Millennium Bulk Terminals—Longview SEPA Environmental Impact Statement

SEPA Coal Market Assessment Technical Report

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Acronyms and Abbreviations

$/MMBtu	dollars per million British thermal unit
Applicant	Millennium Bulk Terminals—Longview, LLC
BNSF	BNSF Railway Company
Btu/lb	British thermal units per pound
CFR	Code of Federal Regulations
CN	Canadian National
CO_2	carbon dioxide
CP	Canadian Pacific
EIA	U.S. Energy Information Administration
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency
FOB	free on board
GHG	greenhouse gas
IEA	International Energy Agency
IPM®	Integrated Planning Model
MMBtu	million British thermal unit
NO_X	nitrogen oxides
SEPA	Washington State Environmental Policy Act
SO_2	sulfur dioxide
TBtu	trillion British thermal unit
WEO	World Energy Outlook

Chapter 1
Introduction

This chapter provides an overview of the coal export terminal proposed for development in Cowlitz County, Washington, and its potential impact on the coal market.

1.1 Project Description

Millennium Bulk Terminals—Longview, LLC (Applicant) is proposing to construct and operate a coal export terminal (Proposed Action) in Cowlitz County, Washington, along the Columbia River (Figure 1). The coal export terminal would receive coal from the Powder River Basin in Montana and Wyoming and the Uinta Basin in Utah and Colorado via rail shipment. The coal export terminal would receive, stockpile, and load coal onto vessels and transport the coal via the Columbia River and Pacific Ocean to overseas markets in Asia.

1.1.1 Proposed Action

Under the Proposed Action, the Applicant would develop the coal export terminal on 190 acres (project area) primarily within an existing 540-acre site that is currently leased by the Applicant (Applicant's leased area). The project area is adjacent to the Columbia River in unincorporated Cowlitz County, Washington near Longview, Washington (Figure 2). The Applicant currently operates and would continue to operate a bulk product terminal within the Applicant's leased area.

BNSF Railway Company (BNSF) or Union Pacific Railroad (UP) trains would transport coal on BNSF main line routes in Washington State, and the BNSF Spur and Reynolds Lead in Cowlitz County to the project area. Coal would be unloaded from rail cars, stockpiled, and loaded by conveyor onto ocean-going vessels for export at two new docks (Docks 2 and 3) located in the Columbia River.

Once construction is complete, the Proposed Action could have a maximum annual throughput capacity of up to 44 million metric tons of coal per year. The coal export terminal would consist of one operating rail track, eight rail tracks for storing up to eight unit trains, rail car unloading facilities, a stockpile area for coal storage, conveyor and reclaiming facilities, two new docks in the Columbia River (Docks 2 and 3), and shiploading facilities on the two docks. Dredging of the Columbia River would be required to provide access to and from the Columbia River navigation channel and for berthing at the two new docks.

Vehicles would access the project area from Industrial Way (State Route 432), and vessels would access the project area via the Columbia River. The Reynolds Lead and BNSF Spur track—both jointly owned by BNSF and UP and operated by Longview Switching Company (LVSW)—provide rail access to the project area from a point on the BNSF main line (Longview Junction) located to the east in Kelso, Washington. Coal export terminal operations would occur 24 hours per day, 7 days per week. The coal export terminal would be designed for a minimum 30-year period of operation.

At full terminal operations, approximately 8 loaded unit trains each day would carry coal to the export terminal, 8 empty unit trains each day would leave the export terminal, and an average of 70

vessels per month or 840 vessels per year would be loaded, which would equate to 1,680 vessel transits in the Columbia River annually.

Figure 1-1. Project Vicinity

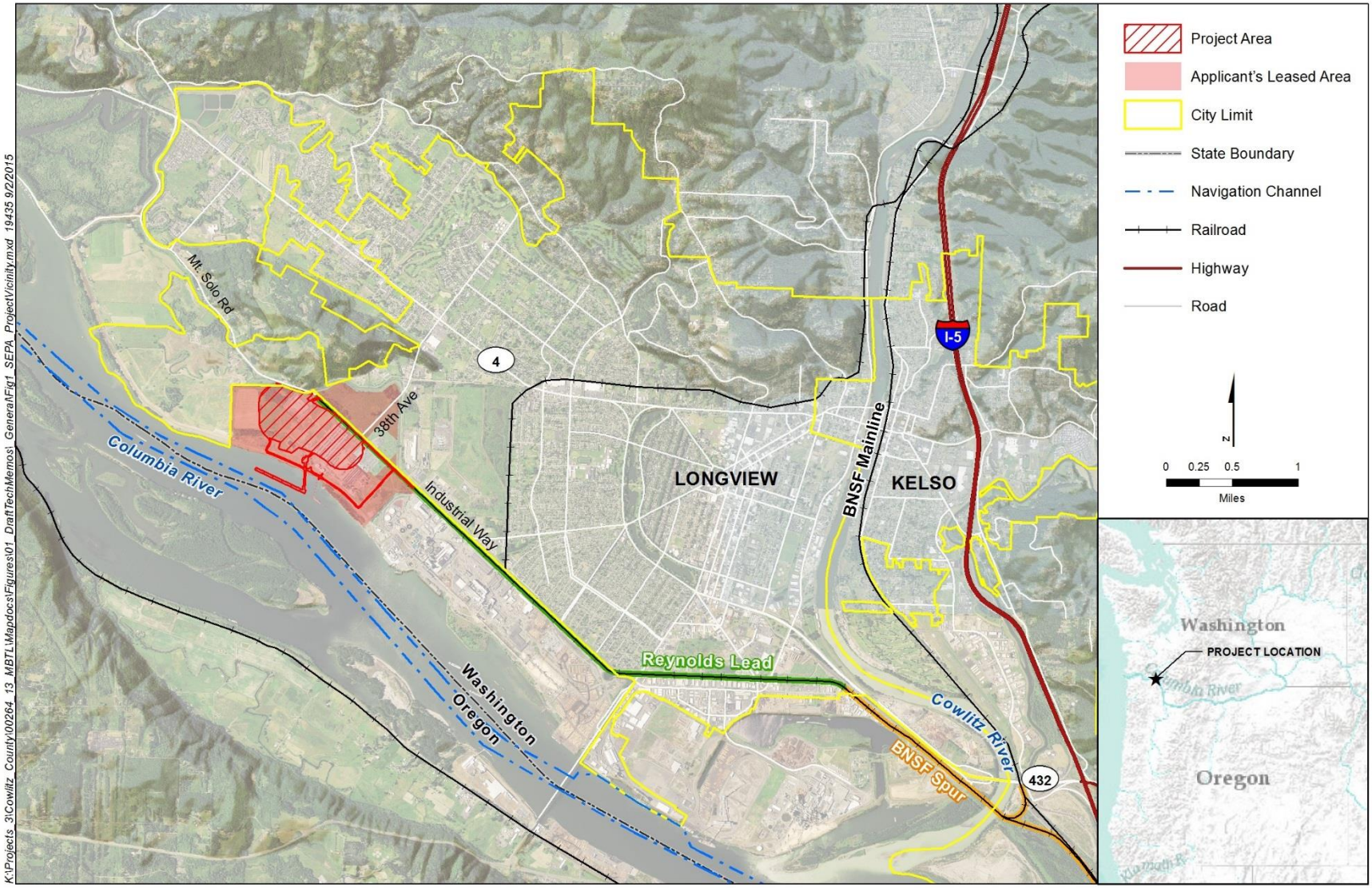
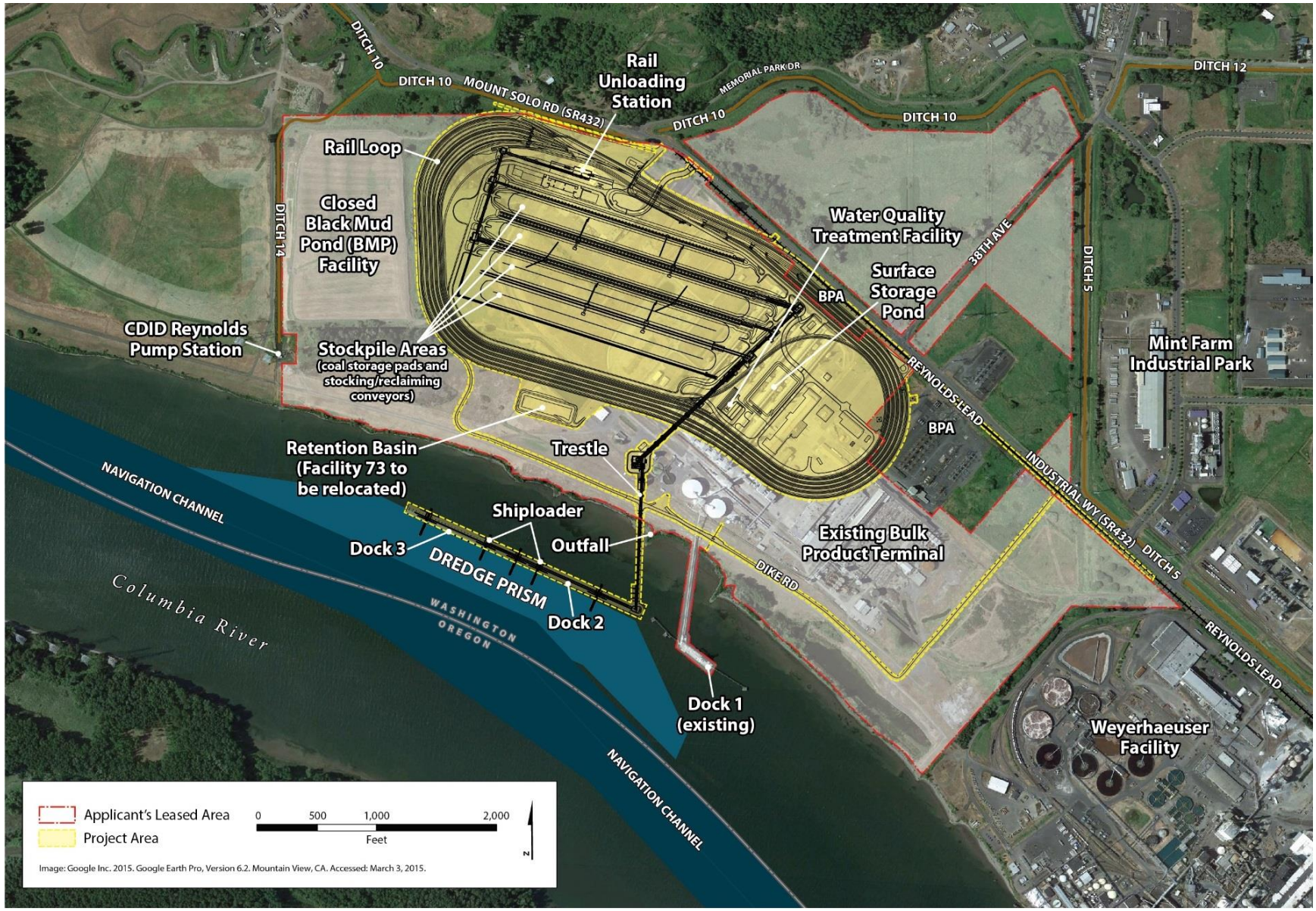


Figure 1-2. Proposed Action



1.2 Overview of Coal Market Analysis

This report presents the analysis of coal production, consumption, distribution, and CO_2 emissions from combustion of coal in relation to the U.S. and Asian markets.[1] The analysis examines the Proposed Action and No-Action Alternative and documents the methods and data used to develop the results and conclusions.

This analysis examines the movement of coal from the Powder River Basin in Montana and Wyoming, and coal from the Uinta Basin in Colorado and Utah, through the proposed coal export terminal to China, Japan, South Korea, and Taiwan. Only coal from these coal basins were examined for export through the proposed coal export terminal based on information provided by the Applicant. To examine the potential impact of the proposed coal export terminal on domestic and Asian coal markets, a least-cost, linear programming model was used to capture the dynamic interactions between the supply and demand regions within these markets.

The international coal market is a global commodity market such that changes in supply or demand in one country can affect coal prices and distribution patterns globally. The global nature of the coal market was demonstrated most recently in the fall of 2016, when China reduced production capacity and international coal prices shot up by 50% over a 2-month period. In addition, coal competes with other fuel sources, such as natural gas, for electric generation. To capture the dynamic changes in the international coal market and the competition among fuel types for electric generation in the United States and Canada, a comprehensive and integrated modeling platform is required. Without this type of modeling, assumptions would be required regarding the ultimate outcome of the exported coal and changes in coal consumption in the United States that would be difficult to make and justify without comprehensive modeling.

The importance of modeling is best illustrated by examples. The modeling for the Draft Environmental Impact Statement (Draft EIS) established that rather than the new coal resource resulting in an increase in coal consumption equal to the amount of coal exported, the increase is close to zero in all but the Upper Bound Scenario. Additionally, the modeling established that there are multiple suppliers and that U.S. exports, while competitive, are not significantly lower-cost than coal supplied from Australia, China, Indonesia, or Russia. The model showed outcomes where displacement (i.e., sale of U.S. coal rather than sale of competing coal produced in other countries), resulted in small changes in delivered coal price, and small to no increases in coal used, except in the Upper Bound Scenario. The modeling established that the differences in carbon content have a somewhat greater effect on net emissions from the Proposed Action than some of the other sources of emissions. Thus, the net emissions from the substitution of coal with different carbon contents in Asia has more of an impact on the net emissions than other emission sources such as international vessel transport. Fourth, if the U.S. power and fuel markets were not highly integrated, diverse, and competitive, the increase in coal price in the United States would not result in substitution of gas and other sources for coal. In some model scenarios, small substitution effects were identified because of the high degree of competition, diversity, and integration.

[1] The Asian market refers to the following countries: Australia, China, India, Indonesia, Japan, Korea, Russia, Taiwan, Thailand, and Vietnam.

Historically, approximately 2% of Powder River Basin coal has been exported.[2] There are four primary reasons that Powder River Basin coal has not been exported in larger quantities in the past.

- The Powder River Basin is far from large U.S. coal export facilities along the Atlantic coast and in the Gulf Coast.
- Canadian coal export facilities in the Pacific Northwest have had limited capacity for Powder River Basin coal or are too far to be economic.
- Powder River Basin coal has a lower heat content than eastern bituminous coals. Lower heat content increases transportation cost per unit of energy delivered.[3]
- Powder River Basin coal is subbituminous coal that is suitable for use in electric power plants, but is not suitable for coking coal, which limits the marketability of the coal.

The Proposed Action would address the first two reasons Powder River Basin coal has not been exported, and thus would reduce the distance to Asian markets and make Powder River Basin coal more competitive with other coal delivered to Asia. Currently, the largest suppliers of coal in Asia are Australia, China, India, and Indonesia. This analysis examines the U.S. and Asian coal market changes that would take place under the Proposed Action, under five different scenarios. The scenarios examine a wide range of possible future market states that would have an influence on how the proposed coal export terminal would affect these markets

1.2.1 Report Organization and Chapter Summary

The following sections describe the remaining chapters of this report.

1.2.1.1 Chapter 2, U.S. Coal Market and Pacific Northwest Export Terminals

This chapter provides a brief overview of the U.S. coal market and more in-depth information about the Powder River Basin and the Uinta Basin. Information on the type of coal mined in these coal basins is included, as well as the historical distribution of the coal. This chapter also discusses the existing and planned Pacific Northwest coal export terminals.

1.2.1.2 Chapter 3, International Coal Markets

Chapter 3 describes the international coal markets into which the coal exported from the proposed coal export terminal would enter. This chapter provides information on the major coal importing and exporting countries and provides a summary of each country that is a possible destination for coal exported from the proposed terminal. Finally, this chapter provides a brief discussion on international coal prices.

[2] Based on EIA U.S. Domestic and Foreign Coal Distribution by State of Origin.

[3] The cost per unit of energy delivered is proportional to the tons of coal transported and the heat content of the coal. If the energy or heat content per ton is low, then the transportation cost per unit of energy is higher.

1.2.1.3 Chapter 4, Model Framework, Methods, and Key Assumptions

Chapter 4 provides a summary of the model, methods, and assumptions used in this analysis to estimate coal production, consumption, distribution, and CO_2 emissions. This analysis uses ICF's Integrated Planning Model (IPM®) to assess coal production, consumption, and distribution patterns that would be affected by the Proposed Action. This computer modeling platform is also used by the U.S. Environmental Protection Agency (EPA), other government entities, electric utilities, independent power producers, coal companies, and environmental groups. The assumptions used in this analysis are largely from publicly available sources.

Chapter 4 provides a base set of assumptions that are used by all the scenarios and describes some of the scenario-specific assumptions that require detailed information. The full scenario descriptions are included in Chapter 5.

1.2.1.4 Chapter 5, Scenarios

Chapter 5 describes the five scenarios analyzed in this report and how the assumptions defining each scenario differ from the base set of assumptions. Under each scenario, both a No-Action Alternative and a Proposed Action are examined to determine the effect of the Proposed Action on the U.S. and Asian coal markets. The five scenarios analyzed in this report are as follows.

- No Clean Power Plan Scenario, which represents the business as usual case in 2016 but does not include the Clean Power Plan.
- Lower Bound Scenario, which is designed to result in a reasonable lower bound of global CO_2 emissions from the power sector. The energy markets under the Lower Bound Scenario could be described as a high renewable energy penetration scenario, where international coal demand and prices are lower than in the base assumptions.
- Upper Bound Scenario, which is designed to result in a reasonable upper bound of global CO_2 emissions from the power sector. The energy markets under the Upper Bound Scenario could be described as a high international coal demand scenario, where international coal demand and prices are higher than in the base assumptions.
- 2015 U.S. and International Energy Policy Scenario, which differs from the base assumptions in that it includes implementation of EPA's Clean Power Plan and assumes greenhouse gas (GHG) reduction policies are implemented in other countries that have made commitments under the Paris Accord of 2015.
- Cumulative Scenario, which differs from the base assumptions only in that it includes the capacity of other proposed Pacific Northwest coal export facilities. The Cumulative Scenario also does not include the Clean Power Plan.

1.2.1.5 Chapter 6, Modeling Results

Chapter 6 presents the modeling results of the five scenarios analyzed. The results are presented for the No-Action Alternative and Proposed Action and for the difference as calculated by subtracting the No-Action Alternative results from the Proposed Action results. Results are presented for coal production from the U.S. and non-U.S. producing regions; coal consumption in the United States and Asia; the distribution of coal in Asia; and CO_2 emissions from the combustion of coal. In addition,

natural gas usage at electric power plants in the United States and the CO_2 emissions from natural gas combustion are reported as natural gas is a substitute fuel when coal consumption decreases.

1.2.1.6 Chapter 7, Conclusions

Chapter 7 provides a summary of the conclusions from the analysis.

Chapter 2

U.S. Coal Market and Pacific Northwest Export Terminals

2.1 General U.S. Coal Market

The United States is the world's second largest coal producer and consumer, with total coal production of 897 million short tons in 2015 (Mine Safety and Health Administration 2016 Part 50 data). The largest coal producer and consumer is China, with total coal production of 4.2 billion short tons (International Energy Agency 2016). This chapter discusses the U.S. coal market to provide context for the focus of this analysis, which is coal produced from the Powder River Basin and the Uinta Basin to be exported through the proposed coal export terminal. The goal of this chapter is to provide a basic understanding of the U.S. coal markets, and Chapter 3, *International Coal Markets*, provides an overview of the international coal markets, both of which will help the reader to understand and interpret the modeling results

2.1.1 Total Production

Between 1990 and 2015, total U.S. coal production has been more than 1 billion tons, except for only six years (Mine Safety and Health Administration 2016). In this period, coal production has averaged 1.06 billion tons and peaked at 1.17 billion tons in 2008 (Mine Safety and Health Administration 2016). However, since 2011, coal production has been declining due to competition from natural gas as an energy source for electric generation. Historically, about 90% of U.S. coal has been used domestically for power generation, with the remainder being used for industrial processes, steel production, or export. The Powder River Basin is the leading source of U.S. coal, at more than 40% of U.S. total coal production (Mine Safety and Health Administration 2016). The majority of Powder River Basin coal is used in domestic power plants, with only 1% to 2% being exported, primarily to Asia. Coal exports from all the United States coal-producing regions have been primarily to Europe.

Coal production and consumption have both decreased since 2011, when natural gas prices first fell below $3.5 per million British thermal unit (MMBtu). Natural gas is a competing fuel for electric generation and thus when natural gas prices are below $3.5/MMBtu the cost of generating electricity from natural gas is below the cost of generating electricity from some types of coal.

Coal is produced in four major coal basins within the United States, along with several smaller coal basins. The four major coal basins are the Powder River Basin, Rocky Mountains, Illinois Basin, and Appalachia. The Appalachian coal basin is further divided into a Northern, Central, and Southern section. The Rocky Mountain area includes the Uinta Basin, which includes Utah and the western part of Colorado, the Wyoming Green River area, and parts of Colorado not in the Uinta Basin.

2.1.2 Types of Coal

Coal has two primary uses: metallurgical and thermal. Coal used to produce coke (a hard porous residue used in steel manufacturing) is called metallurgical coal. Non-metallurgical coal is referred to as thermal or steam coal, because it is used to generate electricity through steam turbines.

Metallurgical coal in the United States is found in the Appalachian basin. Thermal coal is produced in all regions.

Coal is also categorized by rank, with three ranks used in the United States. The coal ranks are, from hardest and highest heat content to softest and lowest heat content, bituminous, subbituminous, and lignite. Bituminous coal is mined in the Appalachian and Illinois Basins as well as in the Rocky Mountains.[4] Subbituminous coal is primarily mined in the Powder River Basin. Lignite coal is primarily found in Texas and the Great Plains area of North Dakota and Montana.

Within each rank, coal is graded by the heat content as well as the trace elements found in the coal, such as sulfur, mercury, and chlorine. Generally, higher heat content coal sells at a higher price, and coal with lower concentrations of trace elements sells for a higher price, all else being equal.

2.1.3 Exports

The United States imports small amounts of thermal coal and exports both metallurgical and thermal coal. Appalachia is the focal point of U.S. coal exports. This is due to high coal quality, nearby infrastructure (i.e., ports), and locational proximity to Atlantic Basin markets. In the past, Appalachian coal demand has increased when international markets strengthened. However, there is large and growing energy demand and coal industry demand in Asia. Delivered Asian coal prices were 2.1 times higher between 2010 and 2013 versus 2000 and 2006. Since coal prices peaked in 2011 Asian coal prices have declined by more than 50%, as of mid-2016. The coal trade in Asia is seaborne.

2.2 Powder River Basin

The Powder River Basin, located in Montana and Wyoming, is the largest source of coal production in the United States, accounting for more than 40% of national coal production (Figure 2-1). Powder River Basin coal is all subbituminous coal that is mined from large surface mines. Since 1970, Powder River Basin coal production has increased at an average annual rate of 10% per year (Figure 2-2). Between 1993 and 2008, production more than doubled, from 228 million short tons per year to a record high of 496 million short tons per year. Coal production in the Powder River Basin was able to expand so quickly because the coal seams are thick compared to all other coal-producing regions in the United States and because the coal is close to the surface and can be mined using surface mining techniques. The largest Powder River Basin coal seams are 100 feet thick, while seams in other coal basins in the United States are typically less than 8 feet thick.

Between 2009 and 2011, coal production averaged 464 million short tons per year, and ranged from 452 million short tons in 2009 to 473 million short tons in 2010 (Mine Safety and Health Administration 2016). In 2012, production decreased to 425 million short tons, driven down by the lowest natural gas prices in 15 years and lower electric power demand (Mine Safety and Health Administration 2016). This trend has continued with 2015 production at 405 million short tons. The U.S. Energy Information Administration (EIA) expects total U.S. coal production in 2016 and 2017 to continue to fall to about 850 million short tons, as compared to 896 million short tons in 2015 (U.S. Energy Information Administration 2016a).

[4] The Uinta Basin is part of the Rocky Mountain coal production area.

Figure 2-1. Powder River Basin (Montana and Wyoming)

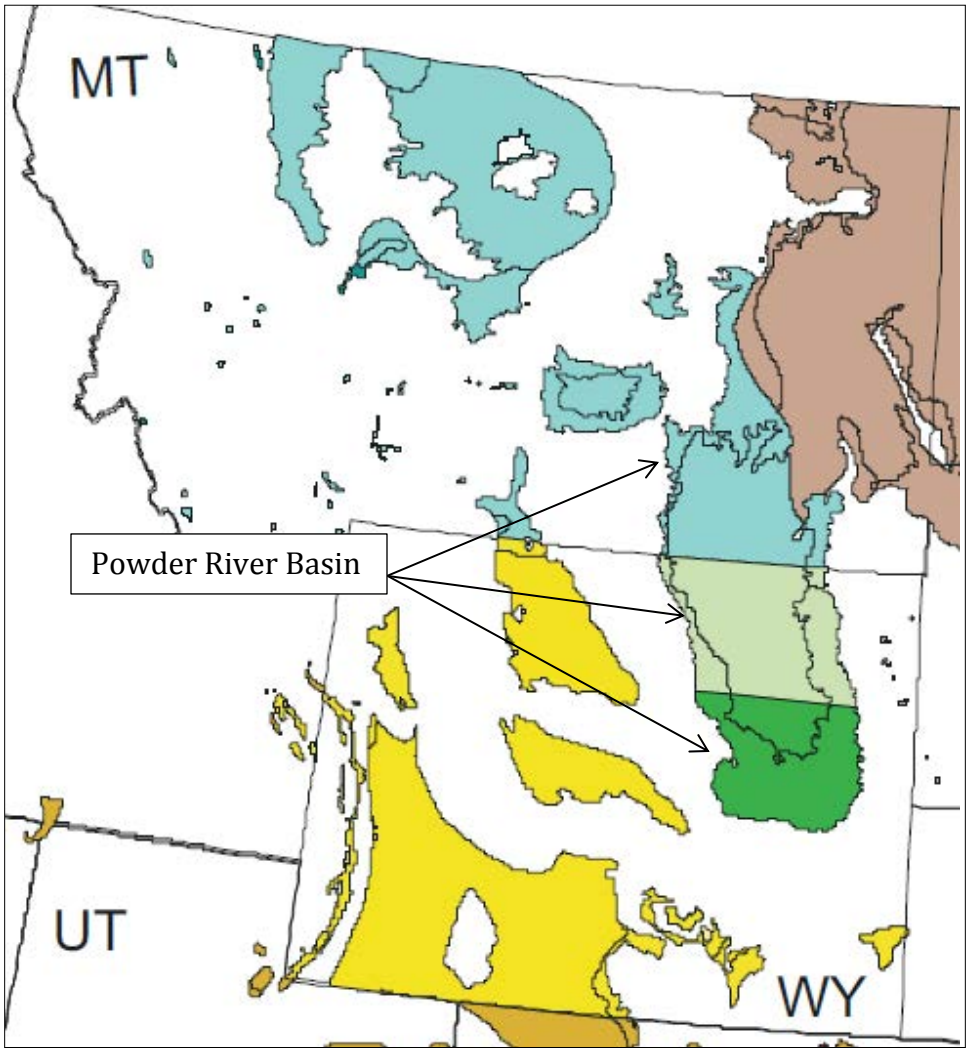
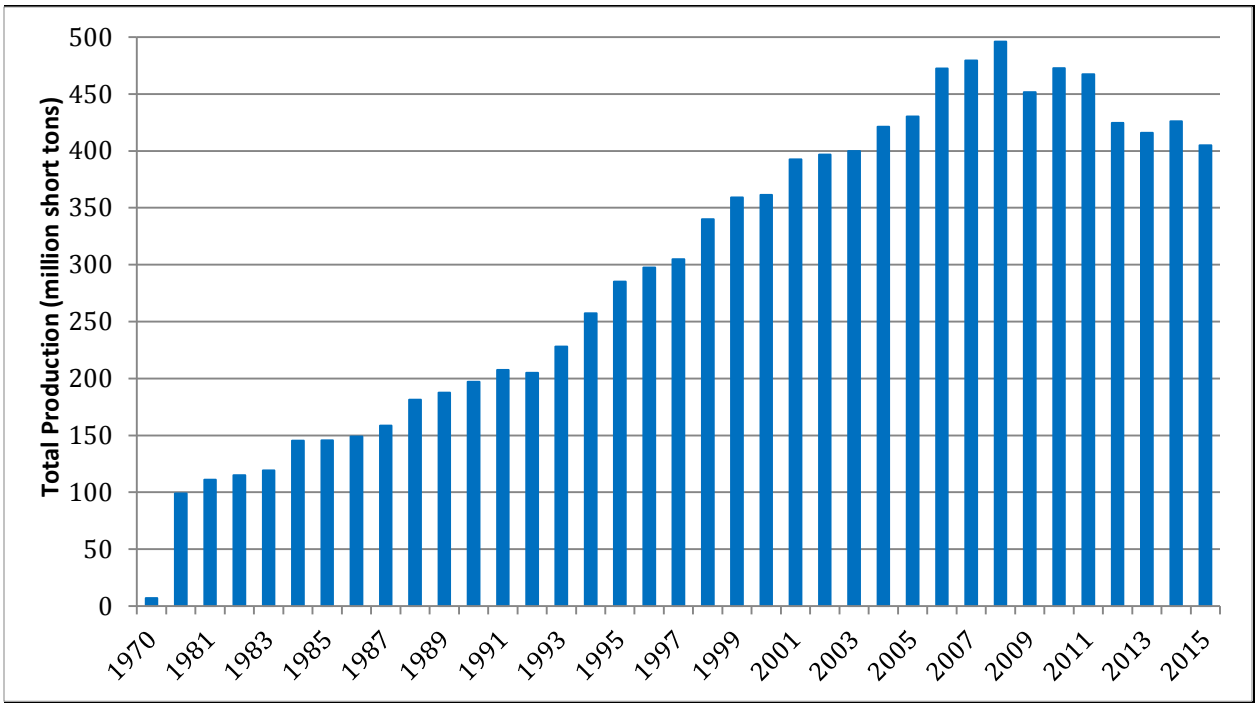


Figure 2-2. Historical Powder River Basin Coal Production (Montana and Wyoming)



Source: BXG Publications 1993 (1970–1982 data); Mine Safety and Health Administration 2016 (1983–2015 data).

This analysis considers the following three sources of Powder River Basin coal.

Montana coal: Coal produced in Montana with a heat content of 9,300 British thermal units per pound (Btu/lb).

Wyoming 8400 coal: Coal produced in Wyoming with a heat content of 8,400 Btu/lb.

Wyoming 8800 coal: Coal produced in Wyoming with a heat content of 8,800 Btu/lb.

Since 2008, Wyoming coalfields have produced about 91% of Powder River Basin coal, with the remaining 9% produced in Montana (Table 2-1). However, because Montana coal has a higher heat content, it is more likely to be exported. Higher heat content coals are more likely to be exported because they contain more heating potential per ton of coal, thus, users have to transport fewer tons of high heat content coal than they would have to import lower heat content coal. For example, a coal consumer would have to import 5.7% more Wyoming 8,800 coal than they would the higher heat content Montana coal.

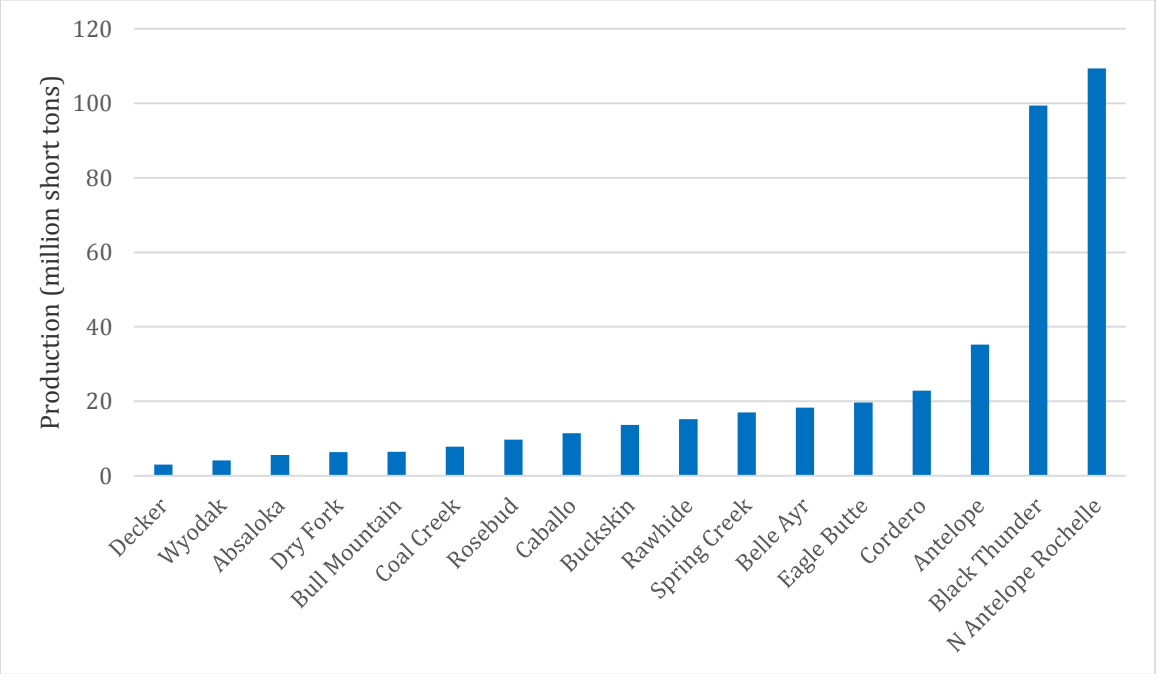
Table 2-1. Powder River Basin Coal Production by State (million short tons)

State	2008	2009	2010	2011	2012	2013	2014	2015	2008–2015 Average
Montana	44	38	44	41	36	42	44	42	41
Wyoming	452	414	428	426	388	374	381	363	403
Total	496	452	473	467	425	416	425	405	445

Source: Mine Safety and Health Administration 2016

Figure 2-3 shows that only 17 mines contribute to coal production in the Powder River Basin, and all except one (Bull Mountain) are surface mines. Two mines (Black Thunder and North Antelope Rochelle) dominate production, accounting for approximately half of the region's coal production.

Figure 2-3. Powder River Basin 2015 Production by Mine (million short tons)



Source: Mine Safety and Health Administration 2016.

Powder River Basin coal mines are large compared to other U.S. coal mines. Most Powder River Basin mines produce at least 10 million short tons per year, and two (the Black Thunder and the North Antelope Rochelle Mines in Wyoming) each produce 100 million short tons per year. For comparison, mines in the eastern United States produce, on average, less than 1 million short tons of coal per year, with very few mines producing more than 4 million short tons per year.

Mining conditions change over time. Initially coal reserves are mined that are the easiest to access and have the least amount of overburden.[5] However, as a mine ages, more overburden must be removed to access the coal, thus increasing the cost of production. Productivity gains have counteracted some of the increased cost of overburden removal. For example, the size of the shovels and trucks has increased, which allows more material to be moved in the same amount of time. The most significant contributor to the cost of surface mining coal production, however, remains the overburden ratio.[6]

2.3 Uinta Basin

The Uinta Basin coalfield is located in the western portion of Colorado and in Utah (Figure 2-4). Coal production in the Uinta Basin is from both underground and surface mines; however, more than 80% of the coal is from underground mines (Mine Safety and Health Administration 2016). The coal produced from the Uinta Basin is both bituminous and subbituminous coal, with bituminous coal the predominant kind at 85% of annual production. The Uinta Basin bituminous coal has an average heat content of 11,315 Btu/lb and the subbituminous coal has an average heat content of 10,000 Btu/lb.[7]

Between 1983 and 2015, coal production in the Uinta Basin has ranged between 26.9 and 62.1 million short tons, with an average of 45.9 million short tons (Figure 2-5) (Mine Safety and Health Administration 2016). Uinta Basin coal production peaked in 2005 with 62.1 million short tons (Mine Safety and Health Administration 2016). Since 2005, Uinta Basin coal production steadily declined through 2010, and then picked up slightly in 2011 before declining again. Since 2011, Uinta Basin coal production has decreased from 45.6 million short tons to 32.5 million short tons in 2015.

This analysis considers two sources of Uinta Basin coal: coal produced in Colorado with a heat content of 11,110 Btu/lb, and coal produced in Utah. Two bituminous coal types are modeled in Utah, one with a heat content of 11,280 Btu/lb and low sulfur content and the second with a heat content of 12,000 Btu/lb and medium sulfur content.

[5] Overburden is the layers of soil and rock covering a coal seam. It is removed prior to surface mining and replaced after the coal has been taken from the seam.

[6] The overburden ratio refers to the ratio of the thickness of soil and rock that lies above a coal seam and the thickness of the coal seam itself. In surface mining, which is the predominant mining method in the Powder River Basin, the soil and rock above a coal seam must be removed before the coal can be mined. For example, a coal seam that is 30 feet thick and overlain by 120 feet of rock and soil would have an overburden ratio of 4.0 (=120/30)

[7] EIA 923 data, using a weighted average over 2010 through 2015 (U.S. Energy Information Administration 2016b).

Figure 2-4. Uinta Basin (Colorado and Utah)

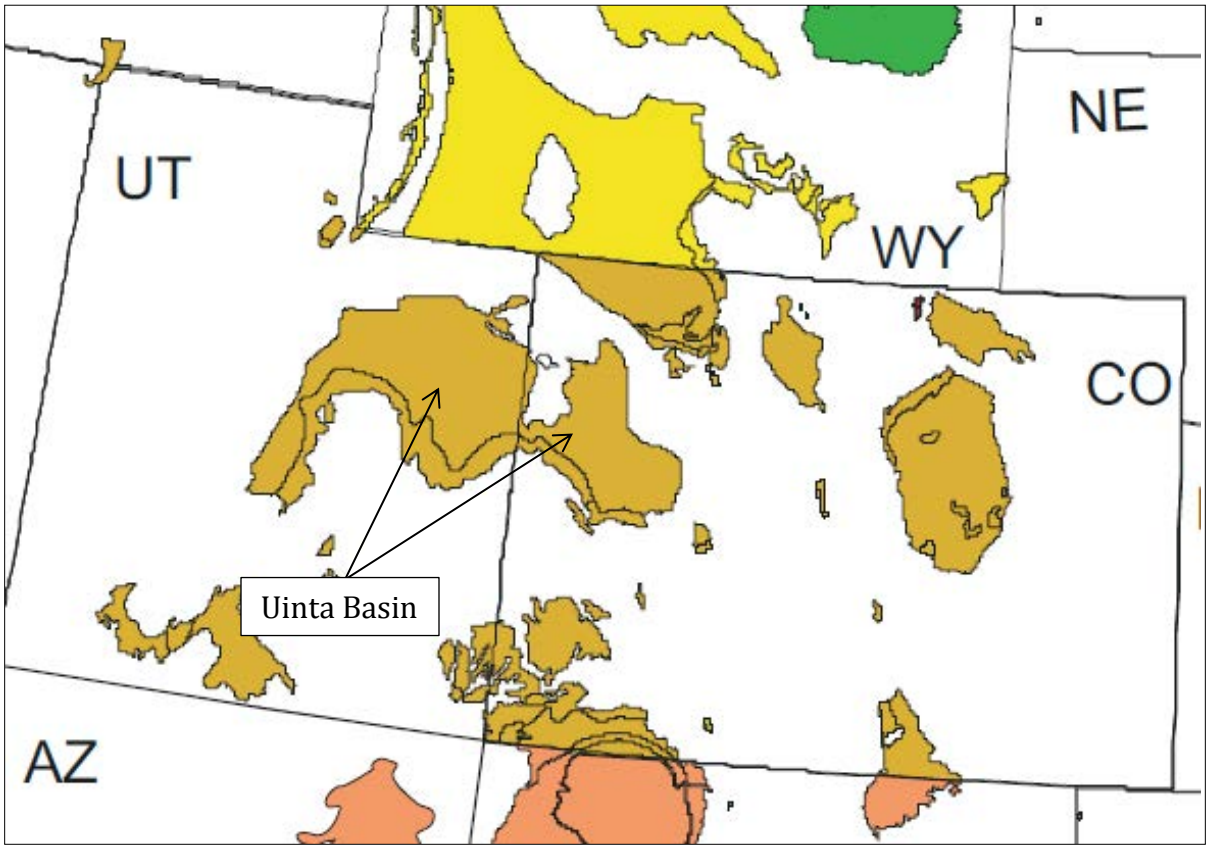
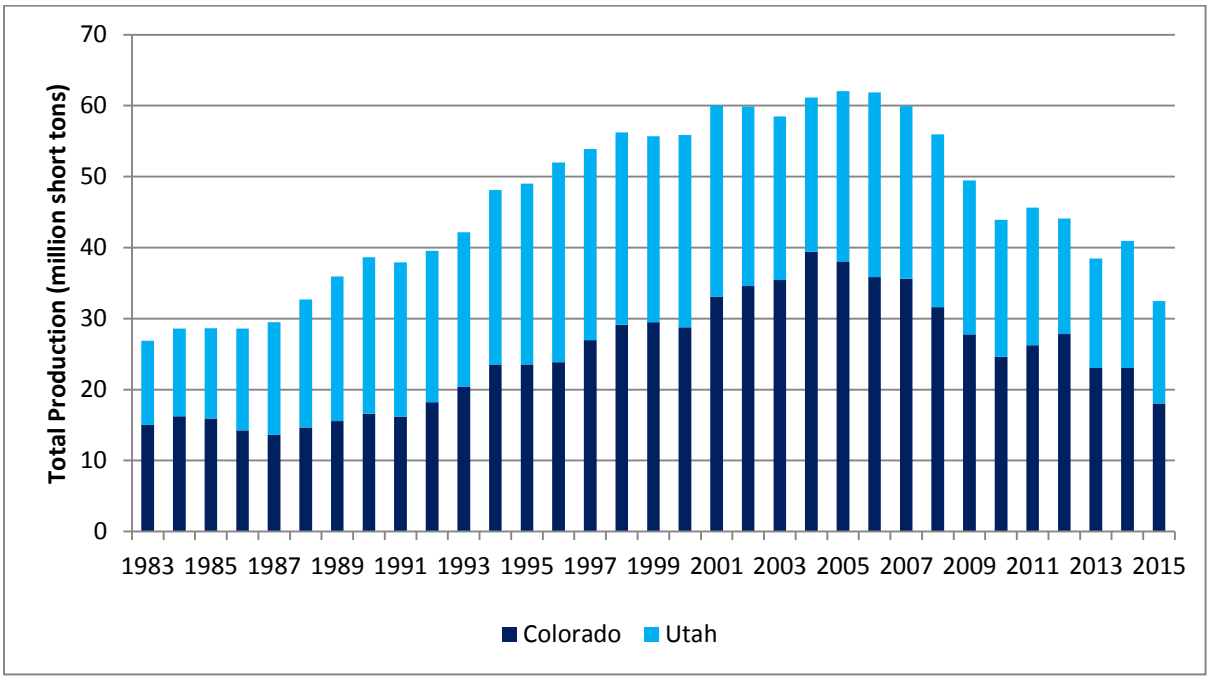


Figure 2-5. Historical Uinta Basin Coal Production (Colorado and Utah)



Source: Mine Safety and Health Administration 2016 (1983–2015 data).

Since 2008, Colorado coalfields have produced about 57% of Uinta Basin coal, with the remaining 43% produced in Utah (Table 2-2). The coal from both regions has a similar heat content; however, the Utah coal is closer to the proposed export terminals, and thus, may be more likely to be exported.

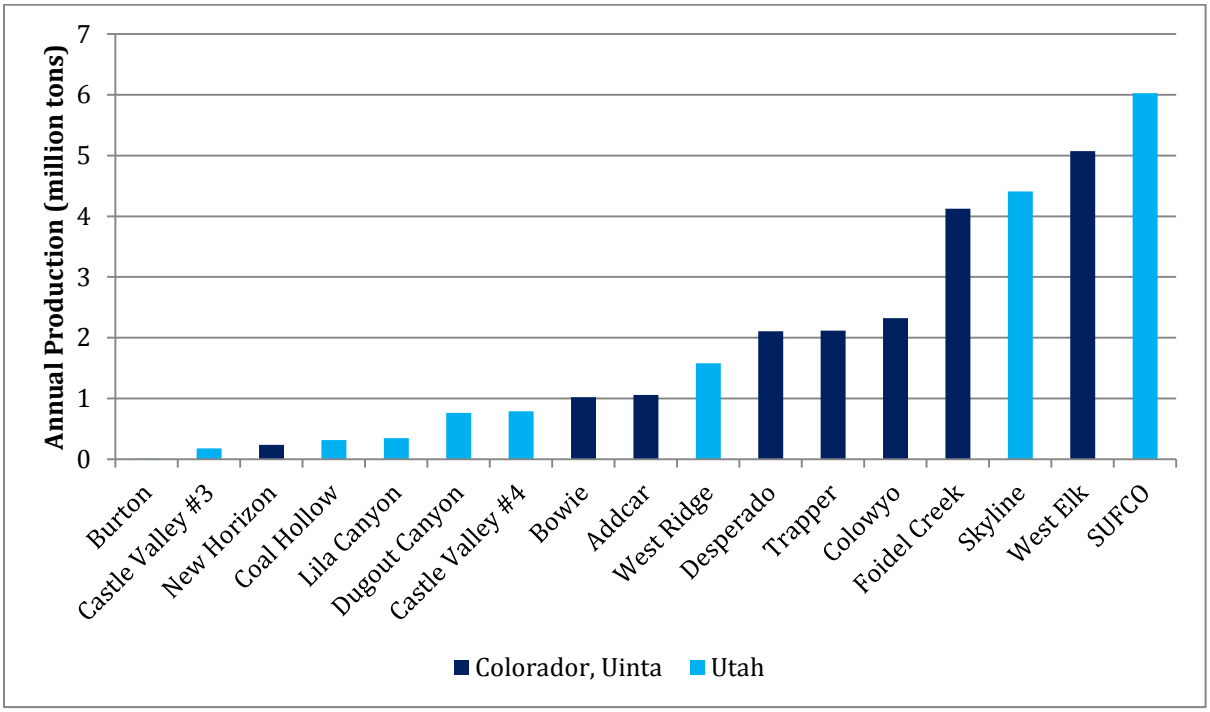
Table 2-2. Uinta Basin Coal Production by State (million short tons)

State	2008	2009	2010	2011	2012	2013	2014	2015	2008–2014 Average
Colorado, Uinta	31.6	27.8	24.6	26.2	27.8	23.5	23.0	18.1	25.3
Utah	24.4	21.7	19.3	19.4	16.3	16.4	17.9	14.4	18.7
Total	56.0	49.5	43.9	45.6	44.1	39.9	41.0	32.5	44.1

Source: Mine Safety and Health Administration 2016

Figure 2-6 shows that only 17 mines contribute to coal production in the Uinta Basin in 2015. Four mines (Foidel Creek Mine, Skyline, Sufco, and West Elk Mine) produce more than 4 million short tons per year and account for approximately half of the region's coal production.

Figure 2-6. Uinta Basin 2015 Production by Mine (million short tons)



Source: Mine Safety and Health Administration 2016

2.4 Coal Distribution

2.4.1 Powder River Basin

Powder River Basin coal is subbituminous and has a lower heat content than the bituminous coal mined in the eastern United States. The lower heat content increases the transportation cost per unit of energy, and has effectively limited the historical distribution of Powder River Basin coal to domestic markets, although in recent years exports of Powder River Basin coal have been increasing.

Historically, 98% of Powder River Basin coal has been distributed to the domestic market. Powder River Basin coal generally reaches large markets in the Midwest, Texas, the southeast, and within the basin itself (U.S. Energy Information Administration 2013a). On average, from 2010 through 2014, Iowa, Illinois, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin, consumed more than 48% (201 million short tons per year) of Powder River Basin coal, while Texas consumed 14% (58 million short tons per year) (Tables 2-3 and 2-4).

Table 2-3. Average Annual Deliveries of Powder River Basin Coal by Region[a]

Region	Montana Coal (million short tons per year)	Wyoming Coal (million short tons per year)	Total (million short tons per year)	Montana Coal (%)	Wyoming Coal (%)
Central United States	15.1	269.7	284.8	41	68
Mid-Atlantic	0.2	1.0	1.1	0	0
Northeast		1.5	1.5	0	0
Powder River Basin	8.9	15.3	24.1	24	4
Rockies		9.8	9.8	0	2
Southeast		24.3	24.3	0	6
Southwest	0.6	6.1	6.8	2	2
Texas	0.0	58.4	58.4	0	15
West	2.6	4.2	6.8	7	1
Exports	9.4	4.2	13.6	26	1
Total	**36.8**	**394.5**	**431.2**	**100**	**100**

Notes:

[a] Domestic deliveries average 2010-2014 data from U.S. Energy Information Administration 923; International deliveries (exports) average 2009-2011 data from U.S. Energy Information Administration *Annual Coal Distribution Report* as 2012 data is not yet available.

Source: U.S. Energy Information Administration 2013a

Table 2-4. Historical Powder River Basin Coal Production by Source State and Destination (million short tons)[a]

State	Historical Distribution	2009	2010	2011	2012	2013	2014	2015
Montana	Domestic Consumption[b]	36	38	33	25	30	44	42
	Exports[c,d]	2	6	8	11	12	0	0
	Total Production[e]	38	44	41	36	42	44	42
Wyoming	Domestic Consumption[b]	411	423	422	384	370	381	363
	Exports[c,d]	3	5	4	4	4	1	0.1
	Total Production[e]	414	428	426	388	374	382	363
Total	Domestic Consumption[b]	447	462	455	409	400	425	405
	Exports[c,d]	5	11	12	15	16	1	0.1
	Total Production[e]	452	473	467	425	416	426	405

Notes:

[a] Estimated exports from Montana have grown six-fold between 2009 and 2013, causing total Powder River Basin exports to more than triple. However, exports of Powder River Basin coal remain less than 4% of total Powder River Basin coal production.

[b] Total production less exports. Includes consumption at electric generating stations and industrial facilities.

[c] U.S. Energy Information Administration 2013a. Export values estimated for 2012 and 2013. U.S. Energy Information Administration 2016c. U.S. Energy Information Administration 2016d. Export values for 2014 and 2015 are only for exports directly from mines. Additional exports may have been made by brokers.

[d] Thapa pers. comm.

[e] Mine Safety and Health Administration 2016

The following factors have historically limited the economic viability of exporting Powder River Basin coal compared to higher heat content thermal coal.

- Long distances to export terminals
- Abundant international coal supply
- Relatively low international coal prices
- Relatively high shipping costs compared to international coal sources

Powder River Basin coal is exported primarily through the Pacific Northwest to Asia, with a small amount exported to Europe (Table 2-5).

Table 2-5. Powder River Basin Coal Exports by Terminal of Departure (2012)

Terminal	Destination	Coal Exports (million short tons per year)
Westshore (Vancouver, BC)[a]	Asia	4.5
Ridley (Prince Rupert, BC)[b]	Asia	2.2
New Orleans and Texas Gulf Coast[c,d]	Asia	2.0
Duluth (Superior, WI)[c,d]	Europe	1.5
Total		**10.2**

Notes:
[a] Westshore Terminals Investment Corporation 2012
[b] IHS McCloskey 2013a
[c] U.S. Securities and Exchange Commission 2012a
[d] U.S. Securities and Exchange Commission 2012b

2.4.2 Uinta Basin

The Uinta Basin consists of coal deposits in Utah and northwestern Colorado, and is part of the broader Rocky Mountain coal production area. In total, the basin covers 14,450 square miles. Over the last 20 years (1996 to 2015), Utah has produced an average of 22.8 million short tons of coal, although production in the last 3 years has fallen to between 17.9 and 14.4 million short tons. The Colorado portion of the Uinta Basin has had average production over the last 20 years of 29.6 million short tons, with production in the last 3 years ranging between 23.5 and 18.1 million short tons (Mine Safety and Health Administration 2016).[8] The coal from this region is bituminous and ideal for energy production, and stays primarily within Colorado and Utah. On average between 2010 and 2015, 72% of Uinta basin coal has been consumed in Colorado and Utah. However, Uinta Basin Coal is also consumed in states to the east, including Alabama, Illinois, Kentucky, Mississippi, and Tennessee[9]. Table 2-6 shows the average annual deliveries of Uinta Basin coal by region.

Table 2-6. Average Annual Deliveries of Uinta Basin Coal by Region[a]

Region	Colorado Uinta Coal (million short tons per year)	Utah Coal (million short tons per year)	Total (million short tons per year)	Colorado Uinta Coal (%)	Utah Coal (%)
Central United States	5.70	0.21	5.91	32	1
Mid-Atlantic	0.07	0	0.07	0	0
Rockies	9.96	12.37	22.34	56	84
Southeast	1.45	0.13	1.58	8	1
Southwest	0.13	0	0.13	1	0
West	0.41	2.06	2.47	2	14
Total	**17.73**	**14.77**	**32.50**	**100**	**100**

Notes:
[a] Domestic deliveries average 2010–2014 data from U.S. Energy Information Administration 923
Source: U.S. Energy Information Administration 2016b

[8] MSHA Part 50 data.
[9] EIA 923 data 2010 through 2015.

2.5 Pacific Northwest Export Terminals

The main operating coal export terminals on the west coast are in Vancouver and Prince Rupert (British Columbia, Canada). These terminals have limited capacity for additional overseas export of U.S. coal in spite of recently completed and proposed capacity expansions. Existing coal traffic from Canadian mines already consumes most of the Canadian terminal capacity (Westshore Terminals 2013). Increased coal terminal capacity in the United States or Canada is foreseeable because several companies in addition to the Applicant, such as Teck Coal and SSA Marine, have recently proposed several new terminals for construction on the west coast and have begun environmental reviews or permitting processes.

2.5.1 Existing Pacific Northwest Terminals

There are three existing terminals and three proposed terminals in the Pacific Northwest through which U.S. coal could be exported. The existing coal export terminals are in British Columbia, Canada, and include Westshore Terminal, Neptune Terminal, and Ridley Terminal. The Westshore and Neptune Terminals are located near Vancouver, while the Ridley Terminal is located at Prince Rupert, which is approximately 1,400 rail miles north of Vancouver.

2.5.1.1 Westshore Terminal

The Westshore Terminal is located at Roberts Bank, British Columbia, less than 1 mile north of the U.S. border. The BNSF Railway Company (BNSF), Canadian Pacific (CP), and Canadian National (CN) railroads serve this terminal. Westshore is one of the largest coal export terminals in North America and serves both Canadian and U.S. coal producers with a capacity of 36.3 million short tons per year.

2.5.1.2 Neptune Terminal

The Neptune Terminal is owned by Canadian coal company Teck Coal and is served by the BNSF, CP, and CN railroads. Neptune's export capacity is 13.2 million short tons per year. Teck Coal plans to expand the Neptune Terminal capacity by an additional 6.6 million short tons per year, with an expected online date of 2020 (Teck Resources Limited 2016). Historically, Neptune Terminal has only shipped metallurgical coal.

2.5.1.3 Ridley Terminal

The Ridley Terminal, located in Prince Rupert, British Columbia, is served by the CN railroad, and has a capacity of 19.8 million short tons per year. Ridley Terminal primarily handles coal from mines in northern British Columbia, although a few million short tons of coal from the Powder River Basin have shipped through this terminal since 2008. Several Powder River Basin coal producers, such as Arch Coal and Cloud Peak Energy, signed 5-year contracts to ship coal through Ridley Terminal. The contracts expired in 2015 and the government-owned terminal is expected to handle only Canadian coal from 2016 onward (Arch Coal 2011, de Place and MacRae 2012).[10] It is also significantly more expensive to ship Powder River Basin or other U.S. coal through Ridley Terminal compared to current or proposed terminals in Washington, Oregon, or Vancouver, British Columbia. Despite having 10% shorter shipping distance to Asia, Ridley Terminal has a rail distance that is about 100%

[10] Arch Coal's agreement with Ridley Terminal to export up to 2.5 million metric tons per year through 2015.

longer than other terminals.[11] At current rail and shipping costs, the overall transportation cost from the Powder River Basin to Asia is higher through Ridley Terminal than through the Westshore Terminal. Due to the current unfavorable market conditions, the planned expansion at Ridley Terminal is modeled as coming online in 2020.

