmination years of the UK coal industry takes place back in the 1950s as coal was still the main source of energy. Since the 1952 coal production peak of 228 Mt, of which most (95%) came from 1 334 deep-mines, the domestic deep-mined production has fallen about 2.6 % per year until 1984. Before 1970, coal was used as a fuel source for industry and transportation but also within households for cooking and heating. Since then, as the UK energy mix had become more diverse, it was mainly used for electricity generation. Today, electricity sector consumes, on average, 80% of the total coal supply in the UK. The remaining is consumed mostly for coke ovens and blast furnaces, and additionally for other industrial purposes. (DECC 2015h). The annual data for coal supply and consumption in the UK is presented in Figure 73 and Figure 74, respectively.

Still in the 1980s the UK was a world leader in deep coal mining. However, the domestic coal production started to decline on accelerated pace after the miners' strike, the UK's biggest trike in the post-war era, in 1984 which lasted for over a year involving nearly 142 000 miners. (Jones 2015). Thereafter, by the early 1990s, the number of pits had shrunk to 50 and the production dropped nearly by a third from 1980 level of 130 Mt. (Jones 2015; DECC 2015g, Table 2.1.1) Though, more closures followed when privatized electricity generating companies switched to cheaper imported coal and alternative generation sources (i.e. mainly to NG). (Jones 2015) Consequently, until then steadily grown coal imports expanded ultimately exceeding the domestic production of 32 Mt in 2001. (DECC 2015g, Table 2.1.1; 2015h)

At that time, coal consumption faced a moderate increase as the growing price of NG encouraged generation from coal. The fall in consumption resumed in 2006 but was followed by three-year recovery as the NG price made coal attractive generation fuel again. (DECC 2015h). However, after the 2012 peak of 55 Mt, the consumption has nearly halved by the end of 2015, mainly due to several power plant outages, closures and conversions, lowered electricity demand and changes in relative prices of NG and coal. (DECC 2015h; 2016c, Table 2.6) While the imports significantly increased during the 1990s and the 2000s eventually reaching the all-time-high level in 2013 (i.e nearly 50 Mt), the domestic production never really changed its downward trajectory leading to ultimately closure of the last three operating deep mines in 2015. (Jones 2015; DECC 2016c, Table 2.5) Combined deep-mined and surface-mined production resulted in 8.5 Mt domestic supply representing c. 60% of the total coal supply in 2015. (DECC 2016c, Table 2.5)

Today, steam coal represents on average 80% of the total UK coal imports. In 2014, steam accounted for 35 Mt or 85% of total imported coal. Russia has long been a main origin of UK imported steam coal, accounting for 46% of the total steam coal imports in 2014. Recently Columbia and the USA have also become main sources for steam coal contributing, on aggregate, 50% of the total steam coal imported in 2014. Steam coal has been mainly used for electricity generation. (DECC 2015h)

The rest, 6 Mt or 15% of 2014 imported coal was coking coal. Of this, 85% originated from three countries alone; USA (48%), Russia (22%) and Australia (20%). Coking coal has been used in coke ovens and similar carbonizing processes within the industrial sector. Though, there were imports of anthracite as well in 2014 (mainly used in the domestic sector) but the amount is negligible in comparison to steam and coking coal. (DECC 2015h)

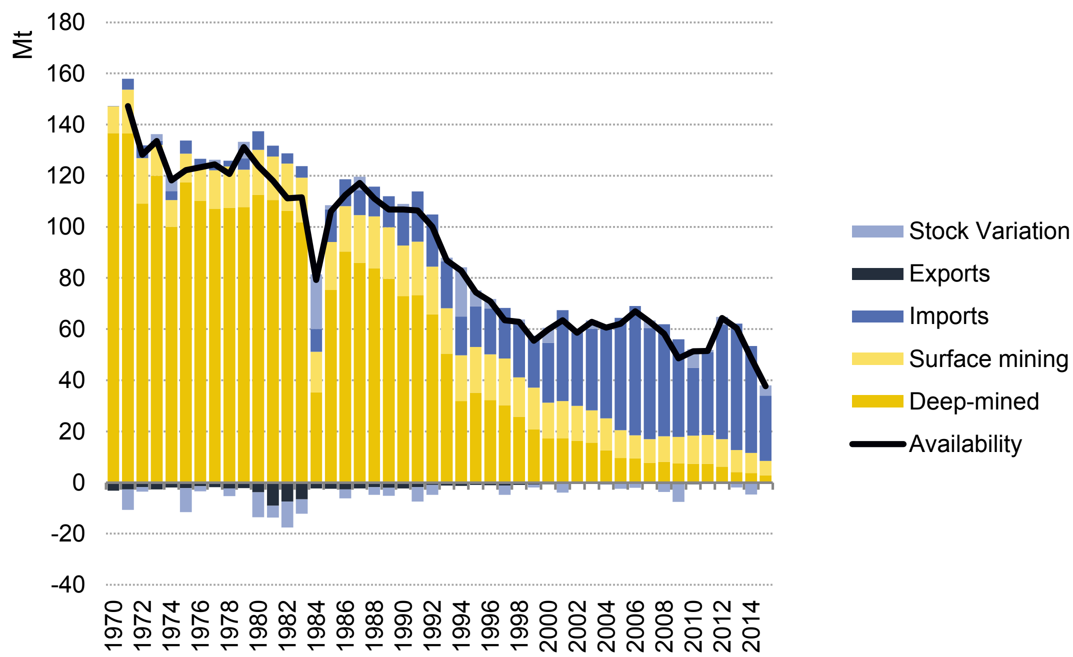

Figure 73 - Coal supply in the UK since 1970 (DECC 2015g, Table 2.1.1; 2016c, Table 2.5)

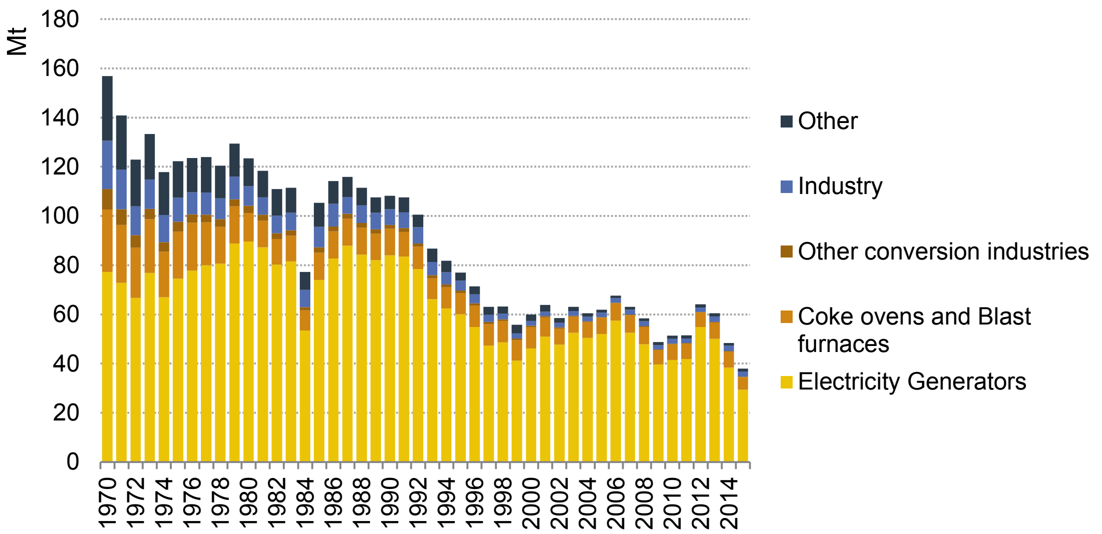

Figure 74 – Coal consumption in the UK since 1970 (DECC 2015g, Table 2.1.2; 2016c, Table 2.6)

