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Carbon Abatement Costs and the Potential of South Korea's Power Sector

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Carbon Abatement Costs and the Potential of South Korea's Power Sector

by

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Dedication

This thesis is dedicated to my wonderful children, Sejin and Ayoung Yoon, who have always loved me unconditionally. I love you with all my heart.

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Abstract

Carbon abatement costs and the potential of South Korea's power sector

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South Korea has set a 2030 target to reduce greenhouse gas emissions by 37 percent from the business-as-usual (BAU) level. Its power sector is expected to play a significant role in achieving this target as it accounts for more than 35% of total national emissions. This thesis examines the emissions reduction potential and costs of South Korea's power sector by constructing a marginal abatement cost curve. Two scenarios were developed for analysis. One is a reference case, in which the current fossil fuel-based generation mix is maintained until 2029. And alternative scenario allows low-carbon measures, such as new and renewable energy, nuclear, and carbon capture and storage (CCS) built out to their maximum potential. The carbon abatement cost curve was created by comparing the two scenarios so as to indicate which abatement measures are cost-effective in terms of reducing South Korea's power sector emissions.

Table of Contents

List of Tables viii

List of Figures x

Chapter 1: Introduction 1

Chapter 2: South Korea's Electricity Sector 3

- Capacity and generation 3
- Greenhouse gas emissions 5
- Industry structure 7
- Legal and regulatory framework 10
- Electricity prices 11

Chapter 3: Greenhouse Gas Abatement Cost Curve 15

- Marginal abatement cost curve 15
- Electricity demand forecast 17
- Abatement options 20
- Scenario modeling for analysis 23
- Construction of a marginal abatement cost curve 31
- Summary and discussion 44

Chapter 4: Limitations and Issues 47

- Limits of marginal abatement cost curve 47
- Sensitivity analysis 48
- Implementation challenges 61

Chapter 5: Conclusion 64

References 66

List of Tables

Table 1: Electricity generation by fuel source in 2015 (KEPCO, 2016) 5

Table 2: National greenhouse gas emissions by sector in $MtCO_2e$ (MOTIE, 2016a) 6

Table 3: Generation capacity and electricity generation of KEPCO and its subsidiaries in 2015 (KEPCO, 2016)..........10

Table 4: Main legislation in Korea's power sector (updated from OECD, 2000) 11

Table 5: Adjustment factors by fuel, 2008 to 2012 (Jeon, 2013)..........12

Table 6: Annual electricity purchase and cost and SMP (KEPCO, 2016 and KPX, undated)..........13

Table 7: Average electricity price for different customer categories in 2015 (KPX, undated) 14

Table 8: GDP growth rate projection (MOTIE, 2015)..........17

Table 9: Population projection (MOTIE, 2015)..........17

Table 10: Retiring generation capacity in MW (MOTIE, 2015) 19

Table 11: Renewable Energy Potential (KEA, 2016a) 21

Table 12: New energy technologies deployment plan, 2016 to 2029 (MOTIE, 2015) 22

Table 13: Generation fuel mix for 2029: Reference scenario (Developed by the author)..........25

Table 14: Generation fuel mix for 2029: Alternative scenario (Developed by the author)..........28

Table 15: Financial assumptions about each power generation technology (Developed by the author) 31
Table 16: Power sector's generation cost and emissions in 2029: Reference scenario (Developed by the author) 36
Table 17: Power sector's generation cost and emissions in 2029: Alternative scenario (Developed by the author) 37
Table 18: Comparison of reference and alternative scenarios (Developed by the author) 39
Table 19: Additional power generation technologies in the reference scenario (Developed by the author) 40
Table 20: Carbon abatement costs and abatement potentials in Korea's power sector (Developed by the author) 42
Table 21: Abatement costs under different interest rates (unit: $/tCO_2$) (Developed by the author) 50

List of Figures

Figure 1: Electricity generation in Korea by fuel (MOTIE, 2016b)..................3

Figure 2: Electricity generation and GHG emissions in Korea's power sector (MOTIE, 2016a and 2016b)..7

Figure 3: Korea's electric power industry structure (KEPCO, undated)...........9

Figure 4: Sample MAC curve (Kesicki and Strachan, 2011)...........................15

Figure 5: Projection of electricity demand and peak capacity (MOTIE, 2015)18

Figure 6: Electricity generation in the reference and alternative scenarios (Developed by the author) 29

Figure 7: Generation capacity in the reference and alternative scenarios (Developed by the author) 30

Figure 8: Carbon emissions in the reference and alternative scenarios (Developed by the author) 30

Figure 9: Carbon abatement cost curve of Korea's power sector for 2029 (Developed by the author) 43

Figure 10: Impacts of changes in financial assumptions on average carbon abatement cost (Developed by the author).......................................49

Figure 11: Carbon abatement cost curve at 4% and 10% interest rates (Developed by the author) 52

Figure 12: Carbon abatement cost as a function of the interest rate (Developed by the author) 53

Figure 13: Ratio of capital cost to total annual cost in 2029 in the alternative scenario (Developed by the author) 54

Figure 14: Carbon abatement cost curve at a ± 50% change in capital cost (Developed by the author) 57

Figure 15: Carbon abatement cost curves at a ± 50% change in fuel cost (Developed by the author) 59

Figure 16: Carbon abatement cost as a function of fuel cost (Developed by the author) 60

Chapter 1: Introduction

Although South Korea (Korea) accounts for only 1.5% of the global greenhouse gas (GHG) emissions as of 2012 (World Resources Institute, undated), Korea has committed to reduce its greenhouse gas emissions to help mitigate global climate change. In June 2015, Korea announced its 2030 national greenhouse gas emission target of 536 million metric tonnes of carbon dioxide equivalent ($MtCO_2e$), which is a 37% reduction from the business-as-usual (BAU) level of 851 $MtCO_2e$ (ME, 2015). This reduction is more ambitious than the previous 2009 emissions target, when the Korean government set a 2020 target of reducing greenhouse gas emissions by 30% from the BAU level. To achieve these targets, Korea enacted its Framework Act on Low Carbon, Green Growth in 2010 (MOLEG, undated-a), the GHG and Energy Target Management Scheme in 2012 (ME, undated-a), and the National Emission Trading Scheme was enforced in 2015 (ME, undated-b).

The power sector accounts for 35% of Korea's total emissions, so it is expected to play a significant role in achieving the emissions target (MOTIE, 2016a). However, in 2015, 64.4% of electricity was generated from fossil fuels including coal, oil and gas, followed by 31.2% from nuclear, whereas only 4.4% was produced by renewable energy sources (KEPCO, 2016). One way to reduce GHG emissions is to change the carbon-intensive energy mix in the power sector. The Korean government is trying to decarbonize the electricity grid by increasing the share of low-emission energy technologies such as nuclear and renewables, as outlined in the National Energy Master Plan (MOTIE, 2014a) and National Basic Plan for New and Renewable Energy (MOTIE, 2014b).

Given the importance of the power sector in GHG emissions reduction, this thesis analyzes the potential for and costs of GHG emissions reduction in Korea's power sector. To estimate the cost-effectiveness as well as the technical CO_2 emission reduction potential of each abatement technology, a marginal abatement cost curve was developed. A sensitivity analysis was conducted to investigate uncertainties in the financial assumptions and their impacts on a marginal abatement cost curve. Finally, this thesis assesses some of the implementation challenges and how to overcome these issues.

Chapter 2: South Korea's Electricity Sector

CAPACITY AND GENERATION

Korea's electricity generation has increased with its economic growth, except in 1998 when the country experienced the economic recession (Figure 1) (MOTIE, 2016b). Korea's electricity generation has increased by an average of 4% annually since 2005. Although most of the electricity generation is fossil-fuel based, nuclear also plays a significant role in the power sector. Renewable energy including solar photovoltaic (PV), wind, fuel cells, bioenergy (bio), waste, and tidal combined, contribute only a small portion of Korea's electricity generation.

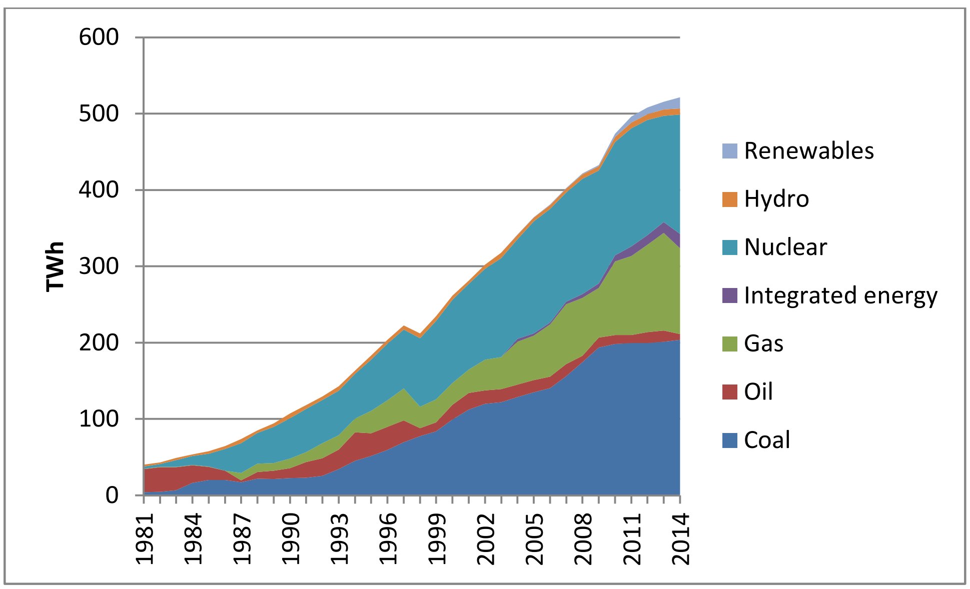


Figure 1: Electricity generation in Korea by fuel (MOTIE, 2016b)

Note: Renewables include solar PV, wind, fuel cells, bioenergy, waste and tidal. "Integrated energy" represents combined heat and power (CHP)

Table 1 summarizes the generation capacity and electricity generation of different types of power sources in 2015. Fossil fuels supplied most of the total electricity generation in 2015. Coal-fired power, mostly with bituminous coal, is the dominant fossil fuel in the electricity sector, generating 39.3% of the total. Coal has been used for baseload power generation owing to its relatively low cost. Natural gas, the second largest source (19.1%), provides electricity to help meet peak loads. Oil accounts for only 1.8% of Korea's total power generation (KEPCO, 2016).

Nuclear power has a low fuel cost and has been used for baseload power generation. Its share in electricity supply was around 35% to 40% in the 2000s. In late 2012, two reactors were shut down for component replacement after discovering that the reactors were using components with forged quality certificates (CNN, 2012). The nuclear share dropped to 26% in 2013 and but rebounded to 31.2% in 2015 after the reactors were restarted (MOTIE, 2016b). A small portion of electricity generation uses renewable sources, including solar PV, and hydropower.

Type		Capacity (kW)	Gross Production (MWh)	%
Coal	Anthracite	1,125,000	7,438,271	1.4
	Bituminous	25,148,600	199,895,424	37.9
Oil	Heavy oil	2,950,000	8,822,006	1.7
	Diesel	329,690	643,164	0.1
Gas	Gas-fired	387,500	222,472	0.0
	Combined cycle	28,512,191	100,598,385	19.1
Integrated energy		5,360,020	22,018,711	4.2
Nuclear		21,715,683	164,762,416	31.2
Renewable sources	Hydropower	6,470,709	5,796,040	1.1
	Solar PV	2,537,558	3,482,731	0.7
	Wind	834,415	1,336,272	0.3
	Bioenergy	254,892	1,059,362	0.2
	Waste	1,596,102	9,235,363	1.8
	Integrated Gasification Combined Cycle (IGCC)	380,700	6,089	0.0
	Ocean (Tidal)	255,000	496,354	0.1
	Fuel Cell	171,400	1,701,786	0.3
Total		98,029,460	527,514,846	100

Table 1: Electricity generation by fuel source in 2015 (KEPCO, 2016)

Note: Public utility only (non-utility generation is not included)

GREENHOUSE GAS EMISSIONS

The Greenhouse Gas Inventory and Research Center (GIR), an affiliate of Korea's Office for Government Policy Coordination (OPC), publishes the National Greenhouse Gas Inventory every year, using 1996 United Nations Framework Convention on Climate

Change (UNFCCC) reporting guideline which is the international standards for national greenhouse gas emissions estimation (GIR, undated). Table 2 shows that the energy sector dominates Korea's national emissions accounting for more than 85% of total emissions. Electricity generation is a sub-category of the energy sector and its share is about 35% of the total.

Year	Energy	Electricity Generation	Industry	Agriculture	Waste	Total ($MtCO_2e$)
2010	565.2 (86.1%)	234.9 (35.8%)	54.0 (8.2%)	22.4 (3.4%)	15.1 (2.3%)	656.6
2011	593.9 (87.0%)	240.8 (35.3%)	51.7 (7.6%)	21.5 (3.1%)	15.5 (2.3%)	682.6
2012	597.7 (87.0%)	244.4 (35.6%)	51.7 (7.5%)	21.9 (3.2%)	15.8 (2.3%)	687.1
2013	606.7 (87.1%)	249.6 (35.8%)	52.0 (7.5%)	21.9 (3.1%)	16.0 (2.3%)	696.5
2014	599.3 (86.8%)	236.6 (34.3%)	54.6 (7.9%)	21.3 (3.1%)	15.4 (2.2%)	690.6

Table 2: National greenhouse gas emissions by sector in $MtCO_2e$ (MOTIE, 2016a)

According to the GIR, Korea's national emissions in 2014 decreased by 5.9 $MtCO_2e$ from the previous year due to the emissions reduction in the power sector (13 $MtCO_2e$) (GIR, 2016). This decline in the power sector's GHG emissions is attributable to the reduction of fossil fuel consumption. Figure 2 illustrates the power sector's GHG emissions and electricity generation from 2010 to 2014. The GHG emissions steadily increased as electricity generation increased until 2013. In 2014, the GHG emissions dropped despite an increase in total electricity generation. This shows that the GHG emissions in the power sector are related not to the total electricity generation but to the fossil fuels electricity generation, and that a correlation exists between GHG emissions and fossil fuel consumption in the power sector.

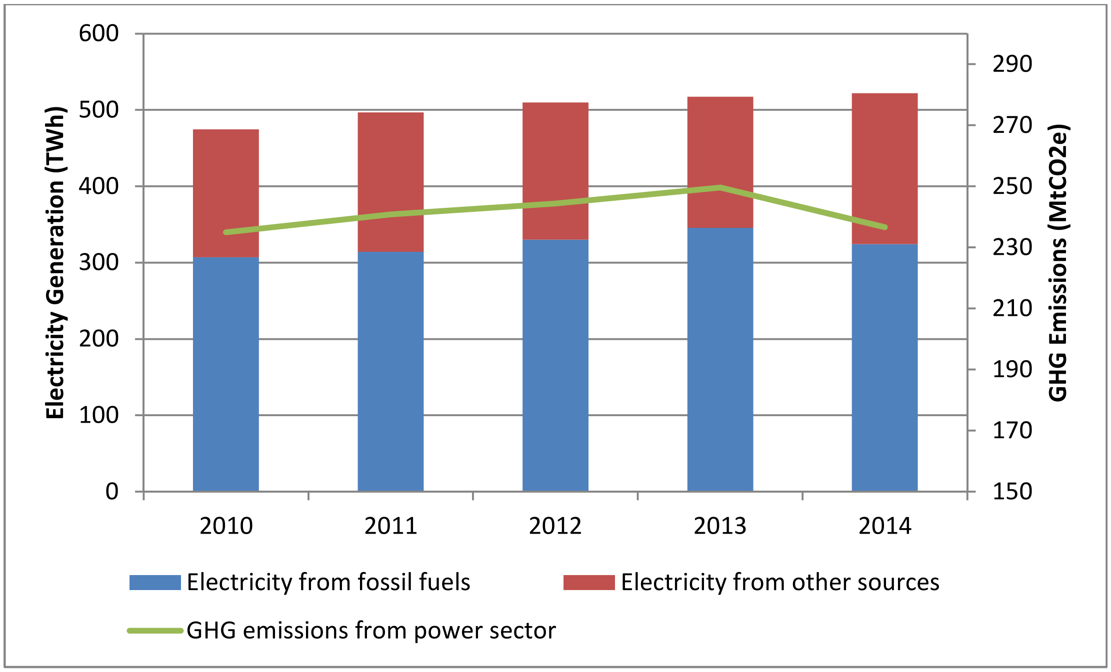


Figure 2: Electricity generation and GHG emissions in Korea's power sector (MOTIE, 2016a and 2016b)

INDUSTRY STRUCTURE

According to the BP Statistical Review of World Energy, Korea was the ninth largest energy consumer in the world in 2015 (BP, 2016). Because Korea lacks domestic energy sources, it imports 98% of is fossil fuels from overseas (EIA, 2017). Furthermore Korea is isolated from adjacent land connections in terms of the electricity grid and does not export or import electricity to or from neighboring countries. Enhancing energy security and ensuring a reliable electricity supply have long been one of Korea's top national priorities, which is why the Korean government heavily regulates and controls the electric power industry.