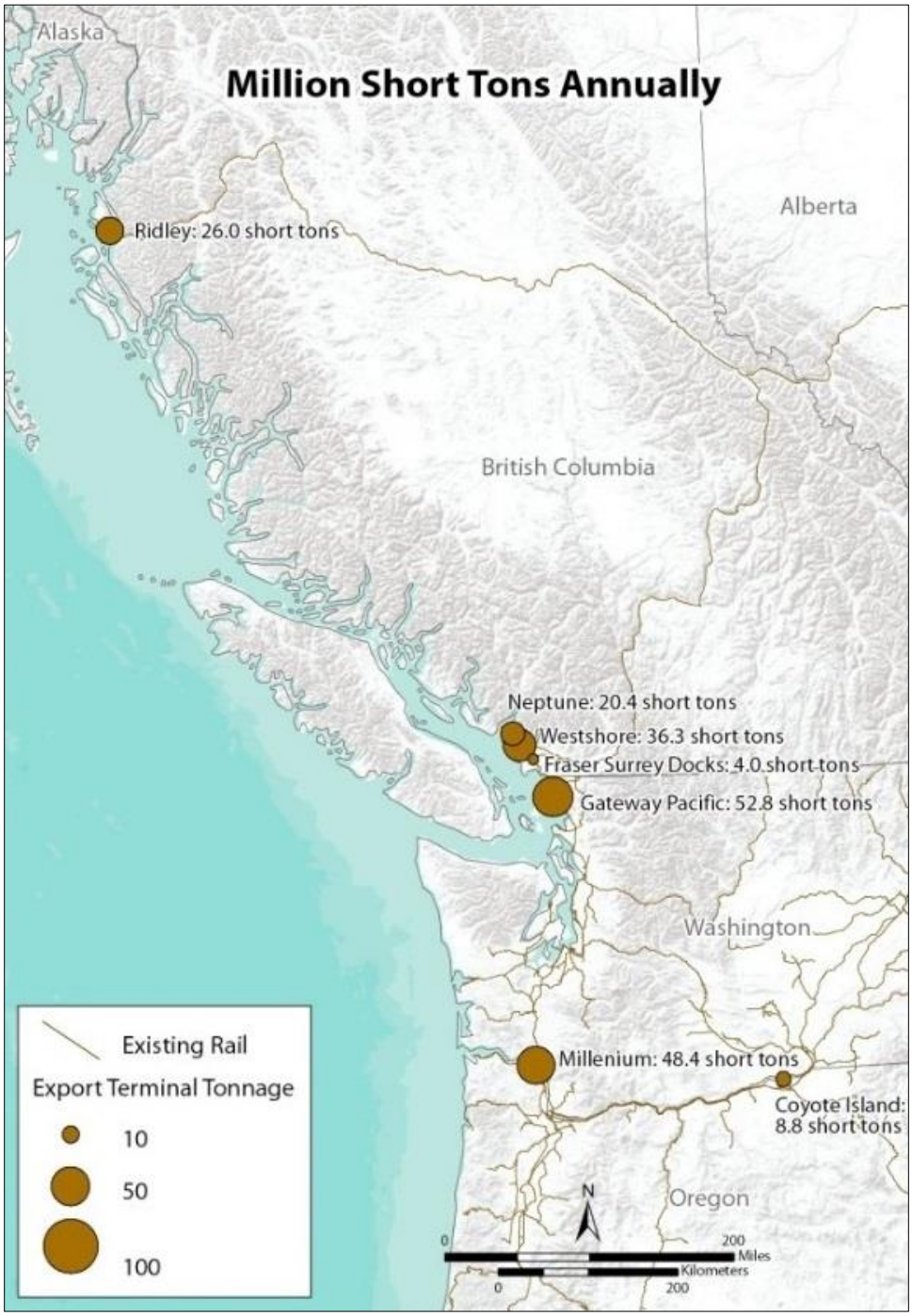
2.5.2 Planned Pacific Northwest Export Terminals

Three new coal export terminals are proposed in Washington and British Columbia that could provide additional capacity for Powder River Basin and other U.S. coal exports.[12] Figure 2-7 shows the export capacities of these terminals. Two of the proposed terminal projects are in Washington State.

[11] Cloud Peak states that the rail distance from their Powder River Basin mines to Ridley is over 2,600 miles and can require up to three different rail carriers (Cloud Peak Energy 2013).

[12] On October 16, 2016, Lighthouse Resources, Inc. announced as a result of the capability to ship coal through Westshore Terminals in Canada, they will exit the Coyote Island Project and will no longer pursue its appeal of the Oregon Department of State Lands permit opinion in 2014.

Figure 2-7. Existing and Planned Coal Export Terminals



2.5.2.1 Gateway Pacific Terminal

The proposed Gateway Pacific Terminal at Cherry Point, Washington, would handle bulk commodities such as coal. The proposed terminal is served by BNSF and has a planned capacity of

52.8 million short tons of coal per year. One advantage of this proposed terminal would be that it could load capesize vessels, which provide a cost advantage over smaller Panamax vessels.[13]

2.5.2.2 Millennium Bulk Terminals—Longview

This is the Proposed Action discussed in this technical report and described in Chapter 1, *Introduction*. The Applicant operates an existing bulk product terminal on the Columbia River in Cowlitz County. Plans include adding infrastructure to unload coal from trains and move it to storage and then to ships. The terminal is served by the BNSF and UP railroads. The terminal can load up to Panamax size vessels, with no plans to modify the port to handle larger vessels.

2.5.2.3 Fraser Surrey Docks

Fraser Surrey Docks, at Vancouver, British Columbia, has applied for a permit to construct a coal transfer facility of 4.4 million short tons per year of capacity. The BNSF railroad would serve this facility. On August 21, 2014, Port Metro Vancouver granted a Project Permit for the terminal's Direct Coal Transfer Project (Port Metro Vancouver 2014). The terminal was scheduled to begin operations in late 2015; however, the project has been delayed and the new online date is uncertain. For purposes of this analysis the terminal is assumed to come online in 2020.

2.5.3 Export Routing

The coal that would most likely be exported out of the proposed Pacific Northwest terminals is from the Powder River Basin, as most other coal basins are farther away or have other export options, such as terminals on the Atlantic or Gulf coast. The one exception is the Uinta Basin that might be competitive through the proposed coal export terminal. The transportation costs were estimated for coal exports through the proposed terminal and the other existing and planned Pacific Northwest terminals.

Tables 2-7 and 2-8 show the details of the cost calculations for transporting coal to Japan from the Powder River Basin through the two most economically viable options, which would be the Proposed Action and the Vancouver, British Columbia, area terminals. This analysis focuses on Asia because it is the fastest growing market for steam coals, and Japan is an example of an Asian movement. Japan was selected for the model to illustrate the total transportation costs, because it has historically imported more coal than any other Asian country, and is one possible destination for coal exports through the proposed terminal. Powder River Basin coal exports to other countries, such as China, South Korea, or Taiwan, would be similar, except that the shipping distances would be longer by 140 to 1,100 miles.

[13] *Capesize* vessels are cargo ships capable of carrying approximately 150,000 metric tons. *Panamax* vessels are smaller and can carry approximately 75,000 metric tons. The Gateway Pacific Terminal would be able to load the larger, capesize vessels because of its deeper waters.

Table 2-7. Estimated Powder River Basin Rail and Ship Export Costs—Pacific Northwest Exports

Powder River Basin Export Routes	Rail Distance (miles)	Rail Rate with fuel surcharge ($/ton-mile)	Total Rail Cost (2012$/ton)[a]	Ship Distance (nautical miles)	Ship Rate ($/ton-nautical mile)	Total Ship Cost via Panamax ($/ton)[b]	Port Fee ($/ton)	Total Transportation Cost ($/ton)
Montana to Japan via Proposed Coal Export Terminal	1,231	$0.0249	$30.65	4,402	$0.0027	$11.88	$11.00	$53.53
Montana to Japan via Vancouver	1,357	$0.0249	$33.79	4,328	$0.0027	$11.69	$11.00	$56.48
Wyoming 8800 Btu/lb to Japan via Proposed Coal Export Terminal	1,360	$0.0249	$33.86	4,402	$0.0027	$11.88	$11.00	$56.74
Wyoming 8800 Btu/lb to Japan via Vancouver	1,483	$0.0249	$36.93	4,328	$0.0027	$11.69	$11.00	$59.62

Notes:

[a] Includes fixed rail cost of $1.50/short ton.

[b] Includes transfer cost of $1.50/short ton.

PNW = Pacific Northwest; Btu/lb = British thermal units per pound

Source: ICF estimates and calculations. Rail distances obtained from BNSF website (http://www.bnsf.com/bnsf.was6/RailMiles/RMCentralController). Shipping distances obtained from SeaRates.com.

Table 2-8. Estimated Powder River Basin Delivered Coal Costs—Pacific Northwest Exports

Powder River Basin Export Routes	Total Transportation Cost ($/ton)[a]	Illustrative Minemouth Price ($/ton)[b]	Total Delivered Cost ($/ton)	Heat Content (MMBtu /ton)	Delivered Cost to Japan ($/MMBtu)
Montana to Japan via Proposed Coal Export Terminal	$53.53	$16.00	$69.53	18.6[c]	$3.74
Montana to Japan via Vancouver	$56.48	$167.00	$72.48	18.6[c]	$3.90
Wyoming 8800 Btu/lb to Japan via Proposed Coal Export Terminal	$56.74	$12.00	$68.74	17.6	$3.91
Wyoming 8800 Btu/lb to Japan via Vancouver	$59.62	$12.00	$71.62	17.6	$4.07

Notes:

[a] Transportation costs are derived in Table 2-7.

[b] Actual minemouth prices will differ by year for the various Powder River Basin coals; $16/ton approximates the Montana Powder River Basin 9,300 Btu/lb coal prices expected in 2016, and $13/ton approximates Powder River Basin Wyoming 8,800 Btu/lb coal prices expected in 2016.

[c] Spring Creek heat content is 9,300 Btu/lb; this is taken as the illustrative existing Montana coal's heat content.

MMBtu = million British thermal units; Btu = British thermal units

Source: ICF estimates.

The existing and proposed Pacific Northwest terminals, not including Ridley Terminal, have the following advantages and characteristics.

- **Shortest export route to Asia.** Shipping distances to Japan from the Pacific Northwest are approximately half the distance from the U.S. Gulf Coast.
- **Lowest-cost export.** There is an ocean freight cost advantage to Asia via the Pacific Northwest as compared to Gulf Coast or California originating exports.
- **Historically used for Powder River Basin shipments**. Historically, Powder River Basin exports have been shipped primarily via Pacific Northwest terminals, supporting the conclusion that this export route is most economical for Powder River Basin coal.

Lastly, as Table 2-8 shows, the delivered costs to Japan via the existing and proposed Pacific Northwest terminals are similar for all Powder River Basin coals. Relatively small changes in production costs or parts of the transportation cost could affect the export prospects of any of the Powder River Basin coals. It may be more economical to export certain Powder River Basin coals to Asia and transport others to domestic locations, as determined by the variables of location, markets, transportation facilities, and heat content of the coal.

Chapter 3
International Coal Markets

3.1 International Coal Demand

As described in Chapter 2, Section 2.3, *Coal Distribution*, only about 2% of Powder River Basin coal is exported to international markets. This chapter discusses this market.

3.1.1 Major Importing and Exporting Countries

The top five global coal-importing countries (Japan, China, South Korea, India, and Taiwan) are located in Asia and together they accounted for 63% of total coal imports globally in 2014. In Europe, while total coal imports have not bounced back to pre-recession levels last seen in 2007, they grew by about 8% from 2009 to 2012. A greater percentage of European coal imports came from the United States over this period, with U.S. coal exports to Europe approximately doubling in just four years. Table 3-1 provides the top coal countries for coal imports in 2014.

Some of the top importers rely heavily on coal imports to meet their consumption. For example, Japan, South Korea, and Taiwan import all of their coal, whereas China and India have significant domestic production and could reduce imports if coal prices increase.

Table 3-1. Top International Coal Importers in Million Short Tons (2014)

Rank	Country	Total Coal Import	Total Coal Consumption	Import (%) of Consumption
1	China	321.0	4,539.7	7.1%
2	Japan	206.9	210.6	98.2%
3	India	203.8	880.2	23.2%
4	Korea, South	144.3	144.4	99.9%
5	Taiwan	74.0	71.8	103.1%
6	Germany	62.9	264.6	23.8%
7	United Kingdom	46.0	53.5	86.0%
8	Turkey	29.6	100.4	29.5%
9	Russia	27.9	242.9	11.5%
10	Brazil	23.9	30.1	79.4%
11	Malaysia	23.5	29.3	80.2%
12	Thailand	23.0	39.7	57.9%
Total Coal Imports		**1,186.8**		

Source: U.S. Energy Information Administration 2016g

The top coal exporters are Indonesia and Australia, together accounting for nearly 54% of the total coal exports in 2012 (Table 3-2). In Australia, companies and port owners propose to construct and expand export terminals, which would triple export capacity from 490 to 1,420 million metric tons per year (Yang and Cui 2012).

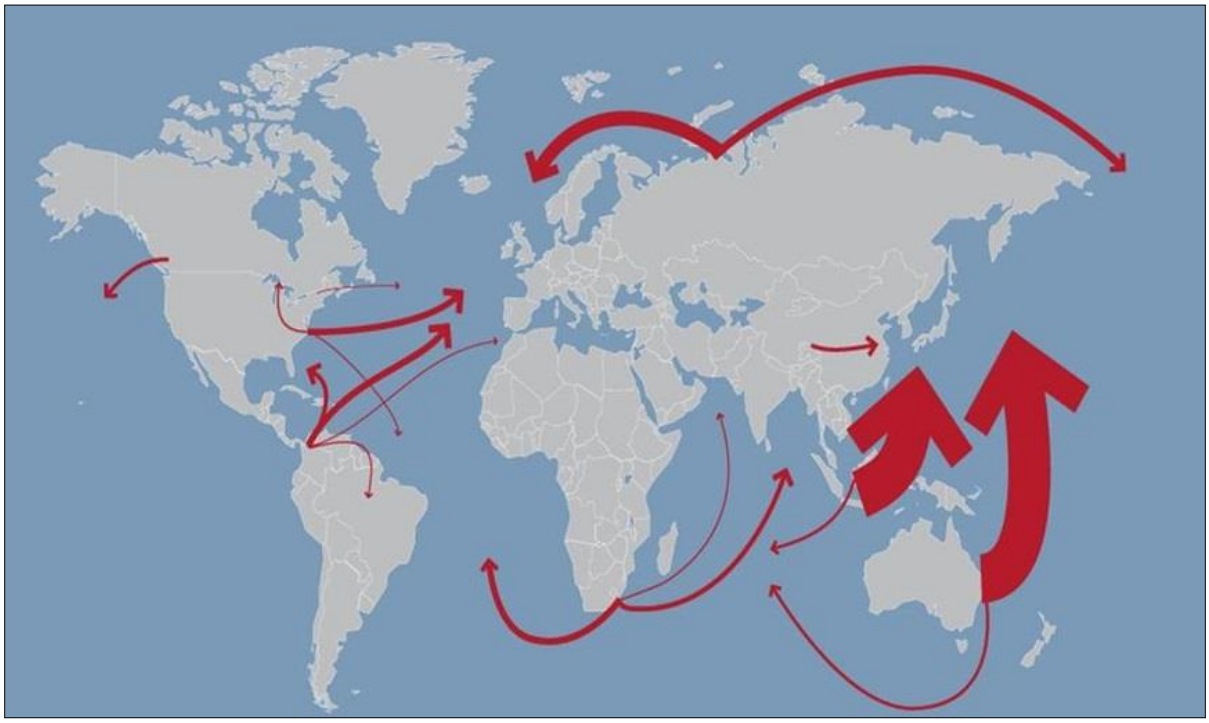
Table 3-2. Top International Coal Exporters in Million Short Tons (2014)

Rank	Country	Total Coal Export	Total Coal Production	Export (%) of Production
1	Indonesia	449.9	518.7	86.7%
2	Australia	387.3	553.3	70.0%
3	Russia	171.4	393.8	43.5%
4	United States	97.3	1,000.0	9.7%
5	Colombia	96.0	97.6	98.3%
6	South Africa	86.1	288.1	29.9%
7	Canada	38.0	74.6	50.9%
8	Kazakhstan	33.0	127.3	25.9%
9	Mongolia	20.7	34.0	61.0%
10	Korea, North	17.2	45.2	38.0%
11	Poland	10.1	150.4	6.7%
12	Vietnam	8.0	39.4	20.3%
Total Coal Exports		**1,414.9**		

Source: U.S. Energy Information Administration 2016g

In summary, the largest markets in Asia are served primarily by the largest exporters in Asia, Australia, and Indonesia (Figure 3-1). Recent Asian coal trade is comparable to the flows presented for 2009. While the Asian market is expected to grow, so is the competition between a few large suppliers.

Figure 3-1. Indonesia and Australia Dominate Asian Coal Markets



Source: Alpha Natural Resources 2010.

While Japan has historically been the largest importer of coal worldwide, India and China surpassed Japan in 2013. The economies in India and China are projected to continue to grow, adding to the demand for energy resources in the Indo-Pacific region. Coal continues to be the fuel of choice to meet burgeoning demand in these growing countries; however, planned coal additions and construction have slowed significantly since 2012. In 2015, India and China had plans to increase coal capacity by nearly 800 gigawatts, down from 1,100 gigawatts in 2012 (Shearer et al. 2015). China's 13th 5-year plan, released in November 2016, shows that China plans to limit coal plant additions such that the total coal-fired capacity remains less than 1,100 gigawatts by 2020. In 2015 China had about 900 gigawatts of coal-fired capacity. Japan, South Korea, and Taiwan lack significant domestic thermal coal reserves and have been key importers in the Asian steam coal import market. Both India and China will likely continue or increase their consumption of coal going forward.

The following sections address market conditions in the top two coal-importing nations, which are expected to remain the top importing countries for the next 10 years: Japan and China. The next three top importers—South Korea, India, and Taiwan—are expected to have flat to increasing imports, with South Korea generally flat and Taiwan increasing slowly, while coal imports to India are expected to grow more rapidly as large amounts of new electrical generating capacity comes online.

3.1.2 Asian Focus

China, Japan, South Korea, and Taiwan have historically been the world's primary importers of coal. The following provides an overview of their coal consumption and recent import level trends.

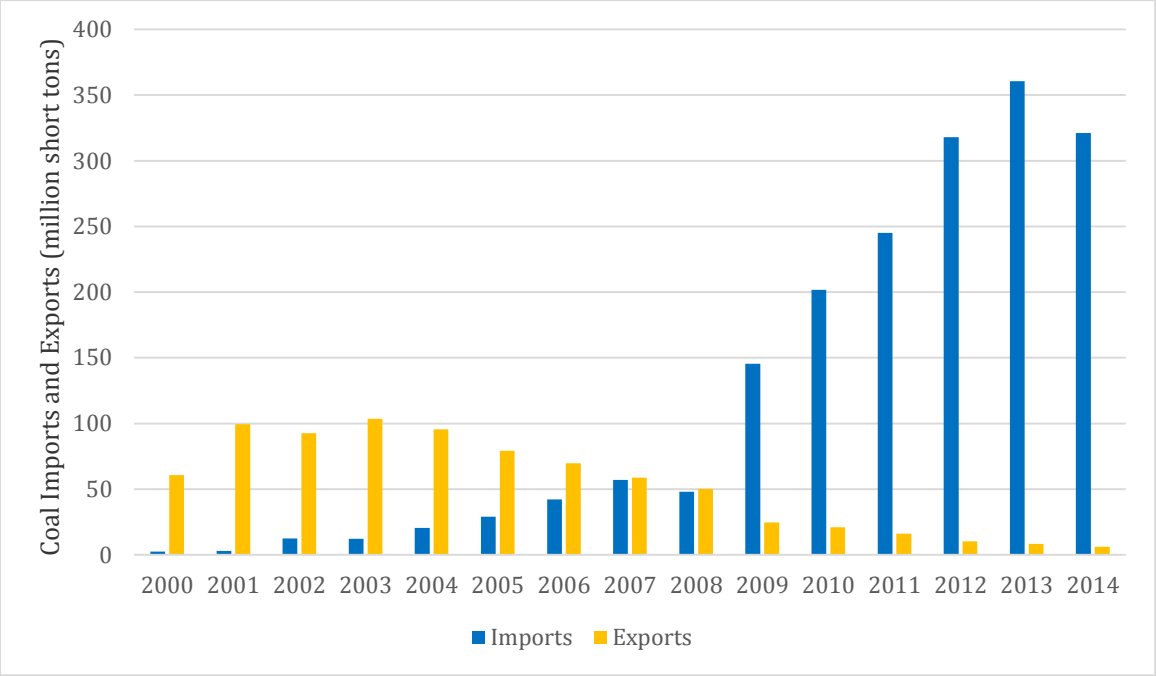
3.1.2.1 China

China is the world's largest coal producer and consumer. China's coal demand, driven by power generation and industrial uses, increased by an average of 8.44% annually from 2001 to 2012. For comparison, coal demand outside of China increased at an average of 3.8% per year (U.S. Energy Information Administration 2013a). However, coal consumption in China and across the globe actually slipped in 2012 by about 1.7% and 1.2%, respectively. As of 2012, China's coal consumption accounted for 47% of global coal consumption at about 3.9 billion tons annually—almost as much as the entire rest of the world combined (U.S. Energy Information Administration 2013b). China's demand for coal is expected to grow in the future. Although current policy changes in China will reduce the growth rate of coal consumption and the share of coal used for generating electricity, the absolute amount of coal consumed is expected to continue to increase at least through 2030, and possibly through 2040, depending on the policy alternatives (International Energy Agency World Energy Outlook 2015). To meet growing electric demand, China is planning for new installed coal capacity to peak at 1,100 gigawatts by 2020 (China's 13th 5 Year Plan). To meet growing electric demand, China is considering proposals for new installed coal capacity of 496 gigawatts (Shearer et al. 2015). For comparison, as of the end of 2015, the total capacity for all coal-fired power plants in the United States was 280 gigawatts, with nearly 18 additional gigawatts of retirements expected by the end of 2016 (SNL Energy 2015). With its vast domestic coal resources, China has historically been a coal exporter. However, China's coal imports exceeded exports for the first time in 2009 (Figure 3-2). In 2012, China imported 318 million short tons of coal, or approximately 8% of total Chinese coal consumption.[14] Chinese coal imports peaked in 2013 and fell in 2014, illustrating the

[14] For reference, 200 million tons is about 45% of recent annual coal production from the Powder River Basin, and about 10 times the permitted annual production of 20 million tons from the Otter Creek Mine.

dynamic nature of the global coal market. Climate policy developments and China's commitments at the Conference of the Parties meeting in Paris in December 2015 will likely result in Chinese coal consumption for power generation growing at 5.8% per year over the next 20 years before starting a slow decline, as projected in the International Energy Agency (IEA) 2015 World Energy Outlook (WEO) New Policies Scenario for China.

Figure 3-2. China's Coal Imports and Exports, 2000–2014 (million short tons)



Source: U.S. Energy Information Administration 2016g.

While analysts expected China's reliance on imports to increase through 2015, Chinese coal imports have actually fallen since peaking in 2013. Weaker economic growth has led to lower coal consumption, while a governmental emphasis on reducing the energy intensity of their economy and lowering air pollution are both compounding factors as well. In response, the government has protected domestic industry and prioritized domestic coal consumption. These measures resulted in a Chinese import tariff of 6% for thermal coal as of October 2014 (The Guardian 2015; Sustainable Enterprises Media 2014).

China has made progress in addressing a number of issues that might have required it to import more coal, and will allow China greater flexibility in sourcing the lowest cost coal in the future (Hook 2011).

- **Transportation bottlenecks.** Mining activity in China has shifted farther north and west, away from the south and eastern coastal cities where many coal-fired power plants are located and the demand for electricity is greatest. The coal must be transported from remote northwest locations, where there is limited demand for electricity, to the northeast ports, where it is shipped to the southern ports for domestic consumption. China has made extensive progress in addressing transportation bottlenecks over the last 5 years, which has reduced the reliance on imported coal.

- **Mine safety.** China produces coal primarily from underground coal mines. The methane concentrations in China's underground mines are responsible for a high number of fatalities, relative to fatalities in U.S. underground mines on a per ton basis. In 2012, the overall death rate in China's coal mines was 0.374 deaths per million short tons of coal production. In contrast, the death rate in the United States was around 0.035 deaths per million short tons of coal production. By closing smaller poorly run mines and through consolidation, China expects to lower overall mining fatalities per ton of coal produced (China Labour Bulletin 2013; Mine Safety and Health Administration 2016).

- **Mine consolidation.** The Chinese government has been consolidating small, private mines into a few large state-owned mines. Initially, consolidation causes coal production to fall dramatically as mines are closed temporarily to retrofit them with additional safety measures (Hook 2011). This consolidation process is well under way and most mines are back to full production.

3.1.2.2 Japan

Japan was the world's largest coal importer through 2010; however, after 2010, China became the world's largest coal importer. Japan imported an average of 193.5 million short tons of coal per year between 2000 and 2012 (U.S. Energy Information Administration 2011). Without domestic steam coal resources, Japan relies heavily on imports to satisfy domestic coal demands. Several factors may drive an increase in Japan's coal consumption and imports in the future.

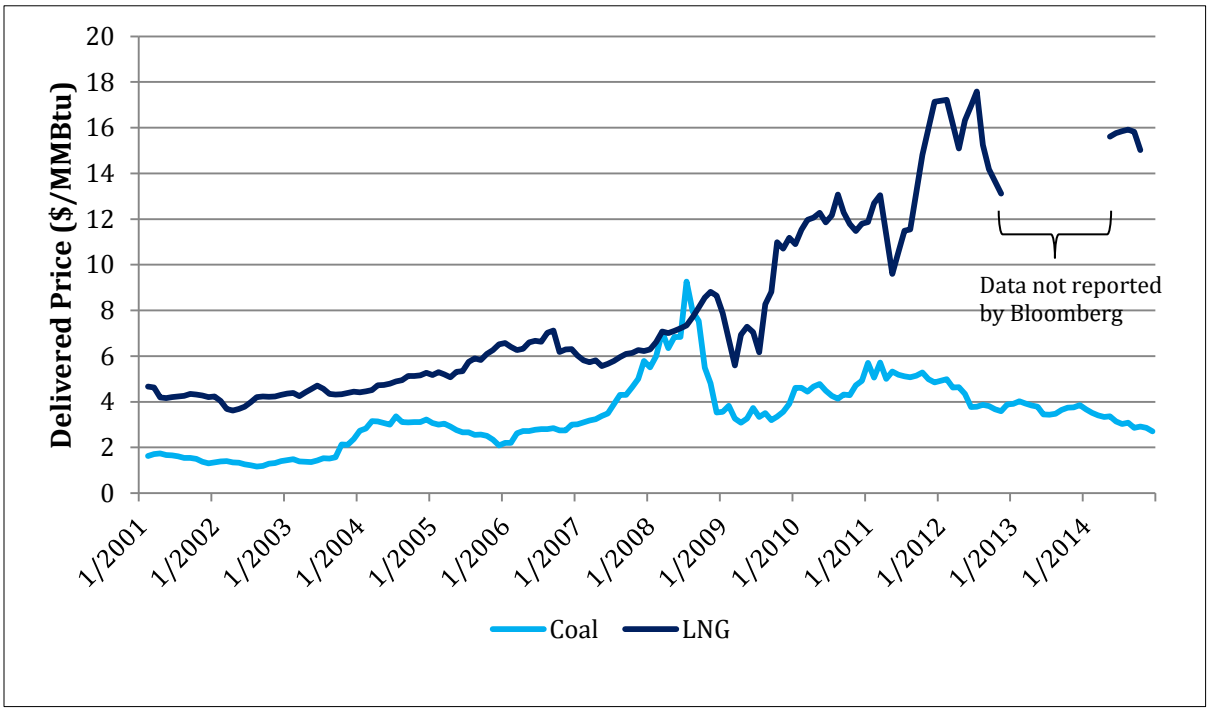
- **Uncertain future for nuclear energy.** The earthquake and tidal wave of March 2011 caused cataclysmic damage at the Fukushima nuclear power plant, precipitating the shutdown of 48 of Japan's 50 nuclear reactors, leaving only two reactors at the Oi nuclear plant in operation (Westlake 2012). Oi Units 3 and 4 ran through 2013, when they were shut down for maintenance and then ordered not to restart (World Nuclear Association 2016). Nuclear energy had previously supplied about 30% of the country's electricity needs, a percentage that, prior to the damage, had been expected to increase to 40% by 2017 and 50% by 2030 (World Nuclear Association 2016). Now the government of Japan is hoping for nuclear to supply 20-22 % of the country's electricity needs by 2030 (The Economist 2016). Since the shutdown of Japan's nuclear reactors, five nuclear reactors have been approved by Japan's Nuclear Regulation Authority to restart operations (Slater-Thompson 2016). Sendai Units 1 and 2 have restarted in August and October 2015, and Ikata Unit 3 in August 2016 (Slater-Thompson 2016). Takahama Units 3 and 4 were restarted in February and March 2016, but forced to shut down after a court injunction (World Nuclear Association 2016). Japan's Institute of Energy Economics has estimated that seven nuclear reactors could restart by March 2017, with 12 more restarting by March 2018 (World Nuclear Association 2016).

- **Relative expense of liquefied natural gas.** Coal has historically been significantly cheaper than liquefied natural gas at generally about half price per unit of energy (Figure 3-3). Much of the recent rush to build U.S. liquefied natural gas export terminals is targeted at exporting gas to Asian countries such as Japan (the world's largest liquefied natural gas importer) to take advantage of the significantly higher natural gas prices in Asia.

- **Renewed government commitment to coal energy.** After withholding approval of all but two proposed coal-fired power plants since 2006, Japan's Ministry of Environment recently lifted a virtual ban on the construction of new coal plants, provided they are equipped with the cleanest

and best technologies. This development is motivated by the economic need to diversify energy resources rather than by environmental or safety considerations (Iwata 2013).

Figure 3-3. Delivered Coal versus Natural Gas Prices to Japan ($/MMBtu)



Source: McCloskey and LNG Japan Corporation data from Bloomberg 2015

3.1.2.3 South Korea

South Korea is one of the top energy importers in the world, relying on fuel imports for about 97% of its energy demand due to lack of domestic fuel resources. In 2013 and 2014, the country was the fourth-largest importer of coal (U.S. Energy Information Administration 2016g). Australia and Indonesia account for the majority of South Korea's coal imports, followed by Russia, Canada, the United States, and China (UN Comtrade 2017). Between 2005 and 2014 coal consumption in South Korea increased by 54.5%. This rise was driven primarily by growing demand from the electric power sector. The electric power sector accounts for 62% of the country's coal consumption, while the industrial sector accounts for most of the remaining amount (U.S Energy Information Administration 2016g).

3.1.2.4 Taiwan

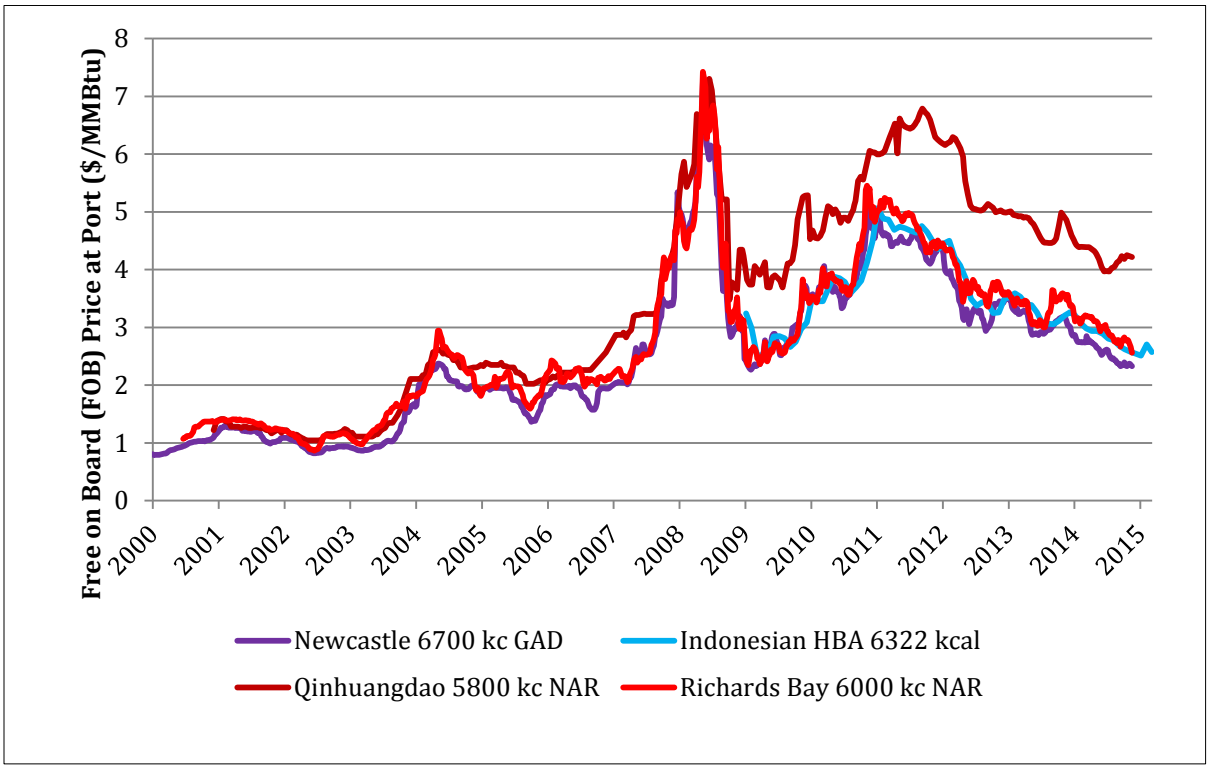
Oil and coal made up 41% and 34% of Taiwan's total primary energy consumption in 2013, respectively, while the remainder was mostly natural gas, nuclear, and smaller amounts of various renewable energy sources. Due to its very limited domestic energy resources, Taiwan imports a large percentage of coal and oil. Taiwan consumed about 72 million short tons of coal in 2014, all of which was imported (U.S. Energy Information Agency 2016g). Coal consumption steadily increased overall since the 1990s and slowed after 2008 because of natural gas and renewables substituting some coal supply in the power sector.

3.1.3 Coal Prices

3.1.3.1 Free On Board Prices

Free on board (FOB) terminal prices refer to the aggregate price of the coal, insurance, loading, transportation to the terminal, and documentation costs, typically paid by the seller. Figure 3-4 shows FOB prices at the supply country's terminal, expressed as price per energy unit ($/MMBtu) to account for coals with different heat content. Key players in the Asian steam coal export market shown in Figure 3-5 include Australia (Newcastle), Indonesia (HBA), China (Qinhuangdao), and South Africa (Richards Bay). The coal prices in Figure 3-5 are not adjusted for the coal moisture content because coals are reported as gross air-dried, gross as received, and net as received.[15]

Figure 3-4. Historical Asian Free On Board Steam Coal Prices



Source: McCloskey, Platts, Indonesia Coal Index, and Newcastle Export Index data from Bloomberg 2015

Trends in FOB costs are relatively consistent across supply ports, with the exception of China's Qinhuangdao prices, which were noticeably higher from late 2008 to 2015. This gap in prices further illustrates demand for lower-cost coal imports in China, although there are non-market effects affecting Chinese prices as well. The most recent peak in prices was in early 2011 at about $5/MMBtu. Since then international coal prices have dropped by 50% to around $2.5/MMBtu. Powder River Basin coal shipped through Vancouver, British Columbia or other Pacific Northwest

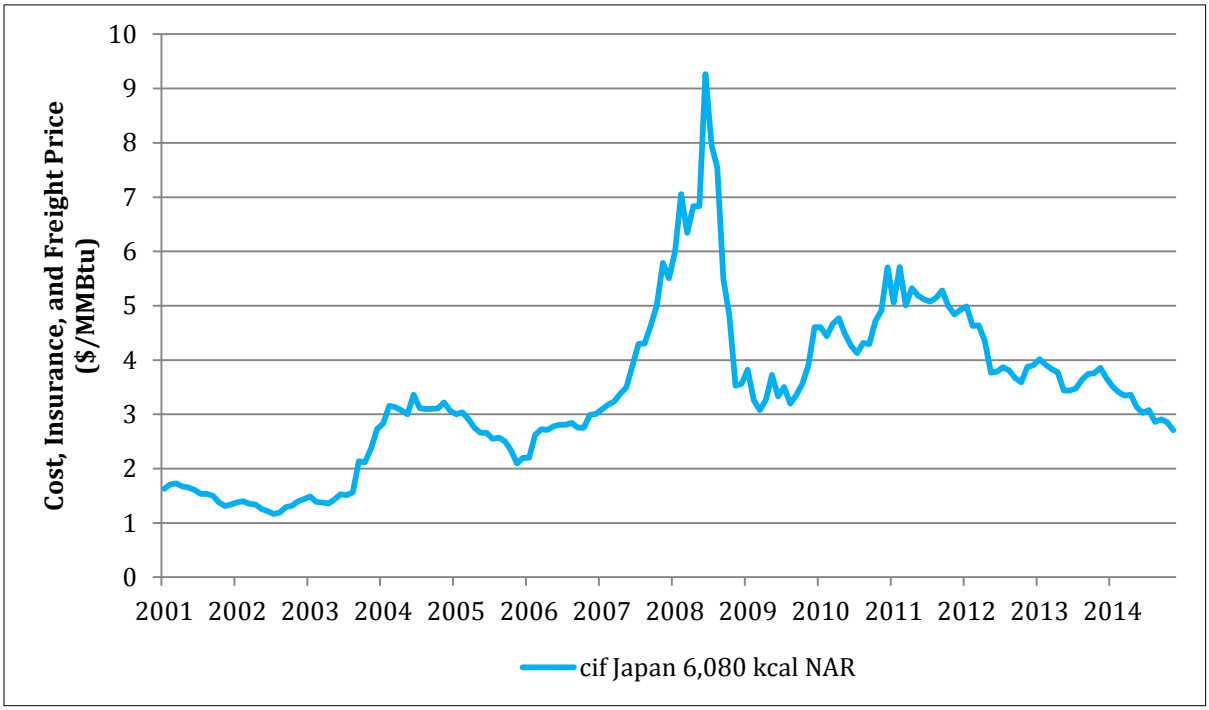
[15] Definitions and conversions can be found at World Coal Association, Coal Conversion Statistics (http://www.worldcoal.org/resources/coal-statistics/coal-conversion-statistics).

ports would have an FOB cost of close to $2.9/MMBtu in 2015, making it somewhat higher than the Asian 2015 coal prices.

3.1.3.2 Delivered Coal Prices to Japan

Delivered coal prices to Japan include the costs of coal, freight, and insurance. These prices are summarized using IHS McCloskey's Japan index benchmarks (IHS McCloskey 2013b), which show delivered prices at the terminal of delivery.[16] Prices ranged from $2.7 to $5.7/MMBtu from their peak in early 2011 through 2014 (Figure 3-5). Delivered prices to Japan in the range of $3.0/MMBtu suggest that Powder River Basin coal would have a difficult time being cost-competitive, if shipped through the Pacific Northwest to Japan or other Asian countries, until international coal prices increase.

Figure 3-5. Asian Steam Coal Prices—Japan



Source: McCloskey data from Bloomberg 2015

[16] IHS McCloskey is a company that provides benchmark coal prices that can be accessed through Bloomberg.

Chapter 4
Model Framework, Methods, and Key Assumptions

IPM® was used to assess likely coal production, consumption, and distribution patterns resulting from development of the proposed coal export terminal. The impacts of economic and regulatory uncertainties on these outcomes were also examined, through the analysis of three scenarios.

This chapter provides an overview of the IPM® framework, the key assumptions for running the model, and the specific methods used in its analysis.

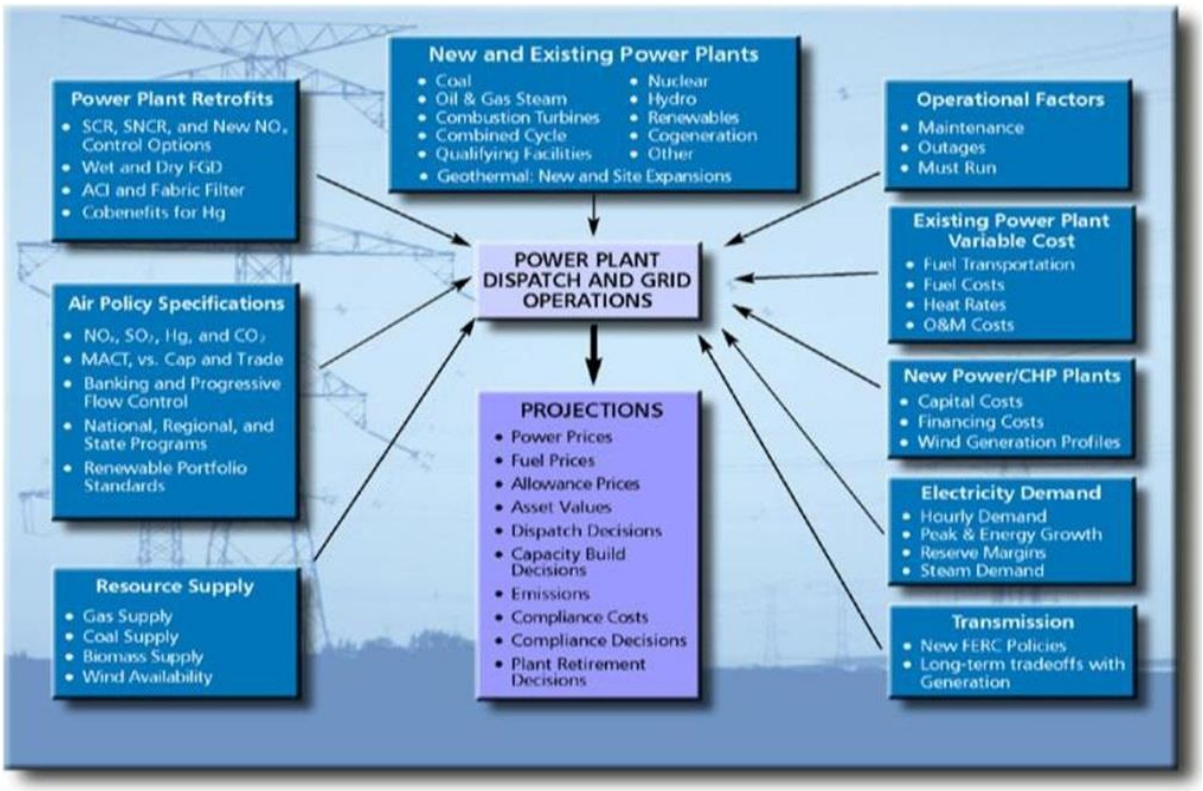
4.1 IPM® Overview and Model Framework

IPM® is an engineering and economic model of the coal and power sectors, supported by an extensive database of coal and power parameters. The model has the ability to add new electricity-generating capacity in response to demand growth and policies, such as renewable portfolio standards. It is widely used to assess domestic and international coal production, transportation, and consumption, and the operations and economics of the U.S. electric power industry. The model also characterizes the U.S. natural gas industry. IPM® is a multiregional model in terms of electricity demand regions, fuel demand regions, and coal supply regions that provides detailed results on a plant, regional, or national level. ICF has maintained IPM® since the mid-1970s.

IPM® simultaneously analyzes the following energy sectors and the important interactions between them (Figure 4-1).

- The coal mining industry, including regional coal mine type and coal quality distinctions.
- Coal transportation sectors, such as rail, barge, and ship.
- The electric power generation sector, including regional and power-plant-type distinctions, and very detailed treatment of existing power plants, especially coal-fired units.
- The electricity consumption portion of the business, including hourly and seasonal variations in demand.
- The electricity transmission sectors and the alternatives available to local power production.
- Environmental regulations (national and state) affecting the power sector including CO_2 emissions limitations and renewable portfolio standards. The model also calculates emissions for each individual plant.
- Investment and long-term operational decisions such as coal power plant retirement, power plant mothballing, new power plant construction, existing coal mine operation, and new coal mine additions.
- Domestic and international coal deliveries and consumption.
- Interactions with the natural gas industry.

Figure 4-1. Integrated Planning Model (IPM®)



IPM® analyzes these markets and calculates competitive market prices based on supply and demand fundamentals. It forecasts the following wide range of parameters.

- Wholesale market power prices for each electricity demand region.
- Power plant dispatch.
- Fuel consumption and both delivered and coal minemouth or gas hub prices.
- Interregional transmission flows.
- Environmental emissions and associated costs.
- Capacity expansion and retirements.
- Retrofits based on an analysis of the engineering economic fundamentals.

The model does not extrapolate from historical conditions. Rather, it provides a least-cost forecast for a given set of current and future conditions that determine how the industry will function. The optimization routine that IPM® uses has dynamic effects—it looks ahead at future years and simultaneously evaluates decisions over an entire specified time horizon, typically 20 to 40 years.

IPM® uses a dynamic linear programming structure to model how electricity demand is met through a mix of generation and transmission in each region, as well as the transmission between

regions. The North American version[17] of IPM® is divided into 73 power demand regions that include nine Canadian provinces. The North American version of the model also includes international coal demand and coal supply regions to forecast global coal production and movement. Regions outside of the United States and Canada in the model are limited to coal supply and demand regions only. Thus, while the North American version of IPM® explicitly includes coal power plants that can have varying coal demand depending on other inputs, such as natural gas prices and environmental regulations, regions outside of the United States and Canada have coal demand represented by a static forecast.

4.1.1 IPM® Users and Documentation

IPM® is widely used, both in the United States and globally, by private sector companies such as electric utilities, coal power plant owners, coal companies, independent power producers, and financial institutions, and public sector entities, such as environmental groups and state public service commissions (Table 4-1).

Table 4-1. Private and Public Sector Entities Using IPM®

Private Sector Entities	Public Sector Entities
PEPCO	U.S. Environmental Protection Agency
Entergy	State public service commissions
Exelon	Environment Canada
Tucson Electric Power	European Union
Florida Power and Light	Environmental groups (e.g., Natural Resources Defense Council)
Dominion	
NRG Energy	
Delmarva Power	
Southwestern Electric Power Company	
Calpine	
APS	
Duke Energy	
American Electric Power	
Otter Tail Power Company	
Xcel Energy	
Dogwood Energy	
Peabody Energy	
Dynegy	

IPM® has been used in support of the following types of analyses.

- Coal price forecasts, including forecasts supporting litigation.
- Other coal industry forecasts, including production, transportation, and consumption.

[17] ICF has completed IPM® systems for Europe, Australia, Japan, China, Korea and India, among other nations.

- Air emissions compliance strategies for coal power plants and emissions allowance price forecasting.
- Impact assessments of alternate environmental regulatory standards including coal sector impacts.
- Assessments of power plant retirement decisions, such as for existing coal power plants.
- Valuation studies for generation and transmission assets, including coal power plant valuations.
- Forecasting of regional forward energy and capacity prices.
- Forecasting of state and regional renewable energy credits.
- Impact assessments of changes in fuel pricing.
- Integrated Resource Planning analyses.
- Economic or electricity demand growth analyses.
- Pricing impacts of demand responsiveness.

EPA uses IPM® to analyze the impact of air emissions policies on the U.S. electric power sector. As part of this analysis, EPA publishes its assumptions and other information regarding its use of IPM® on its website (U.S. Environmental Protection Agency 2013 and 2015). This documentation provides insight into EPA's assumptions, and as many EPA assumptions as possible were used by ICF in this analysis as described in more detail in Section 4.2.

4.2 Key Assumptions

In this use of IPM®, key assumptions were made regarding fuel; air, waste, and water regulations; renewable energy regulations; reserve margin targets; mothballing and retirement of existing power plants; and transmission. To the extent possible, assumptions from publicly available sources, such as the EIA, IEA, and EPA were used. The majority of assumptions were obtained from EPA's v5.15 IPM Base Case (U.S. Environmental Protection Agency 2015). The following subsections discuss the major assumptions used in this analysis.

4.2.1 Assumptions from Millennium Bulk Terminals—Longview

The following project-specific assumptions were provided by the Applicant.

- The proposed coal export terminal would export 44 million metric tons of coal per year.
- The proposed coal export terminal would begin operating in 2021 and ramp up to exporting 44 million metric tons of coal by 2028; however, the IPM analysis models the terminal exporting 44 million metric tons starting in 2025.

- Only Powder River Basin or Uinta Basin coal would be exported through the proposed coal export terminal.
- Destinations for the exported coal would include China, Hong Kong, Japan, South Korea, and Taiwan.

4.2.2 Fuel

Fuel-related assumptions include those concerning coal and natural gas production and demand are presented in this section.

4.2.2.1 Coal Supply Curves and Coal Prices

The coal supply curves are pairs of quantity and price data that are used to determine the coal production and price for each coal supply region and coal type in each model solution. Thus, similar to U.S. and Canadian coal demand, the amount of coal supplied by each coal supply region is a model output and not a model input. Thus in different scenarios, the amount of coal produced from each supply region may be different. While international coal demand is an input to the model, the source of the coal consumed in each international coal demand region is a model output that is based on the coal supply curves and transportation costs to deliver the coal to each coal demand region.

The coal supply curves are built using data primarily from the Mine Safety and Health Administration's (MSHA) Part 50 database, EIA data and company financial reports. The domestic coal curves are developed by determining characteristics of U.S. mines -- including coal types produced, mine productivity, annual production capacity and available reserves – as well as developing assumptions for potential new mines, such as: mining technology type, types of coal produced, coal mine productivity, annual production capacity and reserves available. Production costs are then calculated using ICF's CoalDOM Cost Model. Finally, coal supply curves are generated for each supply region and coal type for each year based on assumptions regarding changes in productivity over time.

The domestic and international coal supply curves go through somewhat different processes to develop the supply curves, due to the lack of adequate data from many countries. The process for developing international coal supply curves entails determining the coal types produced in each supply region, their annual production capacity, available reserves, production growth rates, and costs. The coal supply curves are generated for each supply region and coal type for each year based on assumptions regarding changes in productivity over time.

The coal prices that the coal supply curves (ICF 2017a) produce in each scenario are shown in Tables 4-2 through 4-10 for both domestic and international coal prices that are most directly affected by the proposed coal export terminal. The domestic coal prices in the following tables include Wyoming, Montana, Colorado, and Utah, which are regions from which coal might be exported through the proposed terminal. The international coal prices in the following tables include Australia and Indonesia, which are the two supply regions most likely to have coal displaced by the coal exported through the proposed coal export terminal, and which have the most price visibility in the market. The coal prices presented in Tables 4-2 to 4-10 represent the prices solved by the IPM® using the assumptions defining the No-Action or Proposed Action for each scenario.