6.5 Price of Generation Fuels and Electricity in the UK

Energy prices in the UK are affected by various factors; both local and global. Prices of generation fuels - coal, gas and oil - will certainly affect the price of electricity but can also themselves be influenced by the price of the other generation fuels. In general, cost of other combustion fuels have been historically linked with price of oil, especially that of natural gas. (DECC 2009 p.54)

Ergo, as fossil fuels - particularly coal and more recently NG - have formed a major input in the UK electricity generation mix (see Section 6.1), the price of electricity has also been driven by oil prices. However, lately costs on carbon (i.e. EU ETS and the CPF see Sec. 3.5.1 and 3.6.3) have increasingly played their part in energy prices as well – though not yet with same extent as the fuel prices. (Dempsey et al. 2016 p.13). Hence, it is reasonable to observe the near term oil price development first to understand the development of NG and coal prices although oil itself has only a minor role in the UK generation mix. Near-term price development of generating fuels and electricity are presented in Figure 75 and Figure 76, respectively, and observed in the following subsections; 6.5.1 (oil), 6.5.2 (NG), 6.5.3 (coal) and 6.5.4 (electricity).

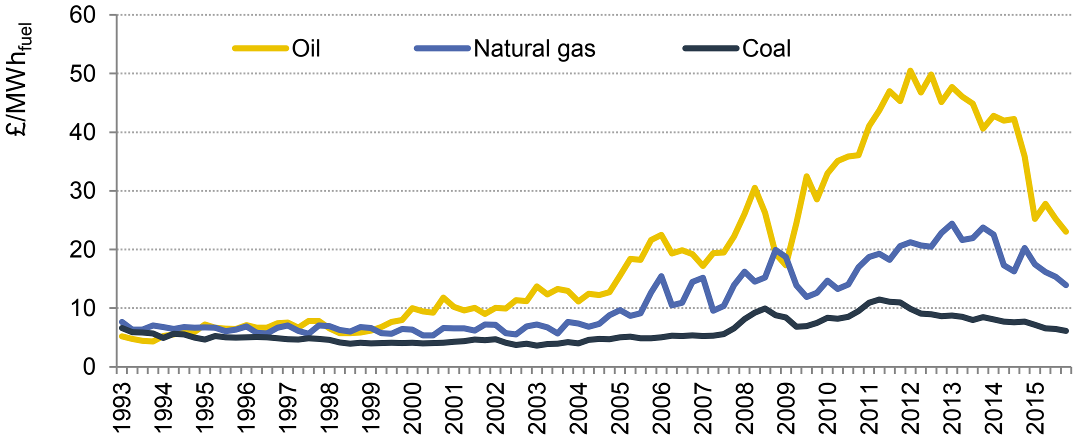

Figure 75 – Quarterly generation fuel prices (DECC 2016f)

6.5.1 Price of Oil

Oil prices grew moderately throughout the 1990s maintaining well below 10 £/MWh$_{fuel}$ (Figure 75) with an exemption of 1997-1998 dip that was a consequence of Asian financial crisis that time. Another dip was caused by decreased US demand following the terrorist attacks of September 11 in 2001. After which, the oil price faced a long-lasting upward, though fluctuating, trajectory mainly as a consequence of geopolitical tensions (Iraq War 2003, Conflict in Lebanon, 2006), natural disasters (Hurricane Katarina and Rita, 2005) and changes in global economy (increased demand of emerging economies and weakened dollar, 2008). (DECC 2009 p.55; DECC 2016g p.24)

As a result of global recession (2008-2009), however, the generating fuel oil price sunk from 30 £/MWh$_{fuel}$ to below 20 £/MWh$_{fuel}$ in just two quarters due to sharply decreased global demand. As the global economy recovered the price of fuel oil grew to historically high levels exceeding 50 £/MWh$_{fuel}$ in the first quarter of 2012. Thereupon, oil prices have faced downward trend, increasingly after 2013, as a consequence of weakened demand and increased supply eventually reaching a six-year low 23 £/MWh$_{fuel}$ during the fourth quarter of 2015. More recently concerns of China's economic performance (2015) and OPEC's decision not to cut production (December 2015) together with lifting of Iranian sanctions have affected the price resulting in persistent oversupply of oil. The next OPEC meeting will convene on 2 June 2016 which may cause upward pressure on price if production limits are agreed. (DECC 2016g p.24)

6.5.2 Price of Natural Gas

While being closely linked with price of oil, NG delivered to the UK power plants maintained correspondingly between 5 £/MWh$_{fuel}$ and 8 £/MWh$_{fuel}$ through the 1990s (see Figure 75). However, whilst the overall consumption for NG increased during the 1990s, particularly from electricity generation, the price still did not face a rapid increasing until the end of 2005. Dempsey et al. lists three reasons for moderate prices; price controls set by regulator, the impact of increased competition and relatively easy supply/demand pressures (Dempsey et al. 2016 p.4). Competition increased indeed during the 1990s particularly as a result of 1995 Gas Act that extended competition in stages to all gas supply in the UK. From the privation of British Gas in 1986, being just the one gas supplying company to consumers, the number of companies was increased to 34 by mid-2001. (DECC 2009 p.28)

However, while being followed the increasing demand, the UK natural gas production begun to deplete since 2000 as the most of UK's natural gas (and oil) fields in the North Sea were discovered in the late 1960's and are being utilized since then (DECC 2009). From the 2000 production peak of 1.260 TWh$_{fuel}$ the production has fallen to 425 TWh$_{fuel}$ by 2014, a level not seen since 1980s. (DECC 2016e, Table 4.1.1) Whilst being a net exporter during 1990s, natural gas imports eventually exceeded the indigenous production in 2011 and recently corresponded to 465 TWh$_{fuel}$ (or 349 TWh on net basis) of the 775 TWh$_{fuel}$ available NG in 2014 in the UK. Of which, 73% or 341 TWh$_{fuel}$ was imported via interregional pipelines mostly originating from Norway (78%) but also from the Netherlands (21%) and Belgium (1%). The rest, 27% or 124 TWh, was imported as a form of liquefied NG mostly from Qatar (92%). (DECC 2016e, Table 4.5)

Presumably, such market transition from indigenous NG supply to highly import-reliant supply has made UK natural gas prices more volatile during the 2000s and 2010s. Price of NG delivered to power generators followed the trend of oil price peaking a year later than oil in 2013 exceeding 24 £/MWh$_{fuel}$. Surely the price is affected by the seasonal factors as well. For instance, extraordinary warm winter in 2013-2014 resulted in excess stock in NG European market which reflected into the whole sale prices in the UK as well by decreasing the price from 23.7 to 16.3 by the summer 2014. Notwithstanding, the slide in 2014 was still remarkable as interruptions to the market were highly expected due to Ukraine-Russia crisis and European and US sanctions on Russia. Though, the price recovered ahead of the winter 2014-15 but still indicated high levels of stored gas. As presented in Figure 75, the price on the UK market has continued to further fall during 2015 and 2016 in part reflecting lower oil prices. The price of NG settled to 13.9 by the end of 2015 i.e. the lowest level since 2010. (Dempsey et al. 2016 p.13)

6.5.3 Price of Coal

Likewise, though not as much as price of NG, coal prices are generally affected by the oil prices. Cost of oil impacts on the costs of coal production and increasingly to transportation due to expanded share of imported coal since the 1990s (see Section 6.4) (DECC 2009 p.56). Similarly as prices of oil and NG peaked during the early 2010s so did that of coal as Figure 75 indicates. By the second quarter of 2011, the price of coal reached 11.5 £/MWh_{fuel} which was twofold compared to the 2000-2009 average price of 5.3 £/MWh_{fuel}.