The Korea Electric Power Corporation (KEPCO), a government-owned company, has historically dominated the electricity system in Korea. In 1999, the Korean government adopted the Basic Plan for Restructuring of the Electricity Supply Industry to reform its electricity sector in an effort to increase economic efficiency through the introduction of effective competition, while securing the reliable supply of electricity (OECD, 2000). KEPCO was restructured based on this plan (Figure 3), by breaking up KEPCO's generation capacity into six generating subsidiaries: five non-nuclear companies (Korea South-East Power (KOSEP), Korea Midland Power (KOMIPO), Korea Western Power (WP), Korea East-West Power (EWP) and Korea Southern Power Co (KOSPO)), and one nuclear company (Korea Hydro & Nuclear Power (KHNP)). The initial plan intended to sell off five non-nuclear subsidiaries but KEPCO still owns them. As the entry into power generation was liberalized, private power generators became able to operate in the electricity market. The Korea Power Exchange (KPX) was set up in 2001 as part of this reform to operate cost-based power market. KPX determines prices sold between electricity generators and the KEPCO grid through electricity trading and executes the real-time dispatch of electricity. Although KPX is a government-owned institution, it is independent from all electric utilities including KEPCO. KEPCO still serves as the electricity retailer and controls national transmission and distribution. It transports electricity it purchases from KPX and sells it to customers across the nation.

Figure 3: Korea's electric power industry structure (KEPCO, undated)

Despite these efforts to reform and liberalize, the electricity market is still dominated by KEPCO and its subsidiaries. As of January 2017, Korea has 1,389 power generation companies in the electricity market, including six KEPCO subsidiaries (KPX, 2017). However, 82% of the electricity was provided by KEPCO subsidiaries in 2015 (Table 3). Furthermore, the transmission, distribution and retail sales are exclusively operated by KEPCO. As KEPCO is the single purchaser in the electricity wholesale market, power generators compete against each other to sell electricity to KEPCO. This monopoly on the demand side increases inefficiency in power generation.

Type	KEPCO and Subsidiaries	Others	Total
Capacity (MW)	73,282 (75%)	24,366 (25%)	97,648
Generation (GWh)	432,758 (82%)	94,756 (18%)	527,514

Table 3: Generation capacity and electricity generation of KEPCO and its subsidiaries in 2015 (KEPCO, 2016)

LEGAL AND REGULATORY FRAMEWORK

Table 4 summarizes several laws that regulate Korea's power sector. An entity planning to conduct business in the electric power sector should obtain a license or approval from a designated organization such as the Ministry of Trade, Industry and Energy (MOTIE) and the local government (MOLEG, undated-b). According to the Electric Utility Act, the Basic Plan on Electricity Demand and Supply is announced every other year (MOLEG, undated-b). This top-down strategic plan outlines comprehensive plans for the electricity sector such as a long-term demand forecast, fuel mix, and construction and decommissioning plans. The Act on the Promotion of the Development, Use and Diffusion of New and Renewable Energy requires power producers to supply a certain amount of electricity from new and renewable energy sources sector (MOLEG, undated-c). A Renewable Portfolio Standard (RPS) was adopted to replace the Feed-in Tariff in 2012 to create a competitive market environment for Korea's renewable energy sector (MOLEG, undated-c). Currently, electricity generators with installed power capacity of more than 500 MW are required to follow the standard (MOLEG, undated-c).

Legislation	Main Provisions
Electric Utility Act	· An entity that intends to operate an electric utility business shall obtain a license from the Ministry of Trade, Industry and Energy (MOTIE) or the local government · Power generators shall engage in electric power transaction in the electricity market operated by KPX · MOTIE shall formulate and announce a master plan for electricity supply and demand
Nuclear Safety Act	· An entity that wishes to construct a nuclear power reactor shall obtain construction permit by the Nuclear Safety and Security Commission which is under the authority of the Prime Minister
Act on the Promotion of the Development, Use and Diffusion of New and Renewable Energy	· MOTIE can oblige certain power generators to provide a certain portion of their generation from new and renewable energy sources
Integrated Energy Supply Act	· Any integrated energy business entity shall obtain a license from MOTIE for each supplied district to conduct business
Korea Electric Power Corporation Act	· Defines the governance of KEPCO
Electric Power Source Development Promotion Act	· An electric power source developer shall establish an execution plan for the business and shall obtain approval from MOTIE
Act on Assistance to Electric Power Plants-Neighboring Areas	· MOTIE can provide assistance program to neighboring areas of electric power plants to raise awareness of electric power business and contribute to regional development

Table 4: Main legislation in Korea's power sector (updated from OECD, 2000)

ELECTRICITY PRICES

According to the Electric Utility Act, domestic electricity must be traded through the electricity market operated by KPX (MOLEG, undated-b). As mentioned earlier, KPX operates a quasi-competitive and one-way bidding wholesale market called the Cost-based Pool (CBP). Market price is determined as the sum of the Marginal Price (MP) and the Capacity Payment (CP), both expressed in Won per Kilowatt hour (Won/kWh) (KPX, 2013).

Under the current system, generators bid the quantity of electricity that they can provide to the grid, but they do not bid an electricity price. Instead, the Cost Evaluation Committee of KPX determines the bid price for each generator every month based on the variable costs that each generator submitted to the Committee. KPX dispatches electricity on a lowest-cost-first basis, so the System Marginal Price (SMP) is determined as the variable costs of the last dispatched generator (Jeon, 2013). However, an adjustment factor is applied to "SMP - generator's variable costs" for the electricity generated from KEPCO subsidiaries (Table 5). For example, assume that the SMP is 100 Won/kWh, a nuclear reactor's variable cost is 4 Won/kWh and the adjustment factor is 0.2. Then this nuclear reactor will make 4+(100-4)×0.2=23.2 Won/kWh, instead of 100 Won/kWh when selling electricity to KEPCO (KPX, 2013). This difference allows KEPCO to purchase the electricity from its subsidiaries at a lower price, to balance profit and loss between KEPCO and the subsidiaries (Jeon, 2013).

Period	Nuclear	Coal	CCGT
Aug 2008 – Aug 2009	0.2184	0.0894	0.0894
Aug 2009 – Aug 2010	0.3052	0.1865	0.327
Aug 2010 – Aug 2011	0.1913	0.1315	0.32
2012	0.2498	0.1560	N/A

Table 5: Adjustment factors by fuel, 2008 to 2012 (Jeon, 2013)

Generators with higher variable costs are unable to sell electricity to the market until all lower cost generators are dispatched. This hierarchy can hinder the development of the electricity industry and increase the economic loss of existing higher cost power plants. To prevent this, a capacity payment (CP) is provided to every generator participating in the bidding, regardless of their electricity sales. To sum up, CP is paid to the bid capacity declared by each generator in the bidding to reimburse fixed costs such as their construction and operation costs, whereas SMP is paid to the electricity that is actually sold in the market (KEPCO, 2009). Table 6 shows the SMP and electricity trading from 2011 to 2015. KEPCO purchased 495,114 GWh of electricity in 2015 and the total payment was 41,913 billion Won. The electricity purchase increased every year, but the purchase cost did not. When the SMP dropped from 142.26 Won/kWh in 2014 to 101.76 Won/kWh in 2015, total payment for electricity decreased despite the increase in the purchase volume.

Type		2011	2012	2013	2014	2015
Electricity Purchase	Volume (GWh)	462,357	471,800	479,287	490,372	495,114
	Payment (billion Won)	36,844	42,613	42,288	44,727	41,913
SMP (Won/kWh)		126.63	160.83	152.10	142.26	101.76

Table 6: Annual electricity purchase and cost and SMP (KEPCO, 2016 and KPX, undated)

Note: The average rate of exchange to Korea Won was 2016 is 1 USD = 1,161 Won

Retail electricity prices are regulated by the Korean Electricity Commission under MOTIE. Tariffs vary on the basis of six customer categories: residential, public, education, industry, agriculture, and street lighting (Table 7). For the residential category, a progressive-rate system is used that consists of six stages. Electricity rates for residential customers increase steeply as the consumption rises. Meanwhile, a flat-rate system is applied to industry and commercial customers. This system was introduced in the 1970s to curb household electricity consumption to meet the industrial electricity demand (*Korea Herald*, 2016). Commercial, education, and industrial tariffs also vary by season.

Categories	Residential	Public	Education	Industry	Agriculture	Street Lighting
Average Electricity Price (Won/kWh)	123.69	130.46	113.22	107.41	47.31	113.37

Table 7: Average electricity price for different customer categories in 2015 (KPX, undated)

Note: 1 USD= 1,161 Won in 2016

Chapter 3: Greenhouse Gas Abatement Cost Curve

MARGINAL ABATEMENT COST CURVE

A marginal abatement cost (MAC) curve is a convenient way to present estimates of the abatement volume and associated marginal costs of low-carbon energy options in a specific year compared to a business-as-usual (BAU) development scenario. This graph contrasts the marginal abatement cost on the y-axis and the emission reduction potential on the x-axis (Figure 4). Each bar represents a single low-carbon measure and is ranked by increasing costs for emission reduction. The width of the bar indicates the abatement potential relative to BAU and the sum of the width of all bars shows the total emissions reduction potential in a given year. The height of the bar represents the abatement cost per year relative to BAU (Van Tilburg et al., 2010). For example, in Figure 4, Measure N's abatement cost is about 65 £/tCO_2, and its abatement potential is about 5 MtCO_2. The MAC curve is a tool to assess the GHG emissions reduction potential of different abatement options and to compare respective incremental costs rather than to predict the actual price of emissions (Dewan Nasional Perubahan Iklim, 2010).

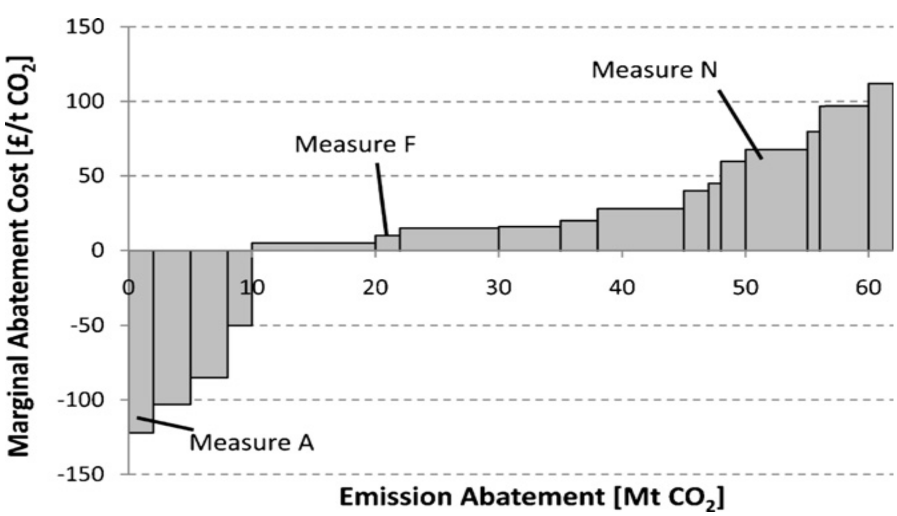


Figure 4: Sample MAC curve (Kesicki and Strachan, 2011)

Many institutes and consultancies have developed MAC curves for various industries in different countries. The concept of a MAC curve has been applied since 1982 when Alan Kevin Meier developed a cost curve for the reduction of electricity consumption (Meier, 1982). The MAC curves have become a tool for assessing the economics of climate change mitigation options since the work of McKinsey & Company (Kesicki and Strachan, 2011). McKinsey published 17 GHG abatement cost curves between 2007 and 2010 to analyze the global economy as a whole as well as the economies of several countries and individual sectors (McKinsey & Company, undated). In the United Kingdom, sectoral MAC curves were commissioned by the Committee on Climate Change (MacLeod et al., 2010) and the Forestry Committee (Valatin, 2012). International organizations such as the World Bank (World Bank, 2014) and the International Maritime Organization (International Maritime Organization, 2014) also produced country-specific or industry-specific MAC curves. However, there is no sector-specific GHG abatement cost curve for the power industry in Korea.

This thesis presents a GHG abatement cost curve to assess cost-effectiveness and GHG abatement potential in Korea's power sector, using the approach of McKinsey. The abatement calculation was conducted in four stages (McKinsey & Company, 2009): 1) The electricity demand is determined, 2) The need to build new electricity production capacity is determined based on the electricity demand forecast and retirements' simulation of existing power plants, 3) Low-carbon technologies are ordered in terms of cost competitiveness and the maximum available volume of each technology is determined, and 4) Each low carbon technology is built out in the model to its maximum potential in order of increasing cost until the electricity demand is filled.

ELECTRICITY DEMAND FORECAST

MOTIE announces the Basic Plan on Electricity Demand and Supply every other year, which includes a long-term national electricity demand forecast. The latest version (MOTIE, 2015) provides demand forecast through 2029; this thesis will use this national plan as a reference.

The electricity demand was estimated using projections of economic growth (Table 8), electricity price simulation, population growth (Table 9), and climate change scenario (Korea Meteorological Administration, undated). From 2015 to 2029, the annual economic growth rate is forecasted to be 3.0% and the annual population growth rate will be 0.2%. On the basis of these assumptions, the electricity demand is expected to rise to 766,109 GWh in 2029. Peak demand used to occur during the summer, when air conditioning demand is high, but since 2009, the peak has been in the winter, usually between 10 a.m. and 12 p.m., due to high heating demand. This trend is assumed to continue throughout the scenario period (Figure 5). The peak capacity to meet both winter and summer peak demand is estimated to be 127,229MW in 2029 (MOTIE, 2015).