Table 4-2. Coal Prices in the 2015 U.S. and International Energy Policy Scenario—No-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	62.5	62.8	63.1	63.9	64.7	66.3
Bull Mountain	BB	33.2	33.4	33.6	28.6	29.9	29.9
CO Uinta	BB	30.7	31.2	31.9	33.3	35.4	39.1
Indonesia	BA	70.9	72.0	73.0	71.5	74.1	79.8
Indonesia	BB	58.9	59.6	60.7	59.9	62.3	67.2
Indonesia	SA	50.3	50.8	51.9	51.3	52.0	53.3
Indonesia	SB	47.5	47.9	49.0	48.4	49.1	50.3
Indonesia	SD	42.1	42.3	43.1	43.1	43.6	44.7
MT Powder River Basin	SA	15.1	15.3	15.5	15.9	17.1	17.7
MT Powder River Basin	SD	13.8	14.0	14.1	14.5	14.7	15.3
WY 8400	SB	9.0	9.1	9.3	9.6	10.0	10.8
WY 8800	SA	10.7	10.9	11.1	11.5	11.9	12.8
Utah	BA	33.6	34.5	35.7	38.5	40.7	44.1
Utah	BE	34.0	34.8	36.2	38.9	42.7	47.4

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-3. Coal Prices in the 2015 U.S. and International Energy Policy Scenario—Proposed-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	62.5	62.8	63.1	63.9	64.7	66.3
Bull Mountain	BB	33.2	33.4	33.6	28.6	29.9	29.9
CO Uinta	BB	30.9	31.4	32.1	33.6	35.8	39.6
Indonesia	BA	70.9	72.0	73.0	71.5	74.1	79.8
Indonesia	BB	58.9	59.6	60.7	59.9	62.3	67.2
Indonesia	SA	50.3	50.8	51.9	51.3	52.0	53.3
Indonesia	SB	47.5	47.9	49.0	48.4	49.1	50.3
Indonesia	SD	42.1	42.3	43.1	43.1	43.6	44.7
MT Powder River Basin	SA	15.2	15.4	15.6	16.9	17.3	17.7
MT Powder River Basin	SD	13.9	14.1	14.3	14.7	15.0	15.6
WY 8400	SB	9.1	9.2	9.4	9.8	10.2	11.1
WY 8800	SA	10.8	11.0	11.2	11.6	12.1	13.2
Utah	BA	33.9	34.8	36.1	39.0	41.4	45.3
Utah	BE	34.3	35.1	36.6	39.4	43.5	48.5

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-4. Coal Prices in the Lower Bound Scenario—No-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	56.2	56.5	56.8	57.5	58.2	59.7
Bull Mountain	BB	32.7	28.9	29.2	30.2	31.2	31.1
CO Uinta	BB	35.6	36.2	36.6	37.7	39.2	42.4
Indonesia	BA	64.1	64.5	65.3	64.9	66.5	71.8
Indonesia	BB	53.0	53.3	54.1	54.1	60.7	62.3
Indonesia	SA	45.2	45.4	46.2	46.2	46.8	47.9
Indonesia	SB	42.6	42.8	43.6	43.6	44.1	45.3
Indonesia	SD	37.1	37.4	38.3	38.1	38.7	39.6
MT Powder River Basin	SA	18.2	17.3	17.8	18.7	19.6	22.2
MT Powder River Basin	SD	16.8	17.0	17.1	17.5	17.9	18.4
WY 8400	SB	10.6	10.7	10.9	11.2	11.5	12.0
WY 8800	SA	12.4	12.0	12.5	12.9	13.3	14.5
Utah	BA	38.3	39.2	40.3	42.7	44.0	45.9
Utah	BE	42.5	42.9	43.1	43.5	46.1	48.1

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-5. Coal Prices in the Lower Bound Scenario—Proposed-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	56.2	56.5	56.8	57.5	58.2	59.7
Bull Mountain	BB	32.7	29.4	29.8	30.9	32.1	32.1
CO Uinta	BB	35.8	36.3	36.8	37.9	39.5	42.9
Indonesia	BA	64.1	64.5	65.3	64.8	66.5	71.8
Indonesia	BB	53.0	53.3	54.1	54.0	60.7	62.3
Indonesia	SA	45.2	45.4	46.2	46.2	46.8	47.9
Indonesia	SB	42.6	42.8	43.6	43.6	44.1	45.3
Indonesia	SD	37.1	37.4	38.3	38.2	38.7	39.6
MT Powder River Basin	SA	18.4	17.8	18.3	19.6	20.0	22.2
MT Powder River Basin	SD	16.8	17.0	17.1	17.5	18.3	18.9
WY 8400	SB	10.9	11.1	11.3	11.7	12.1	12.9
WY 8800	SA	12.7	12.6	12.9	13.9	14.3	15.5
Utah	BA	38.6	39.4	40.6	43.0	44.4	46.2
Utah	BE	42.4	43.1	43.4	43.8	46.6	48.4

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-6. Coal Prices in the Upper Bound Scenario—No-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	93.7	95.5	103.3	96.9	98.8	106.0
Bull Mountain	BB	29.1	27.4	27.5	30.2	32.4	35.7
CO Uinta	BB	28.6	29.3	30.2	32.1	34.5	37.8
Indonesia	BA	104.8	109.2	117.4	111.1	116.7	124.4
Indonesia	BB	88.8	92.6	99.3	94.2	99.0	105.6
Indonesia	SA	78.6	80.4	86.0	81.8	86.0	91.9
Indonesia	SB	70.7	76.0	81.3	81.3	81.3	86.8
Indonesia	SD	63.2	67.0	71.6	71.6	71.7	76.5
MT Powder River Basin	SA	17.0	17.0	14.2	14.5	14.7	15.1
MT Powder River Basin	SD	14.1	14.1	12.4	12.7	13.1	13.8
WY 8400	SB	11.2	11.5	12.1	13.4	15.2	19.3
WY 8800	SA	12.8	13.2	13.9	15.2	17.1	21.6
Utah	BA	32.6	33.6	35.2	37.5	39.8	40.6
Utah	BE	34.5	35.4	37.0	39.4	41.9	42.6

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-7. Coal Prices in the Upper Bound Scenario—Proposed-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	93.7	95.3	103.3	96.7	98.4	106.0
Bull Mountain	BB	29.1	27.4	27.5	30.5	33.2	36.4
CO Uinta	BB	29.0	29.7	30.7	32.7	35.3	39.0
Indonesia	BA	104.8	109.0	117.4	110.8	116.3	124.4
Indonesia	BB	88.8	92.5	99.3	94.2	98.7	105.6
Indonesia	SA	78.6	80.3	86.0	81.6	85.8	91.9
Indonesia	SB	70.7	75.9	81.3	81.0	81.0	86.8
Indonesia	SD	63.2	66.8	71.6	71.3	71.4	76.5
MT Powder River Basin	SA	17.0	17.0	14.2	14.5	14.7	15.1
MT Powder River Basin	SD	14.1	14.1	12.4	12.7	13.1	13.8
WY 8400	SB	11.2	11.5	12.1	13.4	15.2	19.3
WY 8800	SA	12.8	13.2	13.9	15.2	17.1	21.6
Utah	BA	33.1	33.8	35.4	37.7	40.0	43.7
Utah	BE	35.0	35.6	37.2	39.6	46.5	51.2

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-8. Coal Prices in the No Clean Power Plan and Cumulative Scenarios—No-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	62.5	62.8	63.1	63.9	64.7	66.3
Bull Mountain	BB	33.2	33.4	33.6	33.9	30.2	30.6
CO Uinta	BB	31.1	31.7	32.4	34.0	36.3	40.3
Indonesia	BA	70.9	72.7	73.8	73.8	76.3	79.2
Indonesia	BB	59.1	60.6	61.4	61.8	63.7	65.1
Indonesia	SA	51.5	51.9	52.7	53.3	54.9	57.2
Indonesia	SB	48.7	49.0	49.8	50.4	51.8	54.0
Indonesia	SD	42.1	42.3	43.8	44.1	45.6	46.7
MT Powder River Basin	SA	16.0	16.3	16.7	17.1	17.3	17.7
MT Powder River Basin	SD	14.1	14.3	14.5	14.9	15.3	16.2
WY 8400	SB	10.5	10.8	11.2	11.9	12.9	15.3
WY 8800	SA	12.3	12.6	13.0	13.9	15.0	17.5
Utah	BA	37.8	39.0	40.8	44.0	46.8	47.8
Utah	BE	39.9	41.2	42.7	46.2	49.3	50.1

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-9. Coal Prices in the No Clean Power Plan Scenario—Proposed-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	62.5	62.8	63.1	63.9	64.7	66.3
Bull Mountain	BB	33.2	33.4	33.6	33.9	30.0	30.6
CO Uinta	BB	31.1	31.7	32.4	34.0	36.3	40.3
Indonesia	BA	70.9	72.7	73.8	73.8	76.1	79.1
Indonesia	BB	59.1	60.6	61.4	61.8	63.7	65.1
Indonesia	SA	51.5	51.9	52.7	53.3	54.8	57.2
Indonesia	SB	48.7	49.0	49.8	50.4	51.7	54.0
Indonesia	SD	42.1	42.3	43.8	44.0	45.5	47.5
MT Powder River Basin	SA	16.0	16.3	16.7	17.1	17.3	17.7
MT Powder River Basin	SD	14.1	14.3	14.5	14.9	15.3	16.2
WY 8400	SB	10.5	10.8	11.2	11.9	12.9	15.3
WY 8800	SA	12.3	12.6	13.0	13.9	15.0	17.5
Utah	BA	37.8	39.0	40.8	44.0	46.8	47.8
Utah	BE	39.9	41.2	42.7	46.2	49.3	50.1

[a] Coal Types are defined in Tables 4-36 and 4-37

Table 4-10. Coal Prices in the Cumulative Scenario—Proposed-Action Alternative (2012$/short ton)

Supply Region	Coal Type[a]	2016	2018	2020	2025	2030	2040
Australia	BA	62.5	62.8	63.1	63.9	64.7	66.3
Bull Mountain	BB	35.8	34.8	34.9	38.5	41.8	45.1
CO Uinta	BB	31.1	31.7	32.4	34.0	36.3	40.3
Indonesia	BA	70.9	72.7	73.8	73.8	75.8	78.9
Indonesia	BB	59.1	60.6	61.4	61.8	63.7	65.1
Indonesia	SA	51.5	51.9	52.7	53.3	54.5	57.2
Indonesia	SB	48.6	49.0	49.8	50.3	51.5	54.0
Indonesia	SD	42.1	42.3	43.8	44.0	45.5	47.5
MT Powder River Basin	SA	16.3	16.7	17.0	17.4	17.8	18.4
MT Powder River Basin	SD	14.3	14.5	14.8	15.3	15.8	16.8
WY 8400	SB	10.6	10.8	11.2	12.0	13.0	15.4
WY 8800	SA	12.4	12.6	13.1	13.9	15.0	17.6
Utah	BA	37.8	39.0	40.8	44.0	46.8	47.8
Utah	BE	39.9	41.2	42.7	46.2	49.3	50.1

[a] Coal Types are defined in Tables 4-36 and 4-37

4.2.2.2 Natural Gas

The analysis conducted for the Draft EIS used gas price data from EPA IPM v5.13. Due to significant changes in the natural gas market over the last year, the natural gas data used in this analysis incorporates data from the EIA Annual Energy Outlook 2016, since the EPA IPM v5.15 natural gas projections are out of date (U.S. Energy Information Administration 2016a). Table 4-11 shows the natural gas prices at Henry Hub, which is a major natural gas pricing point in Louisiana, for the Draft EIS and Final EIS analysis.

Table 4-11. Natural Gas Prices in the No Clean Power Plan Scenario (2012$/MMBtu)

Year	Draft EIS Henry Hub (2012$/MMBtu)	Final EIS Henry Hub (2012$/MMBtu)
2016	4.73	3.22
2018	5.39	3.74
2020	4.86	4.44
2025	5.34	4.76
2030	5.52	4.47
2040	6.12	5.14

Note: These natural gas prices represent the prices solved by IPM® using the assumptions defining the No-Action Alternative in the No Clean Power Plan Scenario for this analysis.

4.2.3 Air, Waste, and Water Regulations

The regulatory assumptions used in this analysis reflect the assumptions used by EPA in its IPM® v5.15 Base Case. Since the non-U.S. and non-Canadian regions are only represented by coal supply and demand regions and a coal demand forecast, the impacts of environmental regulations for each

country are embedded in the coal demand forecast as described in section 4.2.8. The following regulations for the United States are included in the analysis as per the EPA IPM v5.15 Base Case.

- The provisions of the Cross State Air Pollution Rule are used in the analysis for sulfur dioxide (SO_2) and nitrogen oxides (NO_x) regulations. The rule uses a cap and trade system with allowances to reduce SO_2 and NO_x for 23 eastern states. Phase I of the rule begins in 2015, with a stepdown in available allowances in Phase II in 2017. For the Annual NO_x trading program, the total Annual NO_x allowances issued for 2015 is 1.27 million before dropping to 1.2 million allowances in 2017. For the Ozone Season NO_x trading program, the total seasonal NO_x allowances issued for 2015 is 0.63 million before dropping to 0.59 million short tons in 2017. For the Annual SO_2 trading program, the total allowances issued for 2015 is 3.47 million short tons, dropping to 2.26 million short tons in 2017.
- The EPA's Mercury and Air Toxics Standards final rule is used in the analysis and requires that all coal-fired generating units be controlled for air toxics, or be within 1 year of being controlled, by 2016, or the units must be retired (40 Code of Federal Regulations [CFR] Parts 60 and 63).
- EPA included the CO_2 cap in the Regional Greenhouse Gas Initiative for this analysis. The Regional Greenhouse Gas Initiative is a market-based regulatory program to reduce CO_2 emissions by setting a cap on emissions that decreases each year. Nine states in the northeast are part of the initiative (Regional Greenhouse Gas Initiative 2014).
- EPA also included the California Assembly Bill 32 cap-and-trade program in the v5.15 Base Case, which is expected to be more stringent than any likely federal CO_2 standards. The bill affects both in-state generation and power imported into California (Assembly Bill No. 32 Chapter 488).
- Other state SO_2 and NO_X regulations are included where final regulations exist.

4.2.4 Renewable Energy Regulations

The renewable energy standards used in this analysis reflect EPA's assumptions and regional structure regarding state specific renewable portfolio standards and solar carve-outs. These standards are provided in Table 3-17 of EPA's documentation of its IPM® v5.15 Base Case Updates, and a description of the EPA's approach is presented in Section 3.9.8 of Chapter 3 of EPA's documentation of its IPM® v5.13 Base Case. Since the non-U.S. and non-Canadian regions are only represented by coal supply and demand regions and a coal demand forecast, the impacts of renewable energy regulations for each country are embedded in the coal demand forecast as described in section 4.2.8.

4.2.5 Electric Demand

The analysis models net energy and peak demand using the assumptions in EPA's IPM v.5.15 documentation. EPA divides the 48 contiguous states and the District of Columbia into 64 model regions based on the characterization of operations. IPM also covers the electric power sector in Canada, and Canada is divided into 11 model regions. Figure 4-2 shows the electric demand regions used in the analysis for the EIS.

Figure 4-2. Map of IPM Model Regions

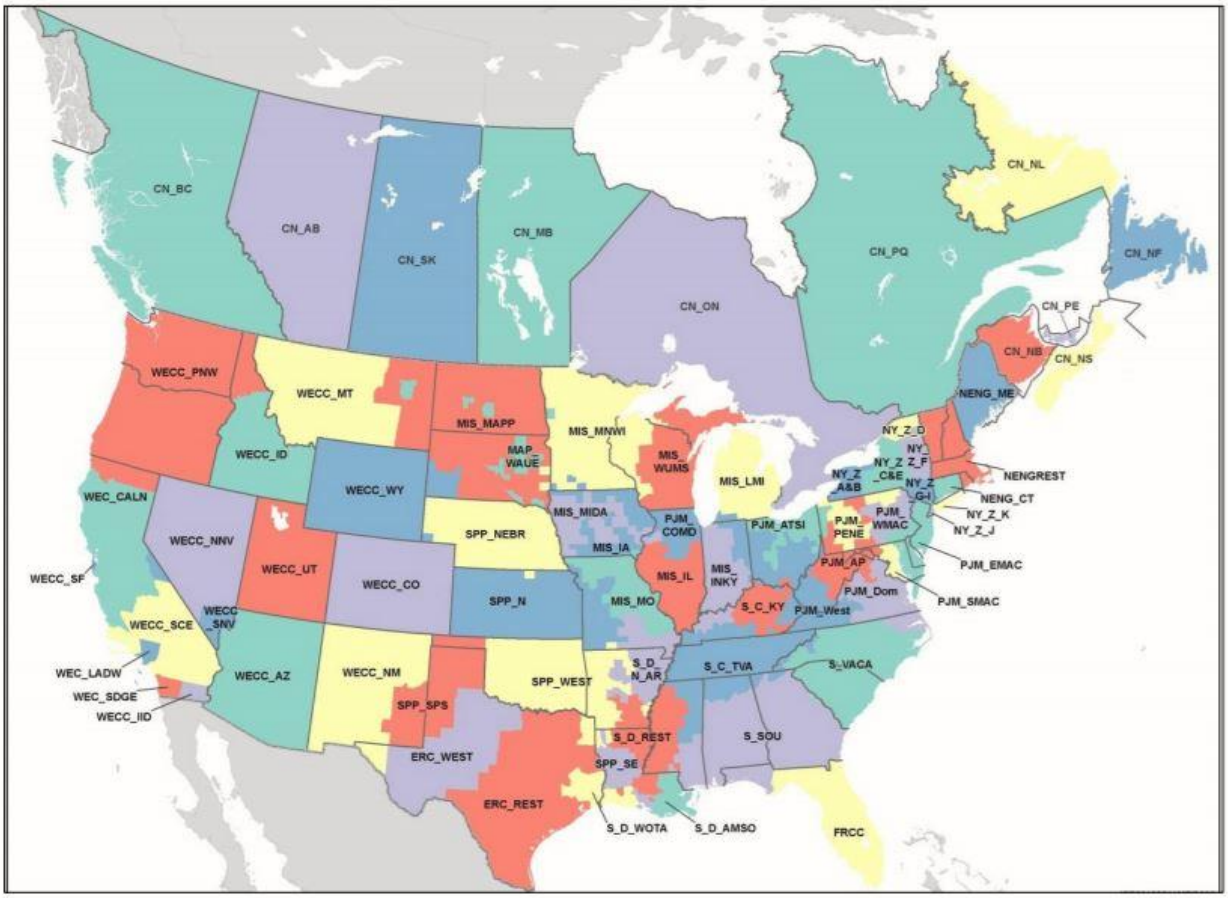


Table 4-12 shows the 64 electric demand regions assembled into eight regional groups that are defined by independent system operator (ISO) or North American Electric Reliability Council (NERC) boundaries. The net energy for load and coincident peak load values assumed in this analysis, are shown in Tables 4-13 and 4-14 by these eight regional groups.

Table 4-12. IPM Region Groups

Model Region Name	General Region Name	General Region Acronym
ERCOT_Tenaska Frontier Generating Station	Electric Reliability Council of Texas	ERCOT
ERCOT_Tenaska Gateway Generating Station	Electric Reliability Council of Texas	ERCOT
ERCOT_Rest	Electric Reliability Council of Texas	ERCOT
ERCOT_West	Electric Reliability Council of Texas	ERCOT
FRCC	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
MAPP_WAUE	Midwest Reliability Organization	MRO
MISO_Iowa	Midwest Reliability Organization	MRO
MISO_Illinois	Midwest Reliability Organization	MRO
MISO_Indiana (including parts of Kentucky)	Midwest Reliability Organization	MRO
MISO_Lower Michigan	Midwest Reliability Organization	MRO
MISO_MT, SD, ND	Midwest Reliability Organization	MRO
MISO_Iowa-MidAmerican	Midwest Reliability Organization	MRO
MISO_Minnesota and Western Wisconsin	Midwest Reliability Organization	MRO
MISO_Missouri	Midwest Reliability Organization	MRO

Model Region Name	General Region Name	General Region Acronym
MISO_Wisconsin- Upper Michigan (WUMS)	Midwest Reliability Organization	MRO
ISONE_Connecticut	ISO New England	ISONE
ISONE_Maine	ISO New England	ISONE
ISONE_MA, VT, NH, RI (Rest of ISO New England)	ISO New England	ISONE
NY_Zones A&B	New York ISO	NYISO
NY_Zone C&E	New York ISO	NYISO
NY_Zones D	New York ISO	NYISO
NY_Zone F (Capital)	New York ISO	NYISO
NY_Zone G-I (Downstate NY)	New York ISO	NYISO
NY_Zone J(NYC)	New York ISO	NYISO
NY_Zone K(LI)	New York ISO	NYISO
PJM_AP	PJM Interconnection	PJM
PJM_ATSI	PJM Interconnection	PJM
PJM_ComEd	PJM Interconnection	PJM
PJM_Dominion	PJM Interconnection	PJM
PJM_EMAAC	PJM Interconnection	PJM
PJM_PENELEC	PJM Interconnection	PJM
PJM_SWMAAC	PJM Interconnection	PJM
PJM West	PJM Interconnection	PJM
PJM_Western MAAC	PJM Interconnection	PJM
SERC_Central_Kentucky	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SERC_Central_TVA	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SERC_Delta_Amite South (including DSG)	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SERC_Delta_Northern Arkansas (including AECI)	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SERC_Delta_Rest of Delta (Central Arkansas)	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SERC_Delta_WOTAB (including Western)	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SERC_Southeastern	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SERC_VACAR	SERC Reliability Corporation + Florida Reliability Coordinating Council	SERC + FRCC
SPP_Kiamichi Energy Facility	Southwest Power Pool	SPP
SPP North- (Kansas, Missouri)	Southwest Power Pool	SPP
SPP Nebraska	Southwest Power Pool	SPP
SPP Southeast- (Louisiana)	Southwest Power Pool	SPP
SPP SPS (Texas Panhandle)	Southwest Power Pool	SPP
SPP West (Oklahoma, Arkansas, Louisiana)	Southwest Power Pool	SPP
WECC_Northern California (including SMUD)	Western Electricity Coordinating Council	WECC
WECC_LADWP	Western Electricity Coordinating Council	WECC
WECC_San Diego Gas and Electric	Western Electricity Coordinating Council	WECC
WECC_Arizona	Western Electricity Coordinating Council	WECC
WECC_Colorado	Western Electricity Coordinating Council	WECC
WECC_Idaho	Western Electricity Coordinating Council	WECC
WECC_Imperial Irrigation District (IID)	Western Electricity Coordinating Council	WECC
WECC_Montana	Western Electricity Coordinating Council	WECC
WECC_New Mexico	Western Electricity Coordinating Council	WECC
WECC_Northern Nevada	Western Electricity Coordinating Council	WECC
WECC_Pacific Northwest	Western Electricity Coordinating Council	WECC
WECC_Southern California Edison	Western Electricity Coordinating Council	WECC
WECC_San Francisco	Western Electricity Coordinating Council	WECC
WECC_Southern Nevada	Western Electricity Coordinating Council	WECC
WECC_Utah	Western Electricity Coordinating Council	WECC
WECC_Wyoming	Western Electricity Coordinating Council	WECC

Table 4-13. Net Energy for Load (GWh), 2016–2040

Year	ERCOT	ISONE	MRO	NYISO	PJM	SERC + FRCC	SPP	WECC	Total
2016	336,781	135,562	523,629	154,648	791,098	1,058,519	265,877	726,464	3,992,578
2017	335,378	137,602	529,019	154,133	796,575	1,067,427	265,681	730,228	4,016,043
2018	339,396	137,741	531,748	153,329	799,977	1,078,305	268,215	735,360	4,044,071
2019	344,623	137,300	535,104	152,941	804,735	1,091,911	271,474	743,130	4,081,218
2020	346,838	135,738	535,239	151,010	802,854	1,096,599	272,832	745,085	4,086,195
2021	349,809	135,046	537,082	149,882	803,749	1,104,174	274,826	750,824	4,105,392
2022	353,286	134,675	540,125	149,152	806,620	1,113,545	277,235	756,705	4,131,343
2023	357,387	134,755	544,524	149,168	812,315	1,126,847	280,255	765,045	4,170,296
2024	361,419	134,812	548,372	149,123	817,361	1,138,496	283,011	772,731	4,205,325
2025	364,711	134,684	551,154	148,866	820,954	1,148,364	285,244	779,232	4,233,209
2026	368,660	134,833	553,938	148,864	824,941	1,158,932	287,754	785,717	4,263,639
2027	371,928	135,059	556,513	148,960	828,709	1,168,639	289,868	792,410	4,292,086
2028	375,271	135,100	558,019	148,929	831,408	1,177,867	291,800	798,702	4,317,096
2029	378,904	135,234	559,371	149,040	834,105	1,186,624	293,777	804,964	4,342,019
2030	381,943	135,117	560,078	148,877	835,612	1,193,392	295,349	809,455	4,359,823
2031	385,342	135,268	561,275	148,993	837,917	1,200,995	297,191	814,606	4,381,587
2032	389,039	135,550	563,542	149,333	841,639	1,210,294	299,354	821,394	4,410,145
2033	393,036	135,925	566,307	149,718	846,035	1,220,957	301,836	829,594	4,443,408
2034	397,367	136,367	569,568	150,090	851,053	1,232,585	304,594	838,089	4,479,713
2035	401,882	136,929	573,401	150,712	856,892	1,245,282	307,559	847,306	4,519,963
2036	406,543	137,454	577,216	151,234	862,814	1,258,074	310,560	856,723	4,560,618
2037	411,608	138,091	581,037	151,769	868,982	1,271,971	313,761	866,580	4,603,799
2038	417,023	138,651	585,140	152,282	875,440	1,286,667	317,218	877,170	4,649,591
2039	422,121	139,116	589,757	152,783	882,045	1,300,014	320,585	887,429	4,693,850
2040	427,127	139,718	594,765	153,407	889,038	1,313,687	324,076	898,730	4,740,548

Source: EPA IPM v.5.15

Table 4-14. Coincident Peak Demand (MW), 2016–2040

Year	ERCOT	ISONE	MRO	NYISO	PJM	SERC + FRCC	SPP	WECC
2016	69,984	25,350	92,566	29,772	144,532	190,958	51,667	127,597
2017	69,854	25,831	93,098	29,761	145,262	192,170	51,723	128,320
2018	70,499	25,941	93,386	29,656	145,687	193,632	52,066	129,279
2019	71,486	25,939	93,963	29,646	146,587	195,846	52,650	130,846
2020	72,157	25,834	94,341	29,471	146,906	197,343	53,091	131,809
2021	72,821	25,820	94,833	29,363	147,401	198,959	53,532	133,140
2022	73,516	25,839	95,414	29,321	148,089	200,664	53,991	134,486
2023	74,307	25,939	96,278	29,404	149,337	203,166	54,566	136,376
2024	75,140	26,036	97,017	29,470	150,464	205,395	55,112	138,027

2025	75,911	26,118	97,649	29,540	151,460	207,456	55,624	139,494
2026	76,861	26,290	98,315	29,650	152,555	209,731	56,225	141,080
2027	77,659	26,452	98,929	29,787	153,624	211,915	56,752	142,686
2028	78,505	26,556	99,434	29,871	154,544	214,054	57,271	144,242
2029	79,492	26,682	99,951	29,992	155,532	216,210	57,853	145,819
2030	80,508	26,785	100,440	30,121	156,487	218,251	58,439	147,206
2031	81,605	26,940	101,029	30,300	157,592	220,469	59,085	148,699
2032	82,756	27,120	101,772	30,510	158,907	222,965	59,800	150,525
2033	83,892	27,299	102,555	30,724	160,281	225,587	60,517	152,515
2034	85,094	27,486	103,423	30,904	161,723	228,343	61,292	154,607
2035	86,305	27,700	104,392	31,123	163,336	231,282	62,089	156,833
2036	87,542	27,908	105,367	31,372	164,999	234,193	62,892	159,067
2037	88,822	28,146	106,359	31,595	166,676	237,265	63,716	161,408
2038	90,170	28,350	107,391	31,798	168,362	240,438	64,588	163,851
2039	91,462	28,528	108,456	31,998	170,022	243,388	65,443	166,310
2040	92,698	28,726	109,573	32,243	171,764	246,338	66,291	168,925

Source: EPA IPM v.5.15

4.2.6 Reserve Margin Targets

IPM's reliability-related assumptions reflect planning reserve margin requirements. These requirements are targets for generating capacity that are used to ensure sufficient generating capacity is available at all times, such as when some plants are out of service for maintenance or equipment problems occur during peak demand periods. The reserve margin assumptions used in IPM® for this analysis are the planning reserve margins used by EPA in its IPM® v5.13 Base Case, as described in Section 3.6 of Chapter 3 of its v5.13 documentation. These assumptions were not updated for v5.15.

Since the non-U.S. and non-Canadian regions are only represented by coal supply and demand regions and a coal demand forecast, the electric power system is not modeled explicitly and thus reserve margin target assumptions are not necessary for these regions.

4.2.7 Planned New Capacity and Retirements

The installation of new generating capacity and retirement of existing capacity is typically planned several years in advance of the capacity coming online or being retired. The analysis for the EIS includes new planned generating capacity and retirements that have been announced and meet threshold criteria. New generating capacity is included in the analysis if the plant has either started construction or meets two of the three criteria:

- All environmental permits have been obtained.
- Financing has been secured.
- At least 50% of the output is under a power purchase agreement.

Announced retirements are included if they have been approved by the relevant utility commission or independent system operator, or are part of a court settlement. Planned new capacity and retirements are important to energy market analyses, as they incorporate known changes to the existing capacity mix. The changes in capacity mix impact the fuels consumed and thus the demand for and prices of fuels within the forecast horizon. Tables 4-15 and 4-16 show the planned new capacity from 2016 through 2020 that are included in the analysis. Table 4-15 shows new capacity by the eight regions described in Section 4.2.5, *Electric Demand,* and shown in Table 4-12. Table 4-16 shows new generating capacity by capacity type. Tables 4-17 and 4-18 show the planned retirements from 2016 through 2020 by region and by capacity type, respectively. A full list of plant and unit names for the planned new capacity and planned retirements can be found in Appendix A, *Planned New Generating Capacity and Planned Retirements.*

Table 4-15. Planned New Capacity by Region, 2016 to 2020 (MW)

Region Name	2016	2017	2018	2019	2020	Total
ERCOT	1,855	5,370	24	400	0	7,649
ISONE	152	923	0	2	0	1,077
MRO	2,158	2,208	386	170	0	4,922
NYISO	694	0	1,154	6	0	1,854
PJM	4,857	4,695	525	48	0	10,125
SERC + FRCC	3,233	1,188	2,425	2,200	1,100	10,146
SPP	1,853	495	400	0	0	2,748
WECC	4,919	565	1,409	1,215	628	8,736
Total	19,721	15,444	6,323	4,041	1,728	47,257

Source: SNL

Table 4-16. Planned New Capacity by Capacity Type, 2016 to 2020 (MW)

Capacity Type	2016	2017	2018	2019	2020	Total
Biomass	437	180	0	0	0	617
Coal	99	134	850	400	0	1,483
Combined Cycle	7,610	11,354	3,265	460	487	23,176
Combustion Turbine	822	1,584	280	0	0	2,686
Geothermal	11	28	165	45	90	339
Hydro	29	8	64	24	0	125
Landfill	10	2	0	0	0	12
Nuclear	1,122	0	1,100	2,200	1,100	5,522
Oil/Gas	8	0	0	0	0	8
Other	282	1,058	0	0	0	1,340
Solar	4,578	239	49	500	51	5,417
Wind	4,713	857	550	412	0	6,532
Total	19,721	15,444	6,323	4,041	1,728	47,257

Source: SNL

Table 4-17. Planned Retirements by Region, 2016 to 2020 (MW)

Region Name	2016	2017	2018	2019	2020	Total
ISONE	0	1,678	0	0	0	1,678
MRO	3,044	51	322	0	176	3,593
NYISO	78	0	0	0	0	78
PJM	4,377	339	1,215	615	0	6,546
SERC + FRCC	3,410	2,299	1,730	664	0	8,103
SPP	810	0	0	1,383	103	2,296
WECC	65	1,214	928	2,070	1,288	5,565
Total	11,784	5,581	4,195	4,732	1,567	27,859

Source: SNL

Table 4-18. Planned Retirements by Capacity Type, 2016 to 2020 (MW)

Capacity Type	2016	2017	2018	2019	2020	Total
Coal	10,713	3,862	3,939	2,388	1,464	22,366
Combustion Turbine	846	704	14	6	0	1,570
Hydro	0	5	0	0	0	5
Nuclear	0	0	0	615	0	615
Oil/Gas	225	1,010	242	1,723	103	3,303
Total	11,784	5,581	4,195	4,732	1,567	27,859

Source: SNL

4.2.8 Mothballing and Retirement

ICF's assumptions reflect the ability of electricity generating plants to mothball and return to service later, or to retire. The capability to model plants entering a mothball state or retiring more realistically represents the actual energy market than a model that does not include this capability.

- To capture market exit behavior, IPM® included mothballing and retirement capabilities. Generating units with high fixed operations and maintenance costs become candidates for mothballing and retirement as more efficient generation capacity is constructed.
- The mothballing option is provided for all oil/natural gas steam facilities and is exercised if short-term annual fixed costs exceed annual revenues in a market with excess supply. The decision to mothball takes into consideration fixed costs, reserve requirements, and the costs of mothballing a unit and returning it to service later.
- Retirement options are available to all existing coal, nuclear, and oil/natural gas steam units in IPM®. The modeling assumes that the retirement option would be exercised if projected discounted cash flows do not exceed projected costs (fixed, variable, and capital). Again, this decision takes long-term reserve requirements and revenues into consideration.

- The analysis assesses higher fixed operations and maintenance costs to uncontrolled coal units after 60 years in service to account for life-extension costs, potentially increasing the amount of coal retirements as the model chooses to retire units rather than pay the life-extension costs.

Since the non-U.S. and non-Canadian regions are only represented by coal supply and demand regions and a coal demand forecast, individual power plants are not modeled in these regions and thus assumptions regarding mothballing and retirement are not needed.

4.2.9 Capital Costs for New Generating Capacity

Table 4-19 shows the "main street" capital costs of new generating capacity for the IPM run years. The "main street" costs are for a representative location, and then adjusted for each electric demand region based on region specific cost multipliers. Costs for all capacity types, except for solar photovoltaic, solar thermal, onshore wind, and offshore wind remain the same in the forecast horizon. Solar and wind capital costs change over the years due to technological development as well as available tax incentives. Costs for capacity types other than solar and wind new generating capacity are based on the assumptions from EPA's power sector modeling platform IPM v.5.15. For solar and wind builds, capital costs are based on EPA's power sector modeling platform IPM v5.15 as well, but with additional adjustments based on the latest production tax credit and investment tax credit structures.

Table 4-19. Capital Costs for New Generating Capacity, 2011$/kW

Capacity Type	Class	Step	2016	2018	2020	2025	2030	2040
Advanced Combined Cycle	N/A	N/A	1,006	1,006	1,006	1,006	1,006	1,006
Advanced Combustion Turbine	N/A	N/A	664	664	664	664	664	664
Nuclear	N/A	N/A	5,429	5,429	5,429	5,429	5,429	5,429
IGCC	N/A	N/A	2,969	2,969	2,969	2,969	2,969	2,969
IGCC with Carbon Sequestration	N/A	N/A	4,086	4,086	4,086	4,086	4,086	4,086
Supercritical Pulverized Coal	N/A	N/A	2,883	2,883	2,883	2,883	2,883	2,883
Biomass-Bubbling Fluidized Bed (BFB)	N/A	N/A	4,041	4,041	4,041	4,041	4,041	4,041
Geothemal	N/A	N/A	1,187 - 15,752	1,187 - 15,752	1,187 - 15,752	1,187 - 15,752	1,187 - 15,752	1,187 - 15,752
Landfill - LGHI	N/A	N/A	8,408	8,408	8,408	8,408	8,408	8,408
Landfill - LGLo	N/A	N/A	10,594	10,594	10,594	10,594	10,594	10,594
Landfill - LGVLo	N/A	N/A	16,312	16,312	16,312	16,312	16,312	16,312
Hydro	N/A	N/A	1,170 - 6,541	1,170 - 6,541	1,170 - 6,541	1,170 - 6,541	1,170 - 6,541	1,170 - 6,541
Fuel Cells	N/A	N/A	7,117	7,117	7,117	7,117	7,117	7,117
Solar PV	N/A	N/A	1,575	1,581	1,583	2,056	1,668	2,134
Solar Thermal	N/A	N/A	3,705	3,713	3,718	4,805	4,849	4,914
Onshore Wind	1	1	1,044	1,043	1,289	1,664	1,675	1,691
Onshore Wind	1	2	945	943	1,228	1,664	1,675	1,691
Onshore Wind	1	3	846	844	1,168	1,664	1,675	1,691
Onshore Wind	1	5	813	810	1,148	1,664	1,675	1,691

Onshore Wind	2	1	730	727	1,098	1,664	1,675	1,691
Onshore Wind	2	2	1,099	1,098	1,322	1,664	1,675	1,691
Onshore Wind	2	3	1,009	1,008	1,267	1,664	1,675	1,691
Onshore Wind	2	5	920	917	1,213	1,664	1,675	1,691
Onshore Wind	3	1	889	894	1,213	1,711	1,731	1,751
Onshore Wind	3	2	814	818	1,167	1,711	1,731	1,751
Onshore Wind	3	3	1,167	1,175	1,382	1,711	1,731	1,751
Onshore Wind	3	5	1,087	1,095	1,333	1,711	1,731	1,751
Onshore Wind	4	1	1,008	1,018	1,294	1,732	1,757	1,779
Onshore Wind	4	2	981	991	1,277	1,732	1,757	1,779
Onshore Wind	4	3	915	924	1,236	1,732	1,757	1,779
Onshore Wind	4	5	1,349	1,364	1,506	1,732	1,757	1,779
Onshore Wind	5	1	1,119	1,131	1,269	1,491	1,512	1,531
Onshore Wind	5	2	945	954	1,091	1,309	1,327	1,345
Onshore Wind	5	3	895	905	1,040	1,258	1,275	1,292
Onshore Wind	5	5	788	796	931	1,145	1,161	1,176
Offshore Wind - Deep	1		4,467	4,444	4,666	5,064	5,094	5,140
Offshore Wind - Deep	2		4,327	4,295	4,571	5,064	5,094	5,140
Offshore Wind - Deep	3		4,266	4,231	4,526	5,064	5,094	5,140
Offshore Wind - Deep	4		4,231	4,194	4,509	5,064	5,094	5,140
Offshore Wind - Deep	5		4,186	4,146	4,475	5,064	5,094	5,140
Offshore Wind - Shallow	1		4,588	4,571	4,745	5,064	5,094	5,140
Offshore Wind - Shallow	2		4,483	4,460	4,672	5,064	5,094	5,140
Offshore Wind - Shallow	3		4,432	4,407	4,644	5,064	5,094	5,140
Offshore Wind - Shallow	4		4,407	4,380	4,627	5,064	5,094	5,140
Offshore Wind - Shallow	5		4,372	4,343	4,599	5,064	5,094	5,140

Source: EPA IPM v.5.15

4.2.10 Transmission

IPM's assumptions took into account the capabilities of transmission lines. These assumptions are based on a thorough analysis of the transmission structure and constraints, and represent the most probable outlook at the time of the forecast.

- Joint capacity constraints were included to reflect limitations across groups of transmission links.
- Total transmission capability assumptions from public sources such as the North American Electric Reliability Corporation and regional reliability councils were used, as well as interface limits published by the International Organization for Standardization, where available.
- In regions where data were unavailable, the analysis used estimates derived from industry contacts and proprietary modeling exercises.

- The model assumed that power transported across power pools would incur a cost of $3.09 per megawatt hour (2011 U.S. dollars) to reflect charges assessed by one power pool to another.
- IPM® did not include regional through-and-out rates for any transactions terminating in the combined PJM-MISO footprint. Regional through-and-out rates are transmission rates for transactions where electricity originated in one transmission control area was transmitted to a point outside that control area.
- Transmission losses vary with line loading and line length, but estimating the exact loss factors for each interconnecting transmission path for the entire country would be impracticable. ICF's analysis, therefore, assumed transmission losses between 2% and 3%, based on industry practices. Note that these losses were intended to capture only bulk power transmission losses; distribution losses were not included.
- Because the non-U.S. and non-Canadian regions are only represented by coal supply and demand regions and a coal demand forecast, the transmission network for these regions is not explicitly modeled and thus assumptions regarding transmission for these regions are not needed.

4.2.11 International Coal Demand

International coal demand in the model is represented by a forecast of a region's or country's total thermal coal demand, which is modeled as a fixed input. The rest of the world, outside of the United States and Canada, is divided into 26 coal demand regions that are comprised of 15 countries and 11 regions. The thermal coal demand for the rest of the world is modeled as the total heating value of the coal in trillion British thermal units (TBtu).[18] The coal demand in these 26 regions is met by delivering coal from one or more of the 58 coal supply regions modeled in the IPM. The coal is "transported" from the supply regions to the demand regions along transportation links that have a cost for moving the coal that is based on the mode of transportation as well as the distance traveled. Thus the fixed coal demand in the 26 international coal demand regions is met by determining the least cost method of meeting the coal demand over the whole planning horizon given the transportation costs and coal supply curves for each of the 58 coal supply regions.

[18] Only thermal coal demand is modeled in the analysis for the EIS, because only thermal coal would be exported through the proposed terminal.

Two sources were used as starting points for the international demand forecast. The first source is the IEA 2015 WEO, which provides an estimate for the demand for coal and other energy sources under three scenarios and for 11 regions and 7 individual countries.[19] Two scenarios in the IEA 2015 WEO were used for the analysis, the New Policies Scenario and the Current Policies Scenario. The analysis for the Final EIS uses the New Policies Scenario and the Current Policies Scenario data for the international coal demand. The coal demand in the Current Policies Scenario is used in the No Clean Power Plan and Cumulative Scenarios, while the coal demand in the New Policies Scenario is used in the Lower Bound and 2015 U.S. and International Energy Policy Scenarios. The New Policies Scenario differs from the Current Policies Scenario in that it includes both implemented policies as well as policies that have been announced, but may not be fully defined. These policies include the energy related aspects of the Intended Nationally Determined Contributions that had been submitted as of October 1, 2015 in preparation for the United Nations Framework Convention on Climate Change Conference of the Parties. While the New Policies Scenario includes policies that have been announced, but have not been implemented, it takes a conservative view on the extent and timing of the implementation of those policies.

2015 WEO Scenario Definitions
The **New Policies Scenario** incorporates policies and measures that affect energy markets and that have been adopted as of mid-2015. This scenario also includes other relevant "intentions" that have been announced, but may not be fully defined or implemented.
The **Current Policies Scenario** takes into consideration only those policies for which implementing measures have been formally adopted as of mid-2015, and assumes that these policies do not change over time.
(International Energy Agency 2015)

Tables 4-20 and 4-21 contain these coal consumption estimates for the Current Policies Scenario and for the New Policies Scenario, respectively. The second source is EIA, which has historical data on coal consumption by country. The EIA data was used to disaggregate the regional coal demand from the IEA 2015 WEO into individual country demands. The regional coal demand from the WEO was allocated to each member country according to the percent of 2014 consumption for the same group of countries. The individual country coal demand was then recombined into the regions used in the model. Table 4-22 shows the 2014 coal consumption by country from the EIA data.

The IEA 2015 WEO incorporates environmental and renewable regulations and policies, among many other inputs, into their energy demand projections. The IEA's Current Policies Scenario includes "…only those policies for which implementing measures had been formally adopted as of mid-2015 and makes the assumption that these policies persist unchanged."[20] The New Policies Scenario includes not only the policies in the Current Policies Scenario, but other announced intentions that may not be fully defined. For example, the New Policies Scenario includes "…the energy-related components of the Intended Nationally Determined Contributions submitted by national governments by 1 October as pledges in the run-up to the United Nations Framework Convention on Climate Change Conference of the Parties."[21]

Coking coal demand was then subtracted from the IEA 2015 WEO data for total primary energy demand for coal to obtain the demand for thermal coal. The global demand for metallurgical coal is

[19] The international coal demand in the Draft EIS was based on the IEA 2014 WEO.
[20] International Energy Agency, 2015 World Energy Outlook, page 34.
[21] Ibid

based on the IEA 2015 WEO projections of metallurgical coal demand under the Current Policies and New Policies Scenarios. Table 4-23 shows the global metallurgical coal demand from the IEA 2015 WEO. The global demand for metallurgical coal was allocated to the demand regions used in the IPM based on historical consumption. Tables 4-24 and 4-25 contain the metallurgical coal forecast for the 21 IPM demand regions that consume metallurgical coal. The metallurgical coal forecast was developed by starting with historical consumption and applying a growth rate based on the developmental stage of the country, its place in global coking coal production, and expected gross domestic product growth, to get within 2% of the IEA 2015 WEO metallurgical coal forecast. One simplifying assumption in the IPM is that metallurgical coal and thermal coal are modeled separately, without the ability of one to cross over into the other type. Since this analysis involves Powder River Basin and Uinta Basin coal, neither of which have metallurgical quality coal, this simplifying assumption will not affect the results.

Table 4-20. Total Primary Energy Demand – Coal – No Clean Power Plan and Cumulative Scenarios (Trillion Btu)

	Current Policies Scenario Consumption (TBtu)				
Country or Region	**1999**	**2013**	**2020**	**2030**	**2040**
OECD	42,871	40,838	39,252	37,835	35,801
OECD Americas	19,463	18,597	18,173	18,575	17,978
OECD Europe	17,920	12,469	11,551	10,048	8,800
European Union	18,077	11,365	10,155	8,298	6,652
OECD Asia Oceania	5,488	9,772	9,528	9,211	9,024
Japan	3,040	4,812	4,519	4,331	4,043
Non-OECD	45,245	115,081	128,507	158,205	187,137
Eastern Europe/Eurasia	14,570	8,706	8,665	9,123	9,955
Russia	7,582	4,297	4,386	4,763	5,068
Non-OECD Asia	27,136	101,190	113,966	141,672	166,910
China	21,153	81,446	85,083	94,690	99,144
India	3,714	13,546	19,804	31,650	45,062
Middle East	28	124	141	163	176
Africa	2,935	4,123	4,529	5,623	7,993
South Africa	2,640	3,783	3,805	3,923	4,147
Latin America	576	938	1,205	1,622	2,104
Brazil	384	653	815	964	1,135

Source: International Energy Agency, 2015 World Energy Outlook, Current Policies Scenario

Table 4-21. Total Primary Energy Demand – Coal – Lower Bound and 2015 U.S. and International Energy Policy Scenarios (Trillion Btu)

Country or Region	New Policies Scenario Consumption (TBtu)						
	1999	2013	2020	2025	2030	2035	2040
OECD	42,871	40,838	36,312	32,830	29,141	26,092	24,389
OECD Americas	19,463	18,597	16,013	14,843	13,312	12,249	12,102
OECD Europe	17,920	12,469	11,046	9,360	7,628	6,205	5,333
European Union	18,077	11,365	9,720	7,923	6,163	4,821	4,025
OECD Asia Oceania	5,488	9,772	9,253	8,627	8,201	7,637	6,954
Japan	3,040	4,812	4,407	4,091	3,916	3,615	3,274
Non-OECD	45,245	115,081	123,727	130,329	138,265	145,413	150,762
Eastern Europe/Eurasia	14,570	8,706	8,377	8,477	8,493	8,791	8,863
Russia	7,582	4,297	4,239	4,556	4,521	4,614	4,490
Non-OECD Asia	27,136	101,190	109,561	115,539	122,835	128,719	132,716
China	21,153	81,446	81,751	81,725	81,627	80,226	76,932
India	3,714	13,546	18,907	22,544	27,399	32,300	37,045
Middle East	28	124	140	150	156	161	163
Africa	2,935	4,123	4,480	4,854	5,292	6,103	7,200
South Africa	2,640	3,783	3,735	3,687	3,556	3,469	3,388
Latin America	576	938	1,168	1,309	1,489	1,639	1,820
Brazil	384	653	808	866	929	966	1,025

Source: International Energy Agency, 2015 World Energy Outlook, New Policies Scenario

Table 4-22. 2014 Coal Consumption by Country, Total Primary Energy Demand (Trillion Btu)

Country	2014 Consumption	Country	2014 Consumption	Country	2014 Consumption
Australia	1,615	Hungary	111	Poland	2,021
Austria	81	India	12,560	Portugal	93
Belgium	110	Indonesia	2,076	Romania	187
Bosnia and Herzegovina	131	Israel	201	Russia	4,118
Brazil	633	Italy	457	Serbia	326
Bulgaria	304	Japan	4,169	Slovakia	125
Canada	692	Kazakhstan	1,489	South Africa	3,789
Chile	267	Korea, North	461	Spain	442
China	72,269	Korea, South	2,859	Sweden	66
Colombia	178	Malaysia	546	Taiwan	1,417
Czech Republic	579	Mexico	351	Thailand	583
Denmark	87	Mongolia	152	Ukraine	1,262
Finland	105	Morocco	147	United Arab Emirates	48
France	307	Netherlands	325	United Kingdom	1,060
Germany	2,884	New Zealand	54	United States	15,872
Greece	229	Pakistan	139	Uzbekistan	52
Hong Kong	290	Philippines	421	Vietnam	586

Source: Energy Information Administration website, International Coal data explorer. Accessed October 12, 2016

Table 4-23. Global Metallurgical Coal Demand

Metallurgical Coal Demand	Historical		Current Policies Scenario		New Policies Scenario	
	2000	2013	2020	2040	2020	2040
Demand in Mtce	452	940	941	851	929	785
Demand in TBtu	12,555	26,109	26,137	23,637	25,804	21,804

Source: International Energy Agency 2015 World Energy Outlook
Mtce = Million tons coal equivalent

Table 4-24. Metallurgical Coal Demand Forecast - No Clean Power Plan, Cumulative, and Upper Bound Scenarios (Trillion Btu)

Country	2016	2018	2020	2025	2030	2035	2040
Australia	134.4	134.9	135.4	136.8	138.2	139.6	141.0
Britain	213.6	211.1	207.7	197.0	187.0	179.2	171.6
China	14,478.5	14,155.8	13,840.2	13,081.6	12,364.6	11,687.0	11,046.4
Colombia	17.0	18.1	19.1	21.2	23.5	24.6	25.7
Europe-East	795.8	799.0	802.2	810.2	818.4	826.6	834.9
Europe-North	105.1	103.8	102.1	96.9	92.0	88.1	84.4
Europe-South	175.8	173.7	170.9	162.1	153.9	147.4	141.2
Europe-West	425.6	420.6	413.7	392.5	372.6	357.0	342.0
Germany	634.0	626.6	616.3	584.6	555.1	531.8	509.5
India	2,378.7	2,450.6	2,524.7	2,719.8	2,930.0	3,156.4	3,400.4
Japan	1,636.6	1,572.4	1,510.8	1,367.0	1,237.0	1,119.2	1,012.7
Kazakhstan	520.6	522.7	524.8	530.1	535.4	540.8	546.2
South Korea	1,005.8	1,015.9	1,026.1	1,052.0	1,078.5	1,105.8	1,133.7
Mexico	31.3	31.9	32.6	34.2	36.0	37.8	39.7
Poland	404.0	399.3	392.8	372.6	353.8	338.9	324.7
Russia	1,562.4	1,599.5	1,637.5	1,736.4	1,841.3	1,952.5	2,070.4
South Africa	81.5	84.6	87.1	91.6	96.1	98.6	101.2
South America	284.7	303.2	319.8	356.0	394.0	411.6	430.0
Spain	108.1	106.9	105.1	99.7	94.7	90.7	86.9
Taiwan	197.8	201.8	205.8	216.3	227.4	239.0	251.2
Ukraine	819.6	822.9	826.2	834.4	842.8	851.3	859.8

Source: Historical data was extrapolated based on IEA 2015 WEO projections for 2020 and 2040 demand.

Table 4-25. Metallurgical Coal Demand Forecast - Lower Bound and 2015 U.S. and International Energy Policy Scenarios (Trillion Btu)

Country	2016	2018	2020	2025	2030	2035	2040
Australia	134.4	134.9	135.4	136.8	138.2	139.6	141.0
Britain	213.6	211.1	207.7	197.0	187.0	179.2	171.6
China	14,478.5	13,873.8	13,294.3	11,949.2	10,740.3	9,653.6	8,676.9
Colombia	17.0	18.1	19.1	21.2	23.5	24.6	25.7
Europe-East	795.8	799.0	802.2	810.2	818.4	826.6	834.9
Europe-North	105.1	103.8	102.1	96.9	92.0	88.1	84.4
Europe-South	175.8	173.7	170.9	162.1	153.9	147.4	141.2
Europe-West	425.6	420.6	413.7	392.5	372.6	357.0	342.0
Germany	634.0	626.6	616.3	584.6	555.1	531.8	509.5
India	2,378.7	2,450.6	2,524.7	2,719.8	2,930.0	3,156.4	3,400.4
Japan	1,636.6	1,570.8	1,507.6	1,360.5	1,227.8	1,108.0	999.9
Kazakhstan	520.6	522.7	524.8	530.1	535.4	540.8	546.2
South Korea	1,005.8	1,015.9	1,026.1	1,052.0	1,078.5	1,105.8	1,133.7
Mexico	31.3	31.9	32.6	34.2	36.0	37.8	39.7
Poland	404.0	399.3	392.8	372.6	353.8	338.9	324.7
Russia	1,562.4	1,604.6	1,648.0	1,761.5	1,882.9	2,012.7	2,151.4
South Africa	81.5	84.6	87.1	91.6	96.1	98.6	101.2
South America	284.7	303.2	319.8	356.0	394.0	411.6	430.0
Spain	108.1	106.9	105.1	99.7	94.7	90.7	86.9
Taiwan	197.8	201.8	205.8	216.3	227.4	239.0	251.2
Ukraine	819.6	822.9	826.2	834.4	842.8	851.3	859.8

Source: Historical data was extrapolated based on IEA 2015 WEO projections for 2020 and 2040 demand.

Tables 4-26 and 4-27 show the final thermal coal demand from IEA 2015 WEO Current Policies Scenario and the New Policies Scenario. The coal demand in the Current Policies Scenario is used in the No Clean Power Plan and Cumulative Scenarios, while the coal demand in the New Policies Scenario is used in the Lower Bound and 2015 U.S. and International Energy Policy Scenarios. The coal demand for the Upper Bound Scenario uses a different methodology, as explained below.

The international coal demand in Tables 4-26 and 4-27 may not exactly match with the IEA 2015 WEO data due to several adjustments that were required to convert the IEA data from the region groups contained in the WEO to the region groups used in IPM. These adjustments include separating out the individual countries in the WEO region groups using historical coal consumption data from IEA 2015 WEO, and combining the individual countries into the region groups used in IPM. For example, the coal demand for India is included as a separate country in the IEA data; however, in IPM both India and Pakistan are included together as one coal demand region, so the coal demand for Pakistan was added to the coal demand for India to obtain the "India" coal demand shown in Tables 4-26 and 4-27.

Table 4-28 shows the thermal coal demand for the Upper Bound Scenario. The coal demand in the Upper Bound Scenario is based on the assumption that the higher coal demand growth of the period of 2000 through 2012 is achieved going forward. This methodology starts with the EIA historical total coal consumption for 2000 through 2012 (U.S. Energy Information Administration 2016e). The

coal demand in subsequent years is determined by using the average growth rate of the 3-year rolling average growth rates for each region. For regions where the 2040 coal demand was more than 100% of the IEA 2015 WEO Current Scenario demand, the growth rate was adjusted down to yield a lower and more reasonable forecast. As with the Current Policies Scenario and the New Policies Scenario, the metallurgical coal forecast is subtracted from the total coal forecast. In this case the metallurgical coal forecast for the Current Policies Scenario was used.