After the peak, the price has followed the downward trend in line with other fuels and has nearly halved to 6.1 £/MWh_{fuel} by the fourth quarter of 2015. That is, a price level not seen since 2007. Capalino et al. (Capalino et al. 2014 p.5) lists two general reasons for declining global prices of steam coal which may though vary by market. Firstly, the coal demand is slowing or turning negative due to more efficient use of energy, competition from other energy sources and regulations to limit air pollution from coal. Secondly, in the export markets, supply has grown robustly as projects undertaken in response to high prices during early 2010s.

Especially the first mentioned reason is surely what is affecting the US market at the moment; as the major coal consumer, the power sector, has notably decreased coal use, the total consumption has decreased by nearly 20% since the 2007 peak (see Section 4.3). Consequently US coal producers have been penetrating to the European market providing competing option for Russian coal that struggles with high transportation costs due to extreme rail haul distances from mines to ports (Capalino et al. 2014 p.16,18).

Although the coal price delivered to the UK power generators has followed the tolerably similar trend as oil price it has not indicated such volatile behavior and thus may not fully follow the actual spot prices of coal. Apparently, at least one reason for rather stable prices is that prices reported are typically for long-term contracts with price escalator factors (DECC 2016f). Hence, there will be delay in the price to settle to the prevalent market price, particularly as some contracts may have been entered into some time ago.

6.5.4 Price of Electricity

During 1990-1996 electricity prices maintained stable, roughly 60 £/MWh_{fuel} on average as Figure 76 presents. Since then prices started a period of consistent falls for the next eight years. According to Dempsey et al. (2016 p.4) it was a result of three causes; regulator-imposed controls on price, reductions in the Fossil Fuel Levy form 1996 onwards and since 1999 increased supply competition. Price of electricity reflects the price of fuels used to generate it thus it faced a persistent upward trend since 2004 when all of generating fuels' prices had changed their trajectory, particularly that of coal and NG (DECC 2009). Additionally the increasing price reflected the implemented measures to add a cost on carbon including introduction of the

EU ETS in 2005 (and its subsequent phases as described in Sec. 3.5.1) and later in 2013 the CPF scheme as a part of the electricity market reform (Sec. 3.6.3).

Yet in 2014 average price of electricity (124.7 £/MWh$_{fuel}$) did not reflect the fall in fossil generating fuel prices, apparently partly due to particular measures. Furthermore, even though increased NG prices temporarily encouraged to increase coal-fired generation with expense of NG during 2012 and 2013 electricity, prices did not fall as still some gas plant was generally been needed to meet demand, and therefore remained the marginal source of supply (Dempsey et al. 2016 p.13). However, not seen in the data provided by Figure 76 but the price have dropped since its 2014 levels through 2015 and as of March 2016 the whole sale price settled just above 100 £/MWh$_{fuel}$ (Dempsey et al. 2016 p.12).

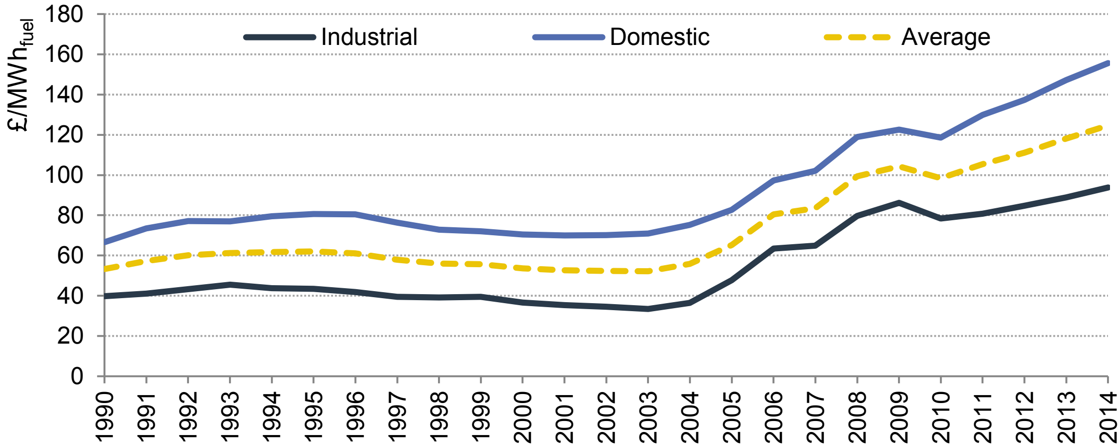

Figure 76 – Annual electricity prices (including taxes) by customer type; based on the IEA data edited and published by the DECC (DECC 2016d, Tables 5.5.1 and 5.3.1)

6.6 Projections

The future of coal-fired generation in the UK seems to be deteriorating. That is to say, in 18 November 2015, in her speech the Secretary of State for Energy and Climate Change (Amber Rudd) announced that the DECC is launching next spring a consultation on when to close all unabated coal-fired power stations (i.e. stations without CCS). The consultation is about to set out proposals to close coal by 2025 - and restrict its use from 2023. Rudd stated that in the ideal situation the carbon price provided by the EU ETS would have been enough to phase out coal but still a major of UK's electricity comes from coal. Thus more actions are required soon. (Rudd and DECC 2015)

The speech (Rudd and DECC 2015) did not give any specific details of how such transition would be done but the message was still clear; new gas capacity replacing old coal. Also more nuclear power is expected possibly increasing its share up to 30% by 2030 (in 2015 it was 21%, Sec 6.1). One main theme was reinvigorating competition and limiting government intervention on the market which boded reforms on the subsidies provided, especially, for renewable generation. Though, Rubb proposes support for offshore wind capacity up to 10 GW during 2020s if it proves to be cost-competitive enough. The role of CCS, however, was left uncertain. This, together with the fact that the government scrapped the £1 billion CCS competition just week later (DECC 2015f), foreshadows that at least the near-term role of CCS, in achieving the UK's decarbonisation plans, remains very limited.

The latest projection of the DECC (2015j), known as "Updated energy and emissions projections: 2015" and published in 18 November 2015, indicates that the UK is actually already on track to phase out coal during 2020s (see Figure 77). With existing and planned policies (as of November 2015), referred as reference case, coal-fired capacity is expected to be limited to 2 GW by 2023 which accounts for 2% of the total projected capacity of 111 GW in 2023. The decline is mainly result of the IED (Sec. 3.5.2), the CPF and other electricity market reform measures (Sec. 3.6.2 and 3.6.3). Gas-fired generation is about to pick up in the near- to medium-term and offset some of the reductions in coal-fired generation. Also increasing renewable capacity will compensate the decrease in coal-fired generation as by 2020 renewable generation is projected to increase twofold to 123 TWh_{elec} compared to 2014 level (see Figure 78). Though, the projected coal-fired generation for 2015, 120 TWh_{elec}, is already c. 40% overestimated compared to more recent data (see Figure 69). At the same time, nuclear and NG-fired generation were both underestimated by 20%. Presumably the dip in NG (and oil) price (Figure 75) has remained longer than expected encouraging more NG generation than was beforehand projected.

Longer-term, by 2035, the DECC (2015j) projects in the reference case that existing NG-fired and nuclear capacity will be mostly replaced by new, after 2014 build units while renewable capacity increases nearly twofold. Instead, capacity of interconnectors will expand over threefold which indicates greater integration with European markets. Concurrently overall fossil generation is about to halve by 2035 while nuclear and renewable generation would both double from the 2014 levels. As a result, renewables would hold the largest share, 42%, in the UK 2035 generation mix. Behind would be nuclear generation with 33% share. Unabated NG-fired generation and coal/NG CCS capacity would account for 12% and 11% of the total generation, respectively.