Year	2015	2020	2027	2029	Annual Average
%/year	3.5%	3.3%	2.5%	2.3%	3.06%

Table 8: GDP growth rate projection (MOTIE, 2015)

Year	2015	2020	2027	2029	Annual Average Growth Rate
1000s of people	50,617	51,435	52,094	52,154	0.2%

Table 9: Population projection (MOTIE, 2015)

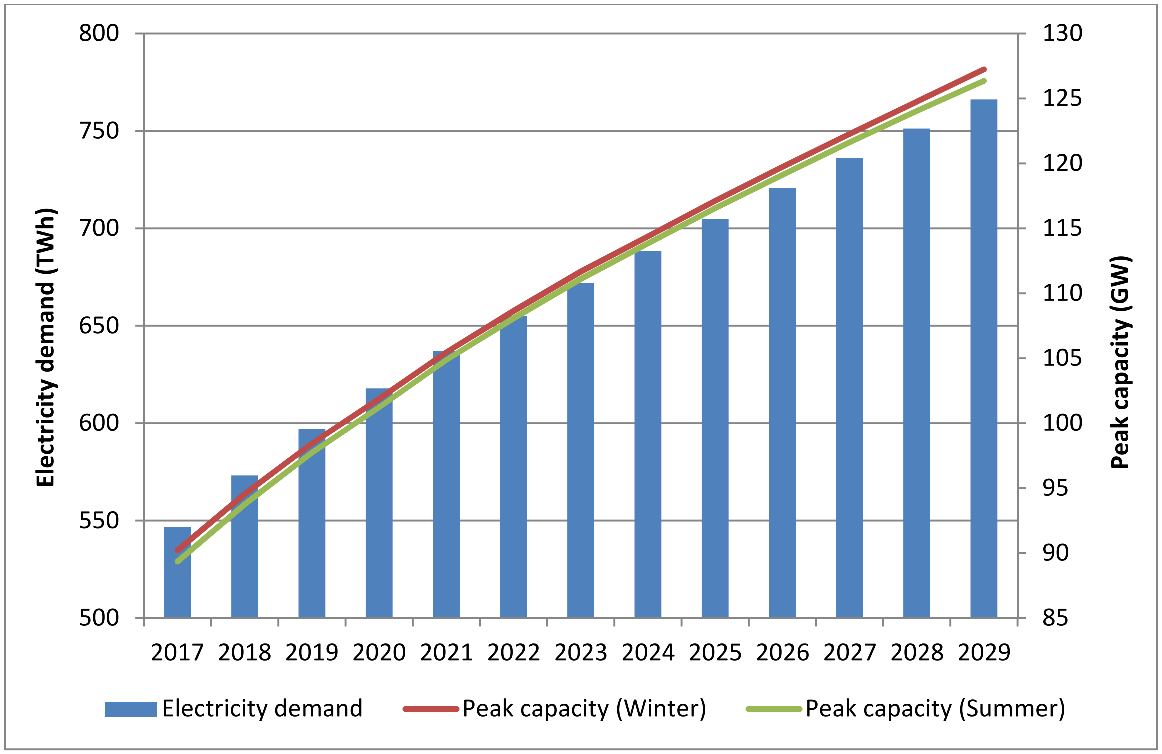


Figure 5: Projection of electricity demand and peak capacity (MOTIE, 2015)

As of December 2015, 98,029 MW of generating capacity had been installed in Korea. According to the 7th Basic Plan on Electricity Demand and Supply, 6,760 MW of capacity will be retired from 2015 until 2029 (MOTIE, 2015). However, these figures include 588 MW of retiring capacity planned for 2015. This paper assumes that the retirement plan for 2015 is already reflected in the 2015 existing capacity. Excluding the 2015 retiring capacity, the retiring capacity from 2016 to 2029 will be decreased to 6,172 MW: coal 400 MW, oil 2,655 MW, gas 2,530 MW, and nuclear 587 MW. Table 10 lists these retiring plans. After reflecting this retiring capacity, the existing plants in 2029 will be 91,858 MW.

Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	26,274	0	0	-400	0	0	0	0	0	0	0	0	0	0	25,874
Oil	3,280	0	0	-55	0	0	-1,200	0	0	-1,400	0	0	0	0	625
Gas	28,900	-250	-480	0	0	0	0	0	-1,800	0	0	0	0	0	26,370
Nuclear	21,716	0	-587	0	0	0	0	0	0	0	0	0	0	0	21,129
Integrated energy	5,360	0	0	0	0	0	0	0	0	0	0	0	0	0	5,360
Hydro	6,471	0	0	0	0	0	0	0	0	0	0	0	0	0	6,471
Solar PV	2,538	0	0	0	0	0	0	0	0	0	0	0	0	0	2,538
Wind	834	0	0	0	0	0	0	0	0	0	0	0	0	0	834
Fuel Cell	171	0	0	0	0	0	0	0	0	0	0	0	0	0	171
Bio	255	0	0	0	0	0	0	0	0	0	0	0	0	0	255
Waste	1,596	0	0	0	0	0	0	0	0	0	0	0	0	0	1,596
IGCC	381	0	0	0	0	0	0	0	0	0	0	0	0	0	380
Ocean	255	0	0	0	0	0	0	0	0	0	0	0	0	0	255
Total (MW)	98,029	-250	-1,067	-455	0	0	-1,200	0	-1,800	-1,400	0	0	0	0	91,858

Table 10: Retiring generation capacity in MW (MOTIE, 2015)

To meet the electricity demand in 2029, more generating capacity needs to be built. Decisions on fuel mix to meet demand will vary. Different generation scenarios are developed that reflect different fuel mix decisions and the MAC curves will be constructed accordingly.

ABATEMENT OPTIONS

Greenhouse gas emissions reduction can be achieved in two ways: decreasing electricity generation by reducing electricity demand/consumption, or replacing fossil-fuel generation with low-carbon alternatives. This thesis considers only the latter option, as the electricity demand reduction comes from other sectors that are beyond the scope of this thesis. Abatement alternatives can be categorized into three groups: new and renewable energy; nuclear energy; carbon capture and storage (CCS).

"New and renewable energy" is a commonly used term in Korea rather than renewable energy alone, as the government policies focuses on promoting both "new" and "renewable" energy. According to the Act on the Promotion of the Development, Use and Diffusion of New and Renewable Energy, new energy is defined as energy sources that are either converted from existing fossil fuels or that use electricity or heat generated through the chemical reaction of hydrogen, oxygen, etc (MOLEG, undated-c). This includes hydrogen energy, fuel cells, and energy from liquefied or gasified coal such as Integrated Gasification Combined Cycle (IGCC). Renewable energy means energy converted from renewable energy sources including sunlight, water, etc. which are in any of the following categories: solar energy, wind power, hydro power, ocean energy, geothermal energy, bio energy converted from biological resources, and energy from waste materials (MOLEG, undated-c). In this thesis, bio represents solid wood and waste represents by-product gas (coke oven gas and blast furnace gas). Korea's renewable energy potential estimates are included in the New and Renewable Energy White Paper that the Korea Energy Agency (KEA) publishes every other year (KEA, 2016a). Table 11 lists the latest estimates. There are no potential estimates for new energy, but the 7th Basic Plan on Electricity Demand and Supply provides the government's new energy deployment plan (MOTIE, 2015). This is considered the maximum capacity that can be possibly deployed until 2029, so this thesis uses this plan as a potential for new energy (Table 12).

Type		Capacity (GW)		
		Theoretical[1)]	Geographical[2)]	Technical[3)]
Solar		97,459	24,178	7,451
Wind	Onshore	487	118	64
	Offshore	423	216	33
Hydro		36	19	15
Bio		237	11	9
Waste		19	18	14
Geothermal	Deep	9,308	N/A	30
	Shallow	29,078	13,913	1,298
Ocean	Current	439	278	43
	Tidal	12	10	6
	Wave	N/A	N/A	N/A
	Ocean Thermal	451	339	3
Total		137,949	39,100	8,966

Table 11: Renewable Energy Potential (KEA, 2016a)

Notes: 1) Theoretical potential is the total amount of energy that exists in the whole territory, 2) Geographical potential is the total amount of energy that exists in the area where facilities can be installed, and 3) Technical potential is the total amount of energy that can be produced at current technology level within the geographical potential.

	Fuel cells	IGCC
Capacity (MW)	1,110	600

Table 12: New energy technologies deployment plan, 2016 to 2029 (MOTIE, 2015)

Note: Excluding construction plan for 2015

Nuclear energy has been utilized in an effort to reduce energy dependency and ensure a reliable supply of electricity, given that Korea lacks domestic energy resources. As of March 2017, Korea is the world's sixth largest nuclear user by both number of reactors (25 reactors) and total generation capacity (23,077 MW) (International Atomic Energy Agency, 2017). According to the 7th Basic Plan on Electricity Demand and Supply, the government plans to install an additional 14,200 MW by 2029 (MOTIE, 2015).

Carbon Capture and Storage (CCS) enables the continuation of the current fossil-fuel based power generation while reducing the GHG emissions. However, CCS is in the pilot stage globally; no CCS-equipped power plant currently exists in Korea. The International Energy Agency (IEA) anticipated that CCS would contribute 14% of the cumulative emissions reduction between 2015 and 2050 (IEA, 2013). The Korean government is also investing in CCS technology development through the Korea CCS 2020 project with the total investment of 173 billion Won (145 million USD) (Korea Carbon Capture & Sequestration R&D Center, 2012). This project was launched in 2011 and will continue until 2020. The goal is to develop CO_2 capture and storage technologies with an additional cost of less than 30% of fossil-fuel power plants' operating cost (Korea Carbon Capture & Sequestration R&D Center, 2012). This thesis assumes that CCS will be economically feasible at a large scale in 2029.

SCENARIO MODELING FOR ANALYSIS

Following the McKinsey's methodology, two scenarios were developed for economic analysis of carbon abatement technologies in the power sector. Given the same existing capacity of 91,858 MW in 2029, the reference scenario and alternative scenario are taking different paths to fill the gap to meet the electricity demand (766,109 GWh) and peak capacity (127,229 MW) for 2029. These scenarios are not actual forecasts for 2029 but they are reflections of possible developments.

The reference scenario with continuation of recent trend can serve as a baseline for emissions reductions. It was constructed to roughly maintain the generation capacity mix of 2015 in order to be useful for judging the alternative emissions scenario. In addition to maintaining the current capacity share, the scenario was designed to meet both the electricity demand and the peak capacity in 2029.

For example, hydro accounted for 7% of the total generation mix in 2015 by capacity. To maintain this share in 2029, an additional 3,000 MW is added to the existing 6,471 MW. The total capacity of hydro (9,471 MW) accounts for 7% of the national generation capacity in 2029. Then the electricity generation is calculated using Equation (1). Multiplying the generation capacity by the capacity factor and 8,760 (the number of hours in one year) gives you the electricity generation. The capacity factor is the ratio of the system's electrical output to the nameplate output. Hydro's capacity factor is 14.5%, so using Equation (1), the electricity generation from hydro is 12,030 GWh in 2029.

$$Electricity\ generation\ (MWh) = C \times CF \times 8{,}760 \qquad \text{Equation (1)}$$

where:

C = Capacity (MW)

CF = Capacity factor (%)

Peak capacity is calculated using a peak coincidence factor, which is the probability that a system will operate coincidentally with peak. Equation (2) computes the peak capacity by multiplying the capacity by the peak coincidence factor. Hydro has 28% of peak coincidence factor (MOTIE, 2015) and using Equation (2), its peak capacity is 2,652 MW.

$$Peak\ capacity\ (MW) = C \times PCF \qquad \text{Equation (2)}$$

where:

C = Capacity (MW)

PCF = Peak Coincidence Factor (%)

The emission is calculated by multiplying the electricity generation by the emission factor (Equation (3)). Emission factor used here is defined as the average emission rate of GHG for a given source, relative to the electricity generation (MWh). The emission factor of hydro is 0, therefore hydro's emission is 0.

$$Emission\ (tCO_2) = E \times EF \qquad \text{Equation (3)}$$

where:

E = Electricity generation (MWh/yr)

EF = Emission Factor (tCO_2/MWh)

These calculations are repeated for all power generation technologies in this scenario. Table 13 shows the total electricity generation, emissions, and peak capacity of the reference scenario in 2029. By capacity, it will be 27 percent coal, 3 percent oil, 29 percent gas, 22 percent nuclear, 6 percent integrated energy, and 13 percent new and renewable energy. Both electricity demand and peak capacity of 2029 are reached while maintaining the 2015 generation capacity mix. The emission from the reference scenario is 337 $MtCO_2$.

Type	Generating Capacity (A)			Capacity Factor[1] (B)	Electricity Generation (C=A×B/100×8,760)	Emission Factor[2] (D)	Emissions (E=C×D/ 1,000,000)	Peak Coincidence Factor[3] (F)	Peak Capacity (G=A×F)
	MW			%	MWh	tCO_2/MWh	$MtCO_2$	%	MW
	Existing	new	Total						
Coal	25,874	12,000	37,874	86.0	285,327,566	0.823	234.82	100	37,874
Oil	625	4,500	5,125	25.7	11,538,015	0.702	8.10	91	4,654
Gas	26,370	15,000	41,370	48.4	175,402,181	0.363	63.58	100	41,370
Nuclear	21,129	10,000	31,129	83.1	226,605,423	0	0	100	31,129
Integrated energy	5,360	2,500	7,860	49.6	34,151,386	0.499	17.06	87.8	6,901
Hydro	6,471	3,000	9,471	14.5	12,030,064	0	0	28.0	2,652
Solar PV	2,538	1,000	3,538	12.1	3,750,138	0	0	13.0	460
Wind	834	500	1,334	21.6	2,524,141	0	0	2.2	29
Fuel Cell	171	100	271	64.1	1,521,708	0.340	0.52	70.1	190
Bio	255	200	455	33.9	1,351,186	0	0	23.3	106
Waste	1,596	695	2,291	37.2	7,465,728	1.408	10.51	68.6	1,572
IGCC	380	100	480	85.0	3,574,080	0.697	2.49	60.0	288
Ocean	255	200	455	22.0	876,876	0	0	1.1	5
Geothermal	0	0	0	74.5	0	0	0	90.0	0
Coal w/CCS	0	0	0	86.0	0	0.120	0	100.0	0
IGCC w/CCS	0	0	0	85.0	0	0.120	0	60.0	0
Gas w/CCS	0	0	0	48.4	0	0.057	0	100.0	0
Total	91,858	49,795	141,653	-	766,118,493	-	337.08	-	127,229

Table 13: Generation fuel mix for 2029: Reference scenario (Developed by the author)

Sources:

1) Average values are used for gas, nuclear, integrated energy, hydro, solar PV, wind, fuel cell, bio, waste, and ocean, 2013-2015. The historical data of fossil fuel refer to 'Korea Energy Statistics Information System' (http://www.kesis.net/) and the data of new and renewable energy refer to '2015 New and Renewable Energy Statistics' (KEA, 2016b); Capacity factor of Coal and Oil are adjusted to decrease from the 2013-2015 average to meet electricity demand and peak capacity in 2029; For IGCC, no historical data was available; data are from the presentation, 'Taean IGCC technology development and demonstration plant construction status' (Korea Western Power Corporation, 2013); For Geothermal, no historical data were available; these data are from (Bruckner et al., 2011)

2) Emission factors for coal, oil, and gas are from 'The 2nd National Energy Master Plan' (MOTIE, 2014a); For integrated energy, data from 'A study on the allocation of emission allowances for power sector' (Korea Environment Institute, 2014) are used; CCS emission factors refer to (Schlömer et al., 2014); Fuel cell emission factor refers to 'Natural gas-fueled distributed generation solid oxide fuel cell system' (J. Thijssen, LLC, 2009); IGCC data refer to 'Criteria Air Pollutant and Greenhouse Gas Emission Factors Compiled by Eastern Research Group for Incorporation in GREET' (Argonne National Laboratory, 2014); Waste data refer to 'CO2 emissions from fuel combustion: highlight,' and coke oven gas and blast furnace gas average data were used (IEA, 2016a).

3) Peak coincidence factors are from the 7th Basic Plan on Electricity Demand and Supply (MOTIE, 2015). The CCS peak coincidence factors are assumed to be same as the fossil fuel sources.

* Note that emission factors reflect values from the references which may not be accurate. For example, the GHG emission from a wind is defined as zero. In reality, there are significant GHG's generated by constructing, installing, and operating a wind turbine. If there needs to be a back-up capacity in the event of a failure of adequate wind, the GHG effluents associated with any fossil fuel back-up ought to be considered in GHG emission from wind power.

The alternative scenario with maximum growth of low-emission technologies assumes that each low-carbon technology is built out to its maximum potential by 2029 (McKinsey & Company, 2009), limited by an annual growth rate. This thesis uses the technical capacity potential in KEA's New and Renewable Energy White Paper (Table 11 and Table 12) and caps the maximum annual growth rate of each technology at 20%. For low-carbon technologies that do not have potential estimates, such as nuclear and CCS, generation potential was determined using the construction plan in the 7th Basic Plan on Electricity Demand and Supply. New and renewable energy technologies will be constructed first, followed by nuclear and CCS. According to the principle of lowest cost first, the next higher cost measure will be applied after all previous measures are built out. To calculate the electricity generation and the peak capacity, Equation (1) and Equation (2) are used as in the reference scenario. The generation mix by capacity in 2029 shows a massive shift from the reference case. By capacity, it will be 13 percent coal, 13 percent gas, 18 percent nuclear, 4 percent integrated energy, 47 percent new and renewable energy, and 5 percent CCS (Coal, IGCC, and Gas) (Table 14). This scenario generates the same amount of electricity as the reference scenario and meets both the electricity demand and the peak capacity in 2029. In 2029, the emission will be 258 $MtCO_2$ (Table 14).