Table 4-26. International Thermal Coal Demand Forecast — No Clean Power Plan and Cumulative Scenarios (Trillion Btu)

Country	2016	2018	2020	2025	2030	2035	2040
Africa, North	182.7	2,355.7	4,528.7	5,076.0	5,623.3	6,808.1	7,992.9
Asia Other	2,602.9	2,968.3	3,333.8	3,739.0	4,144.3	4,513.4	4,882.5
Australia	1,268.3	1,480.6	1,693.0	1,661.2	1,629.4	1,610.1	1,590.8
Britain	752.1	835.0	918.7	826.4	733.4	650.0	566.2
China	57,998.5	64,719.0	71,432.3	77,017.0	82,560.1	85,485.9	88,374.6
Colombia	161.5	179.4	197.5	232.7	267.9	310.1	352.2
Europe-East	597.8	708.4	819.0	773.9	728.7	710.8	692.8
Europe-North	50.9	75.1	99.8	86.6	73.0	60.5	47.8
Europe-South	1,413.8	1,484.0	1,555.0	1,445.1	1,334.6	1,241.2	1,147.6
Europe-West	1,527.6	1,667.5	1,809.3	1,627.3	1,443.9	1,279.4	1,114.3
Germany	2,134.4	2,289.9	2,448.3	2,199.8	1,949.2	1,724.1	1,498.1
Hong Kong	303.4	332.1	360.9	404.7	448.6	488.6	528.5
India	10,213.2	13,833.7	17,452.1	23,201.3	28,935.4	35,433.8	41,914.7
Indonesia	2,485.7	2,534.6	2,583.4	2,897.4	3,211.5	3,497.5	3,783.5
Japan	2,337.0	2,674.0	3,008.5	3,058.3	3,094.5	3,068.1	3,030.4
Kazakhstan	977.4	1,063.3	1,149.1	1,188.1	1,227.0	1,301.9	1,376.8
South Korea	1,716.2	1,911.1	2,106.0	2,028.0	1,949.3	1,891.4	1,832.8
Mexico	313.9	326.3	338.7	341.1	343.5	335.6	327.5
Middle East	221.1	180.9	140.7	151.9	163.2	169.7	176.1
Poland	1,469.4	1,611.2	1,754.8	1,578.6	1,401.2	1,242.0	1,082.2
Russia	2,452.6	2,600.9	2,748.4	2,838.2	2,922.0	2,963.1	2,997.4
South Africa	3,597.5	3,657.4	3,717.8	3,772.5	3,827.1	3,936.4	4,045.6
South America	921.8	935.8	951.5	1,089.4	1,225.5	1,400.7	1,575.1
Spain	400.3	382.2	364.6	327.0	289.1	255.1	220.8
Taiwan	1,091.0	1,324.3	1,557.5	1,761.4	1,964.7	2,148.3	2,331.3
Ukraine	345.8	469.2	592.6	621.8	650.9	710.5	770.0
Total	97,871.4	113,030.4	128,188.2	140,463.6	152,651.2	163,715.5	174,700.2

Source: U.S. Energy Information Administration 2016e; International Energy Agency 2015; ICF calculations

Table 4-27. International Thermal Coal Demand Forecast — Lower Bound and 2015 U.S. and International Energy Policy Scenarios (Trillion Btu)

Country	2016	2018	2020	2025	2030	2035	2040
Africa, North	182.7	2,331.5	4,480.3	4,854.0	5,291.9	6,103.0	7,199.6
Asia Other	2,602.9	2,903.9	3,204.9	3,379.8	3,593.2	3,765.3	3,882.3
Australia	1,268.3	1,454.3	1,640.2	1,518.8	1,435.6	1,326.1	1,193.5
Britain	752.1	810.8	870.5	681.8	496.6	355.6	274.8
China	57,998.5	63,331.4	68,638.9	69,967.3	71,090.3	70,786.2	68,475.5
Colombia	161.5	176.1	190.7	213.9	244.0	270.0	301.2
Europe-East	597.8	678.2	758.5	641.5	517.5	452.2	398.6
Europe-North	50.9	70.8	91.1	60.6	30.5	7.7	0.0
Europe-South	1,413.8	1,446.3	1,479.7	1,229.1	972.8	764.5	639.7
Europe-West	1,527.6	1,619.9	1,714.1	1,341.9	976.5	698.4	539.2
Germany	2,134.4	2,224.3	2,317.1	1,806.4	1,304.7	923.1	705.3
Hong Kong	303.4	325.2	346.9	365.9	389.0	407.6	420.3
India	10,213.2	13,382.2	16,549.1	19,999.2	24,655.4	29,338.7	33,846.4
Indonesia	2,485.7	2,484.7	2,483.6	2,619.1	2,784.5	2,917.8	3,008.4
Japan	2,337.0	2,619.8	2,899.9	2,730.7	2,688.7	2,506.9	2,273.8
Kazakhstan	977.4	1,035.4	1,093.4	1,107.6	1,105.2	1,157.5	1,166.0
South Korea	1,716.2	1,866.0	2,015.7	1,784.0	1,617.4	1,404.9	1,152.2
Mexico	313.9	304.2	294.6	269.0	236.0	212.4	207.5
Middle East	221.1	180.8	140.5	150.1	156.1	160.5	163.1
Poland	1,469.4	1,565.2	1,662.8	1,303.0	949.5	680.6	526.6
Russia	2,452.6	2,522.6	2,591.4	2,794.0	2,637.9	2,601.5	2,338.9
South Africa	3,597.5	3,622.2	3,647.6	3,595.4	3,459.9	3,370.4	3,286.4
South America	921.8	903.6	887.1	948.4	1,034.3	1,123.7	1,250.7
Spain	400.3	372.2	344.5	266.7	190.4	132.3	99.3
Taiwan	1,091.0	1,290.2	1,489.4	1,571.3	1,673.2	1,752.6	1,802.3
Ukraine	345.8	445.6	545.3	553.5	547.7	588.1	591.3
Total	97,871.4	110,354.2	122,817.3	126,129.4	130,376.4	134,044.2	135,953.6

Source: U.S. Energy Information Administration 2016e; International Energy Agency 2015; ICF calculations

Table 4-28. International Thermal Coal Demand Forecast — Upper Bound Scenario (Trillion Btu)

Country	2016	2018	2020	2025	2030	2035	2040
Africa, North	182.7	2,355.7	4,528.7	5,076.0	5,623.3	6,808.1	7,992.9
Asia Other	2,602.9	2,968.3	3,333.8	4,254.9	5,430.4	7,138.0	8,845.6
Australia	1,268.3	1,480.6	1,693.0	1,661.2	1,629.4	1,610.1	1,590.8
Britain	752.1	835.0	918.7	874.7	832.7	792.3	751.5
China	57,998.5	64,719.0	71,432.3	78,781.0	86,597.5	95,218.9	103,803.1
Colombia	161.5	179.4	197.5	232.8	270.9	320.5	370.0
Europe-East	597.8	708.4	819.0	893.6	972.4	1,057.8	1,143.2
Europe-North	50.9	75.1	99.8	86.5	74.4	63.5	52.4
Europe-South	1,413.8	1,484.0	1,555.0	1,651.8	1,752.6	1,858.8	1,964.7
Europe-West	1,527.6	1,667.5	1,809.3	1,658.3	1,519.5	1,394.3	1,268.4
Germany	2,134.4	2,289.9	2,448.3	2,348.5	2,252.7	2,158.4	2,063.1
Hong Kong	303.4	332.1	360.9	425.1	500.8	598.0	695.1
India	10,213.2	13,833.7	17,452.1	23,201.3	30,308.8	40,790.6	51,254.8
Indonesia	2,485.7	2,637.1	2,797.7	3,243.3	3,759.9	4,406.5	5,053.0
Japan	2,337.0	2,674.0	3,008.5	3,283.4	3,548.4	3,807.0	4,054.4
Kazakhstan	977.4	1,063.3	1,149.1	1,229.2	1,313.6	1,405.0	1,496.3
South Korea	1,716.2	1,911.1	2,106.0	2,322.1	2,556.3	2,820.9	3,084.7
Mexico	313.9	326.3	338.7	365.8	395.1	428.1	460.9
Middle East	221.1	225.5	230.1	241.8	254.2	267.4	280.7
Poland	1,469.4	1,611.2	1,754.8	1,706.5	1,659.4	1,611.2	1,562.4
Russia	2,452.6	2,600.9	2,748.4	2,873.2	3,003.4	3,145.6	3,281.1
South Africa	3,597.5	3,677.3	3,759.6	3,975.6	4,204.0	4,454.9	4,705.8
South America	921.8	1,020.0	1,131.3	1,473.0	1,908.5	2,566.3	3,223.2
Spain	400.3	386.5	373.5	344.1	316.8	291.9	266.9
Taiwan	1,091.0	1,324.3	1,557.5	1,761.4	1,964.7	2,148.3	2,331.3
Ukraine	345.8	469.2	592.6	621.8	650.9	710.5	770.0
Total	97,536.7	112,855.4	128,196.0	144,586.8	163,300.8	187,872.9	212,366.7

Source: U.S. Energy Information Administration 2016e; International Energy Agency 2015; ICF calculations

4.2.12 Coal Demand Elasticity

Because the international coal demand is a forecast that is an input to the model, coal demand elasticity was used to adjust the demand based on the change in delivered coal prices. The change in coal demand is referred to as "induced demand" in the following report chapters. The demand elasticity is a measure of how much coal demand will change with a given change in the delivered coal price. As delivered coal prices change, the demand for coal changes in the opposite direction. A

literature search was done to identify an energy-specific demand elasticity for this analysis. Five sources were reviewed that provided information on long-term coal demand elasticity.[22]

Coal plays a crucial role in China, Japan, India, South Korea, and Taiwan, with coal consumption levels forecasted to either peak in the future or continue to grow. China is currently the world's largest coal consumer and producer by a wide margin. Although peak coal demand in China has been forecast in the next decade, the amount of coal needed in China to satisfy its energy needs is significant within international coal markets. Given these trends and the fact that at least half of the coal consumed in these Asian countries is for power generation, coal demand is relatively inelastic, meaning a 1% increase in coal prices would lead to a less than 1% decrease in coal demand. The one exception is China, which has a large sector with direct use of coal for space heating, leading to lower elasticities. Based on a literature review, the price elasticity of coal demand in the United States is -0.11 (consequently, a 1% increase in coal prices results in a 0.11% decrease in coal demand). India, Japan, South Korea, and Taiwan continue to rely on imported coal as intermediate goods in power production and to a lesser degree steel production; therefore, this analysis assumes a -0.11 price elasticity of coal demand in these countries.

The price elasticities of coal demand for India, Japan, South Korea, and Taiwan are held constant in all scenarios, as they exhibit inelastic demand of coal. However, for China, compared to the No Clean Power Plan Scenario, coal demand in the 2015 U.S. and International Energy Policy Scenario and the Lower Bound Scenario is more inelastic, while coal demand in the Upper Bound Scenario is more elastic (i.e., change in price has more of an effect on the quantity of coal demanded than in the 2015 U.S. and International Energy Policy Scenario). To reflect these variations, a price elasticity of -0.32 is assumed in the Lower Bound and 2015 U.S. and International Energy Policy Scenario, while -0.68 is assumed for the Upper Bound in China.

To reflect the change in demand (induced demand) due to a change in delivered coal prices, the analysis assumes that new demand is only induced in one period and is then constant throughout the remainder of the forecast period. This assumption is made because the analysis is examining the impact of the terminal coming online, and it is not reasonable to attribute changes in coal prices 10 or 20 years later to the proposed coal export terminal. The induced demand could be realized in one of two ways; either by existing coal plants operating more, or through the construction of new coal plants. This analysis assumes that existing coal plants would be operated more throughout the forecast period.

Domestic coal demand changes as coal and natural gas prices change within the model. Thus an externally applied demand elasticity for domestic coal demand does not need to be specified or applied, because domestic coal demand will change automatically as other inputs change.

4.2.13 Coal Heat and CO_2 Content

In the IPM for this analysis, coal supply is modeled through 58 coal supply regions. Typically within each region there are between one and six coal types modeled. The coal types within and across coal supply basins differ based on the heat, CO_2, sulfur, mercury, hydrogen chloride, and ash content. For this analysis, the most important coal characteristics are the heat content and CO_2 emission rates. The coal types used in this analysis are identified by a two-letter code. The first letter represents the

[22] The five sources used are: Burke 2015, Jiao 2009, Ma 2016, Parry 2014, and U.S. Energy Information Administration 2012.

rank of the coal and the second letter represents the sulfur content of the coal. The first letter is either "B" for bituminous, "L" for lignite, or "S" for subbituminous. The second letter ranges from "A" to "G" with "A" being low sulfur and "G" being high sulfur. The EPA IPM documentation for v5.13 includes a "Coal" chapter that provides the specific sulfur grade definitions.

To estimate the CO_2 emissions from coal combustion, two main inputs are required. These inputs are (1) the amount of coal consumed in trillion Btu (TBtu), and (2) the carbon content, in pounds per million Btu, of the coal being consumed. The carbon content varies by coal rank (i.e., bituminous, subbituminous, and lignite) and by the source region of the coal. Since IPM® includes all U.S. coal plants, the model calculates the CO_2 emissions in the United States. However, IPM® does not calculate the CO_2 emissions for international coal consumption, as coal plants are not modeled explicitly. The model solution does determine the amount of coal consumed and the type of coal consumed, which covers the two inputs required for calculating CO_2 emissions from international coal demand regions. IPM® assumes that no international coal plants have carbon capture and sequestration technology installed and that it will not be installed on new or existing international coal plants during the timeframe of this analysis.

Tables 4-29 through 4-32 show the CO_2 emission rate and heat content of both domestic and international coal types. These tables include those coal types assumed to be exported through the proposed coal export terminal and that might be displaced by the exported coal. The coal that may be exported through the proposed terminal is from Colorado, Utah, Montana, and Wyoming. The international coals that the coal exported through the proposed terminal might displace includes coal from Australia, Canada, China, Colombia, India, Indonesia, Russia, South Africa, South Korea, Thailand, and Vietnam.

Five data sources were used to compile the coal heat content and CO_2 emission rate values. The first source is the EPA IPM modeling documentation, which has data for domestic and Canadian coal heat content and CO_2 emission rates (U.S. Environmental Protection Agency 2013).[23] The second source is the EIA Form 923 submissions, which contain information on deliveries of coal to power plants that includes the heat content of the coal (U.S. Energy Information Administration 2016b). The third source is the USGS World Coal Quality Inventory, which contains both heat content and carbon content data for some international coal supply regions (Tewalt et al 2010). The fourth source is the EIA 1994 study authored by B.D. Hong and E.R. Slatick. This study provides state specific CO_2 emission rates, which were used for most domestic coals, except for the regions that could export through the proposed coal export terminal. Finally, the fifth source used was the USGS CoalQual database that contains coal samples from within the United States, and was used to update the Wyoming and Montana Powder River Basin CO_2 emission rates, along with the Colorado and Utah Uinta Basin emission rates (Palmer et al 2015).

[23] EPA IPM documentation for IPM version 5.13, Chapter 9, Coal. The Coal chapter of the EPA documentation and the coal assumptions were not updated in either EPA IPM versions 5.14 or 5.15. Thus the use of EPA IPM v5.13 coal data.

Table 4-29. CO_2 and Heat Content in Coal by Type and Source Region: Domestic Coal Types for Appalachia and the Illinois Basin

Supply Region	Rank	Coal Type	Heat Content (MMBtu/ton)[a]	CO_2 Emissions Rate (lb CO_2/MMBtu)[b]
Central Appalachia				
Kentucky, East	Bituminous	BB	25.00	206.4
Kentucky, East	Bituminous	BD	24.80	206.4
Kentucky, East	Bituminous	BE	24.64	206.4
Tennessee	Bituminous	BB	26.20	206.4
Tennessee	Bituminous	BE	25.23	206.4
Virginia	Bituminous	BB	25.90	206.4
Virginia	Bituminous	BD	25.20	206.4
Virginia	Bituminous	BE	25.00	206.4
West Virginia, South	Bituminous	BB	24.40	206.4
West Virginia, South	Bituminous	BD	24.50	206.4
West Virginia, South	Bituminous	BE	23.83	206.4
Northern Appalachia				
Maryland	Bituminous	BD	23.00	204.7
Maryland	Bituminous	BE	23.20	204.7
Ohio	Bituminous	BE	24.20	204.7
Ohio	Bituminous	BG	24.10	204.7
Pennsylvania, Central	Bituminous	BG	24.40	204.7
Pennsylvania, West	Bituminous	BE	26.00	204.7
Pennsylvania, West	Bituminous	BG	25.40	204.7
West Virginia, North	Bituminous	BE	25.35	204.7
West Virginia, North	Bituminous	BG	25.00	204.7
Southern Appalachia				
Alabama	Bituminous	BB	25.50	204.7
Alabama	Bituminous	BE	24.00	204.7
Illinois Basin				
Illinois	Bituminous	BE	23.75	203.1
Illinois	Bituminous	BG	23.50	203.1
Indiana	Bituminous	BB	22.00	203.1
Indiana	Bituminous	BE	22.70	203.1
Indiana	Bituminous	BG	22.40	203.1
Kentucky, West	Bituminous	BD	23.80	203.1
Kentucky, West	Bituminous	BG	23.80	203.1

[a] Heat content data sourced from EPA v5.13 documentation, Chapter 9, Coal, Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade.

[b] CO_2 emission rate data sourced from Hong and Slatick, 1994, and from the USGS CoalQual database.

Table 4-30. CO_2 and Heat Content in Coal by Type and Source Region: Domestic Coal Types for Interior and Western Regions

Supply Region	Rank	Coal Type	Heat Content (MMBtu/ton)[a]	CO_2 Emissions Rate (lb CO_2/MMBtu)[b]
Interior				
Arkansas, North	Bituminous	BG	22.00	202.8
Kansas	Bituminous	BG	22.00	202.8
Louisiana	Lignite	LE	13.80	212.6
Missouri	Bituminous	BG	22.00	202.8
Oklahoma	Bituminous	BG	22.00	202.8
Great Plains, Montana, and Northwest				
Montana, East	Lignite	LE	12.97	219.3
North Dakota	Lignite	LE	13.10	219.3
Montana, Bull Mountains	Bituminous	BB	20.40	212.5
Alaska	Bituminous	BA	24.40	205.5
Alaska	Subbituminous	SA	15.30	214.0
Powder River Basin				
Montana, Powder River	Subbituminous	SA	18.64	213.8
Montana, Powder River	Subbituminous	SD	17.08	213.8
WY, Powder River Basin (8400)	Subbituminous	SB	16.79	212.0
WY, Powder River Basin (8800)	Subbituminous	SA	17.60	209.4
Rockies				
Colorado, Green River	Bituminous	BB	22.74	209.6
Colorado, Green River	Subbituminous	SB	20.00	209.6
Colorado, Raton	Bituminous	BB	23.36	209.6
Colorado, Uinta	Bituminous	BB	22.22	208.4
Utah	Bituminous	BA	22.56	205.6
Utah	Bituminous	BE	24.06	205.6
Wyoming, Green River	Bituminous	BB	22.00	214.3
Wyoming, Green River	Subbituminous	SD	18.80	214.3
Southwest				
Arizona	Bituminous	BB	21.50	207.1
New Mexico, San Juan	Subbituminous	SB	19.60	209.2
New Mexico, San Juan	Subbituminous	SE	18.40	209.2
Texas				
Texas	Lignite	LE	13.47	212.6
Texas	Lignite	LF	12.47	212.6
Texas	Lignite	LG	10.68	212.6

[a] Heat content data sourced from EPA v5.13 documentation, Chapter 9, Coal, Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade, except for Colorado, Uinta; Montana, Bull Mountains; Montana, Powder River; and Utah, which were sourced from EIA 923 data for 2011 to April 2016.

[b] CO_2 emission rate data sourced from Hong and Slatick, 1994, and from the USGS CoalQual database.

Table 4-31. CO_2 and Heat Content in Coal by Type and Source Region: International Coal Types for the Americas and Europe

Supply Region	Rank	Coal Type	Heat Content (MMBtu/ton)[a]	CO_2 Emissions Rate (lb CO_2/MMBtu)[c]
Alberta, Canada	Subbituminous	SA	16.12	214.9
Alberta, Canada	Subbituminous	SB	15.55	211.0
Alberta, Canada	Subbituminous	SD	14.94	214.9
British Columbia, Canada - North	Bituminous	BD	21.40	205.4
British Columbia, Canada - South	Bituminous	BD	21.40	205.4
Colombia[b]	Bituminous	BA	21.60	205.9
Europe - East	Bituminous	BA	21.61	206.0
Europe - East	Lignite	LD	7.69	217.2
Europe - North	Lignite	LD	7.56	217.2
Germany	Bituminous	BA	26.64	208.4
Germany	Lignite	LD	11.93	212.7
Greece/Turkey	Bituminous	BA	20.26	206.0
Greece/Turkey	Lignite	LD	12.53	214.7
Mexico	Subbituminous	SB	17.52	206.3
Other South America	Lignite	LD	11.05	217.2
Other South America	Subbituminous	SB	16.00	212.0
Poland	Lignite	LD	6.75	212.7
Poland	Subbituminous	SB	19.00	206.3
Saskatchewan, Canada	Lignite	LD	13.82	219.3
Saskatchewan, Canada	Lignite	LE	10.58	215.3
Spain	Bituminous	BA	19.44	206.0
Spain	Lignite	LD	13.29	217.2
United Kingdom	Bituminous	BA	25.06	205.7
Venezuela	Bituminous	BA	26.37	199.6

[a] The source for heat content is the USGS World Coal Inventory, unless otherwise identified in these notes.

[b] Source for Colombia and Australia coal heat content is Argus Coal Daily Methodology and IHS Thermal Coal and Petcoke Marker Price Methodology and Specifications.

[c] The source for CO_2 emission rates are from the USGS World Coal Inventory for the following countries: Colombia, Germany, Greece/Turkey, Mexico, Spain, United Kingdom, and Venezuela. The CO_2 emission rate for the following countries was estimated based on the coal type and location: Europe-East, Europe-North, Other South America, Poland, and Spain. The CO_2 emission rate for the Canadian provinces is from EPA v5.13 documentation, Chapter 9, Coal, Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade.

Table 4-32. CO_2 and Heat Content in Coal by Type and Source Region: International Coal Types for the Rest of the World

Supply Region	Rank	Coal Type	Heat Content (MMBtu/ton)[a]	CO_2 Emissions Rate (lb CO_2/MMBtu)[d]
Australia[b]	Bituminous	BA	21.60	206.0
Australia[b]	Lignite	LD	8.44	205.8
China	Bituminous	BA	23.85	212.2
China	Lignite	LD	14.04	218.5
India/Pakistan	Bituminous	BA	22.26	210.9
India/Pakistan	Lignite	LD	11.10	198.7
India/Pakistan	Subbituminous	SB	17.01	210.6
Indonesia[c]	Bituminous	BA	23.43	203.7
Indonesia[c]	Bituminous	BB	20.33	203.7
Indonesia[c]	Lignite	LD	12.95	205.8
Indonesia[c]	Subbituminous	SA	18.05	214.8
Indonesia[c]	Subbituminous	SB	17.09	214.8
Indonesia[c]	Subbituminous	SD	15.12	214.8
Kazakhstan	Bituminous	BA	23.08	212.5
Kazakhstan	Subbituminous	SB	18.92	214.6
Korea, South	Bituminous	BA	21.72	211.3
Korea, South	Lignite	LD	12.53	217.8
Russia	Lignite	LD	12.82	214.7
Russia	Subbituminous	SB	20.00	212.0
South Africa	Bituminous	BA	20.28	206.0
Thailand/Vietnam	Bituminous	BA	22.82	209.4
Thailand/Vietnam	Lignite	LD	12.30	211.8
Ukraine	Lignite	LD	6.00	214.7
Ukraine	Subbituminous	SB	18.19	212.0

[a] The source for heat content is the USGS World Coal Inventory, unless otherwise identified in these notes.

[b] Source for Australia coal heat content is Argus Coal Daily Methodology and IHS Thermal Coal and Petcoke Marker Price Methodology and Specifications

[c] Source of Indonesian coal heat content is the weighted average of mine specific data from nine Indonesian coal mining companies that produced more than 60% of Indonesia's coal in 2013 and 2014.

The nine Indonesian coal companies used are Adaro Energy, Arutmin, Bayan Resources, Berau Coal, Harum Energy, Indo Tambangraya Megah, Kaltim Prima Coal, Kideco, and Sakari Resources.

[d] The source for CO_2 emission rates are from the USGS World Coal Inventory for the following countries: China, India/Pakistan, Indonesia, South Korea, Kazakhstan, and Thailand/Vietnam. The CO_2 emission rate for the following countries was estimated based on the coal type and location: Australia, Russia, South Africa, and Ukraine.

4.2.14 Coal Distribution Limitations

Two limitations were placed on coal distribution and consumption. The first was placed on imports to China to limit the total amount of coal China could import. The limit of coal imports to China were included to ensure that the model did not import an unreasonable amount of coal into China, since China has only recently become a net importer of coal. The limits also were included because it is

unlikely that Chinese energy policy would allow for large amounts of coal to be imported for energy security reasons. The total coal import limits imposed on China restrict imports to less than 227 million metric tons through 2020, 318 million metric tons for 2025 to 2030, and 726 million metric tons in 2040.

The second limitation was placed on subbituminous coal imports into Hong Kong, Japan, South Korea, and Taiwan. Based on import and export data sourced from the United Nations Comtrade database – and assuming that each country already maximizes the amount of subbituminous coal that they can consume – the percentages for subbituminous coal consumption in Table 4-33 were set as the maximum that can be consumed. These percentages result in these four countries being able to consume between 39 and 44 million metric tons of subbituminous coal. Since the capacity of the proposed coal export terminal is 44 million metric tons, some of the exported coal may be shipped to and consumed in China or India.

Table 4-33. Subbituminous Coal Consumption Limits

Region	Weight Based Limit	Heat Content Based Limit[24]
Japan	6.8%	5.2%
Hong Kong	56.7%	49.6%
South Korea	16.3%	12.7%
Taiwan	18.7%	14.7%
Source: UN Comtrade 2017		

4.2.15 Coal Reserves

Coal reserves both domestically and internationally are an important companion input to annual coal production capacity in the coal supply curves. Over time as the reserves on a step on the coal supply curve are exhausted, the solved equilibrium price must solve higher on the coal supply curve, thus generally pushing prices higher over time, all else equal.

International reserve data is generally of lower quality and can be inconsistent between sources. If multiple sources of reserve estimates were available, the analysis used the higher estimates, as technological improvements tend to make resources available that might have been uneconomic previously.

The estimates of reserves at existing U.S. mines is based on information contained in company financial reports and EIA data of state level reserves by mine type (surface or underground). For public mining companies the reserves are obtained from the financial reports. These reserves are then subtracted from the EIA reserve estimates for each state. The remaining reserves in the EIA data are allocated to all the other U.S. mines in each state for which data are not available through company financial reports. The reserves are allocated proportionally based on the annual production capacity. Table 4-34 shows the recoverable reserves at producing mines and the

[24] The Heat Content Based Percentage is calculated by assuming a subbituminous coal heat content of 18 MMBtu/ton and a bituminous coal heat content of 24 MMBtu/ton and taking the weighted average using the quantities for the year with the highest percentage of subbituminous coal in 2012 to 2014, which is the period for which data was available. For example, for Japan the calculation is: (13.8 mst x 18 MMBtu/ton) / (188.7 mst x 24 MMBtu/ton + 13.8 mst x 18 MMBtu/ton) = 0.052 or 5.2%. Where “mst” is million short tons.

estimated recoverable reserves. Recoverable reserves are coal deposits which are considered economically recoverable at the time the estimate is made.

Table 4-34. Recoverable Coal Reserves by Mine Type and State, 2014 (million short tons)

Coal-Resource State	Underground - Minable Coal		Surface - Minable Coal	
	Reserves at Producing Mines	Estimated Reserves	Reserves at Producing Mines	Estimated Reserves
Alabama	213	399	16	2,222
Alaska	-	2,335	53	483
Arizona	-	-	216	-
Arkansas	25	126	-	101
Colorado	207	5,766	126	3,742
Georgia	-	1	-	1
Idaho	-	2	-	-
Illinois	2,426	27,729	37	10,035
Indiana	295	3,515	351	286
Iowa	-	807	-	320
Kansas	-	-	<0.5	679
Kentucky Total	767	6,845	122	7,230
Kentucky (East)	293	317	66	5,003
Kentucky (West)	474	6,528	55	2,227
Louisiana	-	-	92	283
Maryland	8	307	14	31
Michigan	-	55	-	3
Mississippi	-	-	698	-
Missouri	-	689	1	3,154
Montana	240	35,889	618	38,666
New Mexico	16	2,749	169	4,048
North Carolina	-	5	-	-
North Dakota	-	-	1,003	6,657
Ohio	332	7,585	47	3,705
Oklahoma	8	570	1	220
Oregon	-	6	-	2
Pennsylvania Total	1,088	10,232	167	973
Pennsylvania (Anthracite)	1	340	121	418
Pennsylvania (Bituminous)	1,087	9,892	46	555
South Dakota	-	-	-	277
Tennessee	1	273	<0.5	171
Texas	-	-	703	9,169
Utah	95	2,332	2	210
Virginia	230	491	23	306
Washington	-	674	-	6
West Virginia Total	1,554	14,778	475	2,013

Coal-Resource State	Underground - Minable Coal		Surface - Minable Coal	
	Reserves at Producing Mines	Estimated Reserves	Reserves at Producing Mines	Estimated Reserves
West Virginia (Northern)	937	NA	7	NA
West Virginia (Southern)	617	NA	468	NA
Wyoming	35	22,918	6,878	13,683
U.S. Total	7,542	147,079	11,810	108,676

- = No data reported; NA = Not Available.
Source: U.S. Energy Information Administration 2016f

4.2.16 Federal Coal Lease Review

In January 2016, the U.S. Department of Interior Secretary, Sally Jewell, announced that the Interior Department would conduct a comprehensive review of the federal coal lease program and the royalty structure, and imposed a moratorium on new federal leases. The proposed review was to take the form of a Programmatic Environmental Impact Statement to address concerns raised by the public and other government agencies. Approximately 90% of coal on federal lands is in the Powder River Basin, and changes in the federal coal leasing program could affect this analysis. However, there are several factors that will reduce the chance that the change in the federal coal leasing program would affect the results of this analysis.

- First, existing leases have coal resources that will provide enough coal for extraction for the next 20 years, as of 2016 (U.S. Department of the Interior 2016). The existing leases will allow production to continue at 2016 levels through 2036, which is close to the end of the analytical period for this EIS. Therefore, any change to the coal leasing program would only affect the final 4 years of this coal market analysis. To the extent that production levels are lower or higher than in 2016, the 20-year timeframe would expand or decrease.
- Second, potential changes to the federal coal leasing program are highly speculative as of early 2017, and will likely not be known for 2 to 4 years. There is insufficient information available to make judgements on how the federal coal leasing program might change and thus how it should be modeled for this EIS.
- Third, the November 2016 presidential and congressional elections have resulted in an administration and Congress that show a greater interest in sustaining the coal industry and are less likely to overhaul the federal coal lease program in a way that will significantly increase the cost to mine operators.

Thus, while the review of the federal coal leasing program could result in significant changes to the program and thus to coal production costs in the Powder River Basin, there is too much uncertainty to include such possibilities in this analysis.

4.3 Methods

This section provides an overview of the methods used in the analysis.

4.3.1 Model Run Years

Table 4-35 presents a map of calendar years and run years. Run years aggregate calendar years to limit model complexity. In other words, a run year is a calendar year chosen to represent a single year or a group of years in which prevailing electricity and fuel market conditions and environmental policies are expected to be most similar. The number of IPM® run years is limited to decrease model complexity and run time. The analysis period of 2018 to 2038 reflects the 20-year period of reasonably foreseeable construction and coal export by the proposed coal export terminal. The coal market analysis models the proposed coal export terminal as fully online in the 2025 run year, and not operating in the 2020 run year.

Table 4-35. Mapping of Calendar Years and Model Run Years

Calendar Year	Run Year
2016	2016
2017	
2018	2018
2019	2020
2020	
2021	
2022	
2023	2025
2024	
2025	
2026	
2027	
2028	2030
2029	
2030	
2031	
2032	
2033	
2034	2040
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	

4.3.2 Coal

4.3.2.1 Modeling U.S. Coal Production

IPM® optimizes coal production, transportation, and consumption. For this purpose, the model uses coal supply curves developed for EPA, which provide supply curves for 34 different domestic coal supply basins. The international coal supply curves for 25 international supply basins were developed by ICF and added to the domestic supply curves to allow for global coal modeling. Coal supply curves are developed for 15 coal types distinguished by rank and sulfur content. There are multiple coal supply curves for each supply basin corresponding to the major coal quality types in that region. The supply curves consist of a series of supply "steps" that consist of a production cost, annual production capacity, and a coal resource limit. These supply curves are then incorporated into IPM®. Each coal power plant in IPM® is assigned to its own coal demand region in the model.

Coal varies by heat content, SO_2 content, hydrogen chloride content, and mercury content among other characteristics. To capture differences in the sulfur and heat content of coal, a two letter "coal grade" nomenclature is used. The first letter indicates the "coal rank" (bituminous, subbituminous, or lignite) with their associated heat content ranges (as shown in Table 4-36). The second letter indicates their "sulfur grade," i.e., the SO_2 ranges associated with a given type of coal. (The sulfur grades and associated SO_2 ranges are shown in Table 4-37).

Table 4-36. Coal Rank Heat Content Ranges

Coal Type	Heat Content (Btu/lb)	Classification
Bituminous	>10,260–13,000	B
Subbituminous	>7,500–10,260	S
Lignite	Less than 7,500	L

Notes:
Btu/lb = British thermal units per pound

Table 4-37. Coal Grade SO_2 Content Ranges

SO_2 Grade	SO_2 Content Range (lbs/MMBtu)
A	0.00–0.80
B	0.81–1.20
D	1.21–1.66
E	1.67–3.34
G	3.35–5.00
H	> 5.00

Notes:
SO_2 = sulfur dioxide; lbs/MMBtu = pounds per million British thermal unit

IPM® includes integrated U.S. and international coal market modeling. Figures 4-3 and 4-4 show the domestic and international coal supply regions. The modeling platform captures terminal capacity limits, international shipping costs, steam coal supply, and demand from both electricity and non-electricity sectors.

Figure 4-3. Domestic Coal Supply Regions

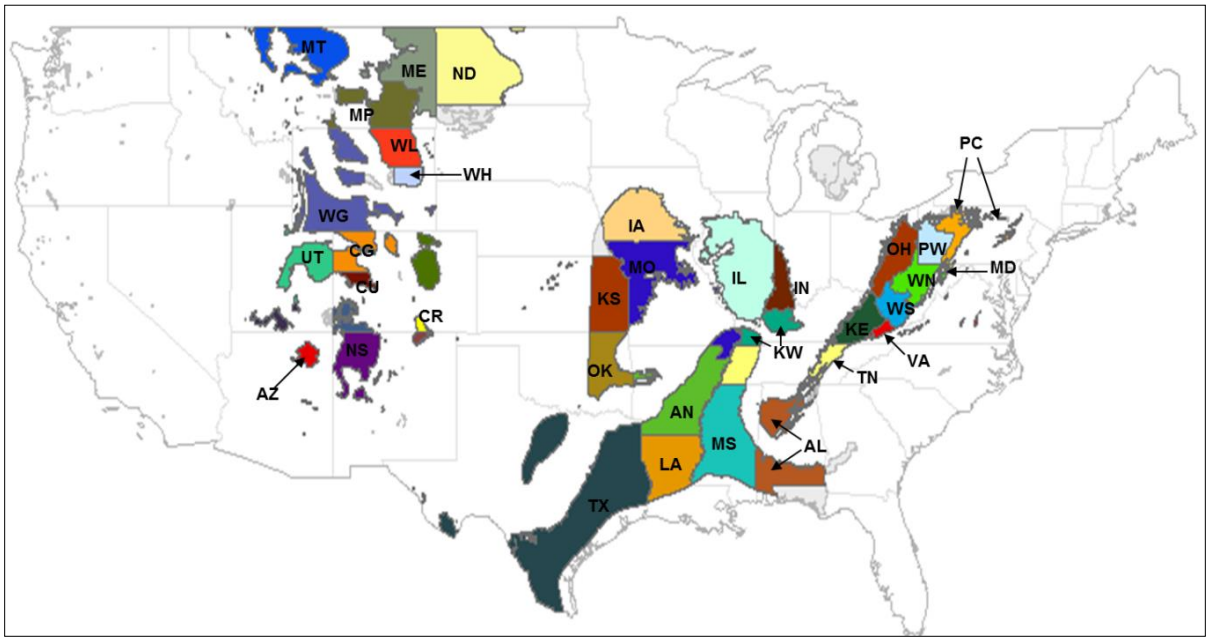
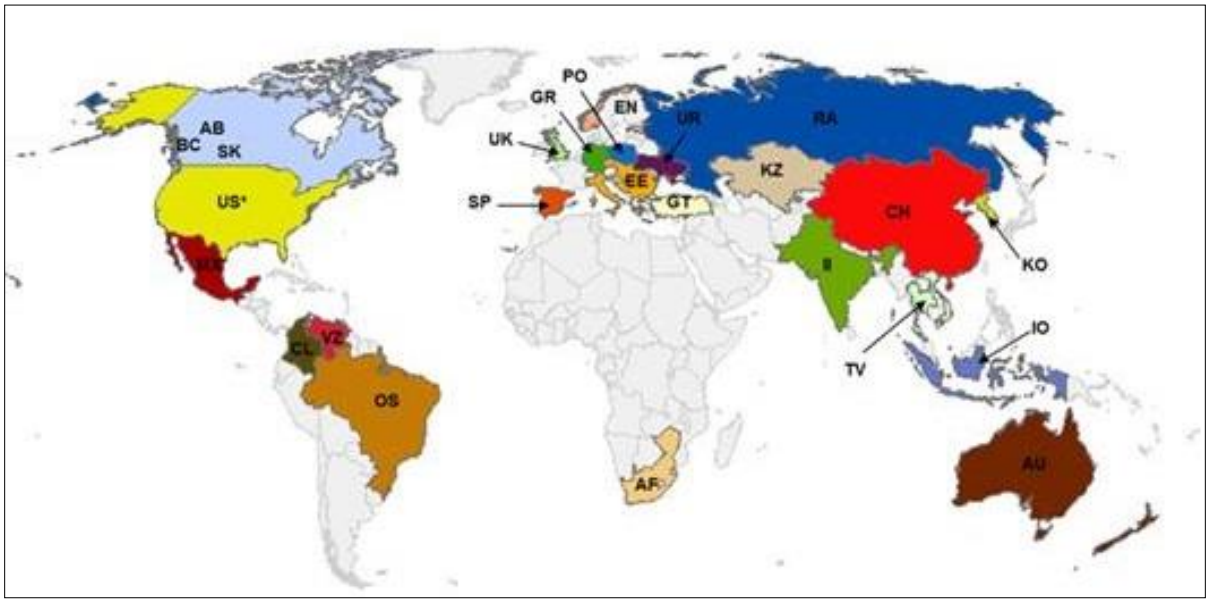


Figure 4-4. International Coal Supply Regions



4.3.2.2 Coal Demand

Using IPM®, coal demand is determined in the United States and Canada by the operation of existing coal-fired power plants, and elsewhere by projections of coal demand by country. Within a model run, IPM® calculates thermal coal consumption for each coal-fired electricity generation plant in the United States and Canada. Thermal coal consumption and coal prices are determined by the supply and demand economics of meeting the electricity demand. Thus if coal prices increase, there will be a reduction in coal demand in response to the higher coal prices. The plant specific coal

consumption and coal supply region price projections result in an integrated and consistent analysis in IPM® of the electricity demand; natural gas supply and prices; air emissions regulations for NO_X, SO_2, hydrogen chloride, and mercury; CO_2 policy alternatives, and renewable portfolio standards and explicit modeling of renewable generation options.

If the future electricity demand cannot be met by existing power plants, IPM® will determine the type and amount of new generating capacity required to meet the electricity demand on a least cost basis. The different types of capacity that can be added consist of combustion turbines, combined cycles, nuclear units, wind plants, coal-fired units, solar PV and thermal, geothermal, biomass, landfill gas, and hydro. Thus, if IPM® determines that new generating capacity in the United States and Canada are necessary and economic, IPM® will "build" new capacity from the types listed above. If the most economical new capacity is a coal plant, then coal demand would increase, resulting in higher coal prices, all else equal. IPM® can also determine that it is most economical to retire existing coal plants, which would decrease coal demand, and result in lower coal prices. This is only applicable in the United States and Canada, as coal plants are modeled explicitly in only these countries. Using this structure, IPM® is able to model explicitly the shifts in coal demand related to environmental mandates, natural gas prices, and coal production and transportation costs. For example, if natural gas prices are low, more electricity will be generated by natural gas-fired combined cycles, and coal consumption will be lower than in a case with higher natural gas prices.

In terms of non-electricity sector demand for thermal coal, IPM® includes domestic and international forecasts that serve as the demand for this coal. IPM® has an international coal supply and demand representation that enables it to project coal exports out of and imports into the United States and other countries. In the United States, coal demand is determined by the dispatch of coal-fired power plants and other generating resources to meet the electric demand. Table 4-38 summarizes the overall U.S. electricity demand forecast used in this analysis.

Table 4-38. U.S. Electric Energy Demand Forecast

Year	Energy Demand (TWh)
2016	4,050.9
2018	4,134.1
2025	4,327.7
2030	4,465.3
2040	4,740.5

Source: EPA IPM V5.15 documentation
TWh = terawatt hours

4.3.2.3 Coal Transportation

The model also connects the 34 U.S. coal supply regions and the 25 international supply regions with the plant specific coal demand regions in the United States and Canada, and 26 international coal demand regions. The transportation costs between supply and demand regions are based on the transportation mode, such as rail, barge, and truck, and the mileage between each region by mode. Each coal demand region has on average 9 supply regions connected to it, using one or more transportation modes. For international shipments, shipping rates are estimated based on published shipping cost data and are adjusted going forward based on projections of the global shipping index, the Baltic Dry Index.

Asian coal demand regions are linked to more than 20 supply regions including U.S. supply regions in Appalachia, the Uinta Basin, and the Powder River Basin and international supply regions such as Australia, Canada, China, Colombia, Indonesia, Korea, Kazakhstan, Russia, South Africa, and Venezuela.

During each run, IPM® determines the least cost means to meet power sector demand for coal as part of an integrated optimal solution for power, fuel, and emissions markets. Thus, IPM® is able to determine the optimal sourcing of coal for each power plant based on the estimated coal prices and transportation costs. Additional information on the coal transportation inputs and methodology used can be found in Chapter 9 of EPA's documentation on the IPM v5.13 Base Case.

4.3.3 Environmental Compliance

4.3.3.1 Plant-by-Plant Compliance Overview

For explicitly modeled coal plants in the United States and Canada, IPM® incorporates constraints on emissions of NO_X, SO_2, hydrogen chloride, mercury, CO_2, and potentially other pollutants into its optimization process. Since coal demand in other countries is done through a forecast and not explicitly modeling coal plants, this is only applicable to U.S. and Canadian coal plants. Constraints are specified based on target emissions rates, cap-and-trade policies, dollars per ton emitted tariffs, or command-and-control policies, and applied to individual generating units or groups of units. Power-generating units subject to environmental regulations have the following compliance options, with any combination or individual use of the first four options as a viable compliance mechanism.

- **Reduce running regime**. To comply with non-command-and-control policies, such as target emissions rates or an emissions cap, a unit can reduce the number of hours in a year it operates and shift when it operates to hours that are more lucrative, which would be during peak demand periods of a day or year. For example, a plant might run only during the peak hours of 6:00 a.m. and 10:00 p.m., or only during the peak summer season.

- **Fuel switch**. Coal-fired units can choose from a variety of coals of different sulfur and mercury contents to minimize emissions and allowance cost impacts. The demand for these lower content coals results in premiums for those coals, over coals with higher pollutant contents. This premium may shrink if, for example, control becomes the dominant compliance option and higher pollutant content coals can be burned by controlled units. Oil units are generally offered fuels with different sulfur contents as well. The system may also fuel switch, from new coal builds to new natural gas builds, for example, to address CO_2 emissions requirements.

- **Retrofit**. For the four pollutants NO_X, SO_2, hydrogen chloride, and mercury, a variety of retrofit technologies is available to reduce emissions. In the case of CO_2, IPM® includes potential carbon capture-and-sequestration technology retrofits that can be applied to both new and existing units.

- **Purchase allowances**. By calculating an allowance price, IPM® is implicitly assuming that some units are sellers of allowances and others are buyers.

- **Retire.** A unit can be forced to retire or be given the economic option to retire if it cannot cover its operating costs going forward.

4.3.3.2 CO_2 Emissions

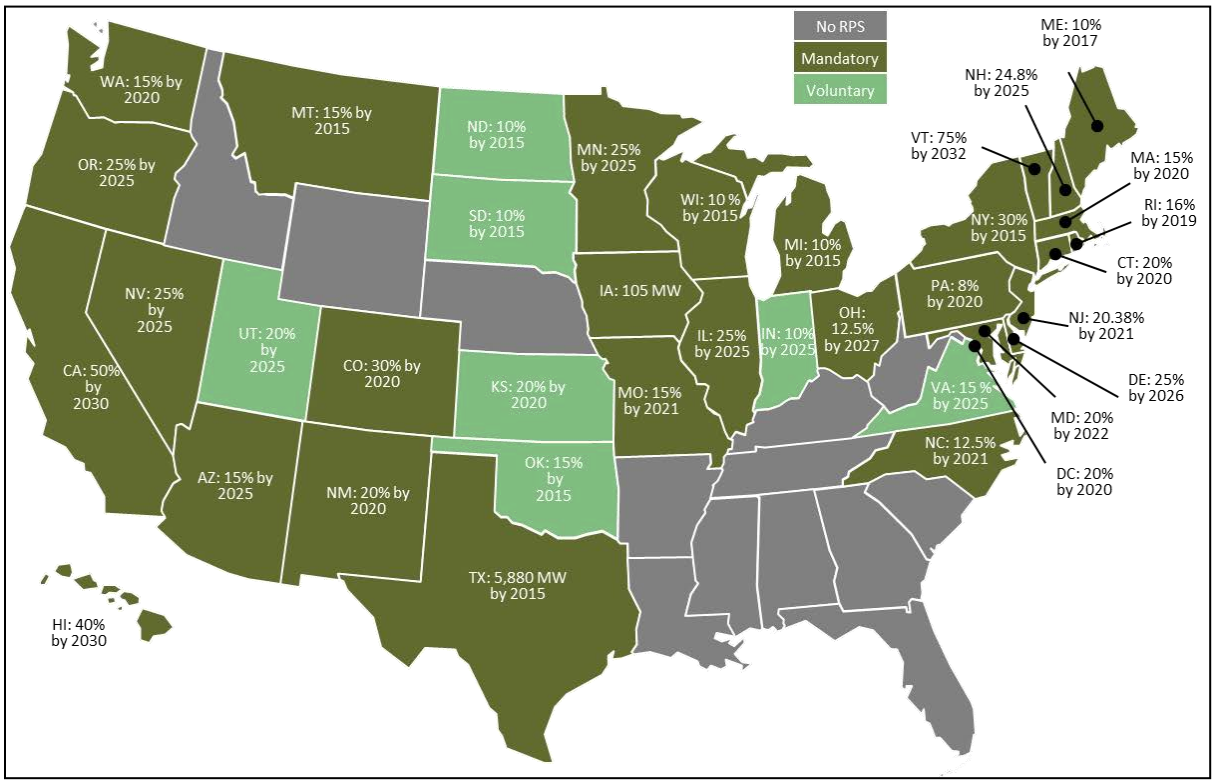
IPM® has the capability to model carbon policies as a cap-and-trade program or as a strict limit on CO_2 emissions from the power sector or the economy as a whole. In the 2015 U.S. and International Energy Policy Scenario, consistent with one of the alternatives under the EPA's proposed Federal Plan for the Clean Power Plan, IPM models EPA's final Clean Power Plan through state specific mass-based new and existing emissions constraints. The New Source Performance Standards for CO_2 for new and modified sources are reflected in the model by requirements that any new coal units, other than those named by EPA as exceptions, would have to be constructed with carbon capture and sequestration.

4.3.3.3 Renewable Portfolio Standards

IPM® treats renewable portfolio standards as follows.

- Twenty-eight states and the District of Columbia have passed mandatory renewable energy requirements; eight more have enacted voluntary standards or goals (Figure 4-5).
- The design of each renewable portfolio standard varies by target and timing, the types of renewable generation allowed, the geographic scope within which a generator might be eligible to meet the standard, and the types of enforcement mechanisms and escape clauses included.

Figure 4-5. Renewable Portfolio Standards



Renewable generation capacity tends to have a higher-leveled cost than fossil-fuel generation. To encourage the development of renewable capacity, many states allow generators to commoditize the

green attributes of renewable power in renewable energy credits.[25] The sale of such credits can provide supplemental revenue. IPM models wholesale power markets for a given set of future conditions (energy demand, new power plant costs, fuel market conditions, environmental regulations, renewable energy standards, etc.), using a least-cost optimization approach. IPM models REC pricing as the value needed to make renewable generators whole, given the gap between generator costs and revenue sources. Revenue sources include energy prices, capacity prices, and other nonrenewable energy certificate subsidies, such as the federal production and investment tax credits and modified accelerated cost recovery system.

4.3.3.4 Other State and Regional Requirements

The modeling also addresses the following state and regional programs.

- IPM® included the CO_2 cap currently specified in the Regional Greenhouse Gas Initiative.
- IPM® includes California Assembly Bill 32 cap-and-trade program, which affects both in-state generation, as well as power imported into California.
- IPM® includes other state SO_2 and NO_X regulations where final regulations exist.

4.3.4 Natural Gas

This analysis uses the natural gas mode from EPA's IPM v5.15 Base Case. A thorough description of the natural gas modeling and assumption is contained in Chapter 10 of EPA's documentation for v5.13, and thus, is not duplicated here.

[25] Alternative terms used for such instruments include *green tags* and *renewable energy certificates*.

Chapter 5
Scenarios

Four main scenarios and a cumulative scenario were modeled using IPM®. The four main scenarios are the No Clean Power Plan Scenario, Lower Bound Scenario, Upper Bound Scenario, and 2015 U.S. and International Energy Policy Scenario. The Cumulative Scenario takes into account the addition of other reasonably foreseeable planned export terminals in the Pacific Northwest. The Lower and Upper Bound Scenarios are designed to provide reasonable bounds on GHG emissions from implementing the Proposed Action. The four main scenarios differ regarding the following six parameters.

- International coal supply curves
- International thermal coal demand
- Coal demand elasticity
- Powder River Basin and Uinta Basin coal supply curves
- U.S. rail transportation costs
- U.S. and International Climate Policy. The U.S. climate policy is incorporated into the modeling by using an assumed version of the Clean Power Plan or by not including the Clean Power Plan.[26] The international climate policies are incorporated into the modeling through the international coal demand used in each scenario.

All five scenarios use a common set of base assumptions, many of which were updated between the Draft EIS and Final EIS. Detailed descriptions of these assumptions are included in Chapter 4. The set of base assumptions include, but are not limited to, the following:

- Coal supply curves for U.S. and international coal supply regions. In the No Clean Power Plan Scenario, the base coal supply curves result in Powder River Basin Wyoming 8800 Btu/lb coal being priced at $12.6/ short ton, Uinta Basin 11,280 Btu/lb coal being priced at $39.0/short ton, and Australian 10,800 Btu/lb coal being priced at $62.8/ short ton.[27] All prices are in 2012$ for the year 2018.
- Coal transportation costs. The base rail transportation costs are $30 to $36 per short ton for coal transported from the Powder River Basin and Uinta Basin to the proposed coal export terminal.
- Natural gas supply curves.
- Air, waste, and water regulations

[26] Since implementation of the Clean Power Plan will occur at the state level and states have not determined how they will implement the Clean Power Plan, a version of the Clean Power Plan consistent with one of the alternatives under the EPA's proposed Federal Plan for the Clean Power Plan that features state specific mass standards for existing units was used.

[27] British thermal units (Btu) are a standardized measurement of the heat content of coal.

- Renewable energy standards and regulations
- Reserve margin targets for each U.S. electric demand region
- Planned new generating capacity and retirements
- Electric transmission limits
- Electric demand
- Capital costs for new electric generating capacity
- International coal demand. The base assumption for international coal demand is the Current Policies Scenario from the IEA 2015 WEO. The Current Policies Scenario includes only those GHG reduction policies for which implementing measures have been formally adopted as of mid-2015, and assumes that these policies remain unchanged going forward.
- Elasticity of coal demand for the Asian countries that can receive coal from the proposed coal export terminal. The base elasticity of coal demand for China is -0.44 and is -0.11 for India, Japan, South Korea, and Taiwan.

5.1 Scenarios Analyzed

A No-Action Alternative and a Proposed Action case were created for each scenario analyzed, except for the Cumulative Scenario, where the Proposed Action is compared to the No Clean Power Plan Scenario No-Action Alternative. This was done to isolate the Proposed Action as the only change between the No-Action Alternative and Proposed Action in each scenario. Table 5-1 summarizes the No Clean Power Plan, Lower Bound, Upper Bound, and 2015 U.S. and International Energy Policy Scenarios and the following sections provide additional details on the differences between each scenario.

Table 5-1. Scenario Definitions

Parameter	Scenario			
	No Clean Power Plan	**Lower Bound**	**Upper Bound**	**2015 U.S. and International Energy Policy**
International Coal curves	No change from base assumptions	Base supply curves decreased by 10%	Base supply curves increase by 50%, based on prices observed between 2012 and 2014	No change from base assumptions
International thermal coal demand	No change from base assumptions	IEA 2015 WEO demand forecast from the New Policies Scenario	Increase coal demand by using historical growth rates from the period 2000 to 2012, when coal demand was rapidly increasing	IEA 2015 WEO demand forecast from the New Policies Scenario
Coal demand elasticity	No change from base assumptions	1.0% change in delivered coal cost results in 0.32% change in demand in opposite direction in China and 0.11% elsewhere	1.0% change in delivered coal cost results in 0.68% change in demand in opposite direction in China and 0.11% elsewhere	1.0% change in delivered coal cost results in 0.32% change in demand in opposite direction in China and 0.11% elsewhere
Powder River Basin and Uinta Basin coal curves	No change from base assumptions	Increase Powder River Basin curves by 25%, based on coal prices between 2012 and 2014	Decrease Powder River Basin and Uinta Basin coal curves by 15%, based on low coal prices between 2012 and 2016	No change from base assumptions
U.S. Rail transportation costs	No change from base assumptions	Increase costs by 20%	Decrease costs by 20%	No change from base assumptions
U.S. and International Climate Policy	No U.S. or international Climate Policies	Clean Power Plan and International GHG reduction commitments	No U.S. or international Climate Policies	Clean Power Plan and International GHG reduction commitments

IEA 2015 WEO = International Energy Agency 2015 World Energy Outlook

5.1.1 No Clean Power Plan Scenario

The No Clean Power Plan Scenario is defined by a set of assumptions that are intended to represent the state of the energy markets as of 2016, but without EPA's Clean Power Plan. The No Clean Power Plan Scenario uses the base set of assumptions and assumes no additional national or international climate policies will be enacted beyond those implemented by mid-2015. For the six parameters that are changed to define the four main scenarios, the No Clean Power Plan Scenario is defined as described in the following bullets.

- International coal curves: no change from base assumptions. Australian bituminous 10,800 Btu/lb (6,000 kilocalorie per kilogram) coal is $62.8 per short ton in 2018 (2012$).
- International thermal coal demand: no change from base assumption, which uses the IEA 2015 WEO coal demand forecast from the Current Policies Scenario.
- Coal demand elasticity: no change from base assumption, which is every 1.0% change in delivered coal cost would result in 0.44% change in demand in opposite direction in China and 0.11% for Hong Kong, India, Japan, South Korea, and Taiwan.
- Powder River Basin and Uinta Basin coal curves: no change from base assumption. The Powder River Basin Wyoming 8800 Btu/lb coal would be $12.6/short ton, and Uinta Basin prices would be $39.0/ton for 11,280 Btu/lb coal in 2018 (2012$).
- Rail transportation costs: no change from base assumptions, which are $30 to $36 per short ton for coal transported from the Powder River Basin and Uinta Basin to the proposed coal export terminal (2012$).
- U.S. and international climate policies: This scenario does not include implementation of the Clean Power Plan or international climate policies that were implemented after mid-2015.

5.1.2 Lower Bound Scenario

The Lower Bound Scenario is designed to result in a reasonable lower bound estimate of global CO_2 emissions from the power sector and to evaluate the likelihood of a smaller CO_2 emissions impact with the construction and operation of the proposed coal export terminal. This scenario is designed to be a plausible and reasonable lower bound, and does not attempt to model an absolute lowest bound of CO_2 emissions or CO_2 emissions due to the Proposed Action. The energy market under the Lower Bound Scenario could be described as a high renewable energy penetration scenario. If renewable energy penetration is higher than expected, international coal consumption and prices would both decline. For the six parameters that are changed to define the four main scenarios, the Lower Bound Scenario for both the No-Action Alternative and Proposed Action is defined as described in the following bullets.

- International coal curves were decreased from the base assumptions by 10%. This change might cause a smaller amount of induced demand because it would reduce the differential in prices between international coal and the coal exported through the proposed terminal. Australian bituminous 10,800 Btu/lb (6,000 kilocalorie per kilogram) coal is $56.5 per short ton in 2018 (2012$).
- International thermal coal demand was obtained from the IEA 2015 WEO coal demand forecast from the New Policies Scenario, as this Scenario includes both existing and proposed GHG reduction policies. Thus the international thermal coal demand in the Lower Bound Scenario is lower than the base assumptions.
- Coal demand elasticity would be less elastic than the base assumptions. In the Lower Bound Scenario a 1.0% change in delivered coal cost would result in a 0.32% change in demand in opposite direction in China and 0.11% elsewhere. To the extent that there would be a decrease

in delivered coal costs, this assumption would cause the amount of induced demand to be less than it would be under the base assumptions.

- The Powder River Basin coal curves are increased by 25% to reflect higher than expected stripping ratios. The Powder River Basin Wyoming 8800 Btu/lb coal would be $12.0/short ton, and Uinta Basin prices would be $39.2/ton for 11,280 Btu/lb coal in 2018 (2012$).
- Rail transportation costs were increased by 20% to reflect higher than expected fuel costs compared to the base assumptions.
- U.S. and international climate policies: The Lower Bound Scenario assumes the Clean Power Plan is implemented in the United States and the international GHG reduction commitments that are included in the IEA 2015 WEO New Policies Scenario.

5.1.3 Upper Bound Scenario

The Upper Bound Scenario is designed to result in a reasonable upper bound estimate of global CO_2 emissions from the combustion of coal and to evaluate the possibility of greater CO_2 emissions due to the construction and operation of the proposed terminal. This scenario is designed to be a plausible and reasonable upper bound on global CO_2 emissions from coal combustion, but does not attempt to model an absolute highest amount of global CO_2 emissions or CO_2 emissions due to the Proposed Action.[28] The world energy outlook under the Upper Bound Scenario could be described as a high coal demand scenario, where coal plant construction, and thus, coal demand, is higher than in the base assumptions. Thus, both international coal consumption and prices would increase. The coal prices would increase because the higher demand would drive the prices higher. For the six parameters that change to define the four main scenarios, the Upper Bound Scenario for both the No-Action Alternative and Proposed Action is described in the following bullets.