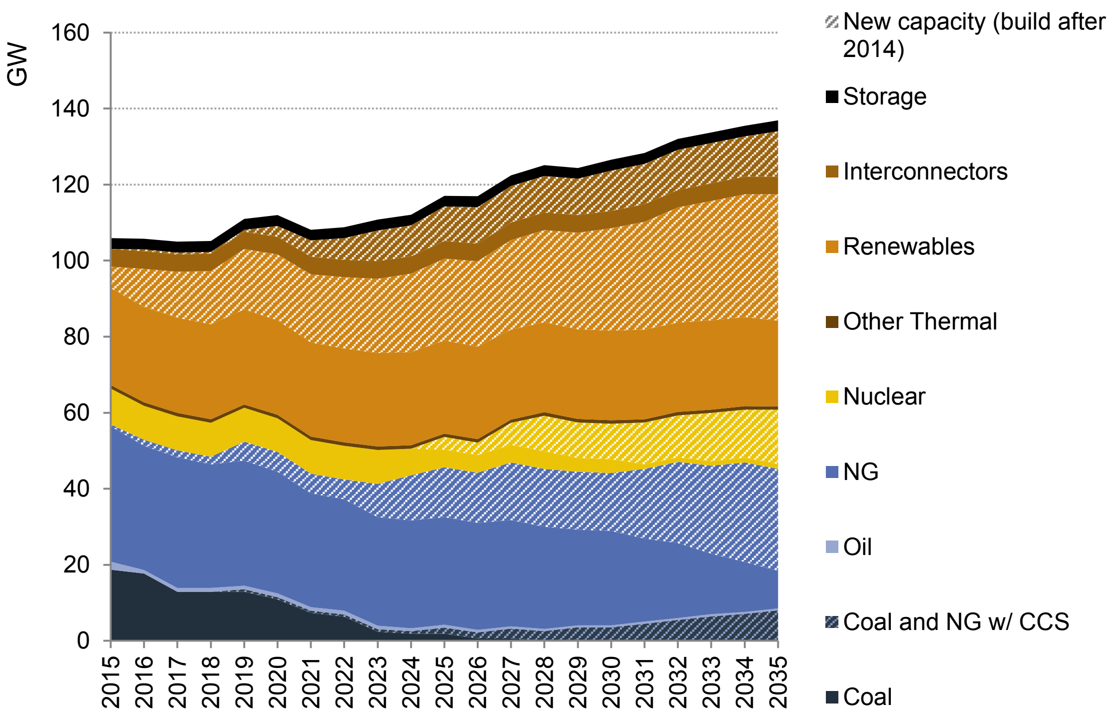

Figure 77 – Projected generation capacity by source (DECC 2015j, Annexes K, L)

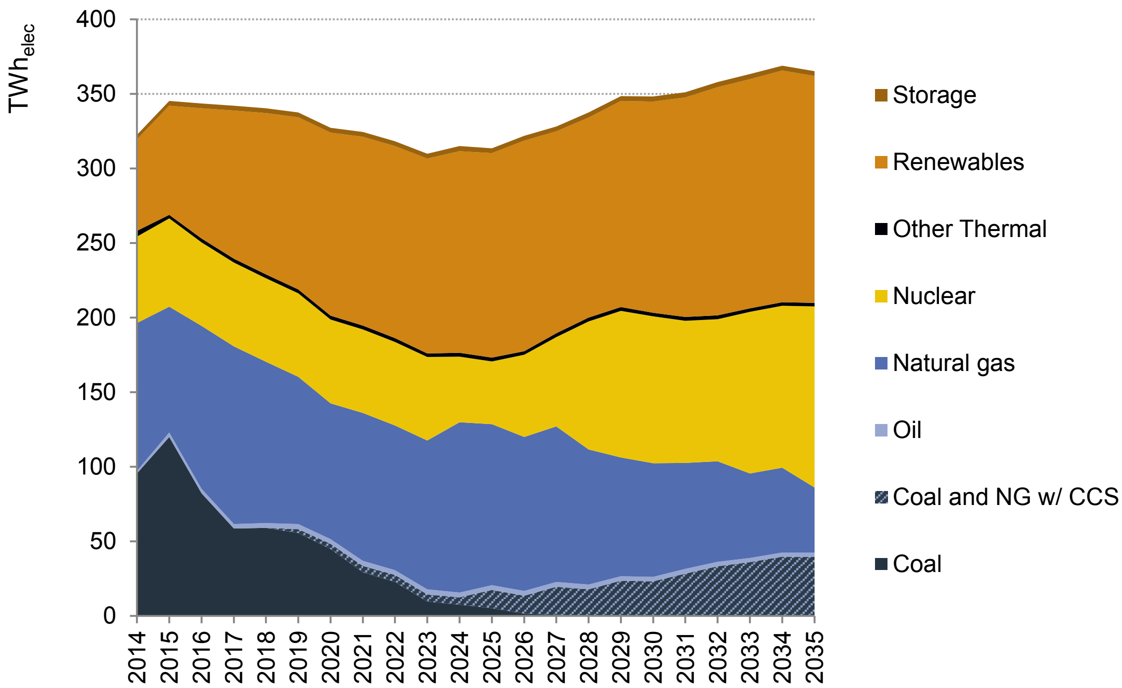

Figure 78 - Projected electricity generation by source (DECC 2015j, Annex J)

Policies taken into account in the projections include continuation and calibration of CFDs (Sec. 3.6.3) for 2021-2035 to achieve decarbonisation target of 100 g_{CO2}/kWh$_{elec}$. Policies also include the recently cancelled CCS program (Sec. 6.3.1). (DECC 2015j, Annex D). Projected, since 2019 operating, CCS capacity of 1 GW would have been presumably a result of the particular competition. Encouraged by the two supported demonstration projects, the capacity with CCS would have grown up to 8 GW by 2035. However, cancellation of the CCS program may have narrowed future prospects of the CCS in the UK thus given projections may be overestimated.

Nonetheless, National Grid (2015a) points out in its own publication, Future Energy Scenarios 2015, that while result of capacity market auction and CFD awards have some certainty of medium term power supply, long-term projections remain uncertain. This is due to ever changing political, environmental, social and technological landscape. Consequently, National Grid provides four scenarios of the future; Gone Green, Slow Progression, Consumer Power and No Progression.

The Gone Green scenario, where ambitions for decarbonisation and government interventions to achieve carbon targets are highest, the existing coal fleet will be entirely retired by 2030 which is about in line with the DECC's 2015 reference case projection. However, in the case of Slow Progression in which policy interventions are constrained by affordability, 2 GW of conventional coal-fired capacity is expected to still last in 2035. While Gone Green scenario estimated 6.2 GW of NG and coal-fired capacity with CCS (1.7 GW and 4.5 GW, respectively) in 2035, the Slow Progression projects less than 1 GW CCS-fitted capacity (0.4 GW and 0.45 GW of gas and coal, respectively). Consumer Power (inter alia relaxed carbon ambition) indicates similar trend while No Progression (reduced carbon policy support and limited new interventions) expects c. 4 GW of coal capacity still remain in 2035 and no CCS capacity. (National Grid 2015a). Again, it is worth noting that these estimates are carried out prior to the withdrawal of the CCS commercialization program.