Type	Generating Capacity (A)			Capacity Factor[1)] (B)	Electricity Generation (C=A×B/100×8,760)	Emission Factor[2)] (D)	Emissions (E=C×D/ 1,000,000)	Peak Coincidence Factor[3)] (D)	Peak Capacity (E=A×D)
	MW			%	MWh	tCO_2/MWh	$MtCO_2$	%	MW
	Existing	new	Total						
Coal	25,874	0	25,874	64.0	145,059,994	0.823	119.38	100	25,874
Oil	625	0	625	25.6	1,403,545	0.702	0.99	91	568
Gas	26,370	0	26,370	48.4	111,804,581	0.363	40.53	100	26,370
Nuclear	21,129	14,200	35,329	83.1	257,179,575	0	0	100	35,329
Integrated energy	5,360	0	5,360	49.6	23,288,986	0.499	11.63	87.8	4,706
Hydro	6,471	15,000	21,471	14.5	27,272,464	0	0	28.0	6,012
Solar PV	2,538	32,586	35,124	12.1	37,229,877	0	0	13.0	4,566
Wind	834	10,708	11,542	21.6	21,839,311	0	0	2.2	254
Fuel Cell	171	1,110	1,281	64.1	7,193,020	0.340	2.45	70.1	898
Bio	255	3,274	3,529	33.9	10,479,860	0	0	23.3	822
Waste	1,596	14,000	15,596	37.2	50,822,997	1.408	71.56	68.6	10,699
IGCC	380	600	980	85.0	7,297,080	0.697	5.09	60.0	588
Ocean	255	3,274	3,529	22.0	6,801,089	0	0	1.1	39
Geothermal	0	15	15	74.5	97,893	0	0	90.0	14
Coal w/CCS	0	9,072	9,072	86.0	50,861,261	0.120	6.10	100.0	9,072
IGCC w/CCS	0	300	300	85.0	2,233,800	0.120	0.27	60.0	180
Gas w/CCS	0	1,239	1,239	48.4	5,253,162	0.057	0.30	100.0	1,239
Total	91,858	105,378	197,236	-	766,118,493	-	258.29	-	127228.9

Table 14: Generation fuel mix for 2029: Alternative scenario (Developed by the author)

Sources: Capacity Factor[1)], Emission Factor[2)], Peak Coincidence Factor[3)] are same as in the reference case.

The two scenarios were constructed to produce the same amount of electricity that meets the electricity demand in 2029. Figure 6 shows a substantial difference in fuel mix between the two scenarios. In the reference scenario, 60% of electricity is generated from fossil fuels such as coal, oil, and gas, but in the alternative scenario, 63% of electricity is produced by low-carbon technologies such as nuclear, new and renewable energy, and CCS.

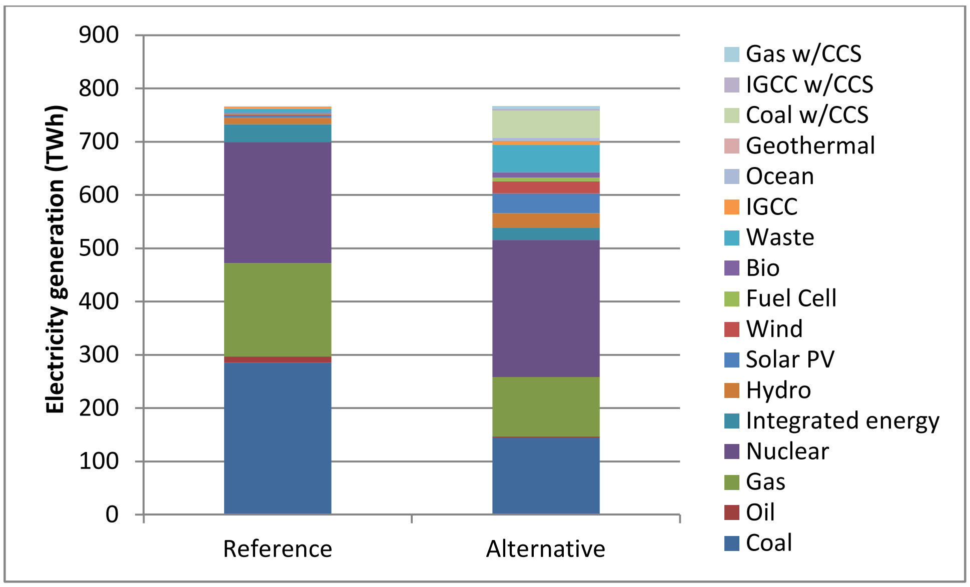


Figure 6: Electricity generation in the reference and alternative scenarios (Developed by the author)

Figure 7 compares the generation capacity of the two scenarios. The alternative scenario uses more renewable energy compared to reference case. Most renewable energy has a lower capacity factor than fossil fuels do, so it requires more generation capacity to generate same amount of electricity as fossil fuels, which is why the alternative scenario has a larger total generation capacity than the reference scenario.

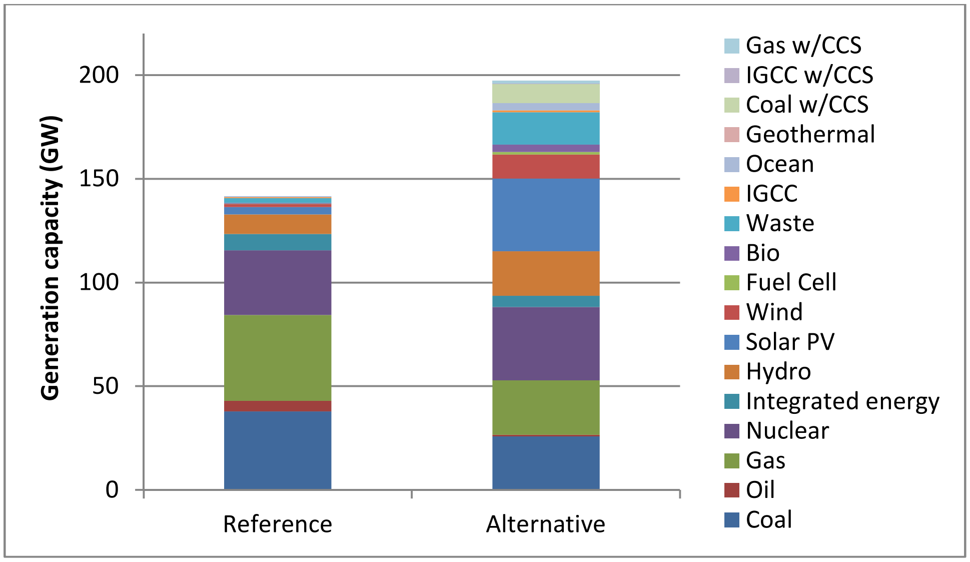


Figure 7: Generation capacity in the reference and alternative scenarios (Developed by the author)

The alternative scenario has more decarbonized fuel mix, so the emission in the alternative case is lower than that in the reference scenario. Figure 8 illustrates the carbon emissions of both the reference and alternative scenarios.

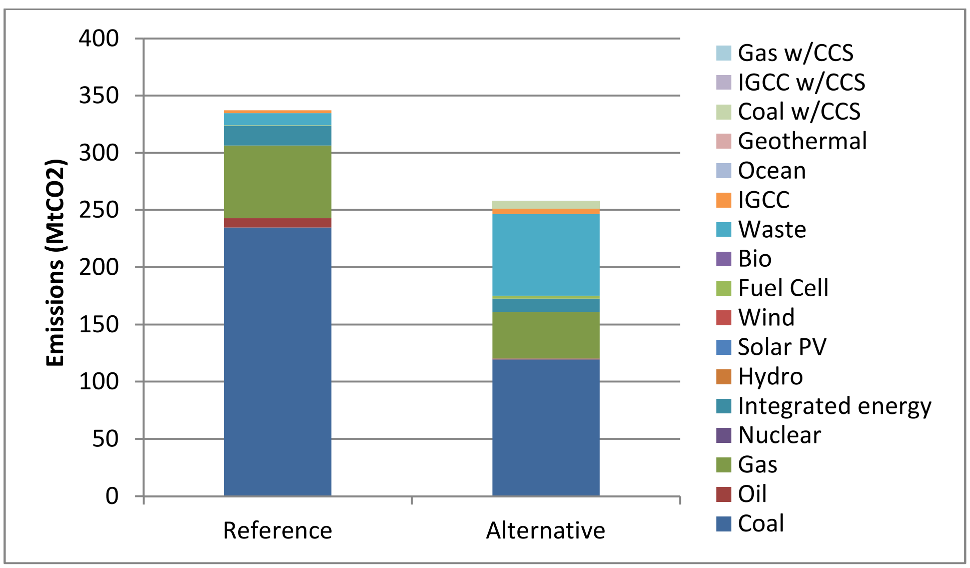


Figure 8: Carbon emissions in the reference and alternative scenarios (Developed by the author)

CONSTRUCTION OF A MARGINAL ABATEMENT COST CURVE

To generate a MAC curve, it is necessary to make some financial assumptions about the technologies. Table 15 lists financial assumptions used for each power generation technology. Note that all costs are expressed in US dollars.

Type	Capital Cost[1)]	Interest Rate	Lifetime[2)]	Fixed O&M cost[3)]	Fuel Price[4)]	Heat Rate[5)]	Fuel Cost[6)]
	$/MW	%	year	$/MW	$/GJ	GJ/MWh	$/MWh
Coal	1,218,000	7	40	65,000	3	9.3	27.9
Oil	720,930	7	40	45,000	-	-	115.5
Gas	845,000	7	20	25,000	12	6.8	81.6
Nuclear	2,021,000	7	40	170,000	-	-	4.81
Integrated energy	1,040,000	7	20	40,000	12	6.33	75.9
Hydro	3,400,000	7	40	70,000	0	N/A	0
Solar PV	1,794,000	7	20	22,000	0	N/A	0
Wind	2,444,000	7	20	46,000	0	N/A	0
Fuel Cell	5,000,000	7	4.57	150,000	12	10	120
Bio	2,300,000	7	20	80,000	10	13	130
Waste	1,690,000	7	20	25,000	0	N/A	0
IGCC	2,100,000	7	40	85,000	3	9.2	27.6
Ocean	6,650,000	7	40	200,000	0	N/A	0
Geothermal	5,200,000	7	20	190,000	0	N/A	0
Coal w/CCS	5,100,000	7	40	180,000	3	12.7	38.1
IGCC w/CCS	5,450,000	7	40	200,000	3	11.3	33.9
Gas w/CCS	2,650,000	7	20	80,000	12	7.9	94.8

Table 15: Financial assumptions about each power generation technology (Developed by the author)

Notes:

1) For coal, gas, nuclear, solar PV, and wind, Korea-specific data from 'Projected costs of generating electricity' (IEA, 2015) is used; For integrated energy, hydro, fuel cell, ocean, IGCC, and CCS, global median value from 'Power generation assumptions in the New Policies and 450 Scenarios in the World Energy Outlook 2016' (IEA, 2016b) are used; For oil, the data from 'The 3rd Basic Plan on Electricity Demand and Supply' (MOTIE, 2006) are used; Waste data refers to the 'POSCO Energy completed the largest by-product power plant of 290MW in Korea' (Energy and Environment News, 2014); Geothermal data refers to (Bruckner et al., 2011)

2) For coal, gas, nuclear, integrated energy, hydro, solar PV, wind, bio, and geothermal, data from 'Capital Cost Review of Power Generation Technologies' (Energy and Environmental Economics, 2014) are used; Ocean data refers to (Bruckner et al., 2011); Fuel cell data is retrieved from https://energy.gov/eere/fuelcells/fuel-cells (DOE, undated); Oil and IGCC are assumed to have same lifetime as Coal, and all CCS plants are assumed to have the same lifetime as those of fossil fuel plants (Coal, Gas, IGCC)

3) For coal, gas, nuclear, integrated energy, hydro, solar PV, wind, bio, fuel cell, ocean, IGCC, and CCS, global median value from 'Power generation assumptions in the New Policies and 450 Scenarios in the World Energy Outlook 2016' (IEA, 2016b) are used; Geothermal data refers to (Bruckner et al., 2011); Oil is assumed to have the same fixed O&M cost as coal, and waste is assumed to have the same fixed O&M cost as gas

4) Fuel prices refer to 'Projected Costs of Generating Electricity' (IEA, 2015) (Coal: $3/GJ, Gas: $12/GJ, and biomass feedstock: $10/GJ)

5) For coal, gas, bio, fuel cell, IGCC, and CCS, 'Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants' (EIA, 2013) were used; Integrated energy refers to 'Cogeneration/CHP Principles' (Gryphon International Engineering Services Inc., undated)

6) An analysis of optimum power generation structure under the new climate regime (Jeong and Hwang, 2016). Exchange rate: 1 USD= 1,150 Won in 2016

Capital cost is the cost of capital required in building a power plant. Fossil fuel power plants have relatively lower capital costs compared to the low-carbon power plants. The interest rate is set at 7% in this thesis. Fixed operation and management (O&M) cost are expenses that do not vary significantly with generation at a power plant. O&M costs include staffing and monthly fees, plant-related administrative expenses, and plant support equipment and labor. Heat rate represents the efficiency of the power plant. The lower the heat rate, the more efficient the power plant is. Multiplying a heat rate by a fuel price yields a fuel cost. Where there was no heat rate or fuel cost available, such as oil and nuclear, a fuel cost is used.

Marginal abatement costs are defined as the additional costs of using low-emission technologies compared with the reference case to produce the same amount of product, which is electricity in this thesis. As indicated in Equation (4), it equals the additional cost of using an alternative technology divided by the emission reduction of using an alternative technology (McKinsey & Company, 2009).

$$Abatement\ cost = \frac{[\text{Full cost of } CO_2 \text{ efficient alternative}] - [\text{Full cost of reference solution}]}{[CO_2 \text{ emissions from reference solution}] - [CO_2 \text{ emissions from alternative}]}$$

Equation (4)

Equation (5) estimates the full cost by adding capital cost, O&M cost, and fuel cost.

$$FC\ (\$) = CC + O\&M + Fuel \qquad \text{Equation (5)}$$

where:

FC = Full Cost

CC = Capital Cost

O&M = Operation and Maintenance cost

Fuel = Fuel cost

This thesis assumes that the capital cost is 100% borrowed and is repaid throughout the plant's lifetime. The capital cost is accounted for as the annual repayments of a loan for capital over the lifetime of the asset. Equation (6) estimates the capital cost as a function of overnight cost, capacity, and capital recovery factor.

$$CC\ (\$) = OC \times C \times CRF \qquad \text{Equation (6)}$$

where:

OC = Overnight Cost ($/kW)

C = Capacity installed (kW)

CRF = Capital Recovery Factor (fraction/yr)

The Capital Recovery Factor (CRF) is used to annualize the total overnight capital cost. Equation (7) computes the capital recovery factor as a function of interest rate and lifetime of the asset.

$$\text{CRF} = \frac{i(1+i)^n}{(1+i)^n - 1} \qquad \text{Equation (7)}$$

where:

i = The interest rate (7% in this thesis).

n = The number of years to serve the debt (herein, the lifetime of the asset).

Operating expenditures including O&M and fuel costs are assessed as the amount to be expensed in each year (McKinsey & Company, 2009). As for the O&M cost, this thesis considers only the fixed O&M cost. Equation (8) estimates O&M cost by multiplying fixed O&M cost by capacity.

$$O\&M\ (\$) = O\&M_{fixed} \times C \qquad \text{Equation (8)}$$

where:

$O\&M_{fixed}$ = the fixed O&M cost ($/kW-yr)

C = Capacity installed (kW)

Equation (9) defines the fuel cost as a function of fuel price, heat rate, and electricity generation.

$$Fuel = FP \times HR \times E \qquad \text{Equation (9)}$$

where:

FP = Fuel Price ($/GJ)

HR = Heat rate (GJ/MWh)

E = Electricity generation (MWh/yr)

Equation (10) estimates the emissions by multiplying electricity generation by emission factor.

$$Emissions = E \times EF \qquad \text{Equation (10)}$$

where:

E = Electricity generation (MWh/yr)

EF = Emission factor (tCO_2/MWh)

By using the above equations, the full costs and emissions of reference case and alternative scenario are calculated, as presented in Table 16 and Table 17, respectively.