- International coal curves were increased from the base assumptions by 50%. This change causes a larger amount of induced demand because it would increase the differential between the international coal prices and the coal exported though the proposed terminal. Australian bituminous 10,800 Btu/lb (6,000 kilocalorie per kilogram) coal is $95.5 per short ton in 2018 (2012$).
- International thermal coal demand was obtained from using historical coal consumption growth rates from the period 2000 to 2012 and applying those growth rates to current consumption. Thus, the international thermal coal demand in the Upper Bound Scenario is higher than the base assumptions.
- Coal demand elasticity would be more elastic than the base assumptions. In the Upper Bound Scenario, a 1.0% change in delivered coal cost would result in a 0.68% change in demand in opposite direction in China and 0.11% elsewhere. To the extent that there would be a change in delivered coal costs, this assumption would cause the amount of induced demand to be greater than it would be under the base assumptions.
- Powder River Basin and Uinta Basin coal curves: the Powder River Basin and Uinta Basin coal curves were decreased by 15% to reflect lower than expected stripping ratios. The Powder

[28] There is no specific confidence interval or probability associated with this scenario.

River Basin Wyoming 8800 Btu/lb coal would be $13.2/short ton, and Uinta Basin prices would be $33.6/ton for 11,280 Btu/lb coal in 2018 (2012$).

- Rail transportation costs were decreased by 20% to reflect lower than expected fuel costs compared to the base assumptions.
- U.S. and international climate policies: The Upper Bound Scenario does not include implementation of the Clean Power Plan or international climate policies that were implemented after mid-2015.

5.1.4 2015 U.S. and International Energy Policy Scenario

The 2015 U.S. and International Energy Policy Scenario was created to evaluate how recent international climate negotiations and perspectives on future climate policies might affect GHG emissions under the Proposed Action. In particular, this scenario includes the November 2014 U.S.-China announcement on climate change action goals, other international GHG reduction commitments made by mid-2015, and implementation of the U.S. EPA Clean Power Plan. This scenario represents the energy market as of late 2015.

The 2015 U.S. and International Energy Policy Scenario uses the base assumptions except for three changes. First, the international thermal coal demand was taken from the IEA 2015 WEO, New Policies Scenario demand forecast. The New Policies Scenario takes into account the policies and implementing measures affecting energy markets that have been adopted as of mid-2015, together with relevant policy proposals, even if specific measures needed to put them into effect have yet to be fully developed. The New Policies Scenario assumed only cautious implementation of these proposed commitments and plans.

Second, this scenario includes EPA's final Clean Power Plan, which is intended to reduce CO_2 emissions in the United States that are a start to achieving the November 2014 commitments. The Clean Power Plan would also likely reduce the amount of coal consumed in the United States. Consistent with one of the alternatives under the EPA's proposed Federal Plan for the Clean Power Plan, the 2015 U.S. and International Energy Policy Scenario features state specific mass standards for existing sources. Allowances are assumed fully tradable between covered fossil units within a state, and can be traded across states. The trading is modeled such that all affected sources in all states can trade allowances with each other except for those in California and the member states of the Regional Greenhouse Gas Initiative, which are limited to trading within California or the Regional Greenhouse Gas Initiative, respectively. EPA's leakage requirement for mass based standards over existing sources is met by including allocations for existing gas and new renewable units, consistent with EPA's proposed Federal Plan and modeling for the Regulatory Impact Analysis for the final rule.

For the six parameters that are changed to define the four main scenarios, the 2015 U.S. and International Energy Policy Scenario is defined as described as follows.

- International coal curves: no change from base assumptions. Australian bituminous 10,800 Btu/lb (6,000 kilocalorie per kilogram) coal is $62.8 per short ton in 2018 (2012$).
- International thermal coal demand was obtained from the IEA 2015 WEO coal demand forecast from the New Policies Scenario, as this scenario includes both existing and proposed GHG

reduction policies. Thus the international thermal coal demand in the 2015 U.S. and International Energy Policy Scenario is lower than the base assumptions.

- Coal demand elasticity would be less elastic than the base assumptions. In the 2015 U.S. and International Energy Policy Scenario a 1.0% change in delivered coal cost would result in a 0.32% change in demand in opposite direction in China and 0.11% elsewhere. To the extent that there would be a decrease in delivered coal costs, this assumption would cause the amount of induced demand to be less than it would be under the base assumptions.
- Powder River Basin and Uinta Basin coal curves: no change from base assumption. The Powder River Basin Wyoming 8800 Btu/lb coal would be $10.9/short ton, and Uinta Basin prices would be $34.5/ton for 11,280 Btu/lb coal in 2018 (2012$).
- Rail transportation costs: no change from base assumptions, which are $30 to $36 per short ton for coal transported from the Powder River Basin and Uinta Basin to the proposed coal export terminal (2012$).
- U.S. and international climate policies: This scenario assumes the Clean Power Plan is implemented in the United States and the international GHG reduction commitments that are included in the IEA 2015 WEO New Policies Scenario.

5.1.5 Cumulative Scenario

The Cumulative Scenario includes the addition of other planned export terminals in the Pacific Northwest in both the United States and Canada. The planned export terminals, and their capacities included in this scenario, are shown in Table 5-2. Each terminal is assumed to operate at full capacity, except for the Ridley terminal due to the long rail distance of this terminal from the Powder River Basin. Thus there is a total export capacity of 183 million metric tons, which would include both thermal and metallurgical coal. Because the Canadian export terminals primarily export Canadian coal and are expected to continue this practice, only a portion of these terminals are available to export U.S. coal, as shown in the last column of Table 5-2. All other assumptions are the same as the base assumptions. The Cumulative Scenario does not include implementation of the Clean Power Plan.

Table 5-2. Planned and Existing Pacific Northwest Export Terminals

Terminal	State/Province	Online Year	Capacity (MMTons/year)	Capacity Available for U.S. Coal (MMTons/year)
Planned				
Millennium Bulk Terminal—Longview	Washington	2025	44	44
Gateway Pacific Terminal	Washington	2030	48	48
Fraser Surrey Docks	British Columbia	2018	4	4
Westshore Expansion	British Columbia	2017	3	3
Ridley Expansion	British Columbia	2016	13	9
Neptune Expansion	British Columbia	2018	6	0
Total Planned			118	108
Existing				
Westshore	British Columbia	N/A	33	8
Neptune (metallurgical coal only)	British Columbia	N/A	12	0
Ridley	British Columbia	N/A	12	5
Total Existing			57	13
Total Planned and Existing			**175**	**121**

MMTons/year = million metric tons per year

Chapter 6
Modeling Results

6.1 Overview of Results

This chapter presents the coal production, consumption, distribution, and emissions modeling results. Coal production results are presented for both U.S. and non-U.S. production, with a focus on Powder River Basin and Uinta Basin coal production. Emissions of CO_2 are presented for the consumption of coal only in Asia, and for coal and natural gas in the United States. Emissions from other sources, such as the transportation of coal, are presented in the air quality and greenhouse gas sections of the EIS. Emissions of CO_2 from natural gas are included in this chapter, because natural gas generation is a replacement for coal-fired electric generation that will have CO_2 emissions; however, emissions from natural gas are included only for U.S. and not international natural gas consumption.[29]. Results are presented for the full modeling time horizon of 2016 through 2040 to provide additional context for the changes that would occur under the Proposed Action. However, the averages presented in the tables are only for the period 2025 to 2040, to focus the changes in results on the period when the proposed coal export terminal is fully operational in the model. Construction of the proposed coal export terminal is expected to begin in 2018 and continue through 2020, with initial operation of the proposed coal export terminal beginning in 2021and ramping up capacity over time. Due to the run year structure, as described in Section 4.3.1, in the IPM the proposed coal export terminal is fully online in the 2025 run year and not online in the 2020 run year.

The proposed coal export terminal may cause changes in coal production at the following scales of production.

- Powder River Basin or Uinta Basin coal production
- U.S. coal production
- Non-U.S. coal production, such as in Australia, China, Indonesia or Russia

This section provides an overview of the No Clean Power Plan Scenario, No-Action Alternative and Proposed Action results, as well as results from the four scenarios analyzed.

- Lower Bound Scenario
- Upper Bound Scenario
- 2015 U.S. and International Energy Policy Scenario
- Cumulative Scenario

All coal production and consumption results in this analysis are presented in million metric tons.

[29] As discussed in Chapter 4, the international representation in the model only includes the consumption of coal.

6.1.1 No Clean Power Plan Scenario Results

Under the No Clean Power Plan Scenario total U.S. coal production for the No-Action Alternative would have an average of 813 million metric tons per year from 2025 to 2040. Coal production in the United States would increase steadily over this period, because of three factors.

- First, natural gas prices increase by $0.38/MMBtu, which keeps coal competitive.
- Second, there are no environmental policies making coal less competitive than other fuels.
- Third, electric demand continues to increase over this period.

Total non-U.S. coal production in this period would have an average of 7,098 million metric tons per year and would increase during the period analyzed to meet the expected growth in coal demand, which is primarily in China and India. For the Proposed Action, the U.S. average coal production over 2025 to 2040 would be 857 million metric tons, an increase of 44 million metric tons over the No-Action Alternative. The non-U.S. average coal production would decrease by 39 million metric tons per year in the Proposed Action.

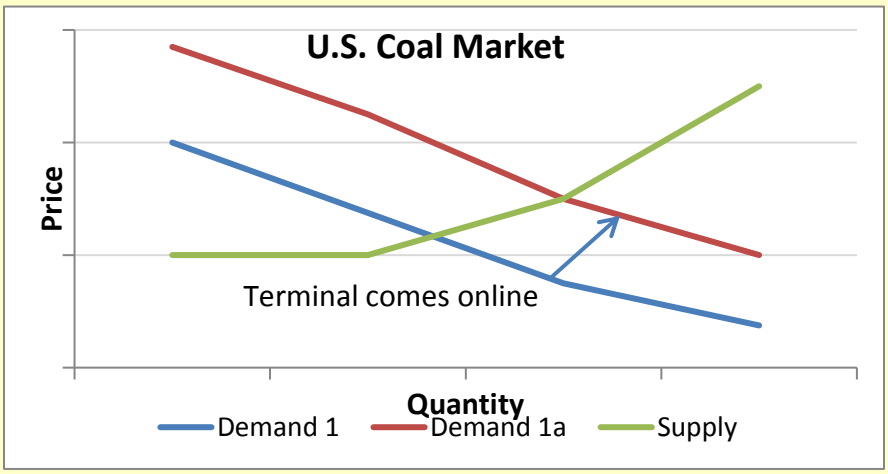
The total average U.S. thermal coal consumption for 2025 to 2040 under the No-Action Alternative would be 671 million metric tons per year, while the average thermal coal consumption in Asia would be 5,855 million metric tons per year. Average annual coal consumption in Asia for the period 2025 to 2040 under the Proposed Action would be within 5 million metric tons of consumption under the No-Action Alternative. The change would be due to the increased consumption of lower heat content coal that replaces some higher heat content coal. Under the Proposed Action, U.S. coal consumption would remain at 671 million metric tons because there is no decrease in U.S. coal consumption when the proposed coal export terminal comes online.

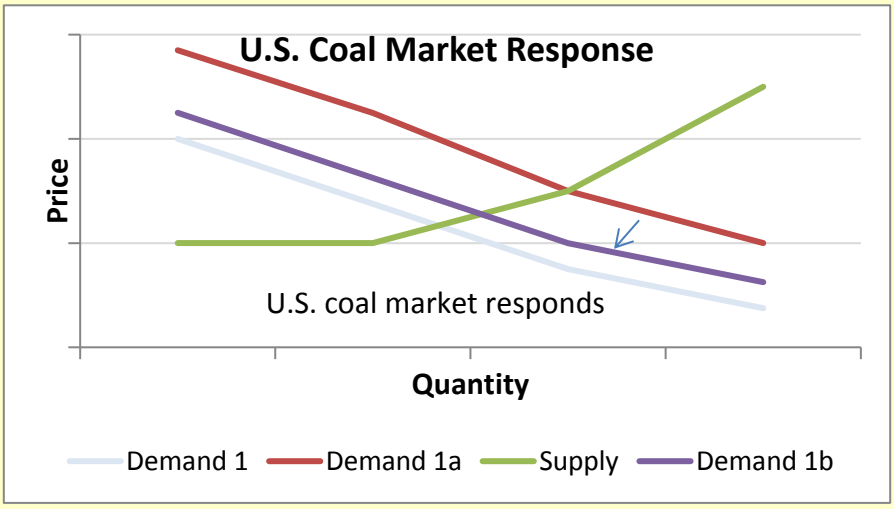
Seaborne thermal coal distribution in Asia would average 511 million metric tons per year during 2025 to 2040 under the No-Action Alternative, and would change by 18 million metric tons under the Proposed Action because the exported coal would replace coal produced in Asia. Under the Proposed Action, coal from the Montana portion of the Powder River Basin would be exported to China, Hong Kong, Japan, South Korea, and Taiwan. The distance that the coal travels would be greater under the Proposed Action than under the No-Action Alternative. Under the Proposed Action, the change in the distance coal would be transported would average 232 nautical miles per shipment more than under the No-Action Alternative.

CO_2 emissions in the United States under the No-Action Alternative from the combustion of coal would average 1,320 million metric tons per year over 2025 to 2040, while emissions from natural gas consumption would average 588 million metric tons per year. In Asia, CO_2 emissions under the No-Action Alternative from the combustion of coal would average 12,715 million metric tons per year over 2025 to 2040. Under the Proposed Action, CO_2 emissions would increase by 1.815 million metric tons per year in Asia to 12,717 million metric tons Coal emissions in the United States would fall slightly, while natural gas emissions would not change. Thus, the total net change in CO_2 emissions under the Proposed Action would be an increase of 1.811 million metric tons per year on average over 2025 to 2040.

Operation of the Proposed Action would further integrate the U.S. and Asian coal markets. However, to the extent that Asian coal prices would be higher than U.S. prices, operation of the Proposed Action would cause Asian coal prices to decline, while U.S. prices would increase. These changes in prices would cause Asian coal demand to increase and U.S. demand to decrease. The reason U.S. coal prices would increase is because the Applicant would act as a "buyer" of coal, and thus, would shift the demand curve (Demand 1) to the right (Demand 1a), setting a new, higher equilibrium coal price. In response, utilities would choose to use less coal and more natural gas, so the coal demand curve shifts back to the left (Demand 1b), but still to the right of the original curve (Demand 1).

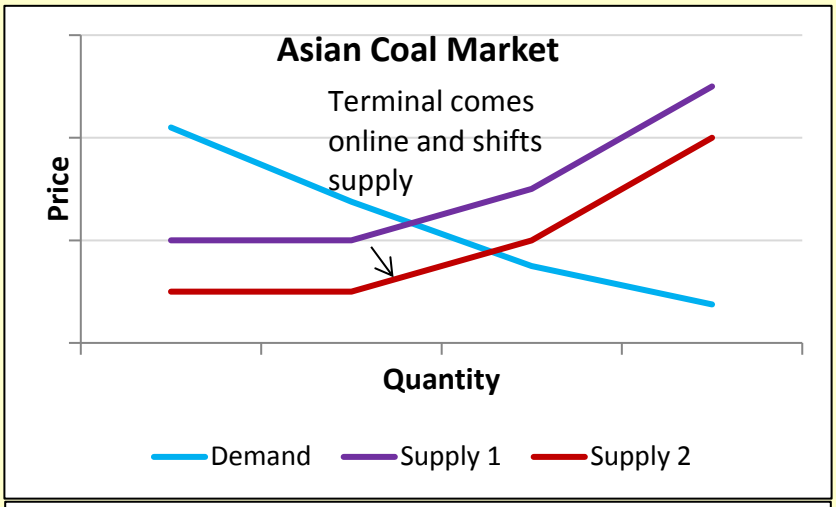
Impact of Proposed Action on Domestic Coal Supply and Demand at Full Capacity

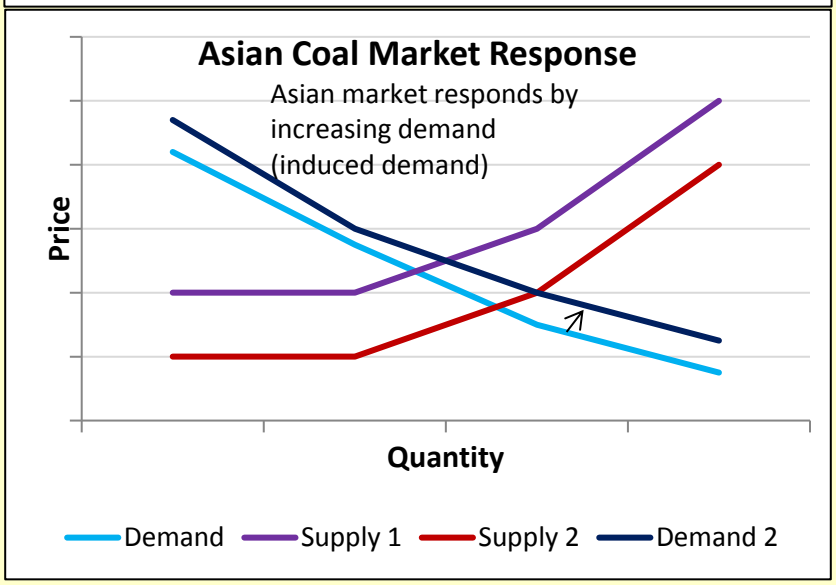




The Proposed Action would cause Asian coal demand to increase because the coal export terminal would act as a new source of coal, and thus, would shift the supply curve (Supply 1) to the right (Supply 2), setting a new, lower equilibrium coal price. In response, Asian countries would choose to use more coal, so the coal demand curve would shift to the right (Demand 2).

Impact of Proposed Action on International Coal Supply and Demand at Full Capacity





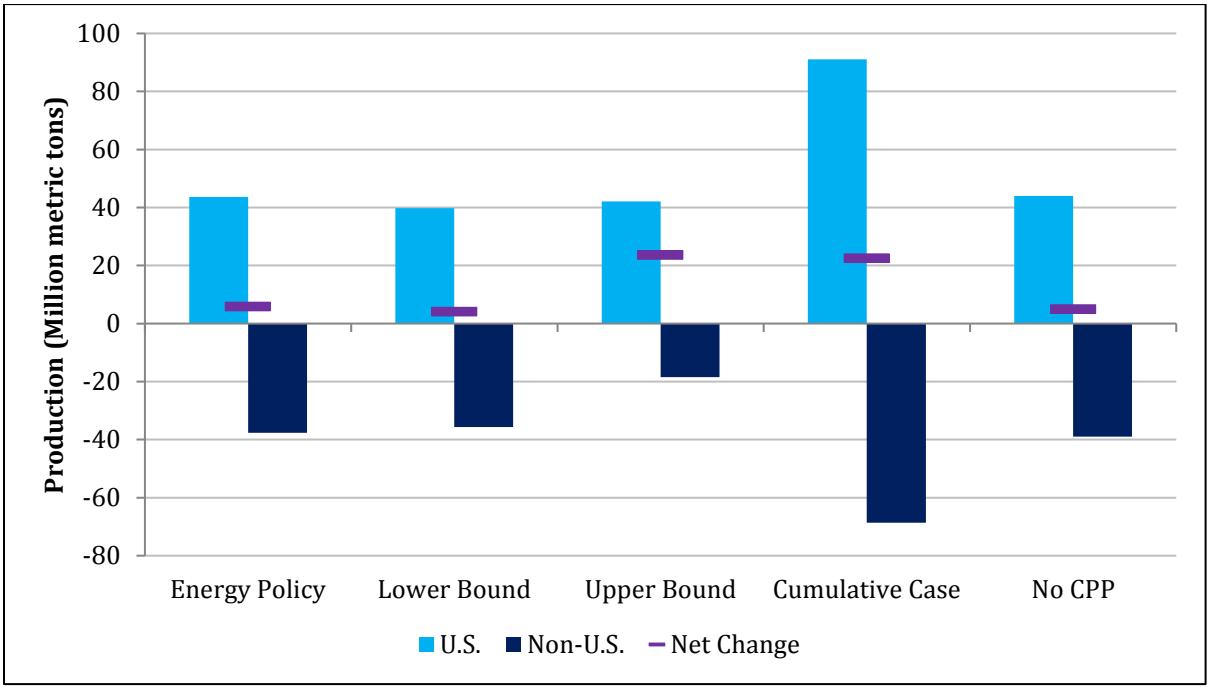
6.1.2 Scenario Results

The five scenarios that were analyzed are used to explore how CO_2 emissions from the Proposed Action would change under different sets of assumptions. Figure 6-1 shows the change in average production under each scenario for 2025 to 2040, where the change is calculated by subtracting the No-Action Alternative production from Proposed Action production. Except for the Cumulative Case,

in which other coal export terminal capacity comes online, the change in the average U.S. thermal coal production is within 5 million metric tons of the capacity of the proposed coal export terminal.

In the Cumulative Scenario, average U.S. coal production over 2025 to 2040 increases under the Proposed Action by 91 million metric tons, which is less than the full 99 million metric tons of new thermal coal export capacity, excluding Ridley Terminal.[30] This increase in U.S. production is less than the full new terminal capacity because there is a decrease in U.S. coal demand and because exports of non-Powder River Basin coal decrease in some years. The decrease in U.S. demand for Powder River Basin coal in the Cumulative Scenario is an average 2.7 million metric tons while the demand for all coal in the United States declines by 0.9 million metric tons.

Figure 6-1. Change in Annual Average Production for 2025 to 2040—Proposed Action minus No-Action Alternative (million metric tons per year)



Non-U.S. coal production declines in each scenario in equal proportion to the increase in U.S. production, with the exception of the Upper Bound scenario. However, the increase in U.S. production is generally slightly higher because the exported Powder River Basin coal would have a lower heat content than some of the coal that it would displace; thus, less total tons would be displaced than exported, while the same amount of total heating value would be replaced. For example, if 10 million metric tons of a 9,000 Btu/lb coal is exported and displaces a 12,000 Btu/lb coal, then the total heat content exported would be 198.4 TBtu (*=10,000,000 metric tons x 1.1023-short tons/metric ton x 2,000 lbs/ short ton x 9,000 Btu/lb x 1 TBtu/10^12 Btu*). The equivalent tons of the 12,000 Btu/lb coal is then 7.5 million metric tons (*=198.4 TBtu x 10^12 Btu/1 TBtu x 1/12,000 Btu/lb x 1 short ton/2000 lbsx 1 metric ton/1.1023 short ton x 1 million metric ton/10^6 metric tons*). Thus, for every 10 million metric tons of 9,000 Btu/lb coal exported, only 7.5 million metric tons of

[30] Results are averaged over the period 2025 to 2040, because in the coal market analysis the proposed terminal comes online at full capacity in 2025. This is due to the years that are explicity run in the model, as explained in Section 4.3.1.

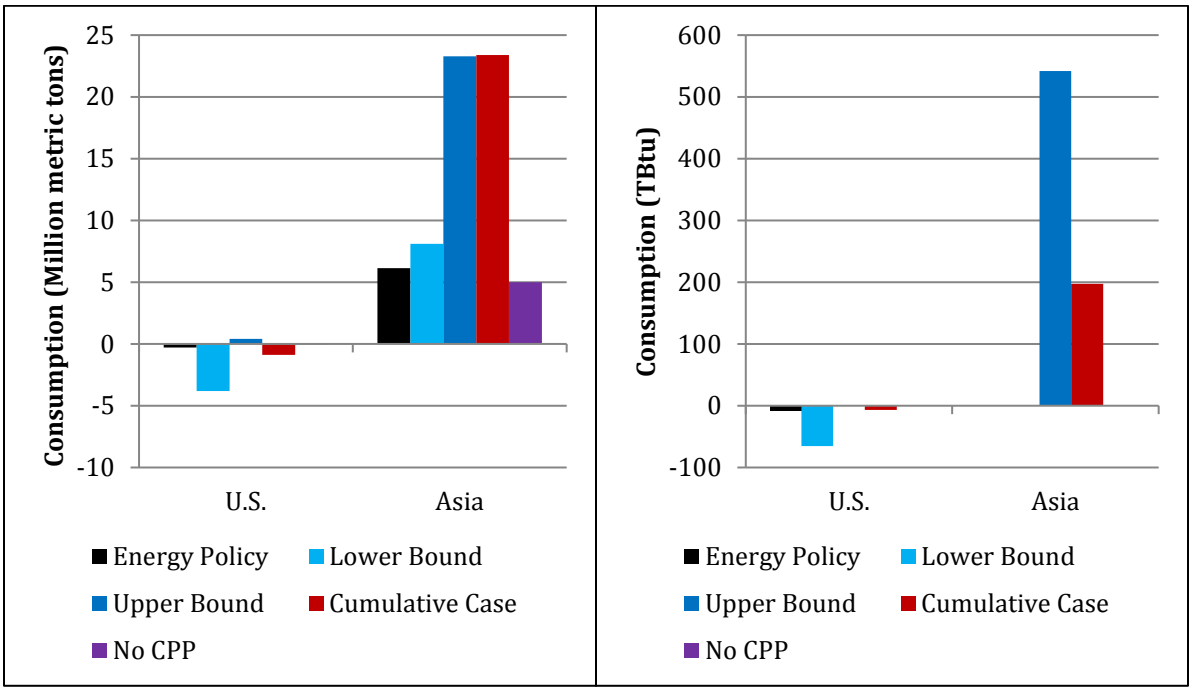
12,000 Btu/lb coal would be displaced. In the Upper Bound Scenario, the reason that the non-U.S. coal production does not decrease as much as the increase in U.S. production is because there is some induced coal demand.

Average coal consumption in the United States would be lower under the Proposed Action because higher Powder River Basin coal prices would depress the U.S. demand for Powder River Basin coal (Figure 6-2). The Powder River Basin coal prices would be higher due to the export of Powder River Basin coal through the proposed coal export terminal, which causes a shift in the demand curve. In all but the Upper Bound Scenario, coal consumption, as measured in tons and TBtu, in the United States is lower under the Proposed Action. In the Upper Bound Scenario, average annual domestic coal consumption from 2025 to 2040 is 0.4 million metric tons higher under the Proposed Action. While the United States consumes less Powder River Basin coal as export increases, domestic coal consumption shifts to coal produced in Northern Appalachia and the Illinois Basin. Without the Clean Power Plan and the higher energy efficiency assumed under the Clean Power Plan, domestic coal demand is higher than the scenarios including the Clean Power Plan and energy efficiency, because overall electric demand is higher without the additional energy efficiency assumed under the Clean Power Plan. Under the Proposed Action, Powder River Basin prices are pushed higher due to increased export via the proposed coal export terminal, but other types of domestic coal remain available economically. In the Cumulative Case where Clean Power Plan and energy efficiency are also excluded, when new export capacity is added, a larger amount of U.S. coal has higher prices due to the larger export increase, thus having a greater effect on decreasing domestic coal consumption in total than the No Clean Power Plan Scenario.

The depressive effect on total U.S. coal consumption would be the largest in the Lower Bound Scenario at an average of 3.8 million metric tons per year (Figure 6-2, left-hand chart), because in addition to the Clean Power Plan and international GHG reduction commitments, Powder River Basin and Uinta basin coal prices have been increased by 25% in the Lower Bound Scenario compared to the Energy Policy, No Clean Power Plan, and Cumulative Scenarios. Moreover, U.S. rail transportation costs have been increased by 20% in the Lower Bound Scenario. Higher domestic minemouth coal prices and transportation costs lead to lower coal consumption domestically.

Coal consumption in Asia on a per ton basis would be higher under the Proposed Action for two reasons. First, lower heat content coal would displace some higher heat content coal. Therefore, to maintain the same level of electric generation, more tons of the lower heat content coal must be consumed than the amount of the higher heat content coal that was displaced. Second, Asian coal consumption is higher because of induced demand in the Upper Bound and Cumulative Scenarios. The change in coal consumption due to the mix of coals is evident by comparing the two charts in Figure 6-2. The left hand chart shows the change in tons of coal consumed and includes changes due to both induced demand and a change in the mix of coal consumed, while the right hand chart shows the change in total heating value of the coal consumed, and thus just the amount of induced demand. Asian consumption in the right hand chart reflects the amount in TBtu of induced demand in each scenario, while the left hand chart shows the combined effects of the induced demand and changes in the mix of coals consumed in tons. In the right hand chart, only the Upper Bound and Cumulative Scenarios have significant non-zero values in Asia because there is induced demand in these scenarios. The largest increase in total coal consumption in tons is in the Cumulative Scenario, where there is a shift in China, Hong Kong, and Taiwan to consuming more Powder River Basin subbituminous coal and less Australian, Chinese, and Indonesian bituminous coal.

Figure 6-2. Change in Annual Average Consumption for 2025 to 2040—Proposed Action minus No-Action Alternative (million metric tons and trillion Btu (TBtu) per year)



The change in the average amount of coal imported in Asia would be positive in all scenarios and would be highest in the Cumulative Scenario (Figure 6-3). The Cumulative Scenario has the largest increase in coal exported from the United States to Asia, because of multiple coal export terminals coming online. Exports from the new coal terminals drive the increase in imported coal, especially for China, since the imported coal displaces some domestic coal production. Also, the exported coal would be displacing the delivery of coal from other countries, and since the coal exported through the proposed terminal would be displacing higher heat content coal on average there would be a net increase in the tons of coal imported and consumed, since the coal demand is assumed to remain constant or increase due to induced demand from lower delivered coal prices.

Because CO_2 emissions from the transportation of coal depend on how far the coal is shipped, Figure 6-4 shows the change in the total distance the coal is shipped as measured by the change in total distance that the ships would travel. For the Lower Bound, Upper Bound, Cumulative, and the No Clean Power Plan Scenarios, the shipping distances track closely to the overall change in tons shipped. However, the 2015 U.S. and International Energy Policy Scenario incurs a slightly larger difference in the distance due to shifts in the sources of coal that would be displaced by coal from the proposed export terminal. Specifically, more coal would be displaced from China and Russia, than from Australia and Indonesia, which have longer shipping distances. The Cumulative Scenario has the highest increase in the distance of shipped coal since the additional export terminal capacity displaces more coal produced and consumed in Asia.

Figure 6-3. Change in Annual Average Imports of Coal in Asia via Ship for 2025 to 2040—Proposed Action minus No-Action Alternative (million metric tons per year)

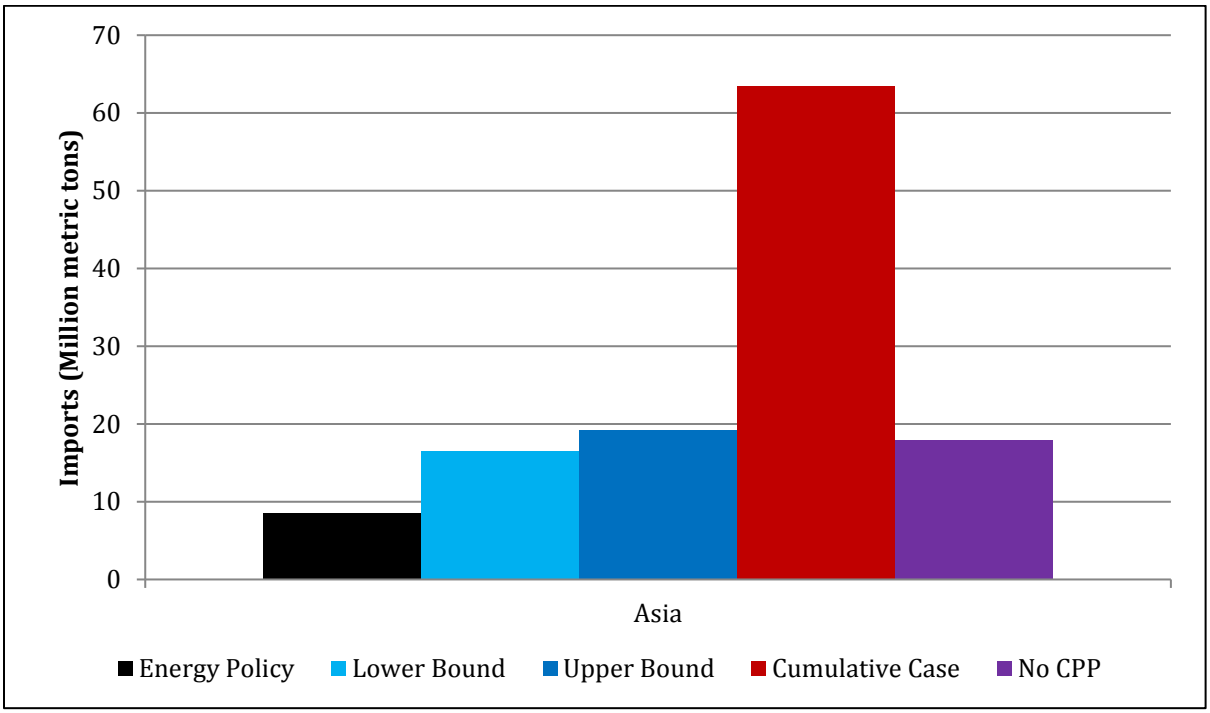
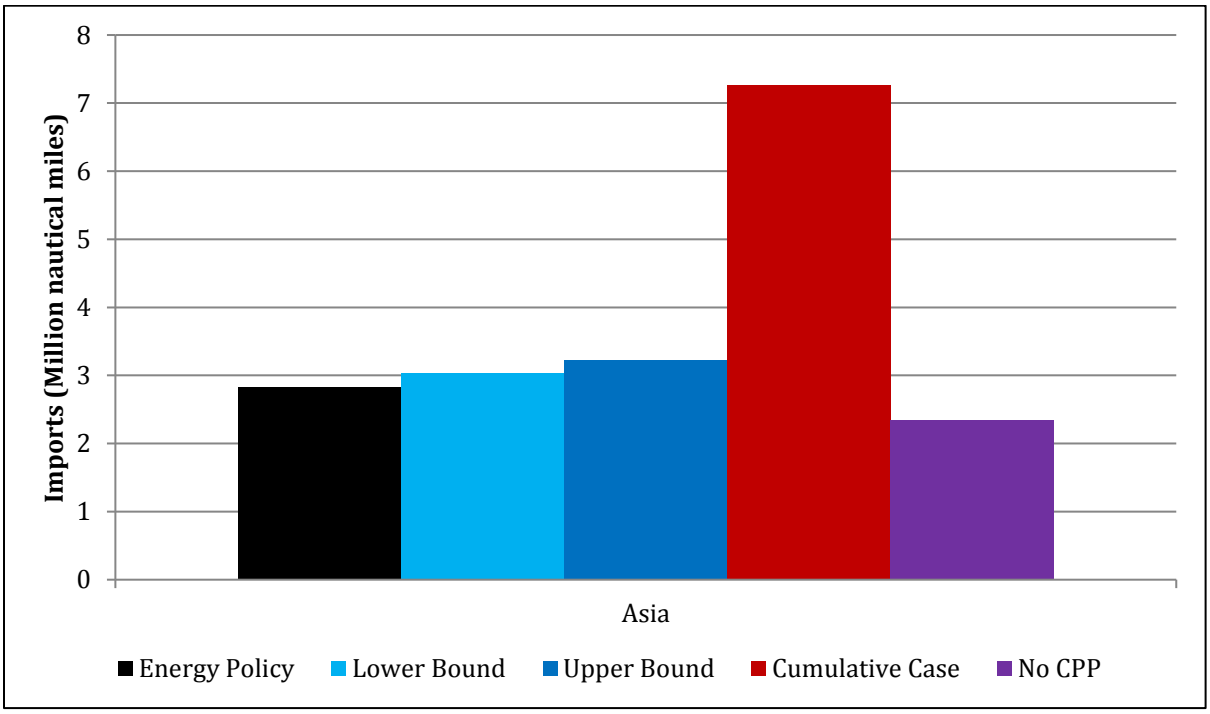
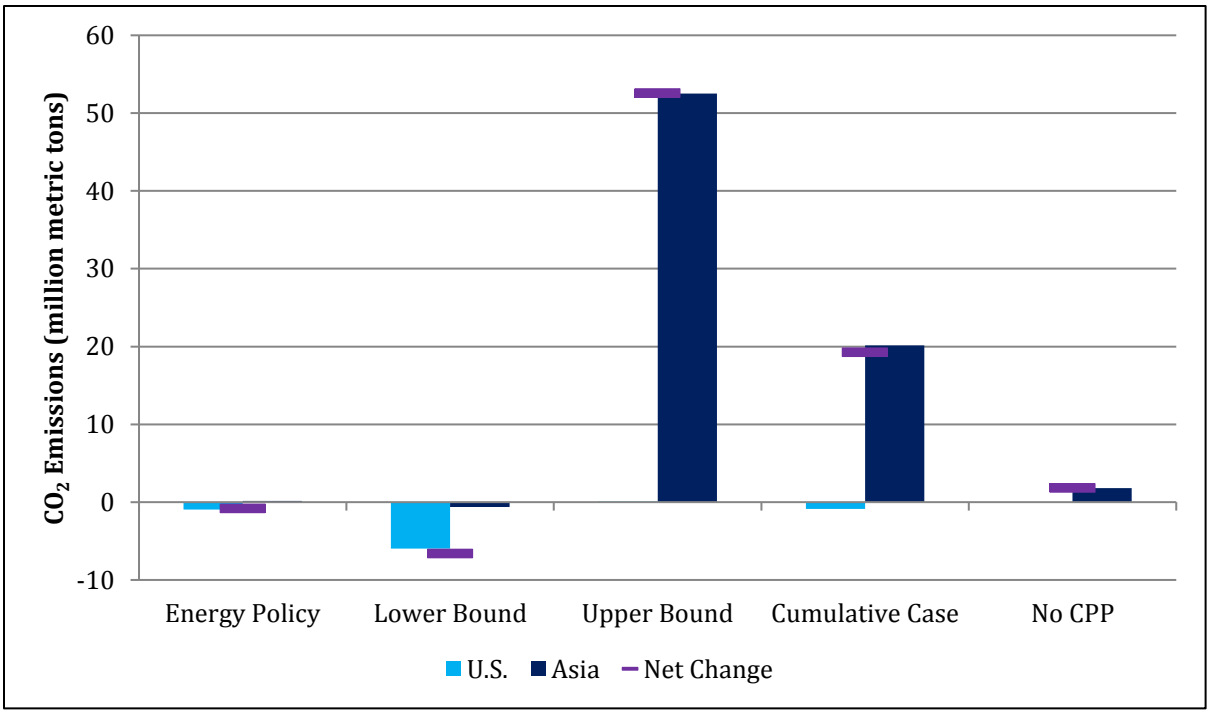


Figure 6-4. Change in Annual Average Imports of Coal in Asia via Ship for 2025 to 2040—Proposed Action minus No-Action Alternative (million nautical miles per year)



CO_2 emissions from the combustion of coal in the United States and Asia are estimated for all five scenarios. Figure 6-5 shows the average change in CO_2 emissions from the combustion of coal for 2025 to 2040. The CO_2 emissions reflect the changes in consumption with U.S. emissions declining in all scenarios except for the Upper Bound Scenario. Demand for Powder River Basin coal is higher under the Proposed Action in the Upper Bound Scenario, because of the lower assumed production costs in the Powder River Basin in this scenario. Asian emissions are increasing in all scenarios, except for the Lower Bound Scenario, due to changes in the mix of coals consumed and the induced demand. The Lower Bound Scenario has lower emissions from the combustion of coal in Asia due to a shift to using coals with lower CO_2 emissions rates. Due to the mix of coals consumed and their respective CO_2 emissions rates, the emissions do not exactly reflect the change in consumption seen in Figure 6-2.

Figure 6-5. Change in Annual Average CO_2 Emissions from the Consumption of Coal for 2025 to 2040—Proposed Action minus No-Action Alternative (million metric tons CO_2 per year)



6.2 No Clean Power Plan Scenario

The No Clean Power Plan Scenario uses the assumptions presented in Chapter 4, *Model Framework, Methods, and Key Assumptions*, and represents the energy market outcome assuming the EPA's Clean Power Plan is not implemented. This section presents the modeling results for the No Clean Power Plan Scenario No-Action Alternative and Proposed Action for coal production, consumption, distribution, and CO_2 emissions.

6.2.1 Coal Production

Under the No-Action Alternative, U.S. thermal coal production would average 813 million metric tons per year for the 2025 to 2040 period.[31] U.S. coal production steadily increases primarily because coal exports increase over time, but also because electric demand and natural gas prices increase, and nuclear units begin to retire between 2030 and 2040. Over the 2016 to 2040 period, non-U.S. coal production would grow at an average annual rate of 2.4% per year from 4,510 to 7,887 million metric tons. Over the same period, U.S. coal production would grow at an average annual rate of 1.3%. Powder River Basin coal production under the No-Action Alternative would average 311 million metric tons per year over 2025 to 2040. Uinta Basin coal production under the No-Action Alternative would average 13.6 million metric tons per year, with production gradually increasing. Table 6-1 shows the No-Action Alternative coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-1. No Clean Power Plan Scenario Coal Production—No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,510	5,115	5,806	6,304	6,839	7,887	7,098
Total U.S. Thermal Coal	628	673	752	773	790	861	813
Powder River Basin Coal	310	286	324	329	292	313	311
Uinta Basin Coal	7.0	7.9	8.5	10.6	14.4	15.0	13.6

Under the Proposed Action, U.S. thermal coal production would average 857 million metric tons per year for the 2025 to 2040 period. As with the No-Action Alternative, U.S. coal production would increase over the full time horizon, although at the slightly higher rate of 1.5%. Non-U.S. coal production would grow at an average annual rate of 2.3%, similar to the growth rate in the No-Action Alternative. Coal production would be slightly lower under the Proposed Action than the No-Action Alternative starting in 2025 when the full capacity of the terminal comes on line. The non-U.S. production would decline in the Proposed Action because the coal exported through the proposed terminal would displace some of the coal that was produced in other countries in the No-Action Alternative.

Powder River Basin coal production under the Proposed Action would average 355 million metric tons per year, with production fluctuating around this average with no clear upward or downward trend. Uinta Basin coal production would average 13.6 million metric tons per year for 2025 to 2040, the same as under the No-Action Alternative. Table 6-2 shows the Proposed Action coal

[31] Throughout the documentation of trends in coal production and coal prices, the period from 2025 to 2040 is evaluated as this period covers years in which the coal terminal is at full capacity and GHG emission are estimated through 2038 in the SEPA Greenhouse Gas Emissions Technical Report (ICF 2017b). Trends over the full 2016 to 2040 modeling period are included for context only, as the modeling results before 2025 are not used for estimating GHG emissions. The SEPA Greenhouse Gas Emissions Technical Report linearly extrapolates from the start of the proposed terminal exports in 2021 to the projected GHG emissions in 2025 assuming that the emissions prior to operation are zero.

production values for each model run year.[32] The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.[33]

Table 6-2. No Clean Power Plan Scenario Coal Production—Proposed Action (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,510	5,115	5,806	6,264	6,798	7,850	7,059
Total U.S. Thermal Coal	628	673	752	817	834	905	857
Powder River Basin Coal	310	286	324	373	336	357	355
Uinta Basin Coal	7.0	7.9	8.5	10.6	14.4	15.0	13.6

Table 6-3 shows the estimated change in coal production between the Proposed Action and the No-Action Alternative by model run year to be close to zero in the years before 2025 when the proposed terminal was assumed fully online. Once the proposed terminal is online and exporting coal, total modeled U.S. coal production would be higher under the Proposed Action, primarily due to an increase in Powder River Basin coal production. The decrease in non-U.S. coal production is due to coal shipped through the proposed coal export terminal displacing coal from other countries.

There are small changes in coal production prior to the proposed terminal coming online because the IPM model is forward-looking and makes adjustments in the near term to optimize the whole period being analyzed.[34] This is referred to as perfect foresight. As described in Chapter Two of the EPA's *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*, perfect foresight in IPM® means that agents know the precise timing and essence of future events that may affect decisions and the overall deployment of resources.

Table 6-3. No Clean Power Plan Scenario Change in Coal Production—Proposed Action minus No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	0	0	0.1	-40.2	-40.4	-36.9	-39.0
Total U.S. Thermal Coal	0	0	0	44.0	44.0	44.0	44.0
Powder River Basin Coal	0	0	0	44.0	44.0	44.0	44.0
Uinta Basin Coal	0	0	0	0	0	0	0

Figure 6-6 shows that total non-U.S. thermal coal production would decrease in similar amounts to the increase in U.S. coal production under the Proposed Action. This trend indicates that U.S. thermal coal exports would mostly replace internationally produced coal, instead of the full exported amount

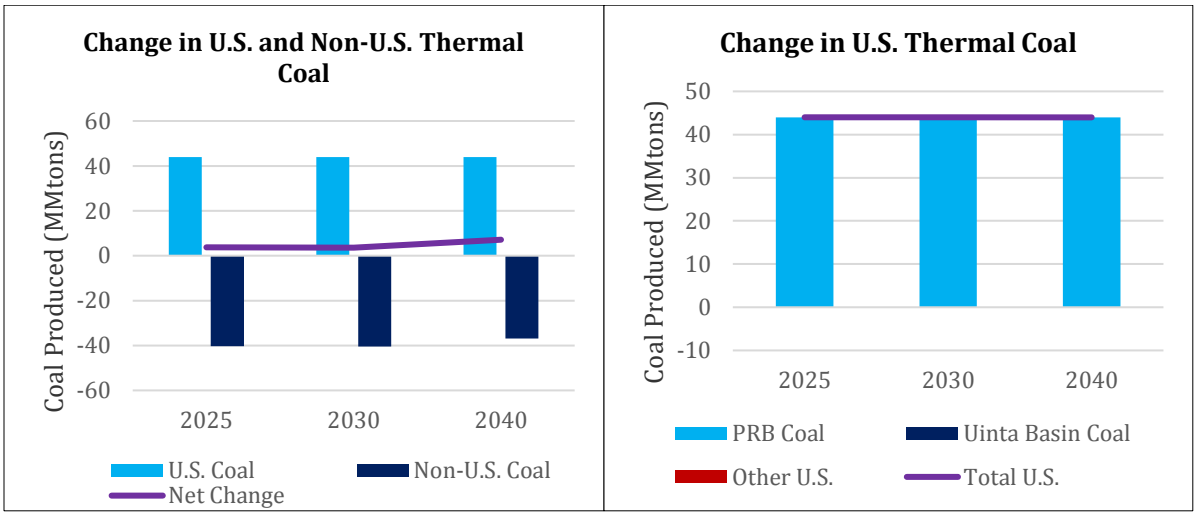
[32] The model run years include 2016, 2018, 2020, 2025, 2030, and 2040.

[33] Five calendar years are mapped to 2025, six years are mapped to 2030, and seven years are mapped to 2040.

[34] As a linear programming model, IPM seeks a solution that minimizes the overall system costs of meeting electric demand. The costs include, but are not limited to, fuel costs, costs for transporting fuel, variable and fixed operating costs of the various generating resources, costs for new generating resources, and the costs for retrofitting existing generating resources with additional environmental controls.

adding to overall global coal demand. The right hand graph in Figure 6-6 shows that the increase in U.S. thermal coal production is due entirely to the increase in Powder River Basin coal production. The export of Powder River Basin coal through the proposed coal export terminal displaces coal produced in Australia, China, Indonesia, and Russia.

Figure 6-6. No Clean Power Plan Scenario Change in Coal Production—Proposed Action minus No-Action Alternative



6.2.2 Coal Consumption

Under the No-Action Alternative U.S. thermal coal consumption would average 671 million metric tons per year for the 2025 to 2040 period. U.S. coal consumption would trend upwards from 2016 to 2040, but fluctuate around the average from 2025 to 2040 because electric demand growth would be primarily met with natural gas and renewable generation. Total U.S. consumption would grow at a fairly flat rate of 0.4% from 2016 to 2040.

Over the 2016 to 2040 period, Asian coal consumption would grow at an average rate of 2.9% per year from 3,395 to 6,679 million metric tons. The growth in consumption is driven by increasing coal consumption in China and India. Table 6-4 shows the No-Action Alternative coal consumption values for each model run year. Table 6-5 shows the coal consumption values in TBtu per year. The average values in the last column of the tables were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

China is responsible for the largest share of global thermal coal consumption, burning 2,269 million metric tons of coal in 2016. This amount is projected to grow under the No-Action Alternative to 3,489 million metric tons by 2040 and average 3,274 million metric tons over the 2025 to 2040 period. India has the highest average annual growth rate at 6.2%, with coal consumption rising from 543 million metric tons in 2016 to 2,287 million metric tons in 2040.

Table 6-4. No Clean Power Plan Scenario Coal Consumption—No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	118	138	166	161	210	252	213
Australia	104	114	123	124	124	125	124
China	2,269	2,534	2,797	3,015	3,239	3,489	3,274
Hong Kong	13	15	16	16	17	20	18
India	543	723	935	1,233	1,558	2,287	1,751
Indonesia	138	142	152	165	188	220	194
Japan	96	113	127	126	119	116	120
South Korea	68	81	89	79	76	71	75
Taiwan	46	56	65	74	83	98	86
Total Asian Coal Consumption	3,395	3,915	4,472	4,993	5,613	6,679	5,855
Total U.S. Coal Consumption	613	606	672	686	651	679	671
Rest of World Coal Consumption	1,131	1,269	1,418	1,401	1,368	1,395	1,388

Table 6-5. No Clean Power Plan Scenario Coal Consumption—No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	2,603	2,968	3,334	3,739	4,144	4,883	4,319
Australia	1,268	1,481	1,693	1,661	1,629	1,591	1,623
China	57,999	64,719	71,432	77,017	82,560	88,375	83,282
Hong Kong	303	332	361	405	449	529	467
India	10,213	13,834	17,452	23,201	28,935	41,915	32,390
Indonesia	2,486	2,535	2,583	2,897	3,212	3,784	3,347
Japan	2,337	2,674	3,009	3,058	3,095	3,030	3,060
South Korea	1,716	1,911	2,106	2,028	1,949	1,833	1,926
Taiwan	1,091	1,324	1,558	1,761	1,965	2,331	2,051
Total Asian Coal Consumption	80,016	91,778	103,528	115,768	127,938	148,269	132,464
Total U.S. Coal Consumption	12,675	12,682	14,022	14,278	13,651	14,201	14,039
Rest of World Coal Consumption	18,366	21,747	25,172	25,128	24,978	26,592	25,647

Coal consumption under the Proposed Action follows similar patterns as the No-Action Alternative, with U.S. thermal coal consumption averaging 671 million metric tons per year for the 2025 to 2040

period. As it would be under the No-Action Alternative, U.S. coal consumption would be fairly flat between 2020 and 2040 as electric demand growth is primarily met with natural gas and renewable generation.

Over the 2016 to 2040 period, Asian coal consumption follows the same pattern as it would under the No-Action Alternative, growing from 3,395 to 6,686 million metric tons.

Table 6-6 shows the Proposed Action coal consumption values for each model run year and Table 6-7 shows those values in TBtu per year. The average values in the last column of the tables were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-6. No Clean Power Plan Scenario Coal Consumption—Proposed Action (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	118	138	166	161	208	252	212
Australia	104	114	123	124	124	125	124
China	2,269	2,534	2,797	3,020	3,243	3,489	3,277
Hong Kong	13	15	16	18	20	23	20
India	543	723	935	1,230	1,558	2,287	1,750
Indonesia	138	142	152	165	186	221	194
Japan	96	113	127	124	119	117	120
South Korea	68	81	89	79	76	72	75
Taiwan	46	56	65	76	84	100	88
Total Asian Coal Consumption	3,395	3,915	4,472	4,997	5,617	6,686	5,860
Total U.S. Coal Consumption	613	606	672	686	651	679	671
Rest of World Coal Consumption	1,131	1,269	1,418	1,401	1,368	1,395	1,388

Table 6-7. No Clean Power Plan Scenario Coal Consumption—Proposed Action (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	2,603	2,968	3,334	3,739	4,144	4,883	4,319
Australia	1,268	1,481	1,693	1,661	1,629	1,591	1,623
China	57,999	64,719	71,432	77,017	82,560	88,375	83,282
Hong Kong	303	332	361	405	449	529	467
India	10,213	13,834	17,452	23,201	28,935	41,915	32,390
Indonesia	2,486	2,535	2,583	2,897	3,212	3,784	3,347
Japan	2,337	2,674	3,009	3,058	3,095	3,030	3,060
South Korea	1,716	1,911	2,106	2,028	1,949	1,833	1,926
Taiwan	1,091	1,324	1,558	1,761	1,965	2,331	2,051
Total Asian Coal Consumption	80,016	91,778	103,528	115,768	127,938	148,269	132,464
Total U.S. Coal Consumption	12,675	12,682	14,022	14,278	13,651	14,201	14,039
Rest of World Coal Consumption	18,366	21,747	25,172	25,128	24,978	26,592	25,647

Table 6-8 shows the estimated change in coal consumption between the Proposed Action and the No-Action Alternative by model run year to be zero in the years before 2025 when the proposed coal export terminal is assumed fully online, except for Indonesia in 2020. Table 6-9 shows the same values in TBtu per year. Once the terminal is online and exporting coal, there is no change in United States and Rest of World coal consumption on a tonnage basis, and only a decrease of 0.1 TBtu in the United States in 2040. The decrease of 0.1 TBtu is equivalent to about 0.005 million metric tons. In Asia, there is no change in the total heating value of the coal consumed; however, there are shifts in the tons of coal consumed.

In Asia, coal consumption in the Proposed Action is higher on average by 5.0 million metric tons per year for 2025 to 2040, which is 0.09% higher than the average Asian coal consumption in the No-Action Alternative shown in Table 6-6. The reason that Asian coal consumption increases is that a larger quantity of lower heat content subbituminous coal is being consumed, while the total heating value of coal demand remains the same. For example, in Hong Kong under the Proposed Action, coal consumption increases by 2.0 million metric tons in 2025 over the No-Action Alternative (Table 6-8); however, the total heat content of the coal consumed remains the same (Table 6-9). This is possible because Indonesia reduces the bituminous coal exported to Hong Kong by 7.78 million metric tons and the United States exports 9.77 million metric tons more of Montana Powder River Basin coal, which has a lower heat content.

Table 6-8. No Clean Power Plan Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia – Other	0	0	0	0	-2.6	0	-0.9
Australia	0	0	0	0	0	0	0
China	0	0	0	4.7	4.2	0	2.7
Hong Kong	0	0	0	2.0	2.2	2.8	2.4
India	0	0	0	-2.9	0	0	-0.8
Indonesia	0	0	0.1	0	-2.2	1.1	-0.3
Japan	0	0	0	-1.8	0	0.5	-0.3
South Korea	0	0	0	0	0	0.5	0.2
Taiwan	0	0	0	1.7	1.9	2.3	2.0
Total Asian Coal Consumption	0	0	0.1	3.8	3.6	7.1	5.0
Total U.S. Coal Consumption	0	0	0	0	0	0	0
Rest of World Coal Consumption	0	0	0	0	0	0	0

Table 6-9. No Clean Power Plan Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia – Other	0	0	0	0	0	0	0
Australia	0	0	0	0	0	0	0
China	0	0	0	0	0	0	0
Hong Kong	0	0	0	0	0	0	0
India	0	0	0	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
Taiwan	0	0	0	0	0	0	0
Total Asian Coal Consumption	0	0	0	0	0	0	0
Total U.S. Coal Consumption	0	0	0	0	0	0	0
Rest of World Coal Consumption	0	0	0	0	0	0	0

6.2.3 Coal Distribution

Coal from the Powder River Basin and the Uinta Basin are distributed primarily in the United States. These distribution patterns are expected to remain largely unchanged under the Proposed Action. Thus, this section focuses on the distribution of coal in Asia and how that distribution would be expected to change with the construction of the proposed terminal. Under the No-Action Alternative,

no coal would be exported through the proposed terminal; however, 313 million metric tons of thermal coal would be distributed in Asia by ship in the seaborne coal market in 2016. Table 6-10 shows the tons of coal that are imported by each country in Asia under the No-Action Alternative. In 2040, a total of 550 million metric tons of thermal coal are expected to be distributed in the Asian seaborne coal market.