In any case, it seems existing coal-fired capacity is diminishing, if not entirely phasing out, during 2010s and 2020s as a result of already implemented policy actions; particularly the IED and the supporting mechanisms of the EMR. Given the announcements in Rubb's 18 November 2015 speech (Rudd and DECC 2015), even further actions are expected to dampen carbon intensive coal-fired generation during 2020s. The question, however, still remains; in what extent will the CCS technology be utilized? With existing policies, government may provide support for new coal-fired CCS capacity under the CFD mechanism. But due to lack of enough progressed projects any proposed CCS capacity, which could provide reference for possible subsequent strike prices under the CFD, haven not yet been awarded.

Estimated generation costs by the DECC (2013a) provides an indicative value of required strike price to make a new coal-fired CCS-fitted plant an attractive investment. However, levelized cost estimates are highly sensitive to the underlying data and assumptions used; e.g capital costs, fuel prices, carbon costs, operating costs, load factor and discount rates. Thus, Figure 79 provides an indicative range of cost estimates in addition to the central, point estimate. As can be seen, costs of coal-fired CCS capacity, both SCPC and IGCC, indicate the widest capital cost ranges from the levelised costs of presented generation methods; SCPC 88 - 132 £/MWh$_{elec}$ and IGCC 104 - 172 £/MWh$_{elec}$. On the other hand, levelised cost of NG-fired generation (OCGT and CCGT) is more prone to fuel price fluctuations. Still, central costs remain lower with CCGT capacity (with or without CCS) compared to coal. Alongside CCGT, nuclear capacity appears to be one of the cost-competitive options with cost range of 70-94 £/MWh$_{elec}$.

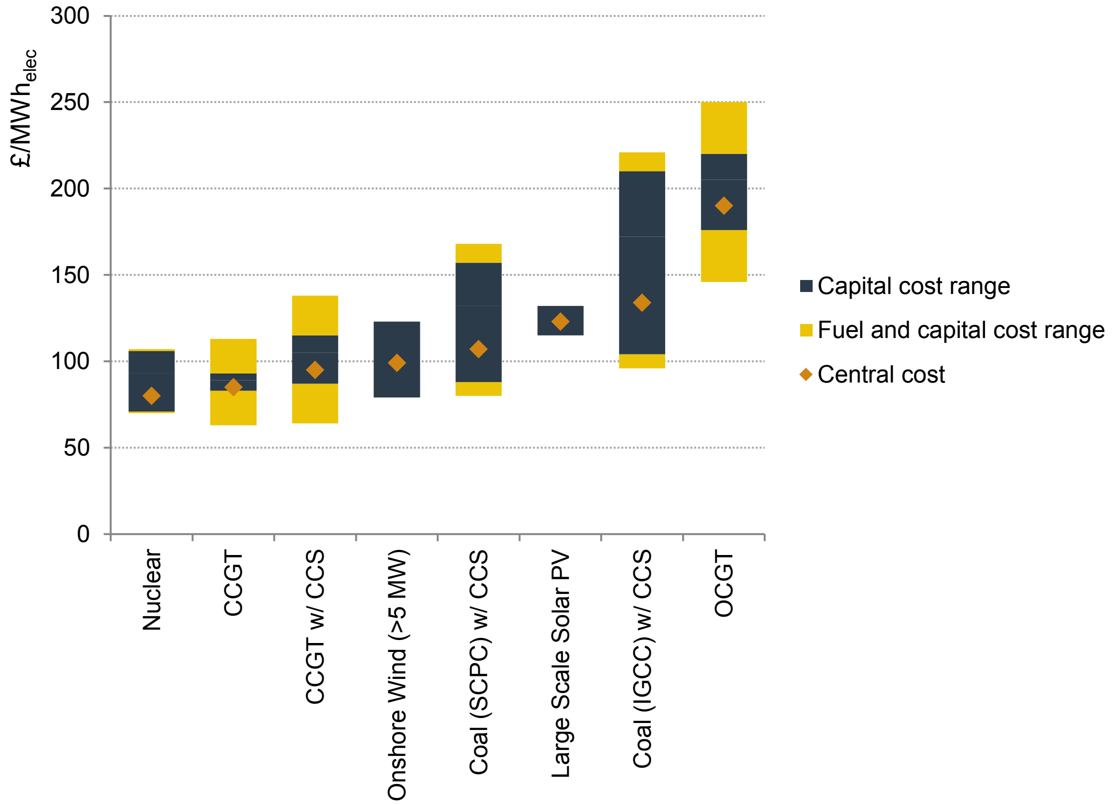

Figure 79 - Levelised cost estimates for projects starting in 2019 with 10% discount rate (DECC 2013a p.22)

In that sense, without awarded strike price of over 100 £/MWh_{elec}, it might be hard for coal to compete with above-mentioned alternatives unless fuel prices highly increase or capital costs of CCS come down. According to analysis of Pöyry and Committee on Climate Change (CCC) (2015) it is actually possible that costs could be reduced below 100 £/MWh_{elec} during the 2020s which would notably increase the cost-competiveness of CCS technology. Though, it would require that CCS capacity from 4 GW up to 7 GW is been deployed over time using shared pipeline and storage infrastructure. The amount depends on whether the UK pursues one or two capture technologies (post and/or oxy-fuel combustion) in a single or multiple clusters.

In turn, wait and see approach (i.e. UK could wait for technological learning in other countries) is possible but unlikely to drive sufficient cost reduction for UK CCS. Namely, the analysis suggests that 70-75% of the cost reductions are likely to be achieved through UK based actions. (Pöyry and CCC 2015). But again, suggested roll-out of CCS capacity with necessary scale during 2020s might remain uncertain without significant external financial support which was still considered to be likely when the analysis was carried out in April 2015.

7 Conclusions and Discussion

This thesis observed the role – past, current, and future – of coal-fired electricity generation in three developed countries; the USA, Canada and the UK. Each of which have long traditions in coal production and consumption. Especially in the USA and the UK coal has been the main source of electricity throughout the 20th century, and still accounts respectively for roughly two-fifths and one-fifth of the total electricity generated – with decreasing trends, though (see Sec. 4.1 and 5.1). Also several Canadian provinces - where availability of hydro power is limited including Alberta, Saskatchewan and Nova Scotia - are still heavily relying on coal (Sec. 5.2). Consequently, today coal consumption in the electricity sector corresponds to most of the domestically used coal in each country, thus the domestic coal markets are highly linked with the electricity sector's coal demand.

There are two main reasons why coal has achieved such a persistent role in national or regional electricity generation mixes. First of all, each nation has had significant domestic coal resources and production industries that have allowed locating power stations adjacent to or within easy transportation from a coal mine and signing of long term delivery contracts. Therefore, generators have benefited from an affordable and stable price of coal even for the whole lifetimes of the power plants. This has been a huge advantage compared to more volatile fuels whose availabilities are prone to geopolitical tensions, particularly oil but also natural gas. Presumably, the contribution to the economies of coal mining regions has also made coal a preferable source of electricity. Secondly, given that coal has been used as a main source of energy for decades since the 19th century, the available utilization technologies are well developed and highly reliable, and therefore a reasonable choice for generators.

However, while there are many benefits of coal use, it is also linked with environmental and health concerns. Combusting coal causes formation of harmful emissions including NO_x, SO_2, particulate matter and mercury, that are harmful for human health and contaminates the environment. With good reason, as problems became more obvious during the second half of the 20th century, countries have been setting progressively stricter rules on emissions that had direct effect on human health and the environment. For instance, the Clean Air Act (Sec 3.2.1) has authorized the US EPA to set regulatory programs for such emissions since 1970, resulting in a series of standards, most recently to the implementation of mercury and air toxic standard (MATS) in 2015. Similarly, Canadian Environmental Protection Act, 1999, has enabled Canadian federal government to set guidelines for emissions including NO_x, SO_2, particulate matter, but also provincial level caps for mercury emissions (3.3.2). Likewise, coal combusting plants in the UK have been obligated to achieve limits on particular emissions under the EU directives LCPD (2001/80/EC) and later IED (2010/75/EU) (section 3.5.2).