Type	Capacity		Emissions		Costs									
	Generating Capacity (A)	Electricity Generation (B)	Emission Factor (C)	Emissions (D=B×C)	Overnight Capital Cost (E)	Interest Rate (F)	Lifetime of power plant (G)	Capital Recovery Factor (H= (F(1+F)^G) /((1+F)^G-1)	Total Fixed Capital Cost (I=A×E×H /1,000,000)	Fixed O&M Cost (J)	Fuel Price (K)	Heat Rate (L)	Fuel Cost (M=K×L)	Total annual cost (N=I+J×A +M×B)
	MW	MWh	tCO_2/MWh	$MtCO_2$	$/MW	%	year	-	Million $	$/MW	$/GJ	GJ/MWh	$/MWh	Million $
Coal	37,874	285,327,566	0.823	234.82	1,218,000	7	40	0.075	3,460	65,000	3	9.3	27.9	13,883
Oil	5,125	11,538,015	0.702	8.10	720,930	7	40	0.075	277	45,000	-	-	115.5	1,840
Gas	41,370	175,402,181	0.363	63.58	845,000	7	20	0.094	3,300	25,000	12	6.8	81.6	18,647
Nuclear	31,129	226,605,423	0	0.00	2,021,000	7	40	0.075	4,719	170,000	-	-	4.81	11,101
Integrated energy	7,860	34,151,386	0.499	17.06	1,040,000	7	20	0.094	772	40,000	12	6.33	75.96	3,680
Hydro	9,471	12,030,064	0	0.00	3,400,000	7	40	0.075	2,415	70,000	0	N/A	N/A	3,078
Solar PV	3,538	3,750,138	0	0.00	1,794,000	7	20	0.094	599	22,000	0	N/A	N/A	677
Wind	1,334	2,524,141	0	0.00	2,444,000	7	20	0.094	308	46,000	0	N/A	N/A	369
Fuel Cell	271	1,521,708	0.34	0.52	5,000,000	7	4.57	0.26	357	150,000	12	10	120	580
Bio	455	1,351,186	0	0.00	2,300,000	7	20	0.094	99	80,000	10	13	130	311
Waste	2,291	7,465,728	1.408	10.51	1,690,000	7	20	0.094	365	25,000	0	N/A	N/A	423
IGCC	480	3,574,080	0.697	2.49	2,100,000	7	40	0.075	76	85,000	3	9.2	27.6	215
Ocean	455	876,876	0	0.00	6,650,000	7	40	0.075	227	200,000	0	N/A	N/A	318
Geothermal	0	0	0	0.00	5,200,000	7	20	0.094	0	190,000	0	N/A	N/A	-
Coal w/CCS	0	0	0.12	0.00	5,100,000	7	40	0.075	0	180,000	3	12.7	38.1	-
IGCC w/CCS	0	0	0.12	0.00	5,450,000	7	40	0.075	0	200,000	3	11.3	33.9	-
Gas w/CCS	0	0	0.057	0.00	2,650,000	7	20	0.094	0	80,000	12	7.9	94.8	-
Total	141,653	766,118,493	-	337.08	-	-	-	-	16,973	-	-	-	-	55,121.8

Table 16: Power sector's generation cost and emissions in 2029: Reference scenario (Developed by the author)

Type	Capacity		Emissions		Costs									
	Generating Capacity (A)	Electricity Generation (B)	Emission Factor (C)	Emissions (D=B×C)	Overnight Capital Cost (E)	Interest Rate (F)	Lifetime of power plant (G)	Capital Recovery Factor (H= (F(1+F)^G) /((1+F)^G-1))	Total Fixed Capital Cost (I=A×E×H /1,000,000)	Fixed O&M Cost (J)	Fuel Price (K)	Heat Rate (L)	Fuel Cost (M=K×L)	Total annual cost (N=I+J×A +M×B)
	MW	MWh	tCO_2/MWh	$MtCO_2$	$/MW	%	year	-	Million $	$/MW	$/GJ	GJ/MWh	$/MWh	Million $
Coal	25,874	145,059,994	0.823	119.38	1,218,000	7	40	0.075	2,364	65,000	3	9.3	27.9	8,092.86
Oil	625	1,403,545	0.702	0.99	720,930	7	40	0.075	34	45,000	-	-	115.5	224.03
Gas	26,370	111,804,581	0.363	40.53	845,000	7	20	0.094	2,103	25,000	12	6.8	81.6	11,885.83
Nuclear	35,329	257,179,575	0	0	2,021,000	7	40	0.075	5,356	170,000	-	-	4.81	12,598.61
Integrated energy	5,360	23,288,986	0.499	11.63	1,040,000	7	20	0.094	526	40,000	12	6.33	75.96	2,509.62
Hydro	21,471	27,272,464	0	0	3,400,000	7	40	0.075	5,476	70,000	0	N/A	N/A	6,978.74
Solar PV	35,124	37,229,877	0	0	1,794,000	7	20	0.094	5,948	22,000	0	N/A	N/A	6,720.63
Wind	11,542	21,839,311	0	0	2,444,000	7	20	0.094	2,663	46,000	0	N/A	N/A	3,193.63
Fuel Cell	1,281	7,193,020	0.340	2.45	5,000,000	7	4.57	0.263	1,686	150,000	12	10	120	2,741.05
Bio	3,529	10,479,860	0.000	0.00	2,300,000	7	20	0.094	766	80,000	10	13	130	2,410.86
Waste	15,596	50,822,997	1.408	71.56	1,690,000	7	20	0.094	2,488	25,000	0	N/A	N/A	2,877.84
IGCC	980	7,297,080	0.697	5.09	2,100,000	7	40	0.075	154	85,000	3	9.2	27.6	439.07
Ocean	3,529	6,801,089	0	0	6,650,000	7	40	0.075	1,760	200,000	0	N/A	N/A	2,466.10
Geothermal	15	97,893	0	0	5,200,000	7	20	0.094	7	190,000	0	N/A	N/A	10.21
Coal w/CCS	9,072	50,861,261	0.120	6.10	5,100,000	7	40	0.075	3,470	180,000	3	12.7	38.1	7,041.24
IGCC w/CCS	300	2,233,800	0.120	0.27	5,450,000	7	40	0.075	123	200,000	3	11.3	33.9	258.37
Gas w/CCS	1,239	5,253,162	0.057	0.30	2,650,000	7	20	0.094	310	80,000	12	7.9	94.8	907.04
Total	197,236	766,118,493	-	258.29	-	-	-	-	35,234	-	-	-	-	71,355.7

Table 17: Power sector's generation cost and emissions in 2029: Alternative scenario (Developed by the author)

All costs and emissions are based on current values. In the reference case, a total of 766,118 GWh of electricity will be generated from 141,653 MW with the emission of 337 $MtCO_2$. The total annual generation cost in 2029 is estimated to be $55,100 million so electricity will cost 72 $/MWh. Meanwhile, the alternative scenario suggests that 197,236 MW of generating capacity will be required to generate 766,118 GWh and the emission will be 258 $MtCO_2$. The total annual generation cost and the electricity cost in 2029 will be $71,400 million and 93 $/MWh, respectively. Due to the relatively higher costs of renewable energy technologies, the electricity cost is higher in the alternative scenario where more low-carbon options are constructed. The emissions difference between the reference case and the alternative scenario is 79 $MtCO_2$. This emissions reduction exceeds the power sector's emissions reduction target of 64.5 $MtCO_2$ presented in the 2030 National Greenhouse Gas Reduction Roadmap (OPC, 2016).

A marginal abatement cost curve is not a tool to compare the total generation cost but to compare the incremental cost of increasing electricity from one source versus other sources of power generation. So generation capacity that is the same in both scenarios will be ignored and only additional capacity will be assessed in calculating a marginal abatement cost. Table 18 shows the difference between the reference scenario and the alternative scenario. In the reference case, additional 4 fossil fuel-based measures (coal, oil, gas, and integrated energy) are used, whereas in the alternative scenario, additional 13 low-emission technologies (nuclear, hydro, solar PV, wind, fuel cell, bio, waste, IGCC, ocean, geothermal, coal w/CCS, IGCC w/CCS, and gas w/CCS) are utilized. This fuel switch will be assessed further to develop a marginal abatement cost curve.

Type	Reference				Alternative				Difference (Alternative - Reference)			
	Capacity	Generation	Cost	Emissions	Capacity	Generation	Cost	Emissions	Capacity	Generation	Cost	Emissions
	MW	MWh	Million $	$MtCO_2$	MW	MWh	Million $	$MtCO_2$	MW	MWh	Million $	$MtCO_2$
Coal	*37,874*	*285,327,566*	*13,883*	*235*	*25,874*	*145,059,994*	*8,093*	*119.38*	*-12,000*	*-140,267,573*	*-5,790*	*-115.4*
Oil	*5,125*	*11,538,015*	*1,840*	*8*	*625*	*1,403,545*	*224*	*0.99*	*-4,500*	*-10,134,470*	*-1,616*	*-7.1*
Gas	*41,370*	*175,402,181*	*18,647*	*64*	*26,370*	*111,804,581*	*11,886*	*40.53*	*-15,000*	*-63,597,600*	*-6,761*	*-23.1*
Nuclear	31,129	226,605,423	11,101	0	35,329	257,179,575	12,599	0.00	4,200	30,574,152	1,498	0.0
Integrated energy	*7,860*	*34,151,386*	*3,680*	*17*	*5,360*	*23,288,986*	*2,510*	*11.63*	*-2,500*	*-10,862,400*	*-1,171*	*-5.4*
Hydro	9,471	12,030,064	3,078	0	21,471	27,272,464	6,979	0.00	12,000	15,242,400	3,900	0.0
Solar PV	3,538	3,750,138	677	0	35,124	37,229,877	6,721	0.00	31,586	33,479,738	6,044	0.0
Wind	1,334	2,524,141	369	0	11,542	21,839,311	3,194	0.00	10,208	19,315,169	2,825	0.0
Fuel Cell	271	1,521,708	581	1	1,281	7,193,020	2,744	2.45	1,010	5,671,312	2,164	1.9
Bio	455	1,351,186	311	0	3,529	10,479,860	2,411	0.00	3,074	9,128,673	2,100	0.0
Waste	2,291	7,465,728	423	11	15,596	50,822,997	2,878	71.56	13,305	43,357,270	2,455	61.0
IGCC	480	3,574,080	215	2	980	7,297,080	439	5.09	500	3,723,000	224	2.6
Ocean	455	876,876	318	0	3,529	6,801,089	2,466	0.00	3,074	5,924,213	2,148	0.0
Geothermal	0	0	0	0	15	97,893	10	0.00	15	97,893	10	0.0
Coal w/CCS	0	0	0	0	9,072	50,861,261	7,041	6.10	9,072	50,861,261	7,041	6.1
IGCC w/CCS	0	0	0	0	300	2,233,800	258	0.27	300	2,233,800	258	0.3
Gas w/CCS	0	0	0	0	1,239	5,253,162	907	0	1,239	5,253,162	907	0.3
Total	141,653	766,118,493	55,122	337	197,236	766,118,493	71,359	258	55,583	0	16,236	79

Table 18: Comparison of reference and alternative scenarios (Developed by the author)

The first step is to compute a generation cost and emissions per production unit (MWh) for the four additional reference measures, averaged to represent the reference option. The reason for averaging the cost and emission of reference measures is that the reference scenario is considered as one single solution in this calculation. Otherwise it is necessary to determine the order of replacing reference options, and the decision of which option should be switched first can change the carbon abatement cost accordingly. For example, the abatement cost under the assumption that the lowest cost reference option should be replaced first will be different from that under the principle that the highest-cost will be replaced first. A total of 224,862,043 MWh is generated with a cost of $15,337,697,637 and an emission of 151,031,396 tCO_2 (Table 19). The average electricity cost of the reference option is 68.2 $/MWh and the average emission factor is 0.672 tCO_2/MWh.

Type	Generating Capacity (MW)	Electricity Generation (MWh)	Emissions (tCO_2)	Total Cost ($)
Coal	12,000	140,267,573	115,440,212	5,789,798,855
Oil	4,500	10,134,470	7,112,371	1,616,374,777
Gas	15,000	63,597,600	23,054,130	6,760,994,494
Integrated energy	2,500	10,862,400	5,424,683	1,170,529,511
Total	34,000	224,862,043	151,031,396	15,337,697,637

Table 19: Additional power generation technologies in the reference scenario (Developed by the author)

Next, this electricity cost and emission factor is applied to the electricity generation from the 13 alternative energy sources. This substitution allows an estimation of how much the cost and emission will be if that electricity is generated from the reference option (Table 20).

Finally, the total costs and emissions of both scenarios are compared and abatement cost is calculated using the equation below:

$$Abatement\ cost = \frac{[\text{Full cost of } CO_2 \text{ efficient alternative}] - [\text{Full cost of reference solution}]}{[CO_2 \text{ emissions from reference solution}] - [CO_2 \text{ emissions from alternative}]}$$

Equation (4)

For example, consider the abatement cost of wind. In the alternative scenario, wind generates 19 TWh of electricity with a cost of $2,824,515,938 and zero emissions. (Note: As discussed in Table 13, the GHG effluents of wind power are defined as zero) To produce the same amount of electricity with a reference measure, it costs $1,317,475,475 and the emission is 12,973,274 tCO_2 (Table 20). So the abatement cost of wind is:

$$Abatement\ cost = \frac{[\$\ 2{,}824{,}515{,}938] - [\$\ 1{,}317{,}475{,}475]}{[12{,}973{,}274\ tCO_2] - [0\ tCO_2]} = \frac{\$\ 1{,}507{,}040{,}463}{12{,}973{,}274\ tCO_2} = 116.2\ \$/tCO_2$$

Table 20 presents all abatement measures, sorted by abatement cost. The overall abatement potential is 78.8 MtCO_2 and to achieve this, an additional $16,236 million will be required during the year 2029. The carbon abatement cost curve can be constructed by using the emissions reduction and abatement cost from Table 20. The abatement measures are ranked on a lowest-cost-first basis. Waste and IGCC have a negative abatement potential of -31.9 MtCO_2 and -0.09 MtCO_2, respectively. This means that these technologies increase GHG emissions when applied to replace reference measures. As explained in the summary section, waste and IGCC marginally increase the GHG load because they have higher emission factors. Therefore, waste and IGCC cannot be considered as abatement technologies and are not included in the carbon abatement cost curve.