Table 6-10. No Clean Power Plan Scenario Seaborne Coal Imports in Asia—No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	80	98	124	142	203	244	202
Australia	0	0	0	0	0	0	0
China	0	65	144	0	0	0	0
Hong Kong	13	15	16	16	17	20	18
India	10	47	0	35	0	0	10
Indonesia	0	0	0	0	0	0	0
Japan	96	113	127	126	119	116	120
South Korea	68	81	89	79	76	71	75
Taiwan	46	56	65	74	83	98	86
Total Asian Coal sent via ship	313	475	567	471	498	550	511

To understand how coal distribution is changing in more detail than the tons of coal imported by each country, the tons of coal shipped to each country were multiplied by the distance in nautical miles that the coal is shipped and then divided by an average ship size. This is important because the change in tons imported might not change significantly; however, where the coal is sourced might change, which has a significant impact on the emissions associated with shipping. Table 6-11 shows the result of multiplying the tons of coal by the nautical miles that the coal was shipped and dividing by the average ship size for coal shipped to each country for the No-Action Alternative.[35] Thus the values in Table 6-11 are in units of million nautical miles.

[35] The average ship size is 66,000 metric tons, which is the weighted average of a Panamax and a Handymax ship, where the weights are 80% for the Panamax and 20% for the Handymax ship.

Table 6-11. No Clean Power Plan Scenario Shipping Distance for Seaborne Coal Imports in Asia—No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	0.44	0.76	2.13	2.65	3.95	4.84	3.93
Australia	0	0	0	0	0	0	0
China	0	1.68	4.51	0	0	0	0
Hong Kong	0.39	0.44	0.47	0.46	0.55	0.24	0.41
India	0.45	2.20	0	1.64	0	0	0.46
Indonesia	0	0	0	0	0	0	0
Japan	5.12	7.17	8.07	6.11	1.59	1.55	2.83
South Korea	1.81	5.23	5.77	0.75	0.72	0.67	0.71
Taiwan	2.89	3.51	4.13	4.67	5.20	6.20	5.44
Total Asian Coal sent via ship	11.10	20.99	25.07	16.27	12.01	13.51	13.78

Under the Proposed Action, coal would be exported through the proposed terminal to destinations in Asia. Table 6-12 shows how the coal exported from the proposed coal export terminal is distributed by the model.

Table 6-12. No Clean Power Plan Scenario Distribution of Coal Exported through Coal Export Terminal—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040
China	0	0	0	21.6	19.1	0
Hong Kong	0	0	0	9.8	10.8	12.8
Japan	0	0	0	0	0	7.7
South Korea	0	0	0	0	0	6.9
Taiwan	0	0	0	12.6	14.1	16.7
Total Asian Coal sent via ship through Proposed Coal Export Terminal	0	0	0	44.0	44.0	44.0

Under the Proposed Action, a similar number of tons is distributed in the Asian seaborne coal market as the No-Action Alternative, as can be seen in Table 6-13, which shows the tons of coal that would be imported by each country in Asia under the Proposed Action. Meanwhile, Table 6-14 shows the shipping mile values for coal distributed in the Asian seaborne coal market under the Proposed Action.

Table 6-13. No Clean Power Plan Scenario Seaborne Coal Imports in Asian —Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	80	98	124	142	201	244	201
Australia	0	0	0	0	0	0	0
China	0	65	144	22	19	0	12
Hong Kong	13	15	16	18	20	23	20
India	10	47	0	43	0	0	12
Indonesia	0	0	0	0	0	0	0
Japan	96	113	127	124	119	117	120
South Korea	68	81	89	79	76	72	75
Taiwan	46	56	65	76	84	100	88
Total Asian Coal sent via ship	313	475	567	503	519	556	529

Table 6-14. No Clean Power Plan Scenario Shipping Distance for Seaborne Coal Imports in Asia—Proposed Action (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	0.44	0.76	2.13	2.65	3.89	4.84	3.92
Australia	0	0	0	0	0	0	0
China	0	1.68	4.50	1.75	1.55	0	1.00
Hong Kong	0.39	0.44	0.47	1.08	1.24	1.23	1.19
India	0.45	2.20	0	2.00	0	0	0.56
Indonesia	0	0	0	0	0	0	0
Japan	5.12	7.17	8.07	5.09	1.59	1.97	2.71
South Korea	1.81	5.23	5.77	0.75	0.72	1.10	0.87
Taiwan	2.89	3.51	4.13	5.03	5.61	6.68	5.87
Total Asian Coal sent via ship	11.10	20.99	25.06	18.36	14.60	15.82	16.12

As can be seen in Table 6-15, which shows the estimated change in tons of coal imported by each of the regions, the largest change in coal imports between the No-Action Alternative and the Proposed Action is in coal exported to China in 2025 with an increase of 21.6 million metric tons. However, the change is only about 0.7% of coal consumption in China.

Table 6-15. No Clean Power Plan Scenario Change in Seaborne Coal Imports in Asia—Proposed Action minus No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	0	-2.6	0	-0.9
Australia	0	0	0	0	0	0	0
China	0	0	0	21.6	19.1	0	12.4
Hong Kong	0	0	0	2.0	2.2	2.8	2.4
India	0	0	0	7.8	0	0	2.2
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	-1.8	0	0.5	-0.3
South Korea	0	0	0	0	0	0.5	0.2
Taiwan	0	0	0	1.7	1.9	2.3	2.0
Total Asian Coal sent via ship	0	0	0.1	31.4	20.7	6.1	18.0

While the changes in the total tons of coal imported to each region are relatively small on a percentage basis, there are some relatively large changes in the shipping mile values, as shown in Table 6-16. The overall distance coal would be shipped in Asia increases by 17% over the No-Action Alternative. For example, in Taiwan in 2025, coal imports increase by 2.3% (1.7 million metric tons) while the shipping miles increase by 7.9% (0.37 million nautical miles). This change is due to Taiwan importing Powder River Basin coal through the proposed coal export terminal, which displaces some coal from Australia, which is closer than the proposed coal export terminal.

Table 6-16. No Clean Power Plan Scenario Change in Shipping Distance for Seaborne Coal Distribution in Asia—Proposed Action minus No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	Annual Average
Asia - Other	0	0	0	0	-0.05	0	-0.02
Australia	0	0	0	0	0	0	0
China	0	0	-0.01	1.75	1.55	0	1.00
Hong Kong	0	0	0	0.62	0.69	0.99	0.78
India	0	0	0	0.36	0	0	0.10
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	-1.02	0	0.41	-0.12
South Korea	0	0	0	0	0	0.43	0.17
Taiwan	0	0	0	0.37	0.41	0.49	0.43
Total Asian Coal sent via ship	0	0	-0.01	2.09	2.59	2.31	2.34

6.2.4 CO_2 Emissions

This section presents the CO_2 estimated emissions from coal combusted in the United States and Asia under the No Clean Power Plan Scenario No-Action Alternative and Proposed Action. In addition, CO_2 emissions from natural gas consumption in the United States are included because decreases in coal consumption may be offset by increases in natural gas consumption. No other emissions of GHGs are included in this section.

Table 6-17 presents the CO_2 emissions under the No-Action Alternative. Total U.S. CO_2 emissions from coal remain fairly flat at an average of 1,319.78 million metric tons for 2025 to 2040, which reflects the flat coal consumption in the United States. Asian CO_2 emissions from coal average 12,714.98 million metric tons per year between 2025 and 2040, which is 9.6 times the total coal CO_2 emissions from the United States.

Table 6-18 presents the CO_2 emissions under the Proposed Action. Total CO_2 emissions from coal in Asia under the Proposed Action are within 2.8 million metric tons of the No-Action Alternative.

Table 6-17. No Clean Power Plan Scenario CO_2 Emissions—No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	247.26	285.00	322.40	347.92	401.48	475.60	415.43
Australia	118.44	138.28	158.12	155.15	152.18	148.56	151.60
China	5,589.28	6,230.49	6,869.91	7,422.30	7,957.21	8,519.96	8,027.47
Hong Kong	28.03	30.69	33.34	37.40	41.52	50.87	44.01
India	971.98	1,314.34	1,663.26	2,208.16	2,757.05	3,991.99	3,084.83
Indonesia	239.90	244.43	248.95	278.94	308.90	363.15	321.67
Japan	218.18	250.63	281.95	288.97	297.84	291.67	292.98
South Korea	161.27	179.24	197.51	195.18	187.61	176.39	185.35
Taiwan	101.94	123.74	145.53	164.58	183.58	217.90	191.65
Asia - Coal	7,676.27	8,796.83	9,920.98	11,098.59	12,287.35	14,236.09	12,714.98
U.S. - Coal	1,192.66	1,191.89	1,318.40	1,342.64	1,283.18	1,334.84	1,319.78
U.S. - Natural Gas	562.33	520.06	472.01	500.29	540.37	692.55	588.42
Rest of World	1,755.77	2,072.97	2,397.94	2,391.95	2,375.45	2,529.00	2,439.75

Table 6-18. No Clean Power Plan Scenario CO_2 Emissions—Proposed Action (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	247.26	285.00	322.43	347.92	400.36	475.60	415.05
Australia	118.44	138.28	158.12	155.15	152.18	148.56	151.60
China	5,589.28	6,230.49	6,869.90	7,422.63	7,957.49	8,519.96	8,027.66
Hong Kong	28.03	30.69	33.34	38.32	42.54	51.06	44.68
India	971.98	1,314.34	1,663.26	2,207.53	2,757.05	3,991.99	3,084.66
Indonesia	239.90	244.43	248.95	278.94	308.90	363.15	321.67
Japan	218.18	250.63	281.95	290.22	297.84	291.80	293.37
South Korea	161.27	179.24	197.51	195.18	187.61	176.50	185.39
Taiwan	101.94	123.74	145.53	165.50	184.60	219.11	192.71
Asia - Coal	7,676.27	8,796.83	9,921.00	11,101.37	12,288.56	14,237.73	12,716.80
U.S. - Coal	1,192.66	1,191.89	1,318.40	1,342.63	1,283.17	1,334.83	1,319.78
U.S.- Natural Gas	562.33	520.06	472.01	500.29	540.37	692.55	588.42
Rest of World	1,755.77	2,072.97	2,397.94	2,391.95	2,375.45	2,529.00	2,439.75

Table 6-19 shows the estimated change in CO_2 emissions for each region, as well as the total net change across all regions. Total Asian CO_2 emissions from coal consumption increase by an average of 1,81 million metric tons per year for 2025 to 2040. The change in CO_2 emissions from individual countries would be between a decrease of 1.12 million metric tons to an increase of 1.25 million metric tons.

Table 6-19. No Clean Power Plan Scenario Change in CO_2 Emissions—Proposed Action minus No-Action Alternative (million metric tons)

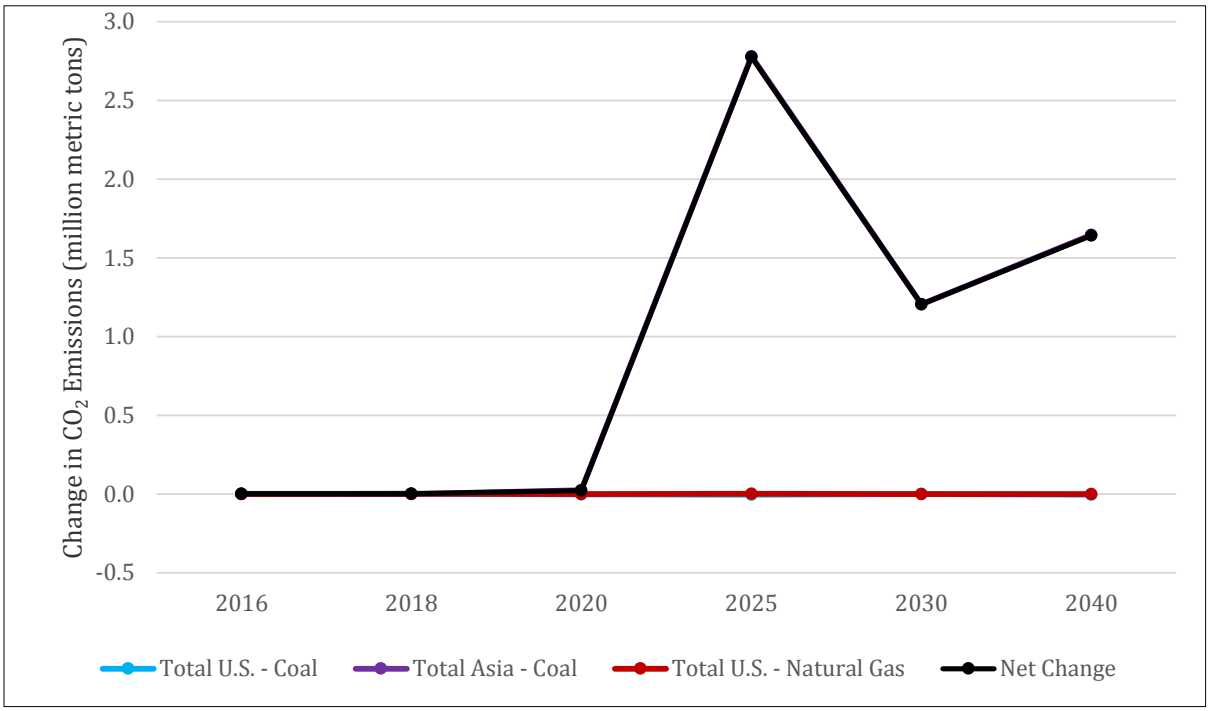
Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0	0	0.03	0	-1.12	0	-0.37
Australia	0	0	0	0	0	0	0
China	0	0	-0.01	0.32	0.29	0	0.18
Hong Kong	0	0	0	0.92	1.02	0.19	0.67
India	0	0	0	-0.63	0	0	-0.17
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	1.25	0	0.13	0.40
South Korea	0	0	0	0	0	0.12	0.04
Taiwan	0	0	0	0.92	1.02	1.21	1.07
Asia[a]- Coal	0	0	0.02	2.78	1.21	1.65	1.81
U.S. - Coal	0	0	0	0	0	0	0
U.S. - Natural Gas	0	0	0	0	0	0	0
Rest of World	0	0	0	0	0	0	0
Total Change	0	0	0.02	2.78	1.20	1.64	1.81

[a] Asia row is sum of Asia-Other through Taiwan rows.

U.S. coal CO_2 emissions would decrease in every year due to a slight decrease in the amount of coal consumed. The total net change in CO_2 emissions, including both coal and natural gas emissions, would increase by an average of 1,81 million metric tons per year for 2025 to 2040, which is primarily due to the increase in Asian emissions from coal consumption.

Figure 6-7 shows the net change in CO_2 emissions between the No-Action Alternative and Proposed Action. The increase in Asian coal emissions would drive the net change to be a net increase in CO_2 emissions under the Proposed Action.

Figure 6-7. No Clean Power Plan Scenario Changes in CO_2 Emissions—Proposed Action minus No-Action Alternative[a,b,c]



a The total change in U.S. CO_2 emissions from the combustion of coal would be zero because coal consumption does not change under the Proposed Action.

b Asian CO_2 emissions from the combustion of coal would increase because more tons of lower heat content coal would be consumed, and because of a shift in the types of coal with different CO_2 emission rates.

c Total U.S. natural gas combustion CO_2 emissions would be zero because natural gas consumption would not change under the Proposed Action.

6.3 Lower Bound Scenario

The Lower Bound Scenario uses the assumptions presented in Chapter 5, *Scenarios*, and represents the lower bound of global GHG emissions that could be reasonably expected if the assumptions are realized. This scenario is designed to model the lowest potential GHG emissions under the Proposed Action, and to provide a low GHG emissions world into which the proposed terminal is constructed and operated. This section presents the modeling results for the Lower Bound Scenario No-Action Alternative and Proposed Action for coal production, consumption, distribution, and CO_2 emissions.

6.3.1 Coal Production

The Lower Bound Scenario is designed to reduce coal consumption and, thus, coal production. Therefore, coal production in the Lower Bound Scenario would be less than the No Clean Power Plan Scenario. Under the No-Action Alternative, U.S. thermal coal production would average 610 million metric tons per year for the 2025 to 2040 period, and would fluctuate around that average with no clear upward or downward trend. Over the 2016 to 2040 period, non-U.S. coal production would grow at an average annual rate of 1.4% per year from 4,467 to 6,172 million metric tons. Powder River Basin coal production under the No-Action Alternative would average 184 million metric tons per year over 2025 to 2040, and would decrease by 45 million metric tons over that period. The

Powder River Basin coal production decreases over time due to the higher assumed production costs in the Lower Bound Scenario. Uinta Basin coal production under the No-Action Alternative would average 4.6 million metric tons per year over 2025 to 2040. Table 6-20 shows the No-Action Alternative coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-20. Lower Bound Scenario Coal Production—No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,467	5,022	5,588	5,673	5,896	6,172	5,941
Total U.S. Thermal Coal	583	589	630	632	589	613	610
Powder River Basin Coal	232	198	217	216	172	171	184
Uinta Basin Coal	6.8	5.6	5.6	5.0	3.5	5.3	4.6

Under the Proposed Action, U.S. thermal coal production would average 650 million metric tons per year for the 2025 to 2040 period. When the proposed terminal comes fully online in 2025, total U.S. coal production would increase by 39.7 million metric tons on average from 2025 to 2040.

Non-U.S. coal production would follow a similar growth rate under the Proposed Action, at 1.3%, as it would under the No-Action Alternative. Powder River Basin coal production under the Proposed Action would average 221 million metric tons per year for 2025 to 2040, with production declining by 42 million metric tons between 2025 and 2030 and then remains flat through 2040. Uinta Basin coal production would average 5.0 million metric tons per year for 2025 to 2040, with production following the same fluctuating trends as it would under the No-Action Alternative, decreasing in 2030 and then increasing in 2040 to 6.1 million metric tons due to changes in coal consumption in the United States.

Table 6-21 shows the Proposed Action coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-21. Lower Bound Scenario Coal Production—Proposed Action (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,467	5,022	5,588	5,633	5,860	6,140	5,906
Total U.S. Thermal Coal	581	584	626	671	628	654	650
Powder River Basin Coal	229	190	211	251	209	209	221
Uinta Basin Coal	6.8	5.6	5.6	5.0	3.6	6.1	5.0

For the United States, Table 6-22 shows the estimated change in coal production between the Proposed Action and the No-Action Alternative by model run year to be a decrease of 8.3 million metric tons or less in the years before 2025 when the proposed terminal would come online. There are changes in coal production prior to the proposed terminal coming online because IPM® is forward-looking and makes adjustments in the near term to optimize the whole period being analyzed. In the Proposed Action, IPM® "knows" that the terminal comes fully online in 2025—and thus it makes adjustments throughout the analysis period to minimize overall costs. Once the

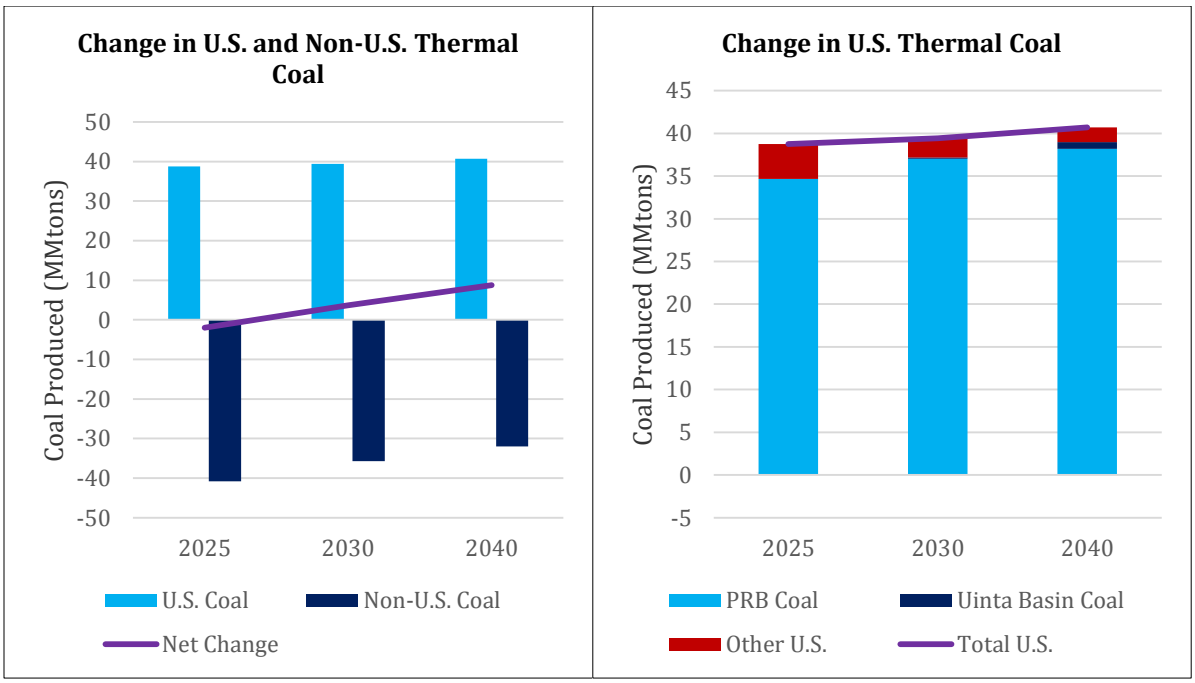
proposed terminal is online and exporting coal, total modeled U.S. coal production would be higher by an average of 39.7 million metric tons under the Proposed Action, primarily due to increases in Powder River Basin production.

Table 6-22. Lower Bound Scenario Change in Coal Production—Proposed Action minus No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	0	0	0.3	-40.8	-35.7	-32.0	-35.7
Total U.S. Thermal Coal	-2.2	-4.8	-3.7	38.7	39.4	40.7	39.7
Powder River Basin Coal	-3.4	-8.3	-5.8	34.7	37.0	38.2	36.8
Uinta Basin Coal	0	0	0	0	0.1	0.8	0.4

The left-hand chart in Figure 6-8 shows that total non-U.S. thermal coal production would decrease in similar amounts to the increase in U.S. coal production when comparing the Proposed Action to the No-Action Alternative. This similarity is indicative of U.S. thermal coal exports taking the place of some internationally produced coal, instead of adding to overall global coal demand. The right-hand chart in Figure 6-8 shows that the changes in Powder River Basin coal production would make up most of the changes in overall U.S. coal production.

Figure 6-8. Lower Bound Scenario Change in Coal Production—Proposed Action minus No-Action Alternative



In the Lower Bound Scenario, the average increase in U.S. coal production (39.7 million metric tons) under the Proposed Action would be close to the 44 million metric tons of coal being exported through the proposed terminal. The No Clean Power Plan Scenario increase would average 44

million metric tons. The difference is due primarily to decreases in coal exports through Canadian export terminals in the No Clean Power Plan Scenario.

6.3.2 Coal Consumption

Under the No-Action Alternative, U.S. thermal coal consumption would average 519 million metric tons per year for the 2025 to 2040 period. U.S. coal consumption declines over the 2016 and 2040 period due to the higher assumed Powder River Basin coal prices and the implementation of the Clean Power Plan. Over the 2016 to 2040 period, Asian coal consumption would grow at an average rate of 1.9% per year from 3,402 to 5,294 million metric tons. The growth in consumption would be driven by increasing coal consumption in China and India. Table 6-23 shows the No-Action Alternative coal consumption values for each model run year. Table 6-24 shows the same values in TBtu per year.

China is responsible for the largest share of global thermal coal consumption, burning 2,269 million metric tons of coal in 2016. This amount is projected to grow in the Lower Bound Scenario under the No-Action Alternative to 2,732 million metric tons by 2040. Total U.S. coal consumption would remain relatively stable through 2025 at an average of 573 million metric tons before declining at an annual rate of -1.3% from 2025 to 2040, finally dropping below 500 million metric tons by 2040.

Table 6-23. Lower Bound Scenario Coal Consumption—No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	121	135	157	148	188	202	182
Australia	104	113	121	118	116	108	113
China	2,269	2,478	2,685	2,747	2,803	2,732	2,760
Hong Kong	14	15	15	14	15	16	15
India	547	717	887	1,075	1,329	1,857	1,464
Indonesia	138	139	141	151	163	181	167
Japan	94	107	122	105	103	86	97
South Korea	70	75	80	70	63	44	57
Taiwan	46	54	63	62	68	69	66
Total Asian Coal Consumption[a]	3,402	3,833	4,271	4,490	4,847	5,294	4,922
Total U.S. Coal Consumption	583	554	580	577	519	477	519
Rest of World Coal Consumption	1,066	1,226	1,370	1,243	1,121	1,015	1,114

[a] Asia row is sum of Asia-Other through Taiwan rows.

Table 6-24. Lower Bound Scenario Coal Consumption—No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	2,603	2,904	3,205	3,380	3,593	3,882	3,646
Australia	1,268	1,454	1,640	1,519	1,436	1,194	1,365
China	57,999	63,331	68,639	69,967	71,090	68,476	69,761
Hong Kong	303	325	347	366	389	420	395
India	10,213	13,382	16,549	19,999	24,655	33,846	26,936
Indonesia	2,486	2,485	2,484	2,619	2,785	3,008	2,826
Japan	2,337	2,620	2,900	2,731	2,689	2,274	2,539
South Korea	1,716	1,866	2,016	1,784	1,617	1,152	1,483
Taiwan	1,091	1,290	1,489	1,571	1,673	1,802	1,695
Total Asian Coal[a] Consumption	80,016	89,658	99,269	103,936	109,927	116,055	110,646
Total U.S. Coal Consumption	12,329	11,843	12,369	12,180	10,980	9,948	10,912
Rest of World Coal Consumption	18,440	21,234	24,086	22,670	20,799	20,071	21,036

[a] Asia row is total of Asia-Other through Taiwan rows.

Coal consumption under the Proposed Action would follow similar patterns as the No-Action Alternative, with U.S. thermal coal consumption averaging 515 million metric tons per year for the 2025 to 2040 period. As with the No-Action Alternative, U.S. coal consumption would be fairly flat until 2025, before decreasing in 2030 and 2040, as electric demand growth would be met primarily with natural gas and renewable generation.

Over the 2016 to 2040 period, Asian coal consumption would follow the same pattern as it grows from 3,402 to 5,306 million metric tons. Tables 6-25 and 6-26 show the Proposed Action coal consumption values for each model run year in million metric tons and in TBtu, respectively. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-25. Lower Bound Scenario Coal Consumption—Proposed Action (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	121	135	157	148	188	202	182
Australia	104	113	121	118	116	108	113
China	2,269	2,478	2,685	2,748	2,804	2,733	2,761
Hong Kong	14	15	15	16	17	19	18
India	547	717	887	1,070	1,329	1,857	1,462
Indonesia	138	139	141	151	163	181	167
Japan	94	107	122	106	104	88	98
South Korea	70	75	80	71	64	46	59
Taiwan	46	54	63	65	70	72	69
Total Asian Coal Consumption	3,402	3,833	4,271	4,492	4,855	5,306	4,930
Total U.S. Coal Consumption	581	549	577	572	515	475	515
Rest of World Coal Consumption	1,066	1,226	1,370	1,243	1,121	1,015	1,114

Table 6-26. Lower Bound Scenario Coal Consumption—Proposed Action (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	2,603	2,904	3,205	3,380	3,593	3,882	3,646
Australia	1,268	1,454	1,640	1,519	1,436	1,194	1,365
China	57,999	63,331	68,639	69,967	71,090	68,476	69,761
Hong Kong	303	325	347	366	389	420	395
India	10,213	13,382	16,549	19,999	24,655	33,846	26,936
Indonesia	2,486	2,485	2,484	2,619	2,785	3,008	2,826
Japan	2,337	2,620	2,900	2,731	2,689	2,274	2,539
South Korea	1,716	1,866	2,016	1,784	1,617	1,152	1,483
Taiwan	1,091	1,290	1,489	1,572	1,673	1,803	1,695
Total Asian Coal Consumption	80,016	89,658	99,269	103,936	109,928	116,055	110,646
Total U.S. Coal Consumption	12,297	11,761	12,321	12,083	10,896	9,920	10,846
Rest of World Coal Consumption	18,440	21,234	24,086	22,670	20,798	20,068	21,034

Tables 6-27 and 6-28 show the estimated change in coal consumption, in million metric tons and TBtu, between the Proposed Action and the No-Action Alternative by model run year to be nearly zero in Asia before 2025 when the proposed terminal was assumed to be fully online. There are small changes in coal consumption prior to the proposed terminal coming online because the IPM model is forward-looking and makes adjustments in the near term to optimize the whole period being analyzed. In the Proposed Action the IPM® model "knows" that the terminal comes fully online in 2025 and thus it makes adjustments throughout the analytical period to minimize overall costs. Once the proposed terminal is exporting coal at full capacity (i.e., 44 million metric tons), total Asian

coal consumption would increase by an average of 8.1 million metric tons between 2025 and 2040. The increase in consumption between 2025 and 2040 would be due to the consumption of a greater quantity of lower heat content coal. U.S. coal consumption would have an average decline of 3.8 million metric tons per year over the 2025 to 2040 period under the Proposed Action due to a decrease in the demand for Powder River Basin coal. Powder River Basin coal demand in the United States would decrease due to higher coal prices caused by higher production when the Powder River Basin coal is exported through the proposed terminal.

Table 6-27. Lower Bound Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	-0.6	0	0	-0.2
Australia	0	0	0	0	0	0	0
China	0	0	0	1.0	0.9	1.4	1.1
Hong Kong	0	0	0	2.3	2.6	2.8	2.6
India	0	0	0	-5.2	0	0	-1.4
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0.9	0.9	1.9	1.3
South Korea	0	0	0	1.4	1.3	2.3	1.7
Taiwan	0	0	0	3.0	2.4	3.6	3.0
Total Asian Coal Consumption	0	0	0	2.7	8.0	12.0	8.1
Total U.S. Coal Consumption	-2.2	-4.8	-3.4	-4.8	-4.1	-2.8	-3.8
Rest of World Coal Consumption	0	0	0.1	0.1	0	-0.1	<0.05

Table 6-28. Lower Bound Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	0	0	0	0
Australia	0	0	0	0	0	0	0
China	0	0	0	0	0	0	0
Hong Kong	0	0	0	<0.1	<0.1	<0.1	<0.1
India	0	0	0	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
Taiwan	0	0	0	0.2	0.2	0.2	0.2
Total Asian Coal Consumption	0	0	0	0.3	0.3	0.3	0.3
Total U.S. Coal Consumption	-31.8	-82.0	-48.6	-96.9	-83.8	-27.3	-65.4
Rest of World Coal Consumption	0	0	0	0	-0.8	-3.0	-1.4

6.3.3 Coal Distribution

Similar to the No Clean Power Plan Scenario, the Lower Bound Scenario distribution patterns for Powder River Basin and Uinta Basin coal are expected to remain largely unchanged under the Proposed Action. Thus, this section focuses on the distribution of coal in Asia and how that distribution would be expected to change with the construction of the terminal. Under the No-Action Alternative, there is no coal exported through the proposed terminal; however, there would be 306 million metric tons of coal distributed in Asia by ship in the seaborne coal market in 2016. Table 6-29 shows the tons of coal that would be imported by each country in Asia under the No-Action Alternative. By 2040, a total of 409 million metric tons of thermal coal are expected to be imported in the seaborne coal market in Asia.

Table 6-29. Lower Bound Scenario Seaborne Coal Imports in Asia—No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	83	95	115	129	180	194	171
Australia	0	0	0	0	0	0	0
China	0	10	32	0	0	0	0
Hong Kong	14	15	15	14	15	16	15
India	0	0	0	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	94	107	122	105	103	86	97
South Korea	70	75	80	70	63	44	57
Taiwan	46	54	63	62	68	69	66
Total Asian Coal sent via ship	306	356	428	379	430	409	408

To understand how coal distribution is changing in more detail than the tons of coal imported by each country, the tons of coal shipped to each country were multiplied by the distance in nautical miles that the coal would be shipped and then divided by an average ship size. The change in tons imported might not change significantly; however, where the coal is sourced might change, which can have a significant impact on the emissions associated with shipping. Table 6-30 shows the shipping miles for coal shipped to each country under the No-Action Alternative.

Table 6-30. Lower Bound Scenario Shipping Distance for Seaborne Coal Imports in Asia—No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	0.50	0.69	1.94	2.37	3.47	3.78	3.29
Australia	0	0	0	0	0	0	0
China	0	0.25	0.84	0	0	0	0
Hong Kong	0.40	0.43	0.46	0.42	0.18	0.19	0.25
India	0	0	0	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	4.39	5.71	7.76	1.40	1.38	1.15	1.30
South Korea	1.91	2.65	2.79	0.66	0.59	0.43	0.55
Taiwan	2.89	3.42	3.95	1.91	3.36	0.57	1.87
Total Asian Coal sent via ship	10.08	13.15	17.73	6.75	8.98	6.13	7.25

Under the Proposed Action coal would be exported through the terminal to destinations in Asia. Table 6-31 shows the distribution of coal exported from the proposed terminal, which would be similar to the distribution in the other scenarios as the coal is delivered to all of the possible destinations.

Table 6-31. Lower Bound Scenario Distribution of Coal Exported through the Coal Export Terminal—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040
China	0	0	0	3.7	3.6	5.3
Hong Kong	0	0	0	9.4	9.9	10.7
Japan	0	0	0	7.3	7.2	6.4
South Korea	0	0	0	11.7	10.6	7.9
Taiwan	0	0	0	11.9	12.7	13.7
Total Asian Coal sent via ship through Proposed Terminal	0	0	0	44.0	44.0	44.0

Under the Proposed Action, a similar number of tons would be distributed in the seaborne coal market as for the No-Action Alternative, as can be seen in Table 6-32, which shows the tons of coal that would be imported by each country in Asia under the Proposed Action. The shipping distance for the coal distribution in Asia is presented in Table 6-33 for the Proposed Action.

Table 6-32. Lower Bound Scenario Seaborne Coal Imports in Asia—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	83	95	115	128	180	194	171
Australia	0	0	0	0	0	0	0
China	0	10	32	4	4	5	4
Hong Kong	14	15	15	16	17	19	18
India	0	0	0	14	0	0	4
Indonesia	0	0	0	0	0	0	0
Japan	94	107	122	106	104	88	98
South Korea	70	75	80	71	64	46	59
Taiwan	46	54	63	65	70	72	69
Total Asian Coal sent via ship	306	356	428	403	440	425	424

Table 6-33. Lower Bound Scenario Shipping Distance for Seaborne Coal Imports in Asia—Proposed Action (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	0.50	0.69	1.94	2.35	3.47	3.78	3.28
Australia	0	0	0	0	0	0	0
China	0	0.25	0.84	0.30	0.29	0.43	0.35
Hong Kong	0.40	0.43	0.46	1.02	0.95	1.03	1.00
India	0	0	0	0.65	0	0	0.18
Indonesia	0	0	0	0	0	0	0
Japan	4.39	5.71	7.76	1.80	1.77	1.52	1.68
South Korea	1.91	2.65	2.79	1.38	1.25	0.92	1.16
Taiwan	2.89	3.42	3.95	2.71	3.77	1.62	2.64
Total Asian Coal sent via ship	10.08	13.15	17.73	10.21	11.51	9.31	10.29

As can be seen in Table 6-34, which shows the estimated change in tons of coal imported by each of the regions, the changes in coal imports between the No-Action Alternative and the Proposed Action mirror the changes in consumption. As mentioned in the previous section, the changes in consumption are due to changes in the mix of coal being consumed and not a change in overall coal demand.

Table 6-34. Lower Bound Scenario Change in Seaborne Coal Distribution in Asia—Proposed Action minus No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	-0.6	0	0	-0.2
Australia	0	0	0	0	0	0	0
China	0	0	0	3.7	3.6	5.3	4.3
Hong Kong	0	0	0	2.3	2.6	2.8	2.6
India	0	0	0	13.8	0	0	3.8
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0.9	0.9	1.9	1.3
South Korea	0	0	0	1.4	1.3	2.3	1.7
Taiwan	0	0	0	3.0	2.4	3.6	3.0
Total Asian Coal sent via ship	0	0	0	24.5	10.7	15.9	16.6

The changes in the total tons of coal imported to each region would be magnified or diminished depending on how the sources of the coal shifted. There would be some relatively large changes in the ton-mile values, as shown in Table 6-35.

Table 6-35. Lower Bound Scenario Change in Shipping Distance for Seaborne Coal Distribution in Asia—Proposed Action minus No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	Annual Average
Asia - Other	0	0	0	-0.01	0	0	<0.005
Australia	0	0	0	0	0	0	0
China	0	0	0	0.30	0.29	0.43	0.35
Hong Kong	0	0	0	0.61	0.77	0.84	0.75
India	0	0	0	0.65	0	0	0.18
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0.40	0.39	0.37	0.38
South Korea	0	0	0	0.73	0.66	0.49	0.61
Taiwan	0	0	0	0.79	0.41	1.06	0.77
Total Asian Coal sent via ship	0	0	0	3.46	2.52	3.18	3.04

6.3.4 CO_2 Emissions

This section presents the estimated CO_2 emissions from coal combusted in the United States and Asia in the Lower Bound Scenario. In addition, CO_2 emissions from natural gas consumption in the United States are included because decreases in coal consumption may be offset by increases in natural gas consumption. Table 6-36 presents the CO_2 emissions under the No-Action Alternative. Total U.S. CO_2 emissions from coal would gradually decline and average 1,022.71 million metric tons between 2025 and 2040. Asian CO_2 emissions would average 10,624.68 million metric tons per year between 2025 and 2040, which is 10.4 times the total CO_2 emissions from the U.S. coal combustion emissions. Natural gas CO_2 emissions would average 567.27 million metric tons per year between 2025 and 2040, which is 21.15 million metric tons lower than the No Clean Power Plan Scenario. The lower natural gas emissions under the Lower Bound Scenario, in spite of higher assumed coal prices in this scenario, are due to the inclusion of the Clean Power Plan, along with additional energy efficiency, which would decrease generation, including gas-fired generation. However, within the Lower Bound Scenario, between 2030 and 2040, CO_2 emissions from natural gas would increase by 152.18 million metric tons. This increase would be due to nuclear units retiring in this period and natural gas-fired generation replacing the retired nuclear generation.

Table 6-37 presents the CO_2 emissions under the Proposed Action. Total CO_2 emissions under the Proposed Action would follow the same trends as under the No-Action Alternative.

Table 6-36. Lower Bound Scenario CO_2 Emissions—No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	249.64	278.72	307.81	315.01	349.95	378.15	351.21
Australia	118.44	135.82	153.19	141.84	134.07	111.44	127.43
China	5,589.28	6,102.28	6,611.34	6,743.76	6,853.22	6,604.62	6,726.13
Hong Kong	28.03	30.04	32.06	33.80	37.44	40.45	37.60
India	972.75	1,275.00	1,577.00	1,905.11	2,348.19	3,221.25	2,564.63
Indonesia	239.90	239.57	239.23	251.81	267.30	287.63	270.90
Japan	217.19	244.08	271.31	262.82	258.78	218.86	244.38
South Korea	161.27	173.30	187.21	171.69	155.66	110.91	142.71
Taiwan	101.94	120.56	139.17	145.35	155.55	173.47	159.69
Asia- Coal	7,678.43	8,599.37	9,518.31	9,971.20	10,560.15	11,146.77	10,624.68
U.S. - Coal	1,157.94	1,110.06	1,160.04	1,142.49	1,028.90	931.85	1,022.71
U.S. - Natural Gas	574.39	551.71	510.16	495.88	517.59	660.85	567.27
Rest of World	1,757.68	2,022.82	2,294.97	2,156.06	1,976.51	1,904.87	1,998.52

Table 6-37. Lower Bound Scenario CO_2 Emissions—Proposed Action (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	249.64	278.72	307.81	314.73	349.95	378.15	351.13
Australia	118.44	135.82	153.19	141.84	134.07	111.44	127.43
China	5,589.28	6,102.28	6,611.34	6,743.66	6,853.13	6,604.49	6,726.03
Hong Kong	28.03	30.04	32.06	34.28	37.20	40.19	37.55
India	972.75	1,275.00	1,577.00	1,903.99	2,348.19	3,221.25	2,564.33
Indonesia	239.90	239.57	239.23	251.81	267.30	287.63	270.90
Japan	217.19	244.08	271.31	262.65	258.62	218.85	244.27
South Korea	161.27	173.30	187.21	171.43	155.42	110.89	142.55
Taiwan	101.94	120.56	139.17	145.97	155.95	173.16	159.87
Asia- Coal	7,678.43	8,599.37	9,518.31	9,970.36	10,559.81	11,146.04	10,624.06
U.S. - Coal	1,154.79	1,102.20	1,155.19	1,133.82	1,021.45	929.05	1,016.73
U.S.- Natural Gas	575.66	554.39	510.85	498.58	519.83	661.50	569.02
Rest of World	1,757.68	2,022.82	2,294.99	2,156.09	1,976.44	1,904.58	1,998.40

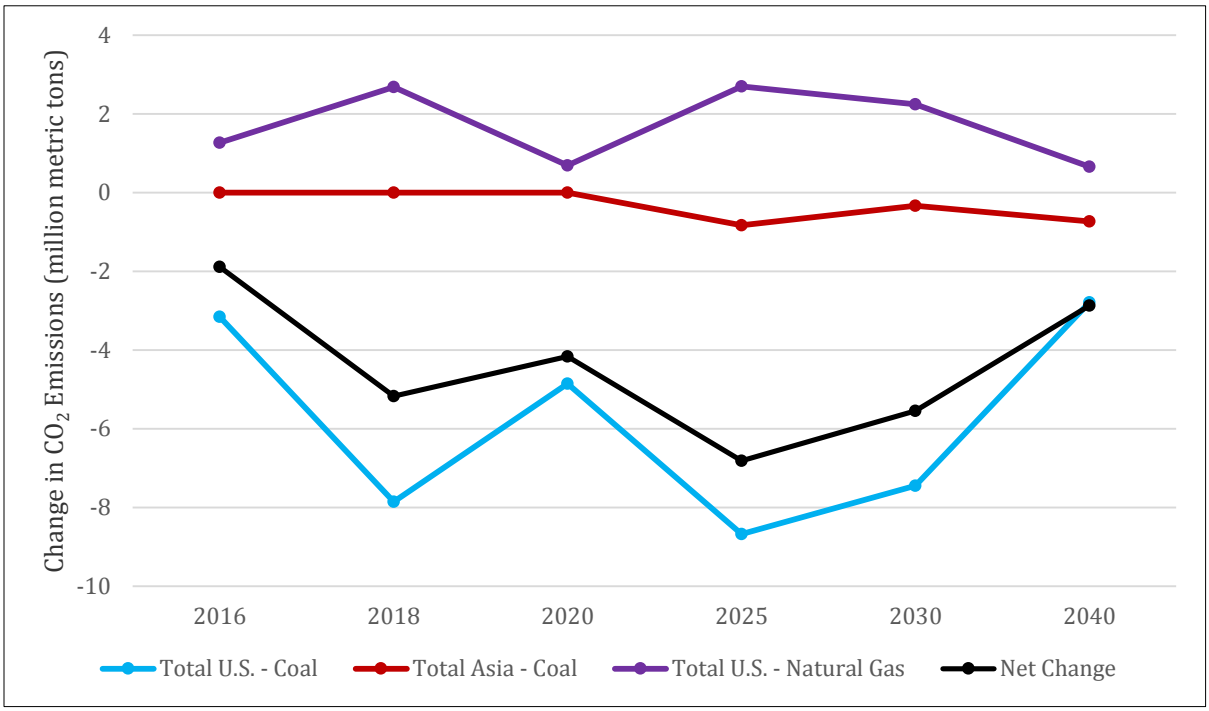
Table 6-38 shows the estimated change in CO_2 emissions for each region and the total net change across all regions. Total Asian CO_2 emissions from coal consumption would decrease by 0.63 million metric tons on average from 2025 to 2040. U.S. coal CO_2 emissions would also decrease in every year due to higher coal prices that would depress U.S. coal demand. The higher coal prices would result from the fact that an additional 44 million metric tons of coal would be exported under the Proposed Action, which would shift the demand curve up and yield higher coal prices in the United States. The decrease in coal consumption would be offset by an increase in natural gas consumption, as is seen by the increase in CO_2 emissions from natural gas, which would average 1.75 million metric tons per year between 2025 and 2040. The total net change in CO_2 emissions would be a decrease of an average of 4.86 million metric tons per year between 2025 and 2040.

Table 6-38. Lower Bound Scenario Changes in CO_2 Emissions—Proposed Action minus No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0	0	0	-0.28	0	0	-0.08
Australia	0	0	0	0	0	0	0
China	0	0	0	-0.09	-0.09	-0.13	-0.11
Hong Kong	0	0	0	0.47	-0.24	-0.26	-0.05
India	0	0	0	-1.11	0	0	-0.31
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	-0.17	-0.16	-0.01	-0.11
South Korea	0	0	0	-0.27	-0.24	-0.01	-0.16
Taiwan	0	0	0	0.62	0.40	-0.32	0.18
Asia- Coal	0	0	0	-0.83	-0.34	-0.73	-0.63
U.S. - Coal	-3.15	-7.85	-4.85	-8.67	-7.45	-2.79	-5.98
U.S. - Natural Gas	1.26	2.68	0.69	2.69	2.24	0.65	1.75
Rest of World	0	0.01	0.02	0.03	-0.06	-0.29	-0.12
Total Change	-1.89	-5.17	-4.17	-6.81	-5.54	-2.87	-4.86

In the Lower Bound Scenario, coal combustion emissions of CO_2 would be lower under the Proposed Action in Asia than under the No-Action Alternative. U.S. emissions would generally decline, with the decline from coal offsetting the increase in emissions from natural gas. Figure 6-9 shows the net change in CO_2 emissions between the No-Action Alternative and Proposed Action. The decrease in U.S. and Asian coal emissions would override the increase in U.S. natural gas emissions and would drive the net change to be a net decrease in CO_2 emissions under the Proposed Action through 2040.

Figure 6-9. Lower Bound Scenario Changes in CO_2 Emissions by Region—Proposed Action minus No-Action Alternative



a. Total U.S. CO_2 emissions from the combustion of coal decrease because the proposed coal export terminal would be a new demand sink for U.S. coal, and thus, would cause coal prices to rise, and U.S. coal consumption to decrease in response to the higher prices.

b. Asian CO_2 emissions from the combustion of coal decrease due to a general shift toward consuming more coal with a lower CO_2 emission rate and away from coals with a higher CO_2 emissions rate.

c. Total U.S. natural gas combustion CO_2 emissions increase because when coal consumption for electric generation declines, natural gas usage for electric generation increases to fill some of the gap.

6.4 Upper Bound Scenario

The Upper Bound Scenario uses the assumptions presented in Chapter 5, *Scenarios*, and represents the upper bound of global GHG emissions that could be reasonably expected if the scenario assumptions are realized. This scenario is designed to model the highest potential GHG emissions under the Proposed Action, and to provide a high GHG emissions environment into which the terminal is constructed and operated. This section presents the modeling results for the Upper Bound Scenario No-Action Alternative and Proposed Action for coal production, consumption, distribution, and CO_2 emissions.

6.4.1 Coal Production

The Upper Bound Scenario is designed to model high levels of coal consumption, and thus, increased CO_2 emissions. Therefore, coal production in the Upper Bound Scenario would be greater than the No Clean Power Plan Scenario. Under the No-Action Alternative U.S. thermal coal production would average 876 million metric tons per year for the 2025 to 2040 period. In contrast, the average U.S. coal production over 2025 to 2040 under the No Clean Power Plan Scenario would be lower by 63 million metric tons at 813 million metric tons. The higher production under the Upper Bound

Scenario would be due to the following factors. International coal prices are 50% higher than the base assumptions, due to higher demand, and Powder River Basin and Uinta Basin coal prices are assumed 15% lower in the Upper Bound Scenario than the base assumptions, while domestic coal transportation costs are decreased. Additionally, international coal demand is higher in the Upper Bound Scenario than in the base assumptions. The increase in demand for U.S. coal exports along with lower costs lead to the increase in U.S. coal production. U.S. coal production would fluctuate over the 2016 to 2040 period in response to both domestic demand and exports, and would end up being 153 million metric tons higher in 2040 than in 2016. Over the 2016 to 2040 period, non-U.S. coal production would grow at an average annual rate of 3.2% per year from 4,417 to 9,470 million metric tons.

Powder River Basin coal production under the No-Action Alternative would average 379 million metric tons per year over 2025 to 2040. The modeled Powder River Basin average production in the Upper Bound Scenario, No-Action Alternative, would be 19.9% below the 2006 to 2011 historical production average of 473 million metric tons (i.e., 379 million metric tons relative to 473 million metric tons). After 2011, natural gas prices dropped to below $3/MMBtu, which significantly reduced coal demand and drove Powder River Basin production to around 435 million metric tons. Uinta Basin coal production under the No-Action Alternative would average 17.2 million metric tons per year over 2025 to 2040, with production remaining flat through 2030 and increasing in 2040. Table 6-39 shows the No-Action Alternative coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-39. Upper Bound Coal Production—No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,417	5,014	5,694	6,371	7,197	9,470	7,852
Total U.S. Thermal Coal	731	790	866	884	859	884	876
Powder River Basin Coal	412	381	428	407	364	372	379
Uinta Basin Coal	15.0	14.9	15.0	14.9	14.9	20.9	17.2

Under the Proposed Action, U.S. thermal coal production would average 918 million metric tons per year for the 2025 to 2040 period. Similar to the No-Action Alternative, under the Proposed Action, U.S. coal production would fluctuate and by 2040 would end at 196 million metric tons higher than production in 2016 at 927 million metric tons. The higher production by 2040 is due to the additional exports through the proposed terminal. Non-U.S. coal production would follow the same growth rate under the Proposed Action as it would under the No-Action Alternative. Powder River Basin coal production under the Proposed Action would average 415 million metric tons per year between 2025 and 2040 with production generally increasing over time. Uinta Basin coal production would average 22.1 million metric tons per year between 2025 and 2040, with production remaining flat through 2025 and then increasing in 2030 and 2040. Table 6-40 shows the Proposed Action coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-40. Upper Bound Scenario Coal Production—Proposed Action (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,418	5,014	5,694	6,357	7,179	9,448	7,833
Total U.S. Thermal Coal	731	790	866	928	898	927	918
Powder River Basin Coal	412	381	428	452	400	401	415
Uinta Basin Coal	14.4	14.9	15.0	13.6	17.7	31.9	22.1

Table 6-41 shows the estimated change in coal production between the Proposed Action and the No-Action Alternative by model run year. Upon the export of 44 million metric tons of coal, total modeled U.S. coal production would be higher under the Proposed Action, primarily due to increases in the Powder River Basin and the Uinta Basin. In response to the increase in exports from the proposed terminal, non-U.S. coal production would decrease by an average of 18.4 million metric tons per year from 2025 to 2040.

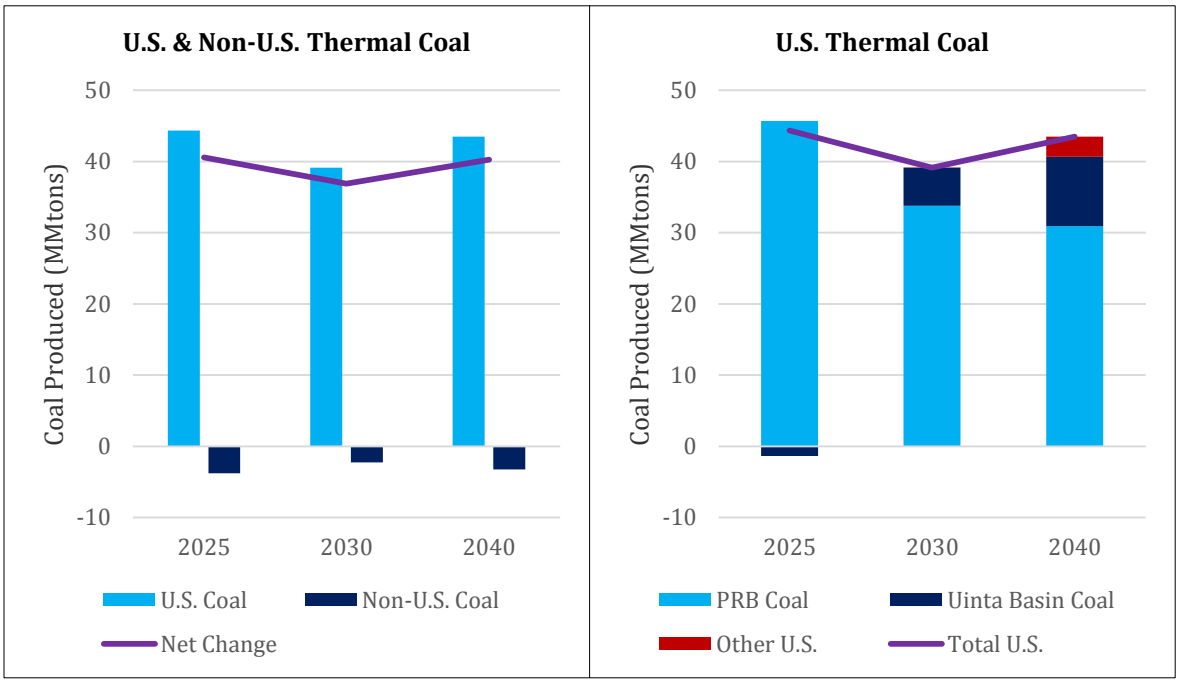
Table 6-41. Upper Bound Scenario Change in Coal Production—Proposed Action minus No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	1.7	0	0	-14.0	-18.5	-21.5	-18.4
Total U.S. Thermal Coal	-0.4	0	0	44.3	39.1	42.9	42.0
Powder River Basin Coal	0.1	0.1	0	45.7	36.3	29.0	36.1
Uinta Basin Coal	-0.6	0	0	-1.4	2.8	11.0	4.9

Figure 6-10 shows that total non-U.S. thermal coal production would decrease under the Proposed Action. The decrease in non-U.S. coal production is smaller than the increase in U.S. coal production because of induced demand in this scenario of between 23 and 33 million metric tons.[36] The positive net change in production that is greater than the amount of induced demand indicates that U.S. thermal coal exports of lower heat content coal would displace some internationally produced higher heat content coal.

[36] The amount of induced demand is determined by the increase in total heating value of coal, which in the Upper Bound Scenario is 542 TBtu. Depending on the mix of coal types consumed between lignite, subbituminous, and bituminous coal, the amount of induced demand on a tonnage basis is expected to be between 23 and 33 million metric tons.

Figure 6-10. Upper Bound Scenario Change in Coal Production—Proposed Action minus No-Action Alternative



6.4.2 Coal Consumption

In the Upper Bound Scenario, under the No-Action Alternative U.S. thermal coal consumption would average 698 million metric tons per year for the 2025 to 2040 period. U.S. coal consumption would be fairly flat over the whole period because of two factors. First, consumption is not driven down by the Clean Power Plan implementation. Second, low natural gas prices and relatively low renewable capital costs result in demand growth being met with natural gas combined cycles and renewable resources.

Over the 2016 to 2040 period, Asian coal consumption would grow at an average rate of 3.6% per year from 3,388 to 7,974 million metric tons. The growth in consumption would be driven by increasing coal consumption in China and India. Tables 6-42 and 6-43 show the No-Action Alternative coal consumption values for each model run year in units of million metric tons and TBtu, respectively.