Due to the fact that the existing coal fleets are fairly old, for example roughly 40 years on average in the USA (Sec. 4.1), complying generators have been forced to retrofit expensive flue gas cleaning technologies. This, additionally, has increased operational costs as cleaners have further decreased already relatively low plant efficiencies (33% on average in the USA). In turn, building more efficient, complying a coal-fired plant with ~~a~~ modern flue gas cleaning technologies requires huge capital investment which is, presumably, why most of the US coal-fired capacity was built prior to 1990s, mainly during the 1970s. The coal fleet in the UK follows a similar trend where the latest units were commissioned in 1986 (see Section 6.2).

In addition to the aforementioned harmful emissions, coal use has a high contribution to the climate change due to coal's high carbon content. That is, combusting coal causes formation of high levels of CO_2 emissions. Given that coal is still the main source of energy worldwide and its CO_2 intensity is the highest among commonly used generation fuels, it is the major source of the global GHG emissions.

However, the first international steps to combat climate change have been taken only recently; the UNFCCC (Sec. 3.1) was established in 1992 followed by the adoption of the Kyoto Protocol in 1997 and later the Paris Agreement in 2015. National and regional acts have come after. For instance, there has not been a federal, nationwide rule in the USA that limits any GHG emissions from mobile and stationary sources until the EPA finalized the Clean Power Plan in 2015 (Sec. 3.2.2). It pursues the reduction of the electricity sector CO_2 emissions by 32% in 2030 compared to 2005 level by providing a performance standard on newly built units and by limiting the share of coal-fired generation in state-level electricity mixes.

This example, however, proves that the rules on GHG emissions are harder to justify than the regulations on other harmful emissions that have a direct, visible impact on citizens and the environment. Namely, the plan faced huge opposition and was ultimately halted by the US Supreme Court in early 2016 while the federal appeals court is hearing the challenges against to the rule. The process might take at least two years since the decision and the outcome remains uncertain – even though the EPA is confident the rule will eventually come into effect. Whether or not the plan is implemented in its current form, it still indicates federal intentions to regulate electricity sector emissions – in one way or another. Therefore, despite being halted, the plan already increases investment risks related to the CO_2 intensive, coal-fired capacity.

When it comes to the implementation, other, US regional policy actions, in turn, have been more successful and are steps ahead of the federal government. For example, there has been, since the early 2010s, two cap-and-trade systems (or ETSs) operational in the USA (and partly in Canada) to reduce the GHG (or CO_2) emissions cost effectively, on market basis, from inter alia the electricity sector. These multi-state (and province) systems are RGGI and the California-Québec ETS (see Sec. 3.4.1 and 3.4.2). However, the problem with ETSs seen thus far (also with the EU ETS, Sec. 3.5.1) has been that the annual/periodical caps on regulated emissions are predetermined even years before the actual compliance period takes place. Therefore, the limits are estimates based on historical data which do not take into account unexpected factors affecting the demand of emission allowances. That is to say, during the initial years of these systems as the economic slowdown that plagued the USA (and the rest of the world) since the late 2000s pushed down the GHG emissions from the regions even before the first caps had taken place. This in turn, particularly in the case of RGGI, resulted to an oversupply of the emission allowances and, therefore, to the lower than initiated price on carbon.

Measures to adjust the cap and the amount of allowances on the markets are, however, indicating sings of price recovery but it is still difficult, at this point, to trace the actual effects of the mentioned cap-and-trade mechanisms on the US coal-fired capacity, especially as the coal-fired generation has had an already low contribution to the overall electricity generation in the US regions in particular. This, again, may be a result of, at least since the 1990s, higher than average US electricity prices (Sec. 4.5) making generation from other sources, such as from natural gas and renewables, profitable – even without the direct price of carbon. High electricity prices may, in turn, indicate the functionality of other existing regional measures to promote less carbon intensive generation, such as renewable portfolio standards and emission performance standards for electricity generators or distributors (Sec. 3.4.3). Secondly, given that US coal-fired plants are on average old and inefficient, and that coal resources are unevenly distributed within the USA (mainly located inland, see Sec. 4.3) coal might not have even been the cheapest option in the first place. Accordingly, a more precise analysis on such cause and effect relationship on state and regional-level would be recommended in further studies to take into account largely varying state-level regulations and market conditions.

During the 2000s and the 2010s, the governments of the UK (together with the EU), Canada and Canadian provinces have also introduced measures to directly or implicitly decrease competition of coal-fired electricity generation in order to reduce electricity sector GHG emissions. These actions include direct taxes (Sec. 3.4.4 and 3.6.3) or emission performance standards on coal-fired units and support for renewable and for other less GHG intensive electricity generation (e.g. RO and CFD, see 3.6.1 and 3.6.2) or ultimately banning coal-fired generation entirely as seen in Ontario, Canada (3.4.6). However, intervening in a liberalized electricity market, as in the UK, may disturb the electricity supply and increase risks of insufficient electricity generation during the peak demand periods. That is to say, operators may not find it profitable enough to keep traditional condensing units available throughout the year to meet the demand when the intermittent generation capacity (e.g. wind) does not provide enough electricity. There might even occur technical challenges as old coal-fired units have been typically designed for baseload operations only, not to provide flexible reserve capacity.

The UK pursues to solve this problem with a capacity market mechanism (3.6.2), implemented as a part of the electricity market reform in 2014 which provides a predefined price for awarded units to stay in reserve and come online when mostly needed. Even though it is expected to ensure system reliability even during the coldest winter months, the mechanism has faced opposition stating that it provides subsidies for the most polluting units rather than encourages less emission intensive generation. This points out the difficult position of authorities and the wide range of factors to take into account when pursuing towards less GHG intensive electricity generation. That is to say, how to decrease the electricity sector emissions cost-effectively without reducing the system's reliability and, in turn, not to edge burden on consumers?

The case of Ontario may provide inspiration for such measures; the province was able to entirely phase-out coal-fired power plants between 2005-2014 by increasing shares of nuclear, hydro, natural gas and renewables in the generation mix. On the other hand, the circumstances in the province were unique and such reform may only be limitedly applied elsewhere. Firstly, coal had already a limited share in the province's generation mix (i.e. 25% before 2005). Secondly, there was no coal production in Ontario, hence the limited impact on job markets. Thirdly, growth in demand was slower than expected, so that new projects did not feed rapidly into retail power prices. Finally, natural gas had become a more abundant and affordable source alongside coal. Furthermore, the Government of Ontario owned the fossil fuel-fired generation plants through the Ontario Power Generation company which absorbed the costs of coal plant retirement. However, the actual costs of the reform remain uncertain, which is a recommended topic for further studies.

A more conservative way, compared to the full phase-out, is to implement an emission performance standard (EPS) affecting a new coal-fired capacity as UK and Canadian governments have done (see Sec. 3.3.1 and 3.6.3). They ensure that CO_2 intensities of new coal-fired units are limited on the level of a modern natural gas-fired unit (via partial, c. 50%, CCS). However, given that these standards apply only on newly built or modified units, it will not have an immediate effect on electricity generation mix if existing units may operate as usual until they reach the end of their useful life, i.e. even 10-20 years from the implementation of the standard. Therefore, the EPS is mainly suitable as a backstop to prevent the deployment of new unabated coal plants in case other measures are not effective enough to promote less GHG intensive generation, as the UK government justified its standard. However, implementing an EPS alone may have an opposite effect than firstly intended. To wit, the implementation procedure of the Canadian EPS for coal-fired units faced criticism for giving too much time for the generators to invest on unabated coal-fired capacity which they might not even otherwise do without upcoming restrictions (the implementation took four years since the proposal in 2011).