Alternative Measures (A)			Electricity Generation	Reference Measure(B)			**Emissions Reduction (C=B-A)**	Cost (D=A-B)	**Abatement Cost (E=D/C)**
Type	Emissions	Cost		Type	Emissions (at 0.672 tCO_2/MWh)	Cost (at 68.2 $/MWh)			
	tCO_2	$	MWh		tCO_2	$	**tCO_2**	$	**$/$tCO_2$**
Nuclear	0	1,497,754,244	30,574,152	Reference measure	20,535,511	2,085,443,562	**20,535,511**	-587,689,318	**-28.6**
Geothermal	0	10,212,648	97,893		65,751	6,677,220	**65,751**	3,535,429	**53.8**
IGCC w/CCS	268,056	258,365,762	2,233,800		1,500,360	152,366,085	**1,232,304**	105,999,678	**86.0**
Wind	0	2,824,515,938	19,315,169		12,973,274	1,317,475,475	**12,973,274**	1,507,040,463	**116.2**
Coal w/CCS	6,103,351	7,041,236,867	50,861,261		34,161,600	3,469,214,416	**28,058,249**	3,572,022,450	**127.3**
Solar PV	0	6,043,665,364	33,479,738		22,487,084	2,283,631,760	**22,487,084**	3,760,033,604	**167.2**
Gas w/CCS	299,430	907,044,748	5,253,162		3,528,352	358,314,840	**3,228,921**	548,729,908	**169.9**
Bio	0	2,100,024,400	9,128,673		6,131,387	622,661,034	**6,131,387**	1,477,363,367	**241.0**
Hydro	0	3,900,372,866	15,242,400		10,237,748	1,039,674,459	**10,237,748**	2,860,698,407	**279.4**
Ocean	0	2,148,144,318	5,924,213		3,979,071	404,086,806	**3,979,071**	1,744,057,511	**438.3**
Fuel Cell	1,928,246	2,163,661,645	5,671,312		3,809,207	386,836,576	**1,880,961**	1,776,825,070	**944.6**
Waste	61,047,036	2,455,092,412	43,357,270		29,121,451	2,957,371,925	-31,925,585	-502,279,512	15.7
IGCC	2,594,559	224,014,396	3,723,000		2,500,599	253,943,474	-93,959	-29,929,078	318.5
Total	72,240,678	31,574,105,608	224,862,042		151,031,396	15,337,697,630	78,790,718	16,236,407,977	**-**

Table 20: Carbon abatement costs and abatement potentials in Korea's power sector (Developed by the author)

Figure 9 illustrates the carbon abatement costs and the potential of Korea's power sector. The abatement potential of nuclear is 20 $MtCO_2$ and the abatement cost is -29 $\$/tCO_2$. It means that when nuclear is used to replace the reference generation technology, it reduces the emission by 20 $MtCO_2$ and the cost of the energy sector by \$29 per tonne of CO_2 reduced, shown as -29 $\$/tCO_2$. The abatement potential of fuel cell is 2 $MtCO_2$ and the abatement cost is 945 $\$/tCO_2$. So utilizing fuel cell to replace the reference technology reduces the emission by 2 $MtCO_2$ at a cost of 945 $\$/tCO_2$. Figure 9 is discussed in detail in summary section below.

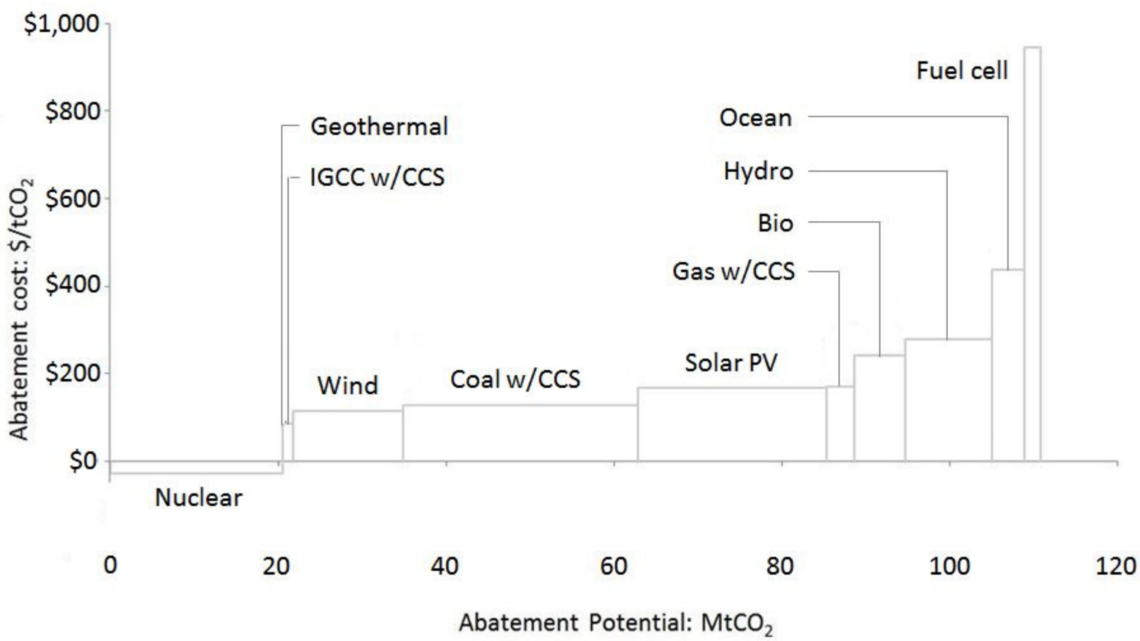


Figure 9: Carbon abatement cost curve of Korea's power sector for 2029 (Developed by the author)

SUMMARY AND DISCUSSION

Korea's electricity demand is expected to increase by 45% from 527,515 GWh in 2015 to 766,109 GWh in 2029. Currently, the power sector's fuel mix is carbon-intensive with fossil fuels, such as coal, oil, and gas, accounting for 60% of the total generation capacity. If the current fuel mix is maintained, the power sector's emission will be 337 $MtCO_2$ in 2029, and the total annual cost will be $55,122 million. But if low-carbon technologies such as new and renewable energy, nuclear, and CCS are built out to their maximum potential by 2029, the power sector's emission will decrease to 258 $MtCO_2$ in 2029, and the total annual cost will increase to $71,356 million.

To estimate the carbon abatement costs and the emissions reduction potential in the power sector, 13 alternative generation technologies were analyzed in this thesis: nuclear, hydro, solar PV, wind, fuel cell, bio, waste, IGCC, ocean, geothermal, coal w/CCS, IGCC w/CCS, and gas w/CCS. Eleven out of 13 low-carbon technologies are applicable to Korea's power sector (Figure 9). Nuclear has a negative abatement cost, meaning that it can reduce emissions and save cost at the same time. Therefore, the cost-effective abatement potential of the power sector in 2029 is equal to nuclear's abatement potential of 20.5 $MtCO_2$. This is about 10% of the power sector's total CO_2 emissions in 2015. Geothermal is the second lowest cost abatement measure in 2029. Currently, there are no geothermal power plants operating in Korea, so it is hard to predict the actual costs and the future volume of geothermal electricity generation. Assuming that geothermal becomes economically feasible by 2029, geothermal can be an attractive source of power generation in Korea. Solar PV has the largest CO_2 emissions reduction potential among new and renewable energy technologies due to the highest generation potential. Fuel cells show the highest abatement cost. This may be due to its short lifetime (4.47 years or 40,000 hours) compared to that of other abatement measures (20 to 40 years), with a subsequent high annual repayment of capital cost as well as the relatively higher fuel (natural gas) cost.

Two alternative technologies (waste and IGCC) have a negative abatement cost. That is to say, utilizing these technologies will generate more GHG than the reference case. Waste uses by-product gas for electricity generation, such as coke oven gas (COG) or blast furnace gas (BFG) from iron and steel plants. The emission factor of the coke oven gas is 0.39 tCO_2/MWh which is not very high. Blast furnace gas has an emission factor of 2.245 tCO_2/MWh; this is the highest among abatement options in the power sector (IEA, 2016a). By-product gas plants utilize both COG and BFG. As COG and BFG are both produced by iron and steel plants and mixed, it is difficult to estimate how much of each gas is used. Thus, this thesis assumes that the average of 0.39 and 2.245 tCO_2/MWh or an emission factor of 1.408 tCO_2/MWh is applied to emissions calculation for waste power generation. This value is still the highest in the power sector, making the emission reduction potential of waste negative. Then why are these by-product gases being used as fuel for electricity generation? Waste gases are produced as by-products during steel production or oil refining processes. These waste gases can be used to produce electricity at a zero marginal cost because the fuel price is already paid for, so these are attractive options for power generation in terms of cost-effectiveness. In addition to the economic benefit, utilizing waste gases for electricity generation has fewer emissions than directly discharging them into the atmosphere. When by-product gases are used for electricity generation instead of being discharged into the atmosphere, the used amount is not counted as the GHG emission of iron or steel plants. Korea counts emissions after being used for electricity production as GHG emissions to prevent double counting. Therefore, if by-products gases are used for electricity generation, GHG emissions from the power generation sector will increase, but total national emissions will decrease. Using them as fuel reduces the total national GHG emissions and saves natural energy sources.

IGCC serves as a cleaner substitute for coal power plants. However, as the emission factor is only 15% lower than the coal, its emission reduction potential is limited. The fact that IGCC's capital cost is almost twice as high as pulverized coal poses a challenge to the wide implementation of IGCC. Meanwhile, when IGCC is equipped with CCS, the carbon abatement cost gets much lower to make IGCC w/CCS the third lowest cost abatement technology. For this reason, Korea's long-term IGCC support policy and technology development are focused on IGCC w/CCS rather than IGCC alone (MOTIE, 2013).

CCS technologies combined generate emissions reduction of 32.5 $MtCO_2$ in 2029, and their abatement costs are similar to those of the commercially operating renewable energy such as solar PV and wind. CCS uses fossil fuels such as coal and gas as a fuel, so its generation potential is the same as fossil fuel. However, its GHG emissions are only 15% of fossil fuel generation so the environmental benefit CCS provides will make it more attractive for power generation. CCS is expected to play an important role in the power sector as a measure that can supplement the variable supply of electricity from intermittent low-emission technologies such as wind and solar power.

Chapter 4: Limitations and Issues

LIMITS OF MARGINAL ABATEMENT COST CURVE

The marginal abatement cost (MAC) curve is a straightforward representation of the cost-effective abatement options and their abatement potential. As the MAC curve shows complex issues in a simple manner, it has been widely used as a starting point of climate change mitigation discussions. However, due to its simplicity, it has some limits that can lead to a biased interpretation.

In developing a MAC curve, it is necessary to make assumptions such as lifetime and capital cost of abatement options and forecasts of interest rates and electricity demand development. There may be significant uncertainties on each assumption, especially when projecting far into the future. The abatement costs may vary depending on these assumptions. For example, the abatement costs in a MAC curve are annualized costs, so they are sensitive to the interest rates. In McKinsey's (2009) "Pathways to a Low Carbon Economy", the interest rate is set at 4%. But if the interest rate increases from 4% to 10%, the overall abatement cost will rise from € 4/tCO_2 to € 14/tCO_2. If the interest rate is 15%, the abatement cost will be € 21/tCO_2 (McKinsey & Company, 2009). Furthermore, in most cases, only one MAC curve is presented, which does not take into account the significant uncertainties that influence the cost and abatement estimates. This can create a wrong impression that a MAC curve is a perfect forecast of the future, or it can create a false sense of certainty. Therefore, a MAC curve should be interpreted as a guide to which abatement option has the lowest marginal cost rather than as a perfect estimate of abatement costs (Kesicki and Strachan, 2011).

A MAC curve depicts only one year, without giving information on investments and technological developments made in previous years. However, abatement costs and potential depend on actions in the past, so a MAC curve without this information gives an incomplete picture. The trajectory in which previously implemented measures influence the available technologies and their costs in the later periods may be more useful because it shows the full scenario with associated costs. Thus, it presents accumulated emissions and costs of abatement options over time instead of within a single year. This shows the real scale of the abatement measures, so it may be a more complete indicator of abatement measures (Kesicki and Ekins, 2012).

A MAC curve is not a perfect tool for assessing the economics of low-emission technologies. Inevitable uncertainty exists in the assumptions and the inter-temporal issues can distort marginal abatement cost estimates. However, a MAC curve can be useful as an illustrative guide to the comparative advantages of abatement technologies. When analyzing a MAC curve, it is essential to be aware of the assumptions and limits of the concept. To investigate the changes of assumptions and their impacts on the marginal abatement cost calculations, a sensitivity analysis was conducted in the following section.

SENSITIVITY ANALYSIS

This section examines the sensitivity of a marginal abatement cost calculated for each generation technology to a variation in the underlying assumptions. Three factors that influence a total generation cost will be analyzed: interest rate, capital cost, and fuel cost. Capital costs of only new and renewable energy technologies and fuel costs of fossil fuels are adjusted for analysis. Some new and renewable energy power plants are already built, so they are not affected by the changes in capital costs. This thesis assumes that only additional new and renewable energy capacity is affected by changes in the capital costs of new and renewable energy.

Figure 10 illustrates, in a tornado diagram, the consequences of adjusting each parameter by ± 50% independently from each other in both reference and alternative scenarios, and their impacts on the average carbon abatement cost. When each parameter is given the same variance of ± 50%, capital cost has the greatest swing ranging from -63% to +63% of the base value. This means when capital cost decreases by 50%, average carbon abatement cost drops by 63%, and when capital cost increases by 50%, average carbon abatement cost rises by 63%. Carbon abatement costs are most sensitive to capital cost, mainly because capital cost accounts for most of the total annual cost. This will be analyzed further in following paragraphs. The least sensitive parameter is fuel cost. Fuel cost changes average the carbon abatement cost by only ± 24%. Fuel cost is inversely correlated with carbon abatement costs. So an increase in fuel cost decreases carbon abatement costs of low-carbon technologies, making low-carbon technologies more cost-effective. Variances in interest rate does not change carbon abatement cost symmetrically. When interest rate decreases by 50%, the average carbon abatement cost decreases by 33%, whereas the 50% rise in the interest rate increases average carbon abatement cost by 37%.

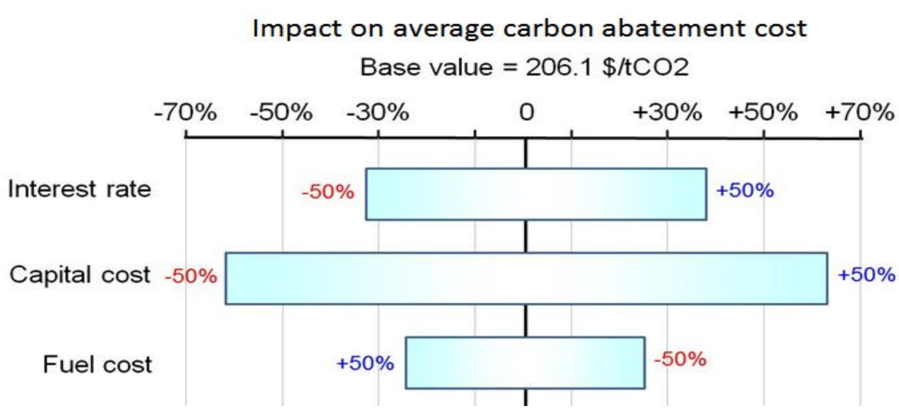


Figure 10: Impacts of changes in financial assumptions on average carbon abatement cost (Developed by the author)

Interest rate sensitivity is analyzed first. A carbon abatement cost is an annualized cost of a generation technology over its lifetime, so an interest rate has a huge impact on the abatement cost calculation. The interest rate is set at 7% initially, but this is changed to 4% and 10% to show the impact of such change on marginal abatement costs. Table 21 shows the abatement costs of each technology under different assumptions for interest rate. As there is no change in the emissions reduction potential, only abatement costs are presented here. Broadly speaking, the abatement costs are positively correlated with interest rate. When the interest rate is 7%, the average abatement cost is 206.1 $/tCO_2$. If the interest rate drops to 4%, the average abatement cost will decrease to 147.2 $/tCO_2$, and if the interest rate rises to 10%, the average abatement cost will increase to 271.2 $/tCO_2$ (Table 21).

Type	Interest Rate		
	7% (base value)	4%	10%
Nuclear	-28.6	-33.7	-22.9
Geothermal	53.8	34.1	75.6
IGCC w/CCS	86.0	59.6	115.4
Wind	116.2	81.1	155.0
Coal w/CCS	127.3	93.0	165.5
Solar PV	167.2	119.8	**219.8**
Gas w/CCS	169.9	154.2	**187.3**
Bio	241.0	**222.0**	262.0
Hydro	279.4	**186.8**	382.5
Ocean	438.3	317.5	572.7
Fuel Cell	943.3	901.3	985.8
Average	206.1	147.2	271.2

Table 21: Abatement costs under different interest rates (unit: $/tCO_2$) (Developed by the author)

Figure 11 compares the marginal abatement cost curves at 4% and 10% interest rates. As an interest rate changes, both marginal abatement costs and the order of the cost-effectiveness of low-carbon technologies also change. For example, when the interest rate is 4%, solar PV is the 6th lowest-cost abatement technology with an abatement cost of 120 \$/tCO_2. If the interest rate rises to 10%, solar PV is the 7th cost-effective alternative technology with an abatement cost of 220 \$/tCO_2. This is attributable to solar PV's higher ratio of capital cost to total cost, which makes solar PV more sensitive to the interest rate change (Figure 13). On the other hand, bio's ratio of capital cost to total cost is relatively low (Figure 13). When the interest rate is 4%, bio is the 9th lowest-cost alternative energy source with an abatement cost of 222 \$/tCO_2. If the interest rate increases 10%, bio will be the 8th lowest-cost technology with an abatement cost of 262 tCO_2 (Figure 11). The interest rate has different impact on the abatement cost of each technology. This will be discussed in the following paragraphs.