China is responsible for the largest share of global thermal coal consumption, burning 2,269 million metric tons of coal in 2016. This amount is projected to grow in the Upper Bound Scenario, No-Action Alternative to 4,076 million metric tons by 2040.

Table 6-42. Upper Bound Scenario Coal Consumption—No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	115	142	158	185	262	440	310
Australia	104	114	123	124	124	125	124
China	2,269	2,533	2,804	3,083	3,393	4,076	3,572
Hong Kong	13	14	17	19	19	26	22
India	543	701	888	1,194	1,541	2,637	1,871
Indonesia	136	147	163	179	217	303	240
Japan	96	113	127	137	136	154	143
South Korea	67	81	89	90	100	117	104
Taiwan	47	56	65	74	84	95	86
Total Asian Coal Consumption	3,388	3,900	4,435	5,085	5,875	7,974	6,472
Total U.S. Coal Consumption	659	645	711	715	682	700	698
Rest of World Coal Consumption	1,102	1,260	1,416	1,457	1,501	1,684	1,560

Table 6-43. Upper Bound Scenario Coal Consumption—No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	2,603	2,968	3,334	4,255	5,430	8,846	6,432
Australia	1,268	1,481	1,693	1,661	1,629	1,591	1,623
China	57,999	64,719	71,432	78,781	86,598	103,803	91,117
Hong Kong	303	332	361	425	501	695	555
India	10,213	13,834	17,452	23,201	30,309	51,255	36,480
Indonesia	2,486	2,637	2,798	3,243	3,760	5,053	4,119
Japan	2,337	2,674	3,009	3,283	3,548	4,054	3,671
South Korea	1,716	1,911	2,106	2,322	2,556	3,085	2,697
Taiwan	1,091	1,324	1,558	1,761	1,965	2,331	2,051
Total Asian Coal Consumption	80,016	91,880	103,742	118,934	136,296	180,713	148,747
Total U.S. Coal Consumption	13,129	12,933	14,282	14,573	14,043	14,513	14,373
Rest of World Coal Consumption	18,316	21,846	25,426	26,538	27,740	32,263	29,165

Over the 2016 to 2040 period, Asian coal consumption under the Proposed Action grows from 3,390 to 7,994 million metric tons, similar to the No-Action Alternative. Due to lower delivered coal prices causing induced demand, the demand in Asian countries increases by 542 TBtu annually from 2025.

Tables 6-44 and 6-45 show the Proposed Action coal consumption values for each model run year in units of million metric tons and TBtu, respectively. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-44. Upper Bound Scenario Coal Consumption—Proposed Action (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	118	142	158	185	259	440	309
Australia	104	114	123	124	124	125	124
China	2,269	2,533	2,804	3,109	3,412	4,095	3,594
Hong Kong	13	14	17	19	22	30	24
India	543	701	888	1,196	1,542	2,634	1,870
Indonesia	136	147	163	179	216	303	240
Japan	94	113	127	136	137	154	144
South Korea	67	81	89	91	100	117	104
Taiwan	47	56	65	76	84	96	86
Total Asian Coal Consumption	3,390	3,900	4,435	5,115	5,896	7,994	6,495
Total U.S. Coal Consumption	659	645	711	715	682	700	698
Rest of World Coal Consumption	1,102	1,260	1,416	1,457	1,500	1,684	1,560

Table 6-45. Upper Bound Scenario Coal Consumption—Proposed Action (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	2,603	2,968	3,334	4,255	5,430	8,846	6,432
Australia	1,268	1,481	1,693	1,661	1,629	1,591	1,623
China	57,999	64,719	71,432	79,292	87,108	104,314	91,628
Hong Kong	303	332	361	426	501	696	556
India	10,213	13,834	17,452	23,224	30,332	51,278	36,503
Indonesia	2,486	2,637	2,798	3,243	3,760	5,053	4,119
Japan	2,337	2,674	3,009	3,287	3,552	4,058	3,675
South Korea	1,716	1,911	2,106	2,325	2,559	3,087	2,699
Taiwan	1,091	1,324	1,558	1,763	1,966	2,333	2,052
Total Asian Coal Consumption	80,016	91,880	103,742	119,476	136,837	181,256	149,289
Total U.S. Coal Consumption	13,118	12,933	14,281	14,573	14,043	14,513	14,373
Rest of World Coal Consumption	18,316	21,846	25,426	26,538	27,740	32,263	29,165

Tables 6-46 and 6-47 show the estimated change in coal consumption between the Proposed Action and the No-Action Alternative by model run year in units of million metric tons and TBtu, respectively. Once the proposed terminal is online and exporting coal in 2025, total Asian coal consumption is higher by an average of 23.3 million metric tons between 2025 and 2040. China's consumption has the largest increase, with an average of 21.5 million metric tons per year between 2025 and 2040. U.S. coal consumption increases slightly by an average of 0.4 million metric tons per year over the 2025 to 2040 period under the Proposed Action. In 2040, the tons of coal consumed in India decreases, while the total heat content of coal consumption increases. This occurs because India increases its use of higher-heat-content Australian bituminous coal and decreases its use of lower heat content domestic subbituminous coal.

Table 6-46. Upper Bound Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia – Other	3.8	0	0	0	-2.9	-0.1	-1.0
Australia	0	0	0	0	0	0	0
China	0	0	0	26.9	19.4	19.4	21.5
Hong Kong	0	0	0	0	2.7	3.7	2.3
India	0	0	0	2.1	1.0	-3.2	-0.3
Indonesia	0	0	0	0	-0.7	-0.1	-0.3
Japan	-2.1	0	0	-0.6	0.7	0.1	0.1
South Korea	0	0	0	0.1	0.5	0.1	0.2
Taiwan	0	0	0	1.4	0.1	0.7	0.7
Total Asian Coal Consumption	1.7	0	0	30.0	20.7	20.7	23.3
Total U.S. Coal Consumption	-0.4	0	0	0.3	0.1	0.7	0.4
Rest of World Coal Consumption	0	0	0	0	0	0	0

Table 6-47. Upper Bound Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia – Other	0	0	0	0	0	0	0
Australia	0	0	0	0	0	0	0
China	0	0	0	510.8	510.8	510.8	510.8
Hong Kong	0	0	0	0.4	0.4	0.4	0.4
India	0	0	0	22.9	22.9	22.9	22.9
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	3.3	3.3	3.3	3.3
South Korea	0	0	0	2.4	2.4	2.4	2.4
Taiwan	0	0	0	2.1	2.1	2.1	2.1
Total Asian Coal Consumption	0	0	0	541.9	541.9	541.9	541.9
Total U.S. Coal Consumption	-11.4	-0.1	-0.2	0.2	0.2	0.1	0.1
Rest of World Coal Consumption	0	0	0	0	0	0	0

6.4.3 Coal Distribution

As with the No Clean Power Plan Scenario, distribution patterns for Powder River Basin and Uinta Basin coal are expected to remain largely unchanged under the Proposed Action. This section focuses on the distribution of coal in Asia and how that distribution would be expected to change with the construction of the terminal. Under the No-Action Alternative, there would be no coal exported through the proposed terminal; however, there would be 308 million metric tons of coal distributed in Asia by ship in the seaborne coal market in 2016. Table 6-48 shows the tons of coal that would be imported by each country in Asia under the No-Action Alternative. By 2040, 1,373 million metric tons of coal are expected to be distributed in the seaborne coal market in Asia.

Table 6-48. Upper Bound Scenario Seaborne Coal Imports in Asia—No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	76	102	116	165	255	432	299
Australia	0	0	0	0	0	0	0
China	0	17	101	0	0	0	0
Hong Kong	13	14	17	19	19	26	22
India	9	112	131	183	334	548	375
Indonesia	0	0	0	0	0	0	0
Japan	96	113	127	137	136	154	143
South Korea	67	81	89	90	100	117	104
Taiwan	47	56	65	74	84	95	86
Total Asian Coal sent via ship	308	495	647	669	927	1,373	1,029

To understand how coal distribution is changing in more detail than the tons of coal imported by each country, the tons of coal shipped to each country were multiplied by the distance in nautical miles that the coal is shipped. The change in tons imported might not change significantly; however, where the coal is sourced might change, which would have a significant impact on the emissions associated with shipping. Table 6-49 shows the shipping miles for coal shipped to each country under the No-Action Alternative.

Table 6-49. Upper Bound Scenario Shipping Distance for Seaborne Coal Imports in Asia—No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	1.23	1.79	1.30	3.14	5.49	8.79	6.12
Australia	0	0	0	0	0	0	0
China	0	1.30	4.33	0	0	0	0
Hong Kong	0.67	0.87	0.50	1.43	0.23	0.32	0.60
India	0.61	6.32	6.31	14.24	27.80	45.69	30.99
Indonesia	0	0	0	0	0	0	0
Japan	7.26	7.15	8.05	7.76	1.82	2.05	3.56
South Korea	0.63	5.23	5.77	0.85	0.94	1.16	1.00
Taiwan	3.08	3.51	4.13	4.73	5.54	3.66	4.58
Total Asian Coal sent via ship	13.48	26.16	30.37	32.14	41.82	61.67	46.85

Under the Proposed Action, coal would be exported through the terminal to destinations in Asia. Table 6-50 shows that the coal exported from the proposed terminal would be distributed by the model to China, Hong Kong, Japan, South Korea, and Taiwan. The distribution of coal in the Upper

Bound Scenario is varied over time and across destinations, as the model strives to minimize overall system costs.

Table 6-50. Upper Bound Scenario Distribution of Coal Exported through the Coal Export Terminal—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040
China	0	0	0	33.7	0	0
Hong Kong	0	0	0	10.3	12.1	16.8
Japan	0	0	0	0	9.0	0
South Korea	0	0	0	0	6.2	0
Taiwan	0	0	0	0	16.8	27.2
Total Asian Coal sent via ship through proposed Coal Export Terminal	0	0	0	44.0	44.0	44.0

Under the Proposed Action, a similar number of tons would be distributed in the seaborne coal market as the No-Action Alternative, except for an increase in imports to China, Hong Kong, India Japan, South Korea, and Taiwan (Table 6-51). Table 6-51 shows the tons of coal that would be imported by each country in Asia under the Proposed Action. The distance weighted coal distribution in Asia is presented in Table 6-52 for the Proposed Action.

Table 6-51. Upper Bound Scenario Seaborne Coal Imports in Asia—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	80	102	116	165	252	432	298
Australia	0	0	0	0	0	0	0
China	0	17	101	34	0	0	9
Hong Kong	13	14	17	19	22	30	24
India	9	112	131	185	335	565	383
Indonesia	0	0	0	0	0	0	0
Japan	94	113	127	136	137	154	144
South Korea	67	81	89	91	100	117	104
Taiwan	47	56	65	76	84	96	86
Total Asian Coal sent via ship	310	495	647	707	930	1,394	1,048

Table 6-52. Upper Bound Scenario Shipping Distance for Seaborne Coal Imports in Asia—Proposed Action (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	1.31	1.79	1.30	3.14	5.98	8.94	6.34
Australia	0	0	0	0	0	0	0
China	0	1.30	4.33	2.76	0	0	0.77
Hong Kong	0.67	0.87	0.50	1.45	1.17	1.62	1.42
India	0.61	6.32	6.31	14.93	27.88	47.05	31.74
Indonesia	0	0	0	0	0	0	0
Japan	6.42	7.15	8.05	7.33	2.31	2.06	3.61
South Korea	0.63	5.23	5.77	0.85	1.32	1.16	1.13
Taiwan	3.08	3.51	4.13	5.00	5.72	4.57	5.07
Total Asian Coal sent via ship	12.71	26.16	30.37	35.47	44.38	65.39	50.07

Table 6-53 shows the estimated change in tons of coal imported by each of the regions. The changes in coal imports between the No-Action Alternative and the Proposed Action generally mirror the changes in consumption, except for China and India. In China, the increase in consumption has a corresponding increase in imports only in 2025, because there is an increase in domestic production and a decrease in exports in 2030 and 2040. In India in 2040, coal consumption decreases by 3.2 million metric tons, while imports increase by 16.4 million metric tons. The increase in imports occurs because domestic production declines by 19.6 million metric tons.

Table 6-53. Upper Bound Scenario Change in Seaborne Coal Imports in Asia—Proposed Action minus No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	3.8	0	0	0	-2.9	-0.1	-1.0
Australia	0	0	0	0	0	0	0
China	0	0	0	34.1	0	0	9.5
Hong Kong	0	0	0	0	2.7	3.7	2.3
India	0	0	0	2.1	1.0	16.4	7.3
Indonesia	0	0	0	0	0	0	0
Japan	-2.1	0	0	-0.6	0.7	0.1	0.1
South Korea	0	0	0	0.1	0.5	0.1	0.2
Taiwan	0	0	0	1.4	0.1	0.7	0.7
Total Asian Coal sent via ship	1.7	0	0	37.2	2.0	21.0	19.2

The changes in the total tons of coal imported to each region are magnified or diminished depending on how the sources of the coal are shifting. There are some relatively large changes in the ton-mile values, as shown in Table 6-54.

Table 6-54. Upper Bound Scenario Change in Shipping Distance for Seaborne Coal Imports in Asia—Proposed Action minus No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	Annual Average
Asia - Other	0.08	0	0	0	0.49	0.15	0.22
Australia	0	0	0	0	0	0	0
China	0	0	0	2.76	0	0	0.77
Hong Kong	0	0	0	0.02	0.94	1.30	0.82
India	0	0	0	0.69	0.08	1.36	0.75
Indonesia	0	0	0	0	0	0	0
Japan	-0.85	0	0	-0.42	0.49	0	0.05
South Korea	0	0	0	0	0.38	0	0.13
Taiwan	0	0	0	0.27	0.18	0.90	0.49
Total Asian Coal sent via ship	-0.77	0	0	3.32	2.56	3.72	3.22

6.4.4 CO_2 Emissions

This section presents the CO_2 estimated emissions from coal combusted in the United States and Asia in the Upper Bound Scenario. In addition, CO_2 emissions from natural gas consumption in the United States are included because decreases in coal consumption may be offset by increases in natural gas consumption. Table 6-55 presents the CO_2 emissions under the No-Action Alternative. Total U.S. CO_2 emissions from coal are relatively flat and average 1,354.72 million metric tons between 2025 and 2040. Asian CO_2 emissions average 14,261.98 million metric tons per year between 2025 and 2040, which is 10.5 times the total coal CO_2 emissions from the United States. Natural gas CO_2 emissions average 580.17 million metric tons per year 2025-2040, or about 43% of U.S. coal CO_2 emissions. Between 2030 and 2040, CO_2 emissions from natural gas increase by 156 million metric tons, which is due to nuclear units retiring in this period and natural gas-fired generation replacing some of the retired nuclear generation.

Table 6-56 presents the CO_2 emissions under the Proposed Action. Total CO_2 emissions under the Proposed Action follow the same trends as under the No-Action Alternative, and are within 1% of the coal CO_2 emissions under the No-Action Alternative.

Table 6-55. Upper Bound Scenario CO_2 Emissions—No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	244.58	282.33	320.98	399.25	518.61	855.45	616.45
Australia	118.44	138.28	158.12	155.15	152.18	148.56	151.60
China	5,589.28	6,236.58	6,877.93	7,592.10	8,345.82	10,004.99	8,781.68
Hong Kong	28.52	31.03	34.25	40.47	48.21	66.90	53.33
India	972.05	1,309.81	1,653.09	2,201.02	2,871.67	4,856.98	3,457.45
Indonesia	239.49	254.42	269.84	312.64	362.34	486.83	396.95
Japan	218.36	250.15	281.46	308.43	341.53	390.25	351.28
South Korea	165.17	179.24	197.51	223.48	246.02	296.91	259.55
Taiwan	102.51	123.74	145.53	164.78	184.52	222.22	193.70
Asia - Coal	7,678.39	8,805.59	9,938.71	11,397.32	13,070.90	17,329.09	14,261.98
U.S. - Coal	1,238.76	1,219.12	1,347.26	1,373.73	1,323.74	1,367.69	1,354.72
U.S. - Natural Gas	547.39	512.32	465.88	493.60	529.59	685.36	580.17
Rest of World	1,748.36	2,079.77	2,418.77	2,522.91	2,635.50	3,066.29	2,771.75

Table 6-56. Upper Bound Scenario CO_2 Emissions—Proposed Action (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	244.58	282.33	320.98	399.25	517.88	855.43	616.20
Australia	118.44	138.28	158.12	155.15	152.18	148.56	151.60
China	5,589.28	6,236.58	6,877.93	7,641.77	8,394.99	10,054.15	8,830.99
Hong Kong	28.52	31.03	34.25	40.51	48.43	67.19	53.53
India	972.05	1,309.81	1,653.09	2,203.54	2,873.81	4,858.35	3,459.39
Indonesia	239.49	254.42	269.84	312.64	362.34	486.83	396.95
Japan	217.69	250.15	281.46	309.27	342.00	390.57	351.80
South Korea	165.17	179.24	197.51	223.71	246.36	297.14	259.82
Taiwan	102.51	123.74	145.53	165.67	184.96	222.60	194.24
Asia - Coal	7,677.72	8,805.59	9,938.71	11,451.51	13,122.93	17,380.84	14,314.50
U.S. - Coal	1,237.69	1,219.11	1,347.24	1,373.76	1,323.76	1,367.83	1,354.79
U.S.- Natural Gas	547.79	512.32	465.88	493.56	529.57	685.36	580.15
Rest of World	1,748.36	2,079.77	2,418.77	2,522.91	2,635.50	3,066.29	2,771.75

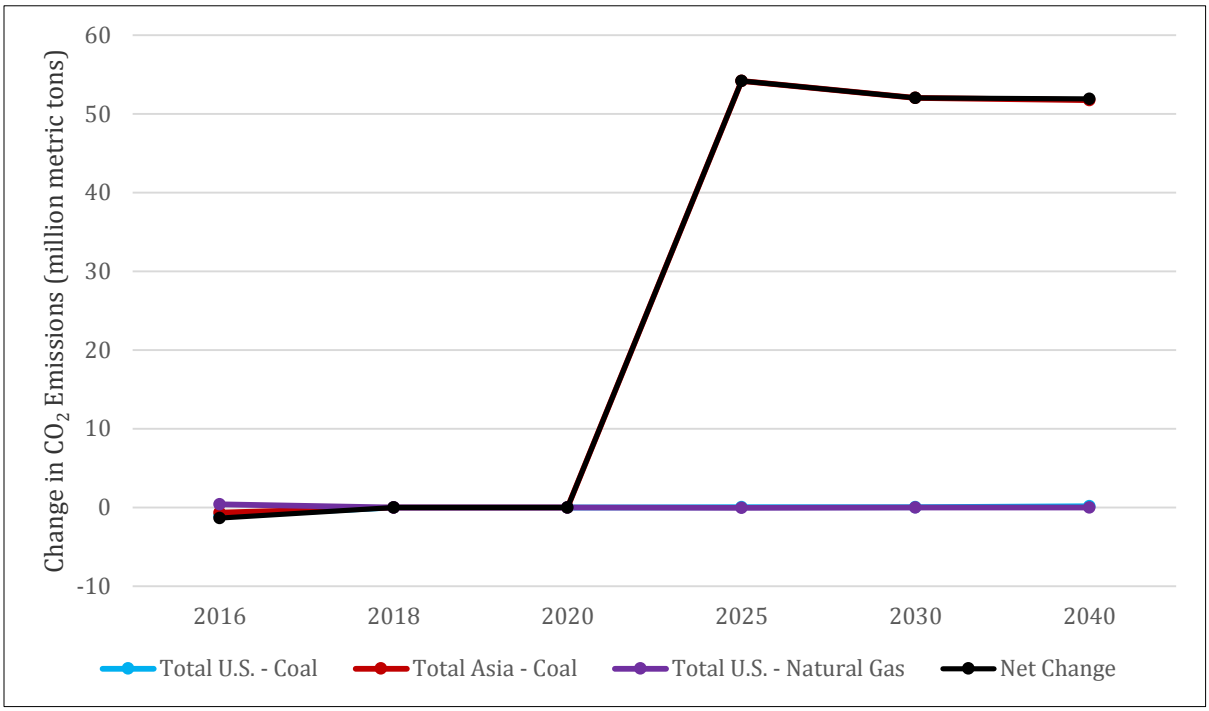
Table 6-57 shows the estimated change in CO_2 emissions for each region, as well as the total net change across all regions. Total Asian CO_2 emissions from coal consumption would increase an average of 52.52 million metric tons per year between 2025 and 2040, , due to induced demand from the reduction in delivered coal prices under the Proposed Action and because of shifts in the type of coal consumed.

Table 6-57. Upper Bound Scenario Changes in CO_2 Emissions—Proposed Action minus No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0	0	0	0	-0.73	-0.02	-0.25
Australia	0	0	0	0	0	0	0
China	0	0	0	49.68	49.17	49.17	49.31
Hong Kong	0	0	0	0.04	0.22	0.29	0.20
India	0	0	0	2.52	2.14	1.37	1.95
Indonesia	0	0	0	0	0	0	0
Japan	-0.67	0	0	0.84	0.47	0.32	0.52
South Korea	0	0	0	0.23	0.33	0.23	0.26
Taiwan	0	0	0	0.89	0.43	0.38	0.54
Asia - Coal	-0.67	0	0	54.19	52.03	51.75	52.52
U.S. - Coal	-1.07	-0.01	-0.02	0.03	0.02	0.14	0.07
U.S. - Natural Gas	0.39	0	0	-0.03	-0.02	0	-0.02
Rest of World	0	0	0	0	0	0	0
Total Change	-1.35	-0.01	-0.02	54.19	52.04	51.89	52.58

In the Upper Bound Scenario the change in coal combustion emissions between the No-Action Alternative and Proposed Action would fluctuate for both Asia and the United States. Figure 6-11 shows the net change in CO_2 emissions between the No-Action Alternative and Proposed Action. The increase in Asian coal emissions would be the main driver of the net positive change to CO_2 emissions under the Proposed Action.

Figure 6-11. Upper Bound Scenario Changes in CO_2 Emissions by Region—Proposed Action minus No-Action Alternative[a,b,c]



a Total U.S. CO_2 emissions from the combustion of coal are close to zero because the proposed coal export terminal would not affect coal prices enough to cause a change in coal consumption.

b Asian CO_2 emissions from the combustion of coal increase primarily due to induced demand from the lower delivered coal prices when the proposed terminal fully comes online in 2025, and also due to a larger quantity of lower heat content coal being consumed.

c Total U.S. natural gas combustion CO_2 emissions are near zero because coal consumption in the United States only changes slightly.

6.5 2015 U.S. and International Energy Policy Scenario

The 2015 U.S. and International Energy Policy Scenario uses the assumptions presented in Chapter 5, *Scenarios*, and is intended to represent a scenario in which the United States and other countries have implemented policies to reduce GHG emissions. These policies would also reduce coal consumption, and thus production, especially in the long term. This section presents the modeling results for the 2015 U.S. and International Energy Policy Scenario No-Action Alternative and Proposed Action for coal production, consumption, distribution, and CO_2 emissions.

6.5.1 Coal Production

Under the No-Action Alternative U.S. thermal coal production would average 672 million metric tons per year from 2025 to 2040. Annual U.S. coal production would initially increases through 2020 and then decline by 53 million metric tons by 2040 because the climate policies would drive down coal demand. Coal production would increase to support increasing exports. Over the 2016 to 2040 period, non-U.S. coal production would grow at an average annual rate of 1.3% per year from 4,513 to 6,148 million metric tons. Powder River Basin coal production under the No-Action Alternative

would average 250 million metric tons per year over 2025 to 2040. Uinta Basin coal production under the No-Action Alternative would average7.6 million metric tons per year. Table 6-58 shows the No-Action Alternative coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-58. 2015 U.S. and International Energy Policy Scenario Coal Production—No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,513	4,981	5,534	5,674	5,865	6,148	5,922
Total U.S. Thermal Coal	638	662	700	700	677	647	672
Powder River Basin Coal	318	293	309	290	250	222	250
Uinta Basin Coal	7.6	6.8	6.8	5.8	9.0	7.6	7.6

Under the Proposed Action, U.S. thermal coal production would average 715 million metric tons per year for the 2025 to 2040 period. As with the No-Action Alternative, U.S. coal production would decline between 2025 and 2040. Non-U.S. coal production would follow the same growth rate under the Proposed Action as it would under the No-Action Alternative, except production would decline by 36 to 41 million metric tons per year once the proposed terminal is fully online in 2025. Thus, the coal exported from the proposed terminal would displace some coal production in other countries. Powder River Basin coal production under the Proposed Action would average 290 million metric tons per year for the 2025 to 2040 period. Uinta Basin coal production would average 10.2 million metric tons per year. Table 6-59 shows the Proposed Action coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-59. 2015 U.S. and International Energy Policy Scenario Coal Production—Proposed Action (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,513	4,981	5,535	5,633	5,827	6,113	5,884
Total U.S. Thermal Coal	638	660	698	745	720	690	715
Powder River Basin Coal	318	290	307	334	293	256	290
Uinta Basin Coal	7.3	6.8	6.8	6.4	8.2	14.6	10.2

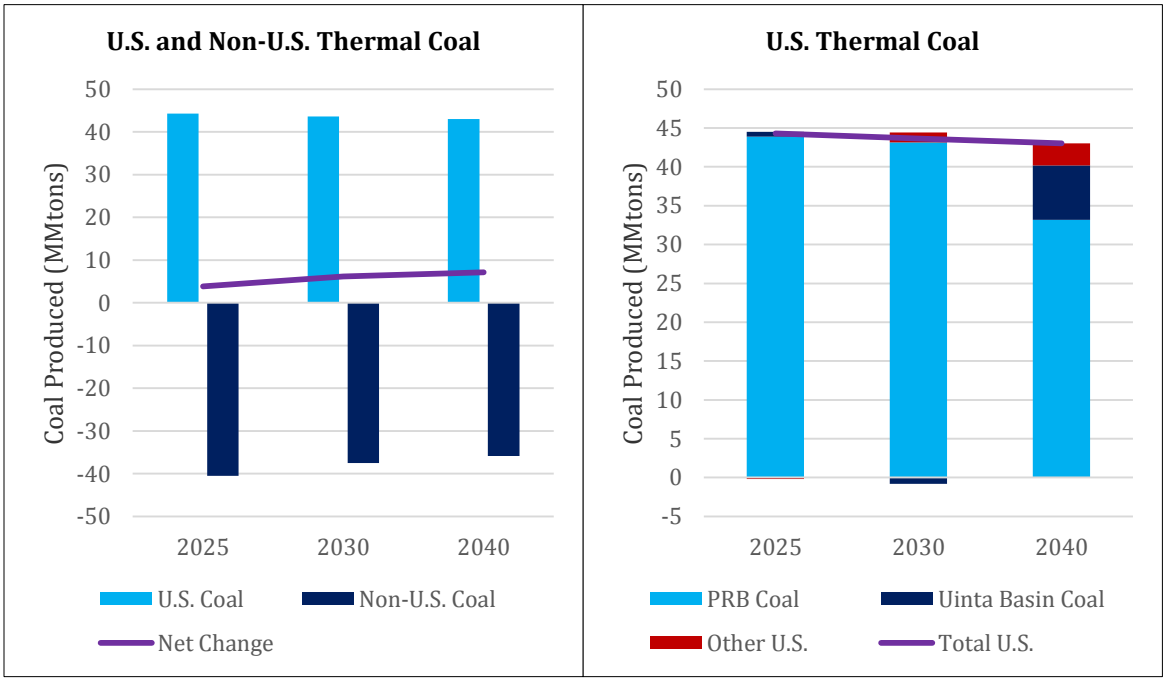
Table 6-60 shows the estimated change in coal production between the Proposed Action and the No-Action Alternative by model run year. Assuming the proposed terminal is online and exporting coal, total modeled U.S. coal production would be higher under the Proposed Action, primarily due to increases in Powder River Basin and the Uinta Basin.

Table 6-60. 2015 U.S. and International Energy Policy Scenario Change in Coal Production—Proposed Action minus No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	0.4	0	1.2	-40.5	-37.5	-35.9	-37.7
Total U.S. Thermal Coal	-0.6	-2.3	-2.1	44.3	43.6	43.0	43.6
Powder River Basin Coal	-0.3	-2.7	-2.3	43.9	43.2	33.2	39.5
Uinta Basin Coal	-0.3	0	0	0.6	-0.8	7.0	2.6

Figure 6-12 shows that total non-U.S. thermal coal production would decrease in proportion to the increase in U.S. coal production under the Proposed Action. The difference in the changes of U.S. and non-U.S. coal production are because the increase in U.S. coal production would be lower heat content subbituminous coal and the decrease in non-U.S. coal production would be higher heat content bituminous coal.

Figure 6-12. 2015 U.S. and International Energy Policy Scenario Change in Coal Production—Proposed Action minus No-Action Alternative



6.5.2 Coal Consumption

In the 2015 U.S. and International Energy Policy Scenario, under the No-Action Alternative U.S. thermal coal consumption would average 548 million metric tons per year for the 2025 to 2040 period. U.S. coal consumption would fluctuate around 610 million metric tons between 2016 and 2025 before it would decline steeply through 2040, as electric demand growth is primarily met with natural gas and renewable generation. Over the 2016 to 2040 period, Asian coal consumption would grow at an average rate of 1.9% per year from 3,399 to 5,294 million metric tons. The growth in consumption is driven by increasing coal consumption in China and India. Tables 6-61 and 6-62 show the No-Action Alternative coal consumption values for each model run year.

Table 6-61. 2015 U.S. and International Energy Policy Scenario Coal Consumption—No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	121	135	160	161	188	202	186
Australia	104	113	121	118	116	108	113
China	2,269	2,479	2,689	2,747	2,803	2,732	2,760
Hong Kong	14	15	16	14	15	16	15
India	543	682	849	1,058	1,317	1,857	1,455
Indonesia	138	139	147	151	163	181	167
Japan	94	111	123	105	103	86	97
South Korea	70	80	86	70	63	44	57
Taiwan	46	54	63	62	71	69	67
Total Asian Coal Consumption	3,399	3,809	4,253	4,485	4,837	5,294	4,917
Total U.S. Coal Consumption	623	594	617	612	561	492	548
Rest of World Coal Consumption	1,130	1,243	1,367	1,280	1,145	1,010	1,130

Table 6-62. 2015 U.S. and International Energy Policy Scenario Coal Consumption—No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025-2040 Average
Asia - Other	2,603	2,904	3,205	3,380	3,593	3,882	3,646
Australia	1,268	1,454	1,640	1,519	1,436	1,194	1,365
China	57,999	63,331	68,639	69,967	71,090	68,476	69,761
Hong Kong	303	325	347	366	389	420	395
India	10,213	13,382	16,549	19,999	24,655	33,846	26,936
Indonesia	2,486	2,485	2,484	2,619	2,785	3,008	2,826
Japan	2,337	2,620	2,900	2,731	2,689	2,274	2,539
South Korea	1,716	1,866	2,016	1,784	1,617	1,152	1,483
Taiwan	1,091	1,290	1,489	1,571	1,673	1,802	1,695
Total Asian Coal Consumption	80,016	89,658	99,269	103,936	109,927	116,055	110,646
Total U.S. Coal Consumption	12,830	12,230	12,704	12,486	11,534	10,003	11,203
Rest of World Coal Consumption	18,358	21,217	24,081	22,656	20,740	20,060	21,008

China is responsible for the largest share of global thermal coal consumption, burning 2,269 million metric tons of coal in 2016. This amount is projected to grow in the 2015 U.S. and International Energy Policy Scenario No-Action Alternative to 2,732 million metric tons by 2040. Under the 2015 U.S. and International Energy Policy Scenario, the growth in coal demand in countries in Asia would be the same as the No-Action Alternative.

Coal consumption under the Proposed Action would follow similar patterns as the No-Action Alternative, with U.S. thermal coal consumption averaging 548 million metric tons per year for the 2025 to 2040 period.

Over the 2016 to 2040 period, Asian coal consumption would follow the same pattern as the No-Action Alternative, growing from 3,399 to 5,303 million metric tons. Tables 6-63 and 6-64 show the Proposed Action coal consumption values for each model run year, in units of million metric tons and TBtu, respectively. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-63. 2015 U.S. and International Energy Policy Scenario Coal Consumption—Proposed Action (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	121	135	160	156	188	202	184
Australia	104	113	121	118	116	108	113
China	2,269	2,479	2,689	2,749	2,804	2,732	2,761
Hong Kong	14	15	16	16	17	18	17
India	543	682	849	1,058	1,317	1,857	1,455
Indonesia	138	139	147	151	163	181	167
Japan	94	111	123	106	104	88	98
South Korea	70	80	86	71	64	45	59
Taiwan	46	54	63	65	72	72	70
Total Asian Coal Consumption	3,399	3,809	4,253	4,488	4,844	5,303	4,923
Total U.S. Coal Consumption	623	592	616	613	561	491	548
Rest of World Coal Consumption	1,130	1,243	1,367	1,280	1,145	1,010	1,130

Table 6-64. 2015 U.S. and International Energy Policy Scenario Coal Consumption—Proposed Action (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	2,603	2,904	3,205	3,380	3,593	3,882	3,646
Australia	1,268	1,454	1,640	1,519	1,436	1,194	1,365
China	57,999	63,331	68,639	69,967	71,090	68,476	69,761
Hong Kong	303	325	347	366	389	420	395
India	10,213	13,382	16,549	19,999	24,655	33,846	26,936
Indonesia	2,486	2,485	2,484	2,619	2,785	3,008	2,826
Japan	2,337	2,620	2,900	2,731	2,689	2,274	2,539
South Korea	1,716	1,866	2,016	1,784	1,617	1,152	1,483
Taiwan	1,091	1,290	1,489	1,571	1,673	1,802	1,695
Total Asian Coal Consumption	80,016	89,658	99,269	103,936	109,927	116,055	110,646
Total U.S. Coal Consumption	12,823	12,198	12,690	12,471	11,524	9,999	11,194
Rest of World Coal Consumption	18,363	21,217	24,081	22,656	20,742	20,060	21,009

Tables 6-65 and 6-66 show the estimated change in coal consumption between the Proposed Action and the No-Action Alternative by model run year in units of million metric tons and TBtu, respectively. Assuming the proposed terminal is online and exporting coal, total Asian coal consumption would be higher with an average of 6.1 million metric tons between 2025 and 2040. The changes in consumption would be due to changes in the mix of coal consumed and the differences in heat content of the coal being consumed. In contrast, U.S. coal consumption would be slightly down at an average of 0.3 million metric tons per year over the 2025 to 2040 period under the Proposed Action. The reduction in U.S. coal consumption is due to both changes in the mix of coal consumed as well as a 0.08% decline in overall coal consumption.

In general, the change in the mix of coals consumed increases the tons of coal consumed in Asia. One exception is in 2025 for the Asia – Other coal demand region, which has a decrease in the tons of coal consumed by 4.8 million metric tons. The tons of coal consumed in the Asia – Other demand coal region decrease because it is switching from Indonesian subbituminous coal to Indonesian bituminous coal, which has a higher heat content and thus fewer tons are needed to achieve the same heating value. The switch to Indonesian bituminous coal is economic: both Hong Kong and Taiwan consume less Indonesian bituminous coal because they are both importing Montana Powder River Basin coal through the proposed coal export terminal.

Table 6-65. 2015 U.S. and International Energy Policy Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia – Other	0	0	0	-4.8	0	0	-1.3
Australia	0	0	0	0	0	0	0
China	0	0	-0.2	1.3	1.2	0	0.7
Hong Kong	0	0	0	1.8	2.1	2.2	2.0
India	0	0	0.2	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0.9	0.9	1.3	1.0
South Korea	0	0	0	1.4	0.7	1.6	1.2
Taiwan	0	0	0	2.5	1.6	3.1	2.4
Total Asian Coal Consumption	0	0	0	3.0	6.4	8.1	6.1
Total U.S. Coal Consumption	-0.4	-1.8	-1.0	0.7	-0.3	-0.9	-0.3
Rest of World Coal Consumption	0	0	0	0	0	0	0

Table 6-66. 2015 U.S. and International Energy Policy Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia – Other	0	0	0	0	0	0	0
Australia	0	0	0	0	0	0	0
China	0	0	0	0	0	0	0
Hong Kong	0	0	0	0	0	0	0
India	0	0	0	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0	0	0	0
South Korea	0	0	0	0	0	0	0
Taiwan	0	0	0	0	0	0	0
Total Asian Coal Consumption	0	0	0	0	0	0	0
Total U.S. Coal Consumption	-7	-31	-14	-14	-10	-5	-9
Rest of World Coal Consumption	5	0	0	0	2	0	1

6.5.3 Coal Distribution

In the 2015 U.S. and International Energy Policy Scenario, as with the No Clean Power Plan Scenario, distribution patterns for Powder River Basin and Uinta Basin coal are expected to remain largely unchanged under the Proposed Action. Thus, this section focuses on the distribution of coal in Asia and how that distribution would be expected to change with the construction of the proposed

terminal. Under the No-Action Alternative, no coal would be exported through the proposed terminal; however, there would be 317 million metric tons of coal distributed in Asia by ship in the seaborne coal market in 2016. Table 6-67 shows the tons of coal that would be imported by each country in Asia under the No-Action Alternative. By 2040, 409 million metric tons of coal are estimated to be distributed in the seaborne coal market in Asia.

Table 6-67. 2015 U.S. and International Energy Policy Scenario Seaborne Coal Imports in Asia—No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	83	95	118	141	180	194	175
Australia	0	0	0	0	0	0	0
China	0	10	36	0	0	0	0
Hong Kong	14	15	16	14	15	16	15
India	10	94	101	47	33	0	24
Indonesia	0	0	0	0	0	0	0
Japan	94	111	123	105	103	86	97
South Korea	70	80	86	70	63	44	57
Taiwan	46	54	63	62	71	69	67
Total Asian Coal sent via ship	317	460	542	439	465	409	436

To understand how coal distribution is changing in more detail than the tons of coal imported by each country, the tons of coal shipped to each country were multiplied by the distance in nautical miles that the coal is shipped and then divided by an average ship size. The change in tons imported might not change significantly; however, where the coal is sourced might change, which can have a significant impact on the emissions associated with shipping. Table 6-68 shows the shipping miles for coal shipped to each country for the No-Action Alternative.

Table 6-68. 2015 U.S. and International Energy Policy Scenario Shipping Distance for Seaborne Coal Imports in Asia—No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	0.50	0.69	2.00	2.63	3.47	3.78	3.36
Australia	0	0	0	0	0	0	0
China	0	0.26	0.99	0	0	0	0
Hong Kong	0.41	0.45	0.48	0.42	0.18	0.19	0.25
India	0.45	4.39	4.72	2.20	1.56	0	1.13
Indonesia	0	0	0	0	0	0	0
Japan	4.41	7.02	7.77	1.40	1.38	1.15	1.30
South Korea	1.92	4.51	5.52	0.66	0.59	0.43	0.55
Taiwan	2.89	3.42	3.95	2.25	4.76	0.57	2.43
Total Asian Coal sent via ship	10.57	20.75	25.42	9.55	11.94	6.13	9.02

Under the Proposed Action, coal would be exported through the terminal to destinations in Asia. Table 6-69 shows the distribution of the coal exported from the proposed terminal. The distribution of the exported coal is similar to the distribution under the No Clean Power Plan Scenario.

Table 6-69. 2015 U.S. and International Energy Policy Scenario Distribution of Coal Exported through the Coal Export Terminal—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040
China	0	0	0	4.8	5.4	0
Hong Kong	0	0	0	8.8	9.4	10.1
Japan	0	0	0	7.3	7.2	5.8
South Korea	0	0	0	11.7	10.0	7.1
Taiwan	0	0	0	11.4	12.0	21.0
Total Asian Coal sent via ship through the proposed Terminal	0	0	0	44.0	44.0	44.0

Under the Proposed Action, a similar number of tons would be distributed in the seaborne coal market as it would under the No-Action Alternative. Table 6-70 shows the tons of coal that would be imported by each country in Asia under the Proposed Action. The distance weighted coal distribution in Asia is presented in Table 6-71 for the Proposed Action.

Table 6-70. 2015 U.S. and International Energy Policy Scenario Seaborne Coal Imports in Asia—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	83	95	118	137	180	194	174
Australia	0	0	0	0	0	0	0
China	0	10	36	5	5	0	3
Hong Kong	14	15	16	16	17	18	17
India	10	94	100	47	33	0	24
Indonesia	0	0	0	0	0	0	0
Japan	94	111	123	106	104	88	98
South Korea	70	80	86	71	64	45	59
Taiwan	46	54	63	65	72	72	70
Total Asian Coal sent via ship	317	460	542	446	476	417	445

Table 6-71. 2015 U.S. and International Energy Policy Scenario Shipping Distance for Seaborne Coal Imports in Asia—Proposed Action (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Avg.
Asia - Other	0.50	0.69	2.00	2.53	3.47	3.78	3.33
Australia	0	0	0	0	0	0	0
China	0	0.26	0.93	0.39	0.44	0	0.25
Hong Kong	0.41	0.45	0.48	0.98	0.91	0.98	0.95
India	0.45	4.39	4.69	2.20	1.56	0	1.13
Indonesia	0	0	0	0	0	0	0
Japan	4.41	7.02	7.77	1.80	1.77	1.48	1.66
South Korea	1.92	4.51	5.52	1.38	1.21	0.86	1.12
Taiwan	2.89	3.42	3.95	3.00	5.11	2.17	3.38
Total Asian Coal sent via ship	10.57	20.75	25.34	12.27	14.47	9.27	11.84

As seen in Table 6-72, which shows the estimated change in tons of coal imported by each of the regions, the changes in coal imports between the No-Action Alternative and the Proposed Action would mirror the changes in consumption, except for China. The change in imports of coal to China would be due to the coal imported from the United States displacing coal produced in China that has a different heat content. So the amount of coal consumed on a tonnage basis changes slightly, while the amount of coal consumed on a heating value basis does not change.

Table 6-72. 2015 U.S. and International Energy Policy Scenario Change in Seaborne Coal Imports in Asia—Proposed Action minus No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	-4.8	0	0	-1.3
Australia	0	0	0	0	0	0	0
China	0	0	-0.2	4.8	5.4	0	3.1
Hong Kong	0	0	0	1.8	2.1	2.2	2.0
India	0	0	-0.6	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0.9	0.9	1.3	1.0
South Korea	0	0	0	1.4	0.7	1.6	1.2
Taiwan	0	0	0	2.5	1.6	3.1	2.4
Total Asian Coal sent via ship	0	0	-0.9	6.6	10.7	8.1	8.5

The changes in the total tons of coal imported to each region would be magnified or diminished depending on how the sources of the coal shift. Table 6-73 shows the change in the total shipping distance traveled to deliver coal imported in Asia. The change in the distance coal is shipped to the Asia – Other coal demand region decreases because of the switch from Indonesian subbituminous coal to Indonesian bituminous coal, which has a higher heat content. The shipping distance in 2040 to Taiwan increases over earlier years because less coal is shipped from nearby China and more coal is shipped from the proposed coal export terminal.

Table 6-73. 2015 U.S. and International Energy Policy Scenario Change in Shipping Distance for Seaborne Coal Imports in Asia—Proposed Action minus No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	Annual Average
Asia - Other	0	0	0	-0.10	0	0	-0.03
Australia	0	0	0	0	0	0	0
China	0	0	-0.05	0.39	0.44	0	0.25
Hong Kong	0	0	0	0.56	0.73	0.78	0.70
India	0	0	-0.03	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0.40	0.39	0.32	0.37
South Korea	0	0	0	0.73	0.62	0.43	0.58
Taiwan	0	0	0	0.75	0.35	1.60	0.95
Total Asian Coal sent via ship	0	0	-0.08	2.72	2.53	3.15	2.82

6.5.4 CO_2 Emissions

This section presents the CO_2 estimated emissions from coal combusted in the United States and Asia in the 2015 U.S. and International Energy Policy Scenario. In addition, CO_2 emissions from natural gas consumption in the United States are included because decreases in coal consumption may be offset by increases in natural gas consumption.

Table 6-74 presents the CO_2 emissions under the No-Action Alternative. Total U.S. CO_2 emissions from coal would increase through 2020 and then decline gradually as the Clean Power Plan implementation ramps up, and would average 1,053.02 million metric tons per year between 2025 and 2040. Asian CO_2 emissions would average 10,624.60 million metric tons per year between 2025 and 2040, which would be 10.1 times the total coal CO_2 emissions from the U.S. Natural gas CO_2 emissions average 559.85 million metric tons per year, or about one-half of coal CO_2 emissions. Between 2030 and 2040, CO_2 emissions from natural gas would increase by 152.81 million metric tons. This increase would be due to nuclear units retiring in this period and natural gas-fired generation replacing some of the retired nuclear generation.

Table 6-75 presents the CO_2 emissions under the Proposed Action. Total CO_2 emissions under the Proposed Action would follow the same trends as under the No-Action Alternative.

Table 6-74. 2015 U.S. and International Energy Policy Scenario CO_2 Emissions—No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	249.64	278.72	310.38	320.48	349.95	378.15	352.73
Australia	118.44	135.82	153.19	141.84	134.07	111.44	127.43
China	5,589.28	6,102.76	6,611.38	6,743.76	6,853.22	6,604.62	6,726.13
Hong Kong	28.25	30.85	32.70	33.80	37.44	40.45	37.60
India	971.98	1,267.46	1,568.87	1,901.31	2,345.49	3,221.25	2,562.68
Indonesia	239.90	239.57	239.23	251.81	267.30	287.63	270.90
Japan	217.62	245.55	271.77	262.82	258.78	218.86	244.38
South Korea	161.27	174.53	189.04	171.69	155.66	110.91	142.71
Taiwan	101.94	120.56	139.17	145.46	156.51	173.47	160.04
Asia- Coal	7,678.31	8,595.82	9,515.72	9,972.97	10,558.42	11,146.77	10,624.60
U.S. - Coal	1,207.73	1,150.40	1,195.32	1,174.92	1,084.13	939.28	1,053.02
U.S. - Natural Gas	555.31	538.48	504.98	491.49	503.86	656.67	559.85
Rest of World	1,755.17	2,022.91	2,293.97	2,156.41	1,973.24	1,902.58	1,996.64

Table 6-75. 2015 U.S. and International Energy Policy Scenario CO_2 Emissions—Proposed Action (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	249.64	278.72	310.38	318.40	349.95	378.15	352.15
Australia	118.44	135.82	153.19	141.84	134.07	111.44	127.43
China	5,589.28	6,102.76	6,611.34	6,743.64	6,853.30	6,604.62	6,726.13
Hong Kong	28.25	30.85	32.70	34.64	37.58	40.60	37.94
India	971.98	1,267.46	1,568.92	1,901.31	2,345.49	3,221.25	2,562.68
Indonesia	239.90	239.57	239.23	251.81	267.30	287.63	270.90
Japan	217.62	245.55	271.77	262.65	258.62	218.95	244.31
South Korea	161.27	174.53	189.04	171.43	155.83	111.01	142.73
Taiwan	101.94	120.56	139.17	146.41	157.38	173.17	160.47
Asia- Coal	7,678.31	8,595.82	9,515.73	9,972.12	10,559.51	11,146.82	10,624.74
U.S. - Coal	1,207.05	1,147.60	1,193.91	1,173.24	1,083.16	938.90	1,052.08
U.S.- Natural Gas	555.51	539.62	505.18	491.49	503.97	656.69	559.89
Rest of World	1,755.61	2,022.92	2,293.97	2,156.41	1,973.45	1,902.58	1,996.71

Table 6-76 shows the estimated change in CO_2 emissions for each region, as well as the total net change across all regions between the No-Action Alternative and Proposed Action. Total Asian CO_2 emissions from coal consumption would increase on average 0.15 million metric tons per year from 2025 to 2040, due to shifts in the type of coal consumed, where the different coal types have different CO_2 emissions rates. In contrast, U.S. coal CO_2 emissions would decrease in every year and average 0.94 million metric tons per year over 2025 to 2040. The decrease in coal consumption would be somewhat offset by an increase in natural gas consumption, as is seen by the increase in CO_2 emissions from natural gas, which would average 0.05 million metric tons per year between 2025 and 2040. The total net change in CO_2 emissions would be a decrease of an average of 0.75 million metric tons per year between 2025 and 2040.

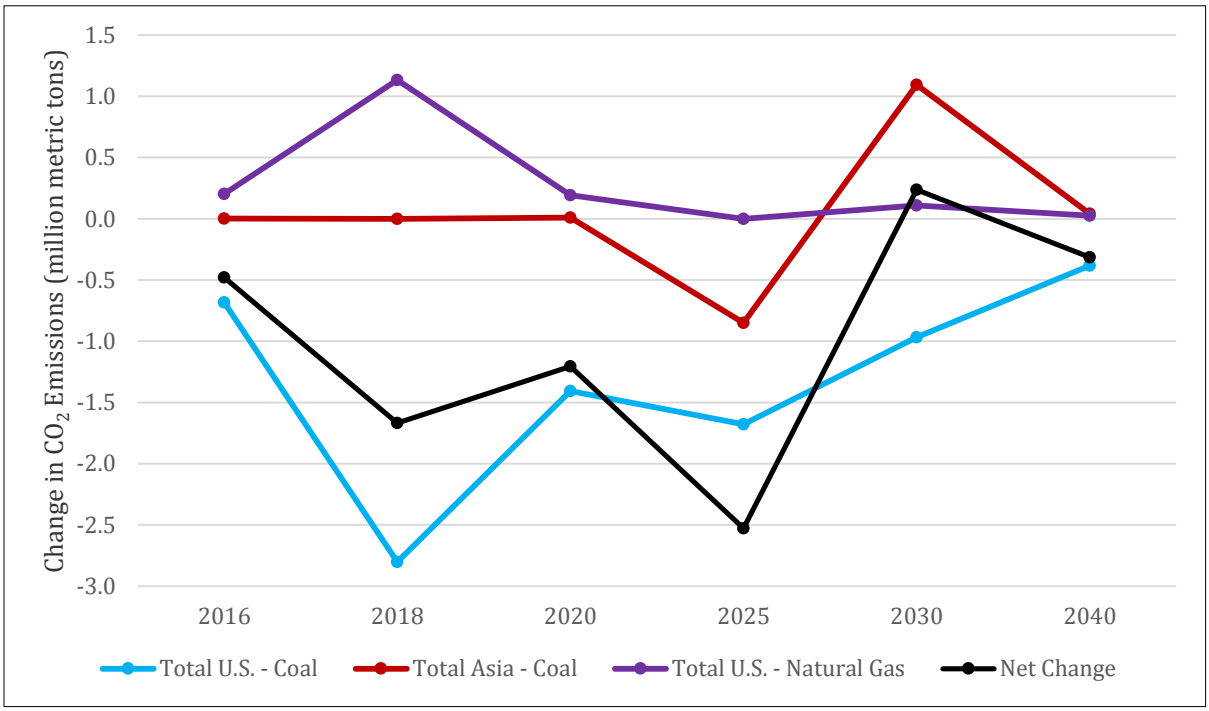
The CO_2 emissions from the Asia – Other coal demand region decrease because fewer tons of coal are consumed due to a switch from subbituminous to bituminous coal and because the bituminous coal has a lower CO_2 emissions rate. For all other regions, coal consumption increases on a tonnage basis; however, CO_2 emissions decrease in some years for China, Japan, South Korea, and Taiwan. A decrease in CO_2 emissions is possible when more coal is consumed if the coal has a lower CO_2 emissions rate in those years.

Table 6-76. 2015 U.S. and International Energy Policy Scenario Changes in CO_2 Emissions—Proposed Action minus No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0	0	0	-2.08	0	0	-0.58
Australia	0	0	0	0	0	0	0
China	0	0	-0.04	-0.12	0.08	0	-0.01
Hong Kong	0	0	0	0.83	0.14	0.15	0.34
India	0	0	0.05	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	-0.17	-0.16	0.09	-0.07
South Korea	0	0	0	-0.27	0.17	0.11	0.02
Taiwan	0	0	0	0.95	0.87	-0.30	0.44
Asia- Coal	0	0	0.01	-0.85	1.09	0.04	0.15
U.S. - Coal	-0.68	-2.80	-1.41	-1.68	-0.97	-0.38	-0.94
U.S. - Natural Gas	0.20	1.13	0.19	0	0.11	0.02	0.05
Rest of World	0.45	0.01	0	0	0.21	0	0.07
Total Change	-0.48	-1.67	-1.21	-2.53	0.24	-0.31	-0.75

Emissions of CO_2 from coal combustion in the United States would decline in general throughout the forecast horizon. U.S. emissions from natural gas tend to move in the opposite direction as emissions from coal. Figure 6-13 shows the net change in CO_2 emissions between the No-Action Alternative and Proposed Action. In the long term, the decrease in U.S. coal emissions would drive a net decrease in CO_2 emissions under the Proposed Action.

Figure 6-13. 2015 U.S. and International Energy Policy Scenario Changes in CO_2 Emissions by Region—Proposed Action minus No-Action Alternative



[a] Total U.S. CO_2 emissions from the combustion of coal decrease through 2040 because the proposed coal export terminal would be a new demand sink for U.S. coal, and thus, would cause coal prices to rise and U.S. coal consumption to decrease in response to the higher prices.

[b] Asian CO_2 emissions from the combustion of coal would increase due to a larger quantity of lower heat content coal being consumed.

[c] Total U.S. natural gas combustion CO_2 emissions generally would increase and decrease in response to the changes in coal consumption.

6.6 Cumulative Scenario

The Cumulative Scenario is the same as the No Clean Power Plan Scenario, except that all of the proposed export terminals in the Pacific Northwest would be constructed and online by 2030 at the latest, and operating at full capacity. This section presents the modeling results for the Cumulative Scenario No-Action Alternative and Proposed Action for coal production, consumption, distribution, and CO_2 emissions. Note that the Cumulative Scenario No-Action Alternative is the same as the No Clean Power Plan Scenario No-Action Alternative.

6.6.1 Coal Production

Under the No-Action Alternative U.S. thermal coal production would average 813 million metric tons per year for the 2025 to 2040 period. Over the 2016 to 2040 period, non-U.S. coal production would grow at an average annual rate of 2.4% per year from 4,510 to 7,887 million metric tons. Powder River Basin coal production under the No-Action Alternative would average 311 million metric tons per year over 2016 to 2040, with production remaining relatively flat. Uinta Basin coal production under the No-Action Alternative would average 13.6 million metric tons per year, with production gradually increasing over the 2016 to 2040 period.