Accordingly, if coal is not to be phased out entirely, CCS (Sec. 2.3.3) may provide a long-term solution to extend the operation of existing units and enable new capacity additions in presence of EPS. There are, however, three main barriers restricting wider use of the CCS. First, the technology itself together with the operating CCS-fitted plant and required infrastructure (e.g. pipelines and storages) are still highly expensive. Second, suitable long-term storages for CO_2 (e.g. depleted oil field) are limitedly available and the storing itself evokes publics concerns. Third, there are very few large-scale power plant applications of available CCS technologies, which raises concern of the system reliability and its suitability for commercial power plant operations. That is, as electricity supply becomes more intermittent as renewable generation increases (e.g. wind and solar), it requires more flexibility from the existing units. Thus it may not be enough for a plant to be able to operate only on full load (i.e. baseload operation) but it should also be capable to reliably adjust the power output.

Despite the concerns related to the CCS, the first ever large-scale coal-fired power plant fitted with CCS, known as Boundary Dam unit 3, commenced operation in Saskatchewan, Canada, in 2014 (Sec. 5.6.1). Although the plant did not achieve the planned performance during the initial operation months, the operator is confident that the unit will be fully operational in 2016. There are four key factors that brought the unit alive. First of all, unit 3 was aging and about to be subject to the new performance standard on coal-fired units and thus the owner was willing to extend its life-time. Second, the project was awarded with government support (i.e. roughly one-fifth funding share of the $\$_{CAN}$ 1.35 billion budget). Third, electricity prices in Saskatchewan were on top of the prices seen in Canadian electricity markets. Finally, the owner has made a contract with a local oil producer to deliver captured CO_2 for enhanced oil recovery operations from which it will receive around 25$\$_{CAN}/t_{CO2}$ additional income – given that it is able to deliver the predetermined amount. Also other byproducts, such as sulphuric acid and fly ash, are sold as well. Similar projects are also under way in the USA which are, likewise, getting support from the government (the DOE's Clean Coal Power Initiative) and selling/utilizing captured CO_2 for EOR operations (see Sec 4.6).

There are, however, examples of unsuccessful CCS projects and government policies as well. For instance, the UK had ambitious plans to encourage CCS development by supporting chosen projects (including White Rose, Sec. 6.3.2) with $ 1 billion. It was suddenly cancelled, though, in 2015 which might also have put the projects into cancellation due to lack of funding. The plan was also to develop, in tandem, a cluster of CCS projects with shared CO_2 pipeline infrastructure operated by National Grid which could have resulted in significant cost savings for the projects. As a result, such venture has become uncertain as well. Unexpected cancellation may have permanently weakened the relationship and confidence between investing companies and the government. Consequently, if any support is provided, it is essential that the government ensures it is able to engage the project for the whole, predefined period and budget.

On the other hand, the Summit Power - owner of the Texas Clean Energy project in the USA (see Sec. 4.6.3) - is about to build a copy of a particular plant to the UK in case it is able to receive a CFD (i.e. a tariff mechanism of the electricity market reform, see Sec. 3.6.2) for the plant. The project is about to utilize the existing natural gas pipeline for delivering the captured

CO_2 for EOR operations. This indicates that the developers are confident with being able to reduce the costs by gaining experience (i.e. learning by doing) and by increasing project volumes, but also through utilizing existing infrastructure. The project may be additionally made more profitable by broadening it outside the power plant boundaries. For instance, as NRG Energy has proceeded (Sec. 4.6.2), the project could partly own the oil field where the captured CO_2 is delivered to ensure the greatest profit from the EOR operations (i.e. the value of recovered oil could be even 10-fold the oil company pays for the price of CO_2 used for the EOR). Therefore, it might also be reasonable to involve companies that have experience of such operations.

While countries are just seeking the right way to reduce conventional coal consumption, the decline is actually already under way of being led by the markets. This is particularly the case in the USA where consumers have benefited from an oversupply of natural gas since the late 2000s (referred as the shale gas boom, see 4.4). That is, during the 2000s, natural gas producers rapidly increased their investments on new shale gas production capacity, encouraged by the developed production methods and increased oil prices. The resulted oversupply has significantly decreased the market price of the natural gas and, hence, encouraged electricity generators to shift to less capital intensive and more flexible natural gas-fired capacity. If the price is not about to change rapidly, the trend is expected to continue through the 2010s and even further, undermining the remaining prospects of coal.

The generation mix in the UK has faced a similar coal-to-gas shift even earlier, since the 1990s, as a result of series of energy market reforms. As new operators entered the electricity market, they preferred less capital intensive natural gas-fired generation technologies while benefiting increased competition in the UK natural gas market. However, as domestic gas fields started to deplete in 2000, the UK gas consumers became more reliant on imported gas making the price more volatile. Thus, it followed the post-economic crisis trend of increasing the oil price temporarily terminating the coal to gas shift. However, as price of natural gas in the UK market has taken a downward trajectory since the late 2014 (due to e.g. increased LNG imports, warm winter, full stocks) the share of natural gas-fired generation is about to increase again. Sure, the carbon price floor (CPF) mechanism (i.e. the combination of the UK-only CPS rate of the CLL, and the EU ETS carbon price, see 3.6.3) have also made natural gas a more competitive option compared to coal. Shifting to gas is actually the main pillar of the UK's future plan to achieve further reductions in the electricity sector GHG emissions and its legally binging targets (i.e. carbon budgets). However, it would be essential to study the actual climate benefits from such shift (e.g. by broadening the scope from the power plant site to cover the whole supply chain). Furthermore, if the coal-to-gas shift is the first step to a carbon free generation mix, what would be the next one? Also, how fast should it be taken if the 2°C target is to be achieved?

As the policy environment as well as the market conditions are constantly changing, it would be recommended to further follow the development of certain factors and derive updated estimates on coal's future. For instance, will the CPP ever come into effect and what are the consequences (e.g. costs for the generators and for the customers, policies effect on GHG emissions and on generation mixes)? What further actions nations and regions are about to take to mitigate the climate change (e.g. will Alberta join coal free provinces by 2030 as proposed, or will the UK retire rest of coal capacity by 2025)? Also, will the natural gas maintain its competitiveness and will it permanently supersede coal? Are there any risks associated with such transition? Furthermore, as more CCS-fitted power plants commence operations, it would be essential to collect and analyze the actual operation data to derive precise profitability estimates of the projects.