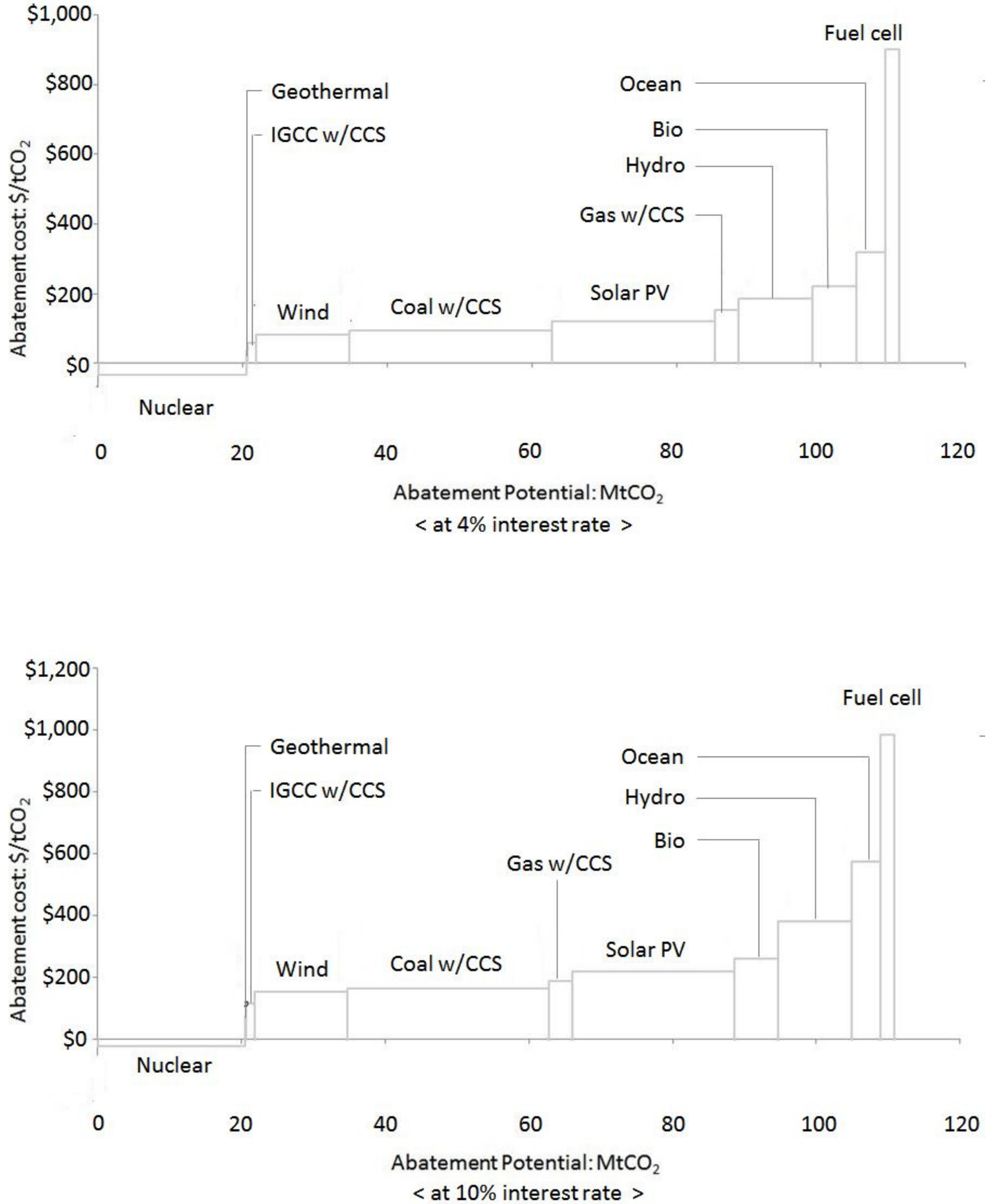


Figure 11: Carbon abatement cost curve at 4% and 10% interest rates (Developed by the author)

All marginal abatement costs change as interest rate changes, but a rate of change is different for each technology. Figure 12 shows each technology's sensitivity to changes in interest rate, when the interest rate changes from 1% to 15%. Geothermal is the most sensitive parameter to interest rate, showing a 592% increase when the interest rate rises from 1% to 15%. The changes reflect geothermal's relatively high ratio of capital cost to total cost which increases rapidly as an interest rises (Figure 13). In contrast, fuel cells are the least sensitive to interest rate, with its abatement cost increasing only 23% over the same range. Fuel cells have relatively high ratio of capital cost to total cost at 1% interest rate, but as the interest rate increases, the ratio does not change much (Figure 13). Gas w/CCS and bio also have limited sensitivity compared with other technologies. When the interest rate is 1%, bio's abatement cost is 205 $/tCO_2$. When the interest rate rises to 15%, the abatement cost increases by only 47% to 300 $/tCO_2$. These technologies have low capital costs relative to their O&M cost and fuel cost (Figure 13).

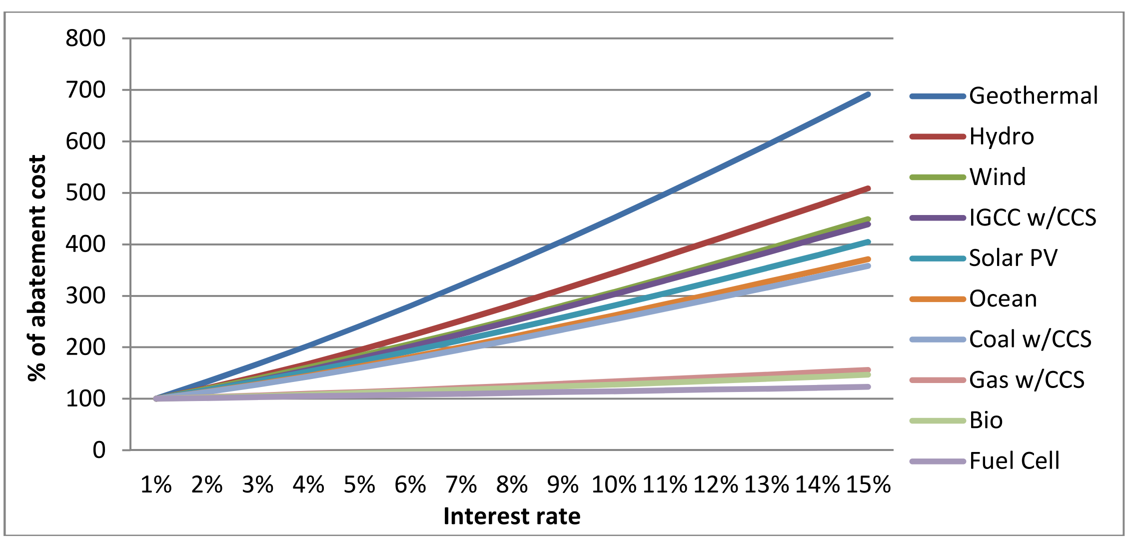


Figure 12: Carbon abatement cost as a function of the interest rate (Developed by the author)

Note: Percentage change on a negative number can produce misleading results. So nuclear is not included in this graph as its abatement costs are negative numbers when the interest changes from 1% to 15%: -38 $/tCO_2$ at 1% interest rate and -13 $/tCO_2$ at 15% interest rate

Figure 13 shows the capital intensity, the ratio of a technology's annualized capital cost to its total annual cost, of each technology as a function of interest rate. Bio and gas w/CCS show the lowest ratio of capital cost to total annual cost. When the interest rate is 1%, bio's capital cost ratio is 21%. If the interest rate increases to 15%, the capital cost ratio of bio will double to 44%, but it is still the lowest. Due to the relatively low ratio of capital cost to total annual cost, these technologies are less sensitive to interest rate (Figures 12 and 13).

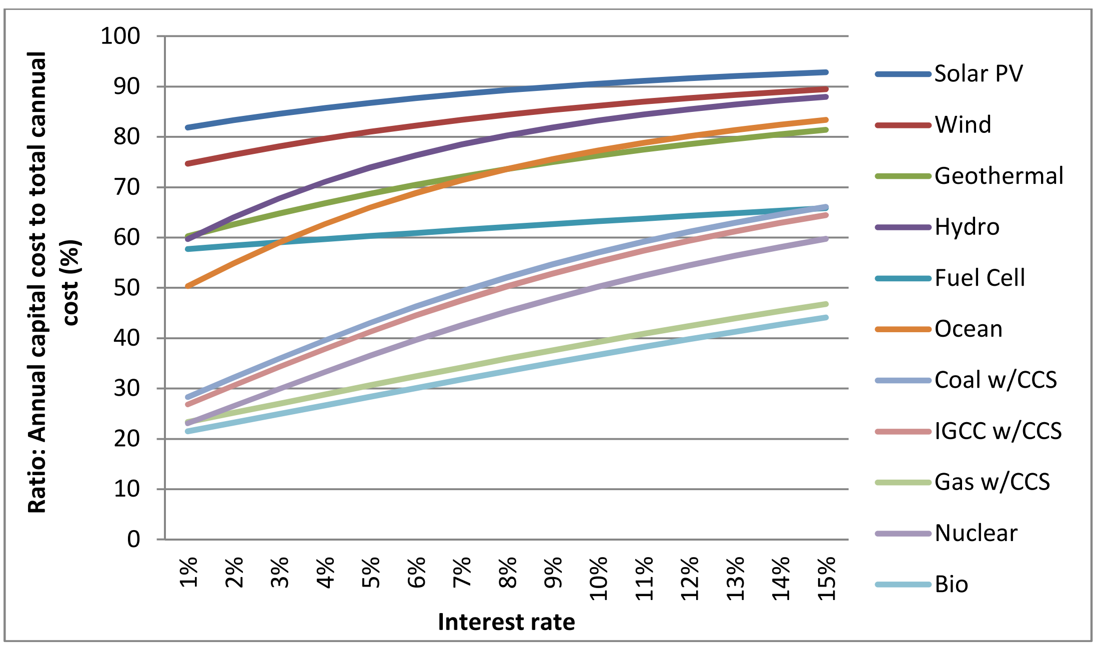


Figure 13: Ratio of capital cost to total annual cost in 2029 in the alternative scenario (Developed by the author)

Capital cost sensitivity is discussed next. As seen in Figure 13, a capital cost accounts for most of the total annual cost in most technologies, so it is necessary to look at capital cost sensitivity. Conventional sources of power generation such as fossil fuel and nuclear are already economical, so these technologies are expected to have no significant change in capital cost. On the other hand, some alternative generation technologies are not yet economically feasible, so there can be some changes in the actual capital cost per generation capacity (kW) of these technologies, depending on external factors such as technology development. So for the capital cost sensitivity analysis, this thesis assumes that capital costs for coal, oil, gas, nuclear, and integrated energy will remain the same until 2029. Capital costs of alternative technologies (hydro, solar PV, wind, fuel cell, bio, waste, IGCC, ocean, geothermal, coal w/CCS, IGCC w/CCS, and gas w/CCS) are assumed to change over time.

Figure 14 shows the marginal abatement cost curves influenced by a ± 50% change in the capital cost of new and renewable energy technologies. Changes in capital costs of new and renewable energy technology produce different carbon abatement cost curves. The decrease in capital costs lowers overall abatement costs. The rise in capital costs increases overall abatement costs of low-carbon technologies. If capital costs of new and renewable energy technology decrease by 50%, the highest marginal abatement cost will be 590 $/tCO_2$ of fuel cell. Meanwhile, if capital costs of new and renewable energy technology increase by 50%, the highest marginal abatement cost will be 1,297 $/tCO_2$ of fuel cell (Figure 14). The most cost-effective technology is nuclear in both scenarios with an abatement cost of -29 $/tCO_2$. As the capital costs of nuclear and fossil fuel technologies are assumed not to change in this analysis, the abatement cost of nuclear is equal in both scenarios. When the capital cost decreases by 50%, wind and solar PV are relatively cost effective, ranking 3rd and 5th lowest-cost technology respectively. The abatement cost of wind is 25 \$/tCO_2 and that of solar PV is 48 \$/tCO_2 at -50% change in capital cost (Figure 14). If the capital cost increases by 50%, wind will be the 5th lowest-cost generation technology with an abatement cost of 207 \$/tCO_2 and solar PV will be the 7th lowest-cost technology with an abatement cost of 286 \$/tCO_2 (Figure 14). Overall, the decrease in capital costs of new and renewable energy enhances the cost-effectiveness of new and renewable energy, whereas the increase in capital costs of new and renewable energy hinders the cost-effectiveness of new and renewable energy.

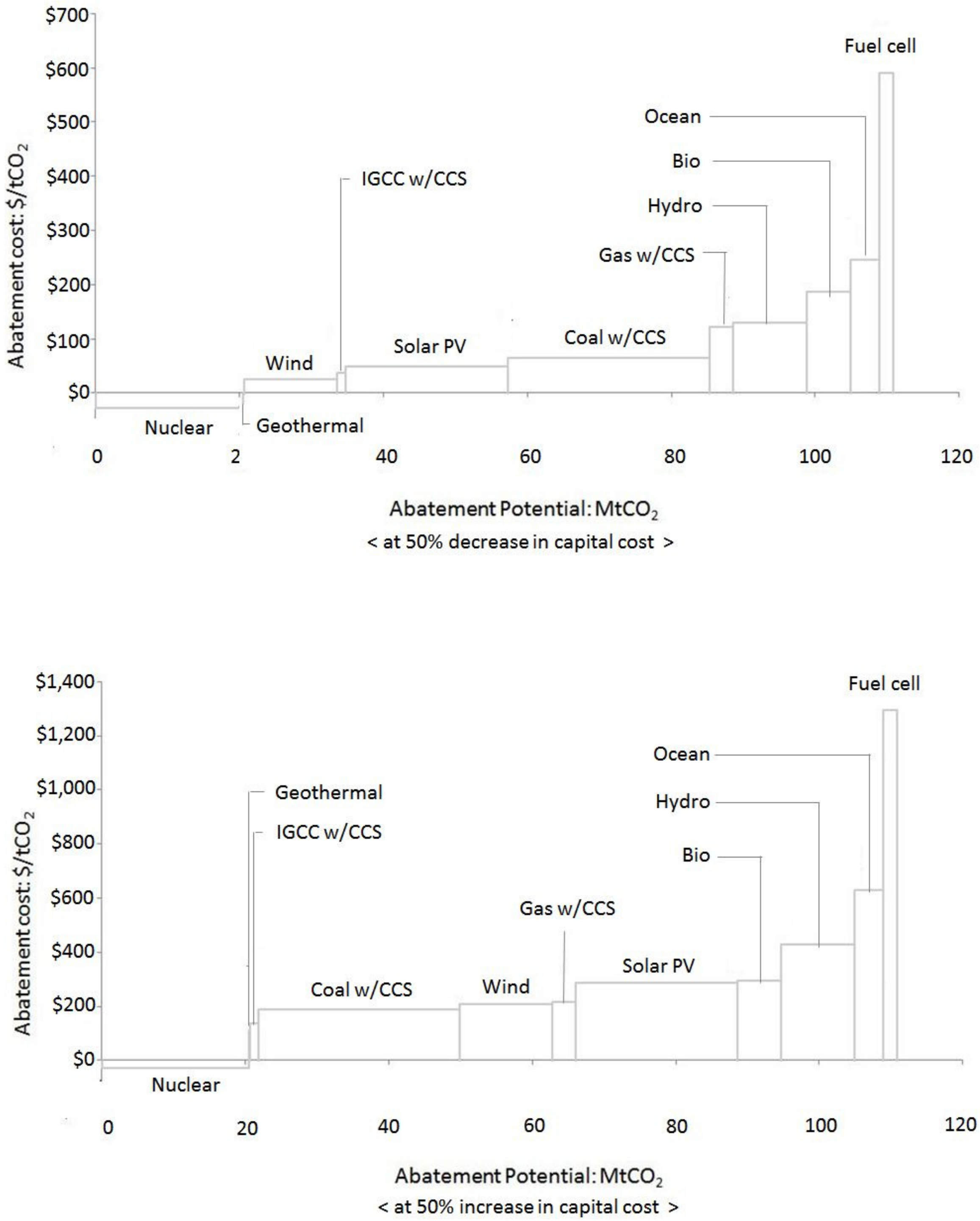
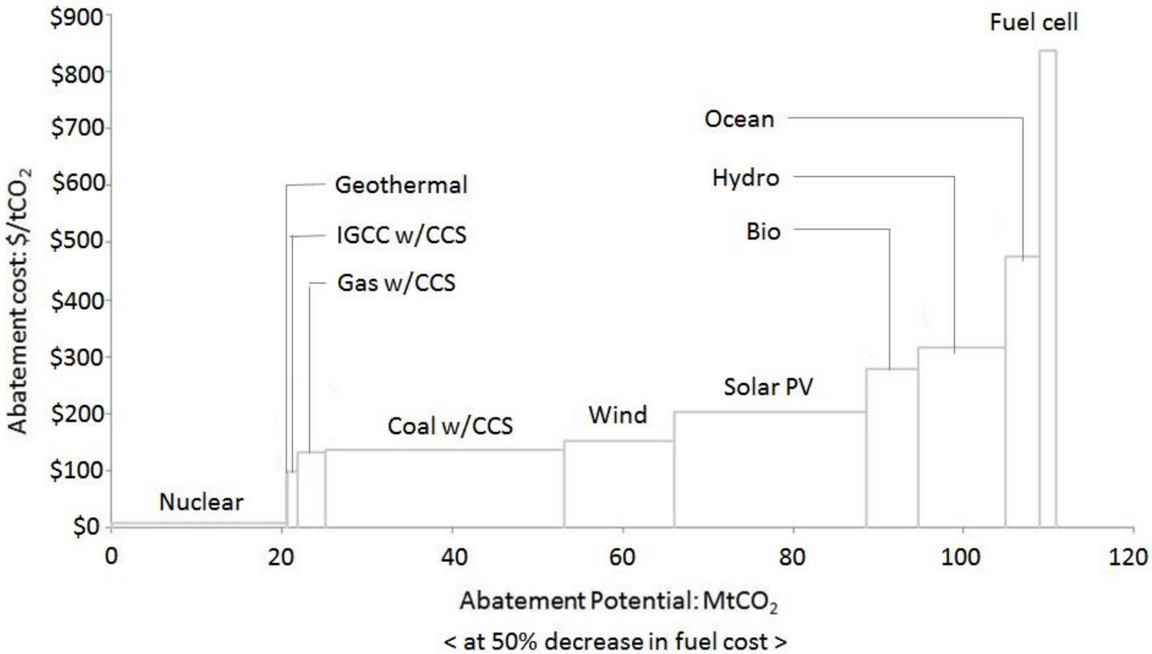