Table 6-77 shows the No-Action Alternative coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-77. Cumulative Scenario Coal Production—No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,510	5,115	5,806	6,304	6,839	7,887	7,098
Total U.S. Thermal Coal	628	673	752	773	790	861	813
Powder River Basin Coal	310	286	324	329	292	313	311
Uinta Basin Coal	7.0	7.9	8.5	10.6	14.4	15.0	13.6

Under the Proposed Action, U.S. thermal coal production would average 904 million metric tons per year for the 2025 to 2040 period. U.S. coal production would have an upward trend as production increases to meet the increased exports. Non-U.S. coal production would have a slightly lower annual growth rate of 2.3% under the Proposed Action than the No-Action Alternative, because some of the exported coal displaces some international coal production. Powder River Basin coal production under the Proposed Action would average 400 million metric tons per year with production generally increasing over time. Uinta Basin coal production would average 13.6 million metric tons per year. Table 6-78 shows the Proposed Action coal production values for each model run year. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-78. Cumulative Scenario Coal Production—Proposed Action (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	4,512	5,114	5,799	6,260	6,756	7,814	7,029
Total U.S. Thermal Coal	628	674	759	827	895	966	904
Powder River Basin Coal	309	286	330	382	396	416	400
Uinta Basin Coal	7.0	7.9	8.5	10.6	14.4	15.0	13.6

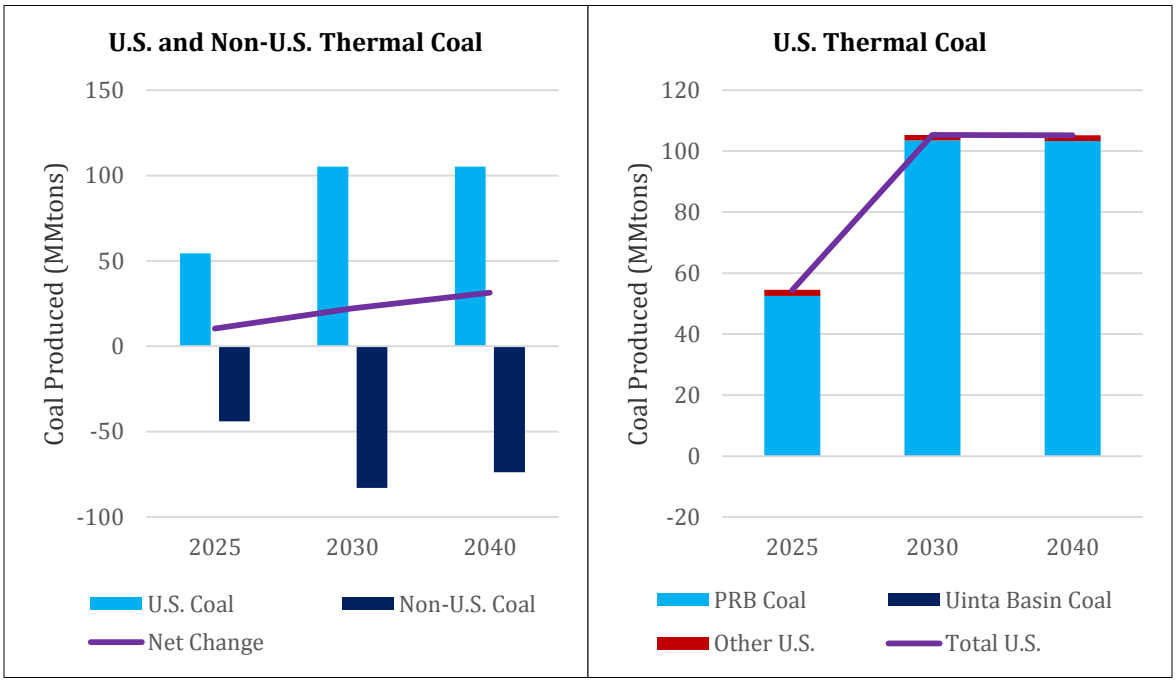
Table 6-79 shows the estimated change in coal production between the Proposed Action and the No-Action Alternative by model run year. Since IPM® is forward–looking and solves all years simultaneously, the model shows that there would be changes to production under the Proposed Action before the terminal is modeled to fully come online in 2025. The changes in coal production prior to 2025 reflect the model optimizing the overall solution based on what it calculates will be happening in the future. Once the proposed terminal is fully online and exporting coal, total average modeled U.S. coal production would be higher under the Proposed Action by 91.1 million metric tons per year, primarily due to increases in Powder River Basin coal production.

Table 6-79. Cumulative Scenario Change in Coal Production—Proposed Action minus No-Action Alternative (million metric tons)

Producing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Total Non-U.S. Thermal Coal	2.0	-1.0	-6.1	-44.0	-83.0	-73.8	-68.6
Total U.S. Thermal Coal	0.6	0.9	7.0	54.4	105.2	105.1	91.1
Powder River Basin Coal	-0.2	0.1	6.5	52.5	103.5	103.3	89.2
Uinta Basin Coal	0	0	0	<-0.05	<-0.05	<0.05	<-0.05

Figure 6-14 shows that total non-U.S. thermal coal production would decrease as U.S. coal production increases under the Proposed Action. This indicates that U.S. thermal coal exports would displace of some internationally produced coal, instead of just adding to overall global coal demand.

Figure 6-14. Cumulative Scenario Change in Coal Production—Proposed Action minus No-Action Alternative



6.6.2 Coal Consumption

Under the No-Action Alternative U.S. thermal coal consumption would average 671 million metric tons per year for the 2025 to 2040 period. U.S. coal consumption would increase through 2020 and then be fairly flat through 2040, as electric demand growth would be primarily met with natural gas and renewable generation. Over the 2016 to 2040 period, Asian coal consumption would grow at an average rate of 2.9% per year from 3,395 to 6,679 million metric tons. The growth in consumption would be driven primarily by increasing coal consumption in China and India. Tables 6-80 and 6-81 show the No-Action Alternative coal consumption values for each model run year in units of million metric tons and TBtu, respectively.

China is responsible for the largest share of global thermal coal consumption, burning 2,269 million metric tons of coal in 2016. This amount is projected to increase in the Cumulative Scenario No-Action Alternative to 3,489 million metric tons by 2040. Total U.S. coal consumption would remain relatively stable, hovering in the mid to upper 600 million metric ton range.

Table 6-80. Cumulative Scenario Coal Consumption—No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	118	138	166	161	210	252	213
Australia	104	114	123	124	124	125	124
China	2,269	2,534	2,797	3,015	3,239	3,489	3,274
Hong Kong	13	15	16	16	17	20	18
India	543	723	935	1,233	1,558	2,287	1,751
Indonesia	138	142	152	165	188	220	194
Japan	96	113	127	126	119	116	120
South Korea	68	81	89	79	76	71	75
Taiwan	46	56	65	74	83	98	86
Total Asian Coal Consumption	3,395	3,915	4,472	4,993	5,613	6,679	5,855
Total U.S. Coal Consumption	613	606	672	686	651	679	671
Rest of World Coal Consumption	1,131	1,269	1,418	1,401	1,368	1,395	1,388

Table 6-81. Cumulative Scenario Coal Consumption—No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	2,603	2,968	3,334	3,739	4,144	4,883	4,319
Australia	1,268	1,481	1,693	1,661	1,629	1,591	1,623
China	57,999	64,719	71,432	77,017	82,560	88,375	83,282
Hong Kong	303	332	361	405	449	529	467
India	10,213	13,834	17,452	23,201	28,935	41,915	32,390
Indonesia	2,486	2,535	2,583	2,897	3,212	3,784	3,347
Japan	2,337	2,674	3,009	3,058	3,095	3,030	3,060
South Korea	1,716	1,911	2,106	2,028	1,949	1,833	1,926
Taiwan	1,091	1,324	1,558	1,761	1,965	2,331	2,051
Total Asian Coal Consumption	80,016	91,778	103,528	115,768	127,938	148,269	132,464
Total U.S. Coal Consumption	12,675	12,682	14,022	14,278	13,651	14,201	14,039
Rest of World Coal Consumption	18,366	21,747	25,172	25,128	24,978	26,592	25,647

Coal consumption under the Proposed Action would follow similar patterns as the No-Action Alternative, with the U.S. thermal coal consumption averaging 671 million metric tons per year for the 2025 to 2040 period. As under the No-Action Alternative, U.S. coal consumption would be fairly flat, as electric demand growth would be primarily met with natural gas and renewable generation.

Over the 2016 to 2040 period, Asian coal consumption would follow the same pattern as it grows from 3,398 to 6,711million metric tons, a 2.9% average annual increase.

Tables 6-82 and 6-83 show the Proposed Action coal consumption values for each model run year in units of million metric tons and TBtu, respectively. The average values in the last column of the table were derived by weighting the modeled values based on the number of calendar years mapped to each model run year.

Table 6-82. Cumulative Scenario Coal Consumption—Proposed Action (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	118	138	166	161	208	252	212
Australia	104	114	123	124	124	125	124
China	2,269	2,534	2,799	3,022	3,264	3,514	3,294
Hong Kong	13	15	16	18	20	24	21
India	543	723	935	1,230	1,558	2,287	1,750
Indonesia	138	142	152	165	184	221	193
Japan	97	113	127	129	119	117	121
South Korea	68	81	89	79	76	71	75
Taiwan	47	56	65	76	85	100	88
Total Asian Coal Consumption	3,398	3,915	4,473	5,004	5,637	6,711	5,879
Total U.S. Coal Consumption	613	606	671	685	650	678	671
Rest of World Coal Consumption	1,131	1,269	1,418	1,401	1,368	1,395	1,388

Table 6-83. Cumulative Scenario Coal Consumption—Proposed Action (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	2,603	2,968	3,334	3,739	4,144	4,883	4,319
Australia	1,268	1,481	1,693	1,661	1,629	1,591	1,623
China	57,999	64,719	71,432	77,017	82,829	88,644	83,476
Hong Kong	303	332	361	405	449	529	468
India	10,213	13,834	17,452	23,201	28,935	41,915	32,390
Indonesia	2,486	2,535	2,583	2,897	3,212	3,784	3,347
Japan	2,337	2,674	3,009	3,058	3,097	3,033	3,061
South Korea	1,716	1,911	2,106	2,028	1,951	1,834	1,927
Taiwan	1,091	1,324	1,558	1,761	1,965	2,331	2,051
Total Asian Coal Consumption	80,016	91,778	103,528	115,768	128,211	148,542	132,661
Total U.S. Coal Consumption	12,673	12,684	14,009	14,271	13,642	14,196	14,032
Rest of World Coal Consumption	18,366	21,747	25,172	25,128	24,978	26,592	25,647

Tables 6-84 and 6-85 show the estimated change in coal consumption between the Proposed Action and the No-Action Alternative by model run year in units of million metric tons and TBtu, respectively. The change is coal consumption is zero, or near zero, in Asia before 2025 when the terminal was assumed fully online. Once the proposed terminal is exporting 44 million metric tons of coal at full capacity in 2025, total Asian coal consumption would be higher with an average change of 23.4 million metric tons per year between 2025 and 2040, with China having the largest average increase in coal consumption at 19.7 million metric tons. Coal consumption in the United States would decrease by an average of 0.9 million metric tons per year under the Proposed Action. The increase of 19.7 million metric tons of coal consumption in China is due to induced demand and to changes in the mix of coal consumed. As shown in Table 6-85, China's coal demand increases by an average of 194.2 TBtu from 2025 to 2040, which is about 9 million metric tons. Thus, about 45% of the increase in China's coal consumption of 19.7 million metric tons is due to induced demand and 55% is due to changes in the coal mix.

Table 6-84. Cumulative Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (million metric tons)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	0	-2.7	-0.3	-1.0
Australia	0	0	0	0	0	0	0
China	0	0.4	2.0	6.4	24.9	24.7	19.7
Hong Kong	0	0	0	2.0	2.1	3.9	2.8
India	0	-0.5	0	-2.9	0	0	-0.8
Indonesia	0	0	0.1	0	-3.4	1.7	-0.5
Japan	1.2	0	-0.4	3.8	0.1	0.1	1.1
South Korea	0.3	0	0	0	0.1	0.1	<0.05
Taiwan	1.4	0	0	1.7	2.2	2.2	2.1
Total Asian Coal Consumption	3.0	-0.2	1.8	11.0	23.3	32.4	23.4
Total U.S. Coal Consumption	-0.3	0	-0.9	-0.6	-1.0	-1.0	-0.9
Rest of World Coal Consumption	0	0	0	0	0	0	0

Table 6-85. Cumulative Scenario Change in Coal Consumption—Proposed Action minus No-Action Alternative (TBtu per year)

Consuming Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	0	0	0	0
Australia	0	0	0	0	0	0	0
China	0	0	0	0	268.9	268.9	194.2
Hong Kong	0	0	0	0	0.2	0.2	0.2
India	0	0	0	0	0	0	0
Indonesia	0	0	0	0	0	0	0
Japan	0	0	0	0	2.4	2.4	1.7
South Korea	0	0	0	0	1.6	1.6	1.1
Taiwan	0	0	0	0	0	0	0
Total Asian Coal Consumption	0	0	0	0	273.1	273.1	197.2
Total U.S. Coal Consumption	-2.0	1.7	-13.3	-7.0	-9.3	-5.0	-7.0
Rest of World Coal Consumption	-0.1	0	0	0	0	0	0

6.6.3 Coal Distribution

As with the No Clean Power Plan Scenario, distribution patterns for Powder River Basin and Uinta Basin coal are expected to remain largely unchanged under the Proposed Action in the Cumulative Scenario. Thus, this section focuses on the distribution of coal in Asia and how that distribution would be expected to change with the construction of the proposed terminal. Under the No-Action Alternative, there would be no coal exported through the proposed terminal; however, there would be 313 million metric tons of coal distributed in Asia by ship in the seaborne coal market in 2016. Table 6-86 shows the tons of coal that would be imported by each country in Asia under the No-Action Alternative. By 2040, a total of 550 million metric tons of coal are expected to be distributed in the seaborne coal market in Asia.

Table 6-86. Cumulative Scenario Seaborne Coal Distribution in Asia—No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	80	98	124	142	203	244	202
Australia	0	0	0	0	0	0	0
China	0	65	144	0	0	0	0
Hong Kong	13	15	16	16	17	20	18
India	10	47	0	35	0	0	10
Indonesia	0	0	0	0	0	0	0
Japan	96	113	127	126	119	116	120
South Korea	68	81	89	79	76	71	75
Taiwan	46	56	65	74	83	98	86
Total Asian Coal sent via ship	313	475	567	471	498	550	511

To understand how coal distribution is changing in more detail than the tons of coal imported by each country, ICF multiplied the tons of coal shipped to each country by the distance in nautical miles that the coal is shipped and then divided by an average ship size. The change in tons imported might not change significantly; however, where the coal is sourced might change, which can have a significant impact on the emissions associated with shipping. Table 6-87 shows the shipping miles for coal shipped to each country for the No-Action Alternative.

Table 6-87. Cumulative Scenario Shipping Distance for Seaborne Coal Distribution in Asia—No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0.44	0.76	2.13	2.65	3.95	4.84	3.93
Australia	0	0	0	0	0	0	0
China	0	1.68	4.51	0	0	0	0
Hong Kong	0.39	0.44	0.47	0.46	0.55	0.24	0.41
India	0.45	2.20	0	1.64	0	0	0.46
Indonesia	0	0	0	0	0	0	0
Japan	5.12	7.17	8.07	6.11	1.59	1.55	2.83
South Korea	1.81	5.23	5.77	0.75	0.72	0.67	0.71
Taiwan	2.89	3.51	4.13	4.67	5.20	6.20	5.44
Total Asian Coal sent via ship	11.10	20.99	25.07	16.27	12.01	13.51	13.78

Under the Proposed Action, coal would be exported through the terminal to destinations in Asia. Table 6-88 shows the distribution of the coal exported from the proposed terminal. In the Cumulative Scenario, a larger portion of the coal exported through the proposed coal export terminal in 2030 and 2040 is delivered to China than in the other scenarios. The Gateway Pacific Terminal is modeled to come online in 2030 and it would cause coal distribution patterns to shift, which is why more coal from the proposed coal export terminal is delivered to China in 2030 and 2040 in the Cumulative Scenario.

Table 6-88. Cumulative Scenario Distribution of Coal Exported through the Coal Export Terminal—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040
China	0	0	0	29.3	44.0	44.0
Hong Kong	0	0	0	9.8	0	0
Japan	0	0	0	0	0	0
South Korea	0	0	0	0	0	0
Taiwan	0	0	0	5.0	0	0
Total Asian Coal sent via ship through proposed Coal Export Terminal	0	0	0	44.0	44.0	44.0

Under the Proposed Action, a similar number of tons would be distributed in the seaborne coal market as it would under the No-Action Alternative, as seen in Table 6-89, which shows the tons of coal that would be imported by each country in Asia under the Proposed Action. The total shipping distance for coal distribution in Asia is presented in Table 6-90 for the Proposed Action.

Table 6-89. Cumulative Scenario Seaborne Coal Distribution in Asia—Proposed Action (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	80	98	124	142	200	244	201
Australia	0	0	0	0	0	0	0
China	0	65	146	29	67	66	56
Hong Kong	13	15	16	18	20	24	21
India	10	48	0	43	0	0	12
Indonesia	0	0	0	0	0	0	0
Japan	97	113	127	129	119	117	121
South Korea	68	81	89	79	76	71	75
Taiwan	47	56	65	76	85	100	88
Total Asian Coal sent via ship	316	477	568	516	567	623	574

Table 6-90. Cumulative Scenario Shipping Distance for Seaborne Coal Distribution in Asia—Proposed Action (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0.44	0.76	2.13	2.65	4.75	5.69	4.53
Australia	0	0	0	0	0	0	0
China	0	1.78	4.84	2.37	5.42	5.35	4.55
Hong Kong	0.39	0.44	0.47	1.08	1.19	1.83	1.41
India	0.45	2.26	0	2.00	0	0	0.56
Indonesia	0	0	0	0	0	0	0
Japan	5.75	7.17	8.05	8.20	1.59	1.56	3.41
South Korea	2.37	5.23	5.77	0.75	0.72	0.67	0.71
Taiwan	3.13	3.51	4.13	5.02	5.71	6.64	5.88
Total Asian Coal sent via ship	12.54	21.15	25.38	22.07	19.38	21.74	21.05

As seen in Table 6-91, which shows the estimated change in tons of coal imported by each of the regions, the changes in coal imports between the No-Action Alternative and the Proposed Action would mirror the changes in consumption, except for China. The average increase in imports of coal into China is 56.3 million metric tons per year for 2025 to 2040, while the increase in consumption averages 19.7 million metric tons per year. The change in consumption is entirely due to changes in the mix of coal consumed. The increase in imports is because coal exported from the proposed coal export terminal is displacing coal produced in China, thus causing the larger increase in imports compared to the increase in consumption.

Table 6-91. Cumulative Scenario Change in Seaborne Coal Distribution in Asia—Proposed Action minus No-Action Alternative (million metric tons)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia – Other	0	0	0	0	-2.7	-0.3	-1.0
Australia	0	0	0	0	0	0	0
China	0	0.4	2.0	29.3	67.1	66.2	56.3
Hong Kong	0	0	0	2.0	2.1	3.9	2.8
India	0	1.3	0	7.8	0	0	2.2
Indonesia	0	0	0	0	0	0	0
Japan	1.2	0	-0.4	3.8	0.1	0.1	1.1
South Korea	0.3	0	0	0	0.1	0.1	<0.05
Taiwan	1.4	0	0	1.7	2.2	2.2	2.1
Total Asian Coal sent via ship	3.0	1.7	1.7	44.5	68.9	72.2	63.4

The changes in the total tons of coal imported to each region would be magnified or diminished depending on how the sources of the coal shift, and there would be some relatively large changes in the total shipping mile values, as shown in Table 6-92. The largest change in shipping distance is in China, because there is an increase in imported coal that displaces domestic Chinese coal production.

Table 6-92. Cumulative Scenario Change in Shipping Distance for Seaborne Coal Distribution in Asia—Proposed Action minus No-Action Alternative (million nautical miles)

Importing Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0	0	0	0	0.80	0.85	0.60
Australia	0	0	0	0	0	0	0
China	0	0.10	0.33	2.37	5.42	5.35	4.55
Hong Kong	0	0	0	0.62	0.63	1.59	1.00
India	0	0.06	0	0.36	0	0	0.10
Indonesia	0	0	0	0	0	0	0
Japan	0.63	0	-0.02	2.09	0	0	0.58
South Korea	0.57	0	0	0	0	0	0
Taiwan	0.24	0	0	0.36	0.51	0.45	0.44
Total Asian Coal sent via ship	1.44	0.16	0.31	5.81	7.37	8.24	7.27

6.6.4 CO_2 Emissions

This section presents the CO_2 estimated emissions from coal combusted in the United States and Asia in the Cumulative Scenario. In addition, CO_2 emissions from natural gas consumption in the United States are included because decreases in coal consumption may be offset by increases in natural gas consumption. Table 6-93 presents the CO_2 emissions under the No-Action Alternative.

Total U.S. CO_2 emissions from coal would slightly increase and average 1,319.78 million metric tons per year over 2025 to 2040. Asian CO_2 emissions would average 12,714.98 million metric tons per year between 2025 and 2040, which would be 9.6 times the total coal CO_2 emissions from the U.S. Natural gas CO_2 emissions average 588.42 million metric tons per year, or about 45% of U.S. coal CO_2 emissions. Between 2030 and 2040, CO_2 emissions from natural gas would increase by 152 million metric tons. This increase would be due to nuclear units retiring in this period and natural gas-fired generation replacing some of the retired nuclear generation.

Table 6-94 presents the CO_2 emissions under the Proposed Action. Total CO_2 emissions under the Proposed Action for this scenario would follow the same trends as the No-Action Alternative, and would be within 2.5% of the coal CO_2 emissions under the No-Action Alternative.

Table 6-93. Cumulative Scenario CO_2 Emissions—No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	247.26	285.00	322.40	347.92	401.48	475.60	415.43
Australia	118.44	138.28	158.12	155.15	152.18	148.56	151.60
China	5,589.28	6,230.49	6,869.91	7,422.30	7,957.21	8,519.96	8,027.47
Hong Kong	28.03	30.69	33.34	37.40	41.52	50.87	44.01
India	971.98	1,314.34	1,663.26	2,208.16	2,757.05	3,991.99	3,084.83
Indonesia	239.90	244.43	248.95	278.94	308.90	363.15	321.67
Japan	218.18	250.63	281.95	288.97	297.84	291.67	292.98
South Korea	161.27	179.24	197.51	195.18	187.61	176.39	185.35
Taiwan	101.94	123.74	145.53	164.58	183.58	217.90	191.65
Asia- Coal	7,676.27	8,796.83	9,920.98	11,098.59	12,287.35	14,236.09	12,714.98
U.S. - Coal	1,192.66	1,191.89	1,318.40	1,342.64	1,283.18	1,334.84	1,319.78
U.S. - Natural Gas	562.33	520.06	472.01	500.29	540.37	692.55	588.42
Rest of World	1,755.77	2,072.97	2,397.94	2,391.95	2,375.45	2,529.00	2,439.75

Table 6-94. Cumulative Scenario CO_2 Emissions—Proposed Action (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	247.26	285.00	322.43	347.92	400.35	475.51	415.01
Australia	118.44	138.28	158.12	155.15	152.18	148.56	151.60
China	5,589.28	6,230.61	6,870.98	7,422.74	7,984.10	8,546.83	8,047.01
Hong Kong	28.03	30.69	33.34	38.32	42.49	50.42	44.42
India	971.98	1,314.23	1,663.26	2,207.53	2,757.05	3,991.99	3,084.66
Indonesia	239.90	244.43	248.95	278.94	308.90	363.15	321.67
Japan	218.23	250.58	281.49	286.63	298.07	291.90	292.49
South Korea	159.39	179.24	197.51	195.18	187.76	176.54	185.45
Taiwan	102.20	123.74	145.53	165.50	184.93	219.05	192.80
Asia- Coal	7,674.70	8,796.79	9,921.62	11,097.90	12,315.82	14,263.95	12,735.11
U.S. - Coal	1,192.38	1,192.02	1,317.06	1,341.66	1,282.11	1,334.19	1,318.90
U.S. - Natural Gas	562.33	519.96	472.01	500.25	540.47	692.55	588.44
Rest of World	1,755.76	2,072.97	2,397.94	2,391.95	2,375.45	2,529.00	2,439.75

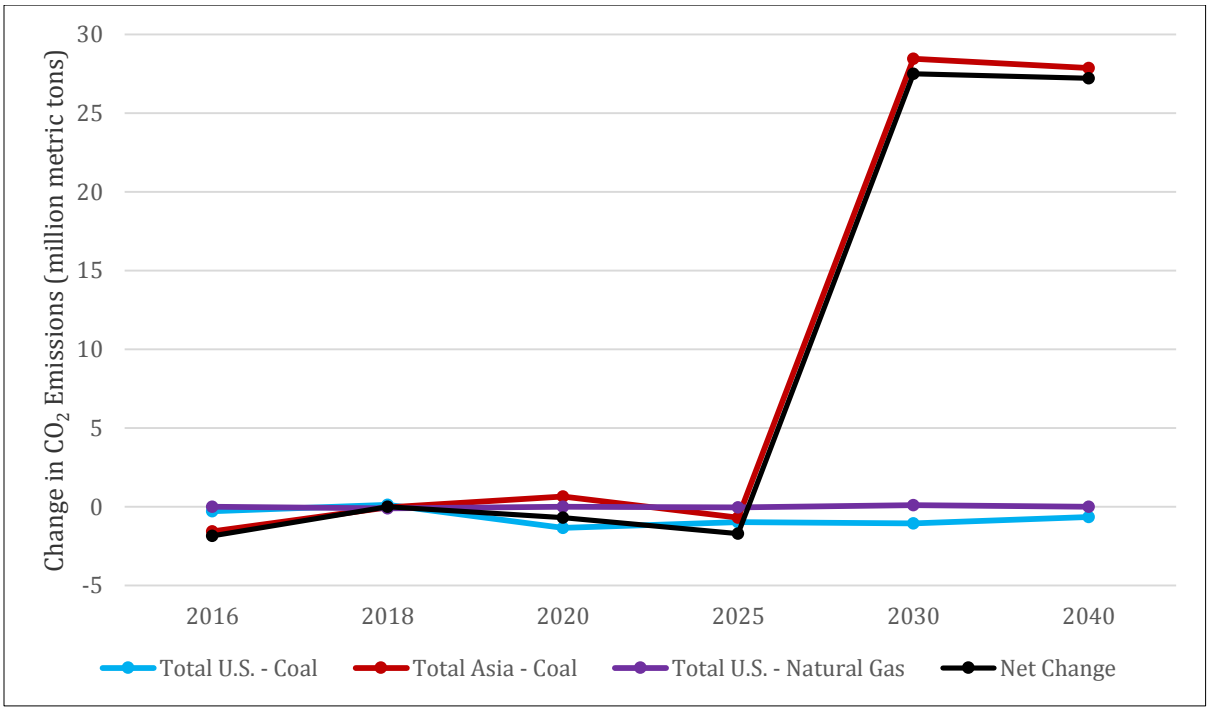
Table 6-95 shows the estimated change in CO_2 emissions for each region, as well as the total net change across all regions. Total Asian CO_2 emissions from coal consumption would increase an average of 20.13 million metric tons per year from 2025 to 2040 because of shifts in the type of coal consumed and due to induced demand. In contrast, U.S. coal CO_2 emissions would decrease 0.88 million metric tons over 2025 to 2040 due to higher coal prices that depress domestic coal demand. The higher coal prices result from the fact that an additional 44 million metric tons of coal is exported starting in 2025, and another 48 million metric tons of coal is exported starting in 2030 from the Gateway Pacific Terminal, under the Proposed Action, which shifts the demand curve up and yields higher coal prices in the United States. The decrease in coal consumption is offset by an increase in natural gas consumption, as is seen by the increase in CO_2 emissions from natural gas, which would average 0.02 million metric tons per year over 2025 to 2040. Natural gas consumption does not increase in proportion to the decrease in coal consumption because there is an increase in renewable generation. The total net change in CO_2 emissions would be an increase of an average of 19.28 million metric tons per year over 2025 to 2040.

Table 6-95. Cumulative Scenario Changes in CO_2 Emissions—Proposed Action minus No-Action Alternative (million metric tons)

Region	2016	2018	2020	2025	2030	2040	2025–2040 Average
Asia - Other	0	0	0.03	0	-1.13	-0.09	-0.41
Australia	0	0	0	0	0	0	0
China	0	0.12	1.07	0.44	26.89	26.87	19.53
Hong Kong	0	0	0	0.92	0.98	-0.45	0.41
India	0	-0.11	0	-0.63	0	0	-0.17
Indonesia	0	0	0	0	0	0	0
Japan	0.05	-0.06	-0.46	-2.34	0.23	0.23	-0.48
South Korea	-1.88	0	0	0	0.15	0.15	0.11
Taiwan	0.26	0	0	0.92	1.35	1.16	1.15
Asia- Coal	-1.57	-0.04	0.64	-0.69	28.47	27.87	20.13
U.S. - Coal	-0.28	0.13	-1.34	-0.98	-1.06	-0.65	-0.88
U.S. - Natural Gas	0	-0.09	0.01	-0.04	0.10	0	0.02
Rest of World	-0.01	0	0	0	0	0	0
Net Change	-1.85	-0.01	-0.69	-1.71	27.50	27.21	19.28

Figure 6-15 shows the net change in CO_2 emissions between the No-Action Alternative and Proposed Action. In the long term, the increase in Asian coal emissions would drive the net change to be a net increase in CO_2 emissions under the Proposed Action.

Figure 6-15. Cumulative Scenario Changes in CO_2 Emissions by Region—Proposed Action minus No-Action Alternative



[a] Total U.S. CO_2 emissions from the combustion of coal would decrease because the proposed coal export terminal would be a new demand sink for U.S. coal, and thus, would cause coal prices to rise and U.S. coal consumption to decrease in response to the higher prices.

[b] Asian CO_2 emissions from the combustion of coal would increase due to a larger quantity of lower heat content coal being consumed and due to induced demand from the lower delivered coal prices when the proposed coal export terminal fully comes online in 2025, and when the Gateway Pacific Terminal comes online in 2030.

[c] Total U.S. natural gas combustion CO_2 emissions would increase slightly because when coal consumption for electric generation declines, natural gas usage for electric generation increases to fill some of the gap.

Chapter 7
Conclusions

This analysis examined the coal production, consumption, distribution, and CO_2 emissions associated with the operation of the coal export terminal under five scenarios. The results of the analysis show that the operation of the terminal would likely cause changes in the production, consumption, and distribution of coal in the United States and Asia. These changes would cause a change in CO_2 emissions as well, with the net average annual emissions ranging from a decrease of 6.61 million metric tons CO_2 in the Lower Bound Scenario to an increase of 52.59 million metric tons CO_2 in the Upper Bound Scenario, when averaged over 2025 to 2040.

7.1 Summary of Key Results

The Co-Lead Agencies defined the study area for the coal market analysis as the United States and Asian coal markets. Within the United States, results for the CO_2 emissions from the combustion of coal and natural gas are the primary results from this analysis that are used in the GHG analysis report. Additionally, the GHG analysis uses the change in the distribution of coal in Asia to estimate the CO_2 emissions from the change in the transportation of coal.

7.1.1 Coal Production

This analysis shows that coal production in the United States would increase in all five scenarios under the Proposed Action, as the export of coal through the terminal would cause additional coal to be mined in the United States, beyond that which is produced for domestic consumption under the No-Action Alternative. If production did not increase under each scenario, it would imply either that there is a decrease in the consumption of Powder River Basin and Uinta Basin coal in the United States, or that exports of other coal are decreasing. The results also show that coal production in Asia would decrease in all five scenarios, as the exported coal displaces some coal production from Asian coal producing countries.

The amount of increase in production varies by scenario and by year in each scenario. The Lower Bound Scenario has the lowest change in U.S. coal production at an average of 39.74 million metric tons, because this scenario has the largest decrease in domestic coal consumption once the terminal comes online. Thus, the increase in the U.S. coal production due to the Proposed Action is reduced by the amount of coal no longer consumed domestically. However, all scenarios besides the Cumulative Scenario have increases in U.S. production between 39.74 and 44.00 million metric tons.

The 2015 U.S. and International Energy Policy Scenario is similar to the other scenarios in that U.S. coal production increases, but not as much as the full terminal capacity. The reason that coal production in the United States increases an average 43.6 million metric tons per year under the 2015 U.S. and International Energy Policy Scenario, and not the full 44 million metric tons of the proposed coal export terminal's capacity, is that there is a decline in U.S. demand for Powder River Basin and Uinta Basin coal. The increase is slightly lower than under the No Clean Power Plan Scenario because there is a larger decrease in domestic coal consumption in this scenario.

Finally, the Cumulative Scenario has an average annual increase in U.S. coal production of 91.09 million metric tons. In this scenario, Powder River Basin coal demand in the United States declines by 2.7 million metric tons in the long term as the higher export demand on Powder River Basin coal increases the prices, which in turn, suppresses domestic demand for Powder River Basin coal. The other reason that U.S. production increases by less than the total amount of new export capacity is that exports from Appalachian coal regions are lower under the Proposed Action.

7.1.2 Coal Consumption

This analysis shows that coal consumption in the United States would decrease in all but the Upper Bound Scenario under the Proposed Action. U.S. coal consumption decreases because the export of coal through the proposed coal export terminal would cause additional demand for U.S. coal, which causes coal prices to rise. In response to the higher coal prices, U.S. coal plants consume between 0.01 and 3.8 million metric tons per year less coal. If flatter coal supply curves were used in this analysis, then the decrease in U.S. coal consumption would be less. Similarly, if steeper coal supply curves were used in this analysis, then the decrease in U.S. coal consumption would be greater.

Coal consumption in the Upper Bound Scenario increases slightly in the United States because of changes in the electric demand region containing North and South Carolina.

The results also show that the tons of coal consumed in Asia would increase in all scenarios. The tons of coal consumed increases because a larger quantity of lower heat content coal is consumed and because of induced demand in the Upper Bound and Cumulative Scenarios. The exported coal has a lower heat content than the coal that it displaces and more coal must be consumed to achieve the same electric power output. The induced demand is another factor causing higher coal consumption in Asia. In all scenarios with induced demand, the amount of induced demand is less than about 33 million metric tons per year.

7.1.3 Coal Distribution

Coal distribution in Asia changes when the proposed terminal comes online because the coal exported through the terminal displaces coal from other sources. Primarily the exported coal displaces coal from Australia, China, Indonesia, and Russia. The average change in coal distribution under the Proposed Action, as measured by the change in the total amount of Asian coal imports, is less than 19.2 million metric tons over 2025 to 2040, for all but the Cumulative Scenario, and ranges from 8.5 to 19.2 million metric tons. The change in coal distribution is used to estimate the change in the distance that the coal imported by the Asian countries must be shipped. This is done by multiplying the tons of coal imported by the distance traveled between supply and demand region, and then dividing by the average capacity of a shipping vessel. The average annual change in shipping distances for the five scenarios ranges from 2.3 to 7.3 million nautical miles.

7.1.4 CO_2 Emissions from Coal Consumption

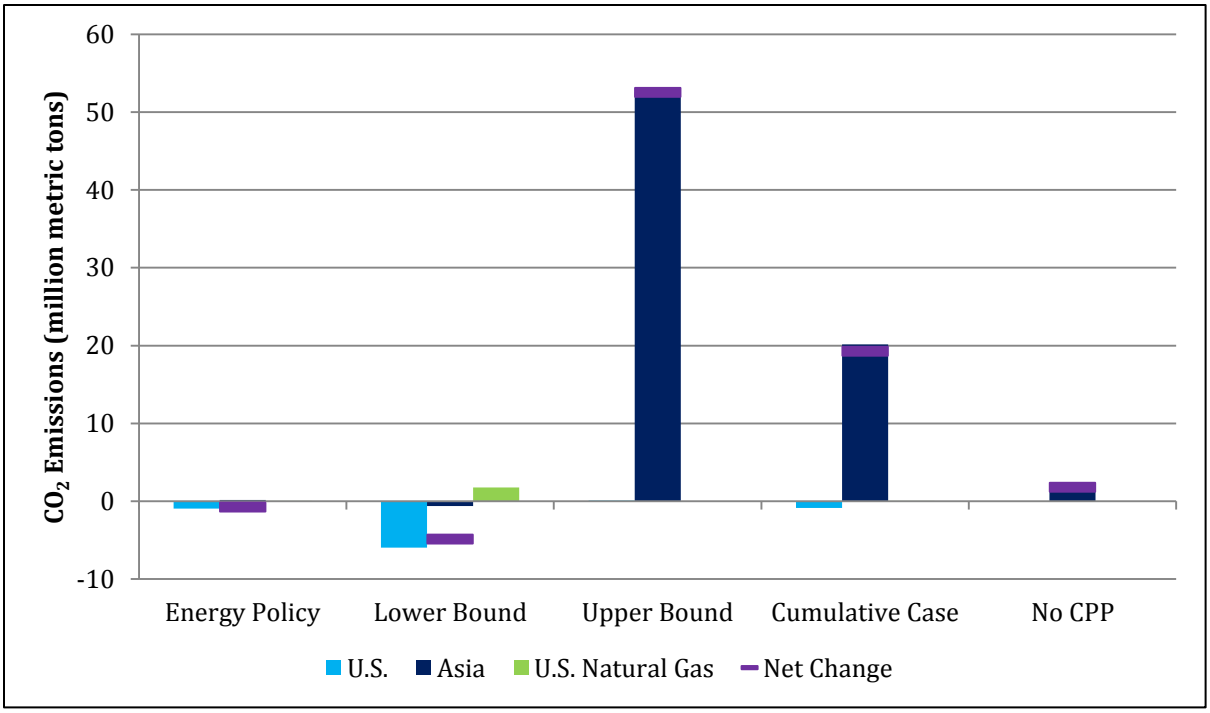
The CO_2 emissions from the combustion of coal follow a similar pattern as the changes in consumption under the Proposed Action, especially in the United States but somewhat less so in Asia. Thus, in the United States, CO_2 emissions from coal consumption would decrease in all but the Upper Bound Scenario, while CO_2 emissions from Asia would increase in all but the Lower Bound Scenario. Under the Proposed Action, the No Clean Power Plan Scenario would result in a net average increase in U.S. CO_2 emissions from the combustion of coal of 1.81 million metric tons, the

Cumulative Scenario would result in an increase of 19.25 million metric tons, and the Upper Bound Scenario would result in an increase of 52.59 million metric tons, while the other two scenarios would show a decrease. The largest change would be in the Upper Bound Scenario, where U.S. CO_2 emissions from the combustion of coal would increase under the Proposed Action by 52.59 million metric tons. The Lower Bound scenario would have the largest decrease in U.S. CO_2 emissions at 5.98 million metric tons because it would have the largest increase in Powder River Basin coal prices, and thus, the largest response in the decrease of U.S. demand. Table 7-1 shows the CO_2 emissions results by scenario and region of origin. Figure 7-1 shows the same emissions information in a chart.

Table 7-1. Average Change in CO_2 Emissions by Scenario and Region—Proposed Action minus No-Action Alternative (million metric tons)

Scenario	Asian Coal	U.S. Coal	U.S. Natural Gas	Total
No Clean Power Plan	1.81	<0.005	<0.001	1.81
Lower Bound	-0.63	-5.98	1.75	-4.86
Upper Bound	52.52	0.07	-0.02	52.58
2015 U.S. and International Energy Policy	0.15	-0.94	0.05	-0.75
Cumulative	20.13	-0.88	0.02	19.28

Figure 7-1. Change in Annual Average CO_2 Emissions from the Consumption of Coal and Natural Gas in the United States for 2025 to 2040—Proposed Action minus No-Action Alternative (million metric tons CO_2 per year)



The results show that the net change in average CO_2 emissions from the combustion of coal would be a net positive for the Upper Bound, Cumulative, and No Clean Power Plan Scenarios, and a net negative for the 2015 U.S. and International Energy Policy and Lower Bound Scenarios.

This analysis also estimated the change in CO_2 emissions from the combustion of natural gas in the United States for use in electric power generation. When the emissions from the consumption of natural gas are included, the net change in CO_2 emissions under the Proposed Action shift slightly higher for all but the Upper Bound and No Clean Power Plan Scenarios.

Chapter 8
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Appendix A

Planned New Generating Capacity and Planned Retirements

Appendix A
Planned New Generating Capacity and Planned Retirements

Table A2-1. Planned New Generating Capacity for 2016 to 2020

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Colorado Bend Energy Center	Generator: CC3	ERCOT	Combined Cycle	2017	1,157
FGE Texas I Project	Generator: CA1	ERCOT	Other	2017	336
FGE Texas I Project	Generator: GT1	ERCOT	Combustion Turbine	2017	231
FGE Texas I Project	Generator: GT2	ERCOT	Combustion Turbine	2017	231
FGE Texas II Project	Generator: CA1	ERCOT	Other	2017	336
FGE Texas II Project	Generator: GT1	ERCOT	Combustion Turbine	2017	231
FGE Texas II Project	Generator: GT2	ERCOT	Combustion Turbine	2017	231
Indeck Wharton Energy Center	Generator: 1	ERCOT	Combustion Turbine	2017	220
Indeck Wharton Energy Center	Generator: 2	ERCOT	Combustion Turbine	2017	220
Indeck Wharton Energy Center	Generator: 3	ERCOT	Combustion Turbine	2017	220
La Paloma Energy Center	Generator: CC	ERCOT	Combined Cycle	2016	700
Lake Livingston Hydroelectric Project	Generator: HY1	ERCOT	Hydro	2018	8
Lake Livingston Hydroelectric Project	Generator: HY2	ERCOT	Hydro	2018	8
Lake Livingston Hydroelectric Project	Generator: HY3	ERCOT	Hydro	2018	8
Los Vientos 4 Wind Project	Generator: GEN1	ERCOT	Wind	2016	200
Los Vientos V Wind Project	Generator: 1	ERCOT	Wind	2016	110
OCI Alamo 1 Solar	Generator: PV3	ERCOT	Solar	2016	355
OCI Alamo 5 (Mega Solar Project)	Generator: OCIA5	ERCOT	Solar	2016	100
P.H. Robinson Peaking CT	Generator: PHR1	ERCOT	Combustion Turbine	2016	65
P.H. Robinson Peaking CT	Generator: PHR2	ERCOT	Combustion Turbine	2016	65
P.H. Robinson Peaking CT	Generator: PHR3	ERCOT	Combustion Turbine	2016	65
P.H. Robinson Peaking CT	Generator: PHR4	ERCOT	Combustion Turbine	2016	65
P.H. Robinson Peaking CT	Generator: PHR5	ERCOT	Combustion Turbine	2016	65

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
P.H. Robinson Peaking CT	Generator: PHR6	ERCOT	Combustion Turbine	2016	65
Tenaska Brownsville Generating Station	Generator: CC	ERCOT	Combined Cycle	2017	800
Texas Clean Energy Project	Boiler: 1 - Generator: IGCC	ERCOT	Coal	2019	400
Wolf Hollow	Generator: 1	ERCOT	Combined Cycle	2017	1,157
Athens Biomass Plant- Cogen	Generator: 1	ISONE	Biomass	2016	8
Ball Mountain Dam Hydro(Blue Heron)	Generator: HY 1	ISONE	Hydro	2019	2
Beaver Wood Energy Fair Haven Biomass Project	Generator: GEN1	ISONE	Biomass	2017	30
Bingham Wind - Blue Sky West	Generator: 1	ISONE	Wind	2017	185
Block Island Offshore Wind	Generator: BIWF	ISONE	Wind	2016	30
Fair Haven Energy Center	Generator: GEN1	ISONE	Biomass	2017	34
Hancock Wind Project	Generator: ANC1	ISONE	Wind	2016	51
Johnston Waste-to-Energy Project	Generator: 1	ISONE	Biomass	2016	3
Lebanon Solar Project (Ecos Energy)	Generator: 1	ISONE	Solar	2016	6
Palmer Renewable Energy	Generator: FB 1	ISONE	Biomass	2016	35
Salem Harbor Gas Project	Generator: 5	ISONE	Combined Cycle	2017	216
Salem Harbor Gas Project	Generator: 6	ISONE	Combined Cycle	2017	216
Salem Harbor Gas Project	Generator: 7	ISONE	Combined Cycle	2017	242
Stafford Solar Project (Stafford Middle School)	Generator: 1	ISONE	Solar	2016	3
WED Coventry 3	Generator: WEDC3	ISONE	Wind	2016	2
WED Coventry 4	Generator: WEDC4	ISONE	Wind	2016	2
WED Coventry 5	Generator: COV5	ISONE	Wind	2016	2
WED Coventry 6	Generator: COV6	ISONE	Wind	2016	2
WED Coventry 6	Generator: COV6A	ISONE	Wind	2016	2
WED Coventry 6	Generator: COV6B	ISONE	Wind	2016	2
WED Coventry Wind Farm	Generator: WT 1	ISONE	Wind	2016	2
WED Coventry Wind Farm	Generator: WT 2	ISONE	Wind	2016	2
Antelope Hills Wind Farm	Generator: 1	MISO	Wind	2016	172
Black Oak Wind Farm-Geronimo	Generator: 1	MISO	Wind	2016	42
border wind project	Generator: WT1 66	MISO	Wind	2016	152
Campbell County Wind Farm (CCWF)	Generator: 1	MISO	Wind	2016	98
deerfield wind	Generator: wt 15	MISO	Wind	2017	114
Ecoharmony West Wind Project	Generator: WT1 134	MISO	Wind	2016	280
Getty Wind Project	Generator: 1	MISO	Wind	2016	40
GLACIAL RIDGE WIND FARM	Generator: WT1 8	MISO	Wind	2019	20

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
H T Pritchard/Eagle Valley	Generator: CC GT1	MISO	Combined Cycle	2017	210
H T Pritchard/Eagle Valley	Generator: CC GT2	MISO	Combined Cycle	2017	210
H T Pritchard/Eagle Valley	Generator: CC ST1	MISO	Other	2017	251
Highland Wind Energy	Generator: WT1 218	MISO	Wind	2016	500
Holland City CC Project	Generator: 10	MISO	Combined Cycle	2016	149
lake country wind energy	Generator: WT2	MISO	Wind	2018	150
lake country wind energy	Generator: WT3	MISO	Wind	2019	150
Mankato Power Plant	Generator: CTG1	MISO	Combustion Turbine	2018	200
Marshalltown Generating Station	Generator: CC1	MISO	Combined Cycle	2017	650
Meade Wind Park	Generator: 1	MISO	Wind	2016	99
Midland Cogeneration Venture	Generator: GT15-6	MISO	Combined Cycle	2017	668
Red Rock Hydro	Generator: HY 1	MISO	Hydro	2018	18
Red Rock Hydro	Generator: HY 2	MISO	Hydro	2018	18
Spiritwood Energy	Boiler: AB - Generator: AB	MISO	Coal	2016	99
Thunder Spirit Wind Farm	Generator: THNDR	MISO	Wind	2016	108
Twin Falls Upgrade (WI)	Generator: 1	MISO	Hydro	2016	9
Walnut Ridge Wind Farm	Generator: WT1 100	MISO	Wind	2016	210
Walnut Ridge Wind Farm	Generator: WT101 150	MISO	Wind	2017	105
Waverly Wind Farm	Generator: GEN1	MISO	Wind	2016	200
CPV Valley Energy Center	Generator: 1	NYISO	Combined Cycle	2016	667
CPV Valley Energy Center	Generator: DUCT	NYISO	Combined Cycle	2018	84
Cricket Valley Energy	Generator: CT	NYISO	Combined Cycle	2018	627
Cricket Valley Energy	Generator: ST	NYISO	Combined Cycle	2018	443
Richwood Greenworks Solar Project	Generator: 1	NYISO	Solar	2016	6
Rochester 2	Generator: 3	NYISO	Hydro	2019	6
TBE-Montgomery LLC	Generator: CTG	NYISO	Biomass	2016	21
Ahoskie 561 Solar Project	Generator: 1	PJM	Solar	2016	5
Ahoskie FIA Solar Project	Generator: 1	PJM	Solar	2016	5
Battleboro Solar Project	Generator: 1	PJM	Solar	2016	5
Brunswick County Power Station	Generator: CC1	PJM	Combined Cycle	2016	1,300
Buckeye Wind Project	Generator: 1A	PJM	Wind	2017	135
Capital Partners Solar Project III	Generator: 1	PJM	Solar	2016	12

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Carroll County Energy Center	Generator: 1	PJM	Combined Cycle	2017	231
Carroll County Energy Center	Generator: 2	PJM	Combined Cycle	2017	231
Carroll County Energy Center	Generator: 3	PJM	Combined Cycle	2017	238
Chowan Jehu Road Solar	Generator: 1	PJM	Solar	2016	5
Coatesville Solar Initiative	Generator: 1	PJM	Solar	2016	9
Colerain Hwy 45 Solar Project	Generator: 1	PJM	Solar	2016	5
CPV St. Charles Energy Center	Generator: GTG	PJM	Combined Cycle	2016	725
CPV Woodbridge Energy Center	Generator: 1	PJM	Combined Cycle	2016	700
CPV Woodbridge Energy Center	Generator: IC1	PJM	Oil/Gas	2016	2
Dans Mountain	Generator: 1	PJM	Wind	2019	48
EC Okisko Solar	Generator: 1	PJM	Solar	2016	5
EcoPower Biomass Plant	Generator: 1	PJM	Biomass	2017	59
Fairfield Renewable Energy Cogen	Generator: ST 1	PJM	Biomass	2016	159
FDS Co-Generation Facility	Generator: 1	PJM	Other	2017	135
FERN Blueribbon Offshore Wind Farm - FACW	Generator: 1	PJM	Wind	2016	25
Frederick Regional Waste-to-Energy Facility	Generator: 1	PJM	Biomass	2016	51
Freeman Farm Solar Project	Generator: 1	PJM	Solar	2016	5
Gliden Jehu Solar Project	Generator: 1	PJM	Solar	2016	5
Good Spring NGCC 1 & 2	Generator: GT1	PJM	Combined Cycle	2016	335
Good Spring NGCC 1 & 2	Generator: HRSG1	PJM	Combined Cycle	2016	108
Hardin Wind Farm	Generator: WT1 200	PJM	Wind	2016	300
Indiana Gasification	Boiler: IGCC - Generator: IGCC	PJM	Coal	2017	134
Lake Erie Offshore Wind Project (Icebreaker)	Generator: WTG1-6	PJM	Wind	2017	18
Middletown Energy Center	Generator: CC CT 1	PJM	Combined Cycle	2018	525
Mill Pond Solar (SunEnergy1)	Generator: 1	PJM	Solar	2016	5
Moxie Liberty Project	Generator: CC1	PJM	Combined Cycle	2017	468
Moxie Liberty Project	Generator: CC2	PJM	Combined Cycle	2017	468
New Creek Wind Farm	Generator: 1	PJM	Wind	2016	98
Northwest Ohio Wind	Generator: NWOH1	PJM	Wind	2016	100
Oregon Energy Centre (OH)	Generator: CC1	PJM	Combined Cycle	2017	800
Pasquotank County Solar Project	Generator: 1	PJM	Solar	2016	5

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Patriot Power Generation Plant (Moxie Patriot)	Generator: CC GEN1-CT1	PJM	Combined Cycle	2016	274
Patriot Power Generation Plant (Moxie Patriot)	Generator: CC GEN1-ST1	PJM	Other	2016	141
Patriot Power Generation Plant (Moxie Patriot)	Generator: CC GEN2-CT2	PJM	Combined Cycle	2016	274
Patriot Power Generation Plant (Moxie Patriot)	Generator: CC GN2-ST2	PJM	Other	2016	141
Peanut Market Farm Solar	Generator: 1	PJM	Solar	2016	5
River Road Solar Project	Generator: 1	PJM	Solar	2016	5
Rockford Solar Project	Generator: PV2	PJM	Solar	2016	3
Roundtop	Generator: GEN1	PJM	Combustion Turbine	2016	4
Roundtop	Generator: GEN2	PJM	Combustion Turbine	2016	4
Roundtop	Generator: GEN3	PJM	Combustion Turbine	2016	4
Roundtop	Generator: GEN4	PJM	Combustion Turbine	2016	4
Roundtop	Generator: GEN5	PJM	Combustion Turbine	2016	4
Shawboro Meads Solar Project	Generator: 1	PJM	Solar	2016	5
Shiloh Hwy 1108 Solar	Generator: 1	PJM	Solar	2016	5
Stephenson Farm Solar Project	Generator: 1	PJM	Solar	2016	5
Stonewall Combined-Cycle Project	Generator: CC	PJM	Combined Cycle	2017	778
Weldon Trueblood Solar	Generator: 1	PJM	Solar	2016	5
Wildcat Point Generation Facility	Generator: CC CT1	PJM	Combined Cycle	2017	1,000
ABD Farm	Generator: 1	SERC + FRCC	Solar	2016	5
Albany Green Energy Cogen Plant	Generator: 1	SERC + FRCC	Biomass	2017	42
Bearford Farm Solar Project	Generator: 1	SERC + FRCC	Solar	2017	5
BG Stewart Solar Farm	Generator: 1	SERC + FRCC	Solar	2016	5
Boaz Farm	Generator: 1	SERC + FRCC	Solar	2016	5
Broadridge Solar	Generator: 1	SERC + FRCC	Solar	2016	5
Calypso Farm	Generator: PV1	SERC + FRCC	Solar	2016	5
Central Energy Plant	Boiler: 1 - Generator: CT 1	SERC + FRCC	Oil/Gas	2016	6
Cline Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Clipperton Holdings	Generator: PV1	SERC + FRCC	Solar	2016	5
Coats Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Creech Solar 2 Project	Generator: 1	SERC + FRCC	Solar	2016	5
Duck Solar	Generator: PV1	SERC + FRCC	Solar	2016	5
Eden Solar Project (Innovative Solar 34)	Generator: IS034	SERC + FRCC	Solar	2016	48
Elm Solar Farm	Generator: 1	SERC + FRCC	Solar	2016	5
Exum Farm Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Faison Farm Solar Project	Generator: PV1	SERC + FRCC	Solar	2016	5
Fremont Farm	Generator: PV 1	SERC + FRCC	Solar	2016	5
Garland Farm	Generator: PV1	SERC + FRCC	Solar	2016	5
Greenville 2 Solar Farm	Generator: PV1	SERC + FRCC	Solar	2016	3
Guernsey Solar Project	Generator: PV1	SERC + FRCC	Solar	2016	5
Haywood Farm	Generator: 1	SERC + FRCC	Solar	2016	5
Highlands Ethanol Cogeneration Facility	Generator: 1	SERC + FRCC	Biomass	2016	30
Hoke County Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Innovative Solar 38 Project	Generator: 1	SERC + FRCC	Solar	2016	35
Innovative Solar 42 Project	Generator: 1	SERC + FRCC	Solar	2016	73
Innovative Solar 46 Project	Generator: 1	SERC + FRCC	Solar	2016	80
Innovative Solar 48	Generator: 1	SERC + FRCC	Solar	2016	5
Innovative Solar 64	Generator: 1	SERC + FRCC	Solar	2016	5
Innovative Solar 72	Generator: 1	SERC + FRCC	Solar	2016	35
Kalish Farm	Generator: 1	SERC + FRCC	Solar	2016	5
Kelly Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Kings Mountain Energy Center	Generator: KMEC1-A	SERC + FRCC	Combined Cycle	2018	272
Kings Mountain Energy Center	Generator: KMEC1-B	SERC + FRCC	Combined Cycle	2018	203

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Manway Solar Farm	Generator: 1	SERC + FRCC	Solar	2017	5
Maxton Solar 1	Generator: 1	SERC + FRCC	Solar	2016	5
McDougald Solar	Generator: 1	SERC + FRCC	Solar	2016	5
Misenheimer Farm Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Montgomery Solar	Generator: PV1	SERC + FRCC	Solar	2016	20
Mount Olive Farm (Chatham Park)	Generator: PV 1	SERC + FRCC	Solar	2016	20
Nan Solar Center	Generator: PV 1	SERC + FRCC	Solar	2016	40
Nash 97 Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Ostrich Solar Farm	Generator: 1	SERC + FRCC	Solar	2016	5
Owen Solar	Generator: PV1	SERC + FRCC	Solar	2016	6
Oxford Solar 1	Generator: 1	SERC + FRCC	Solar	2016	5
Plant Washington	Boiler: 1 - Generator: ST1	SERC + FRCC	Coal	2018	850
Polk 2 Combined Cycle	Generator: C 2A	SERC + FRCC	Combined Cycle	2017	165
Polk 2 Combined Cycle	Generator: C 2B	SERC + FRCC