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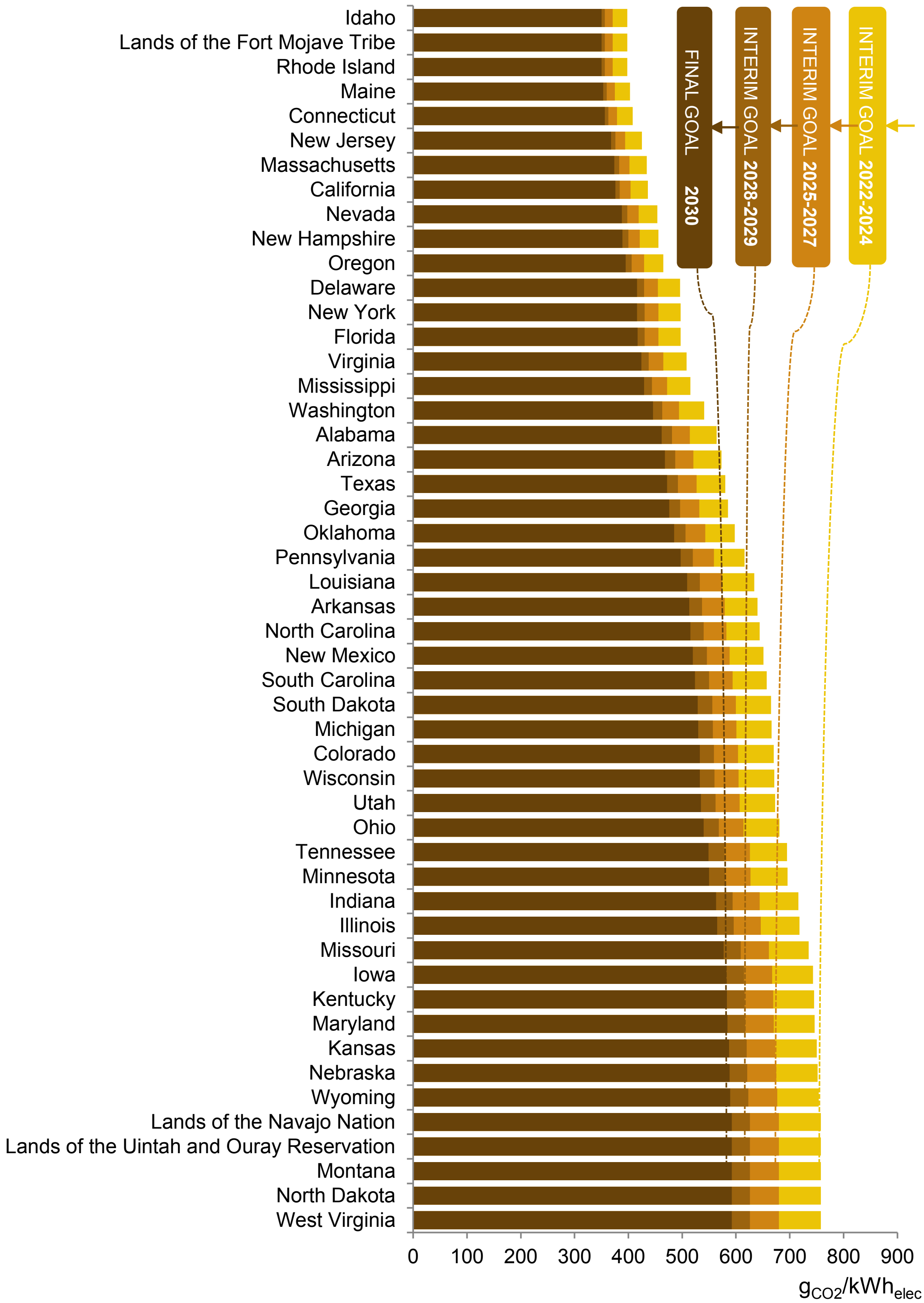
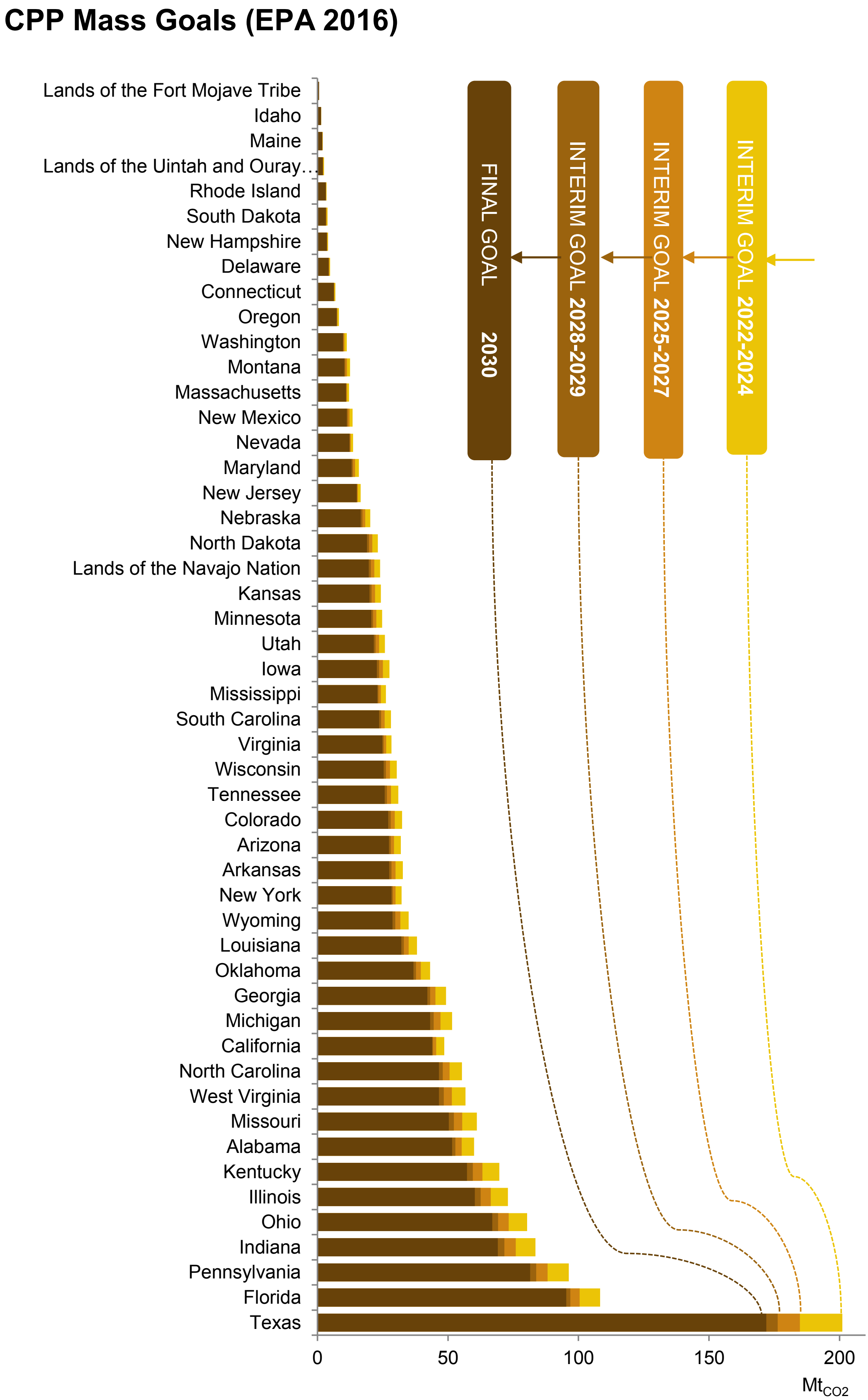
Appendix

CPP Rate-Based Goals (EPA 2016)




CPP Mass Goals (EPA 2016)
FINAL GOAL 2030
INTERIM GOAL 2028-2029
INTERIM GOAL 2025-2027
INTERIM GOAL 2022-2024
Lands of the Fort Mojave Tribe
Idaho
Maine
Lands of the Uintah and Ouray…
Rhode Island
South Dakota
New Hampshire
Delaware
Connecticut
Oregon
Washington
Montana
Massachusetts
New Mexico
Nevada
Maryland
New Jersey
Nebraska
North Dakota
Lands of the Navajo Nation
Kansas
Minnesota
Utah
Iowa
Mississippi
South Carolina
Virginia
Wisconsin
Tennessee
Colorado
Arizona
Arkansas
New York
Wyoming
Louisiana
Oklahoma
Georgia
Michigan
California
North Carolina
West Virginia
Missouri
Alabama
Kentucky
Illinois
Ohio
Indiana
Pennsylvania
Florida
Texas
0
50
100
150
200
Mt_{CO2}

CPP Mass Goals with New Source Complement (EPA 2016)