Figure 14: Carbon abatement cost curve at a ± 50% change in capital cost (Developed by the author)

Fuel cost sensitivity is analyzed in the following paragraphs. Korea imports 98% of its fossil fuel. Domestic productions of coal, natural gas, and oil are negligible, accounting for less than 1% of national consumption (EIA, 2017). Fuel prices in Korea depend on global fuel markets, which cannot be controlled domestically. In this regard, it is important to analyze fuel cost sensitivity in determining the cost-effectiveness of low-carbon technologies. This thesis used fossil fuel cost assumptions derived from IEA's Projected Cost of Generating Electricity, 2015 Edition (IEA, 2015): 3 $/GJ for coal and 12 $/GJ for gas. For oil, the cost assumption is 115.5 $/MWh, based on previous research (Jeong and Hwang, 2016).

Figure 15 shows the carbon abatement cost curves influenced by a ± 50% changes in fossil fuel prices. It is interesting to see that if fuel costs decrease by 50%, nuclear's abatement cost will be a positive number (8 $/t$CO_2$). In Chapter 3, the abatement cost of nuclear was a negative number, -28 $/t$CO_2$, mainly due to its low fuel cost. Nuclear's fuel cost is assumed to be 5 $/MWh, whereas fuel costs of other technologies range from 30 $/MWh to 130 $/MWh (Table 15). But as fuel costs of other technologies decrease, nuclear loses its comparative advantage of low fuel cost, and thus nuclear becomes less competitive in terms of cost-effectiveness. New and renewable energy also becomes less cost-effective when the fossil fuel costs decrease. For example, when the fuel costs decreases by 50%, wind is the 6th cost-effective generation technology with an abatement cost of 153 $/t$CO_2$. But when the fuel costs increase by 50%, wind is the 4th cost-effective technology with an abatement cost of 79 $/t$CO_2$. On the other hand, CCS technologies, which use either coal or gas as a fuel, will gain economic competitiveness if fossil fuel costs decrease (Figure 15).



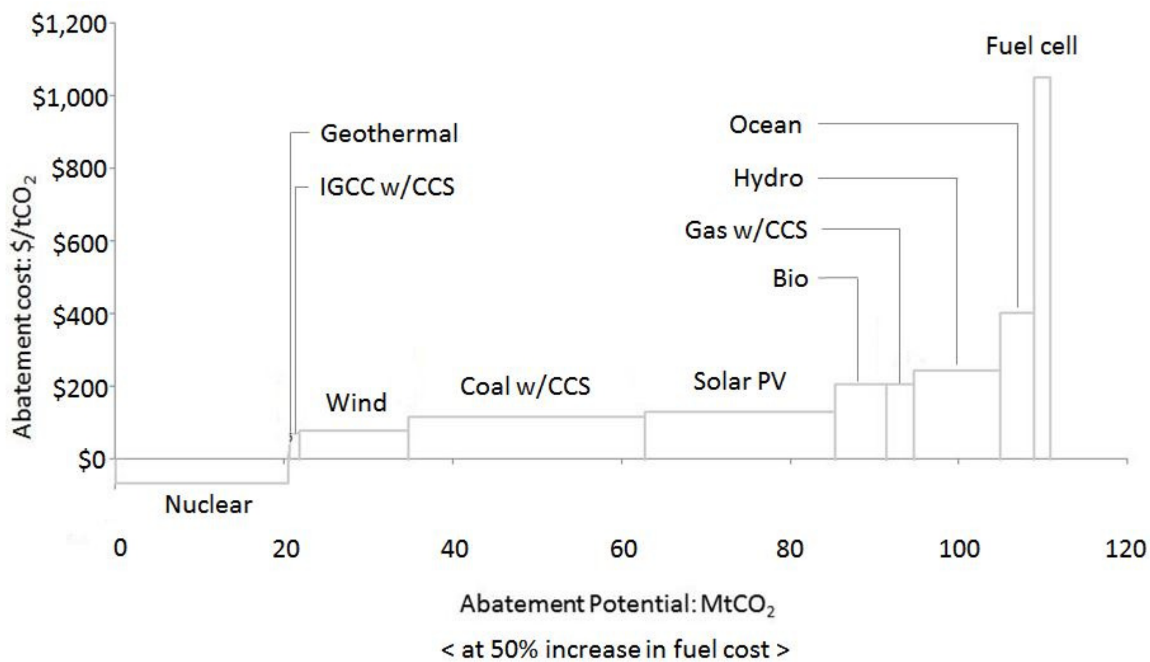


Figure 15: Carbon abatement cost curves at a ± 50% change in fuel cost (Developed by the author)

Figure 16 shows the influence of increasing or decreasing fuel cost on marginal abatement costs for each technology. Overall, fuel costs are inversely correlated with abatement costs, so when the fuel costs increase, most abatement costs decrease. Fuel cell and gas w/CCS which use natural gas as a fuel show a positive correlation between abatement costs and fuel costs. When fuel costs increase, the abatement costs of fuel cell and gas w/CCS increase as well. The price of coal is 3 $/GJ, and the price of gas is 12 $/GJ, which is 4 times higher than that of coal. So even if the fuel price changes at the same rate, its impact on the total cost is greater for gas than for coal. For this reason, among three CCS technologies, only gas w/CCS shows a positive correlation between carbon abatement cost and fuel cost.

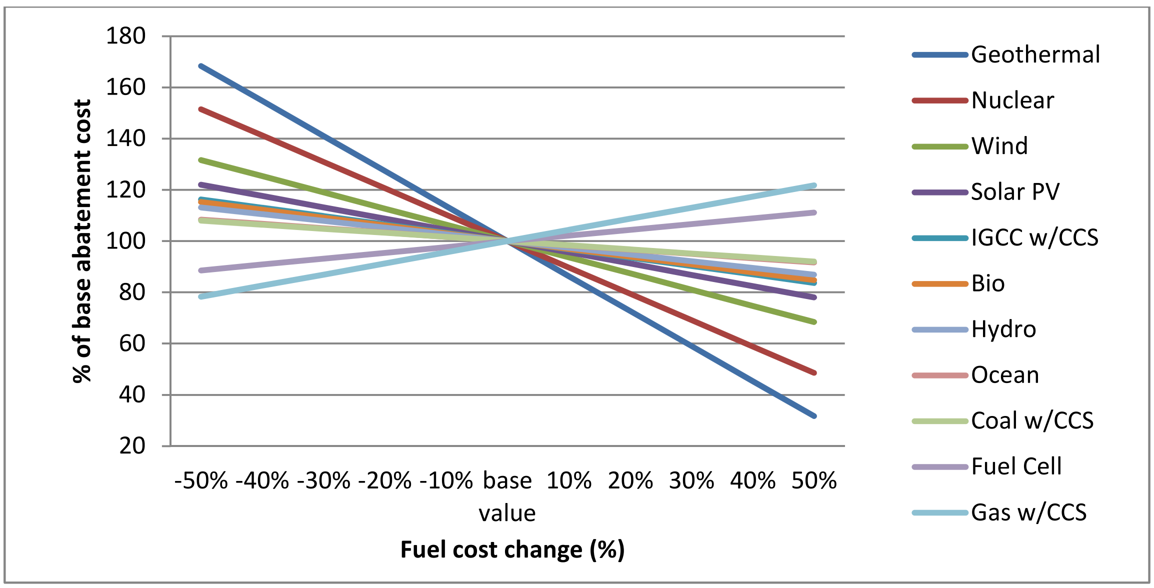


Figure 16: Carbon abatement cost as a function of fuel cost (Developed by the author)

IMPLEMENTATION CHALLENGES

As mentioned earlier, Korea's power sector is dominated by the government-owned KEPCO and its subsidiaries (Chapter 2) which are used to regulations and regulatory incentives. So the implementation of low-carbon technologies will be less difficult if the government maintains the policies for GHG mitigation with regulations and incentives. The implementation challenge lies in abatement technology and cost. Many low-carbon generation technologies are not yet technologically mature or commercially viable. For example, CCS technology is in the pilot stage, and only 17 large-scale CCS projects are in operation globally (Global CCS Institute, undated). In Korea, no commercially operating CCS power plants exist, and only demonstration projects are being conducted. The ability to store CO_2 for long periods is also in the experimental stage. The primary storage option for Korea is geological storage, especially in the deep ocean. The Ministry of Ocean and Fishery has identified three possible sites for the CO_2 storage: the Kunsan Basin, the Ulleung Basin, and the Cheju basin. A demonstration storage project is now under way in the Ulleung Basin off the east coast of Korea; it is considered to have the greatest potential of the three (Global CCS Institute, 2016). To see wider deployment of CCS, it is necessary to invest more in technology development to improve the generation efficiency, technical maturity, and cost-effectiveness. Even if support regulations and incentives are provided, the technologies cannot be implemented unless they are proven and economically feasible. Technology development can reduce cost of low-carbon technologies. Most low-carbon technologies are more expensive than conventional sources of power generation, such as coal and natural gas. More incentives could compensate for the higher per unit costs of these emerging technologies and improve technical feasibility.

Non-financial barriers such as social acceptance may bring some challenges to the implementation. For example, there has been a conflict over the construction of transmission networks in Miryang, Korea. The transmission lines were supposed to distribute electricity generated from nearby nuclear power plants, but protests arose from local residents over possible health threats (*The New York Times*, 2013). Now the networks are established, but construction took almost 7 years, double as the time forecast in the initial plan of 3 years. Thus, implementation of an energy project can be difficult without social agreement, even if the project is led or supported by the government. In 2014, the Korea Institute of Energy Economics estimated the Willingness to Pay (WTP) for new and renewable energy as a measure of social acceptance (Lee, 2014). WTP for new and renewable energy in Korea has increased over time from 1,562 Won/month (1.35 USD/month) in 2010 to 3,456 Won/month (3 USD/month) in 2014. After adjustments for electricity rates, the WTP of Korea is 4.05 USD/month, which is only half of that of Japan (7.37 USD/month) and that of the U.S. (8.64 USD/month) (Lee, 2014). Low WTP can translate into low social acceptance. Relatively low social acceptance can undermine the realization of emissions reduction potential of low-carbon technologies, but these issues are not considered in the costs shown in a MAC curve. To overcome such barriers, the Korean government could provide accurate information about low-carbon technologies. Low-carbon technologies are relatively new and unfamiliar to the public, so people might have some initial resistance. Increasing public awareness of low-carbon technologies through media and education can help improve social acceptance. In Korea’s power sector, most new construction plans are determined when establishing the biennial National Basic Plan on Electricity Demand and Supply (MOTIE, 2015). This top-down process sometimes fails to engage stakeholders. For example, when notified of transmission construction plans, Miryang residents were unhappy and began to protest because they were not given enough information and were excluded from the decision-making process. Had they received sufficient information and been encouraged to express their opinions and concerns, and to have discussions with the government, the construction could have been less difficult. In order to improve the likelihood of project implementation, stakeholders would appreciate communication at early stage of the project to increase their understanding and justify their acceptance. Electricity pricing that reflects external costs of low-carbon technologies can be helpful. For example, noise from wind turbines or light reflection from solar panels can affect the lives of local residents. Korea's current electricity market does not consider many negative externalities of power plants, so people do not want power plants built nearby. If a lower electricity tariff is charged to the residents to compensate for negative externalities, the implementation of low-carbon technologies could be less problematic (Lee, 2014).

Chapter 5: Conclusion

Korea's power sector accounts for 35% of the nation's greenhouse gas emissions. Given the importance of the sector to the greenhouse emissions reduction, this thesis analyzed the emissions reduction potential and costs of the power sector by constructing a MAC curve. A MAC curve for Korea's power sector is informative. It assesses the economics of abatement measures and shows which technology is desirable from the perspective of cost-effective emissions reduction. The year 2029 was a reference year and 13 abatement technologies were analyzed. Nuclear is the most attractive alternative source of power generation: it has a negative abatement cost (-28.6 $/t CO_2) and substantial abatement potential (20 MtCO_2 for year 2029). CCS technologies combined (coal w/CCS, gas w/CCS, and IGCC w/CCS) contribute 30% of the total abatement potential. Fuel cells are the least preferred technology due to its highest abatement cost (944.6 $/t$CO_2$) and the second lowest abatement potential (1.9 MtCO_2). Some abatement measures have a negative abatement potential, such as waste and IGCC. Waste may increase the emissions in the power sector, it may eventually contribute to the total national emissions reduction, and IGCC needs more developments in both technology and cost reduction.

This thesis conducted a sensitivity analysis of how interest rate, capital cost, and fuel cost affect the comparative advantage of alternative sources of energy. Carbon abatement costs are most sensitive to capital cost. The ± 50% variation in capital cost of new and renewable energy generates ± 63% changes in carbon abatement costs, whereas a ± 50% variation in other factors influence abatement costs by only ± 30 %. Interest rates and capital costs are positively correlated with carbon abatement costs, but fuel costs have a negative correlation with carbon abatement costs. Total abatement potential does not change with the variation of the financial assumptions. In implementing low-carbon technologies in the power sector, the obstacles include technology, cost, and social acceptance. More investments and incentives could promote technology development and lower the costs of low-carbon technologies. Engaging stakeholders and providing accurate information could enhance social acceptance. Internalization of the negative externalities of low-carbon technologies can also make the implementation less challenging, such as providing a lower electricity tariff to residents living near low-carbon energy power plants.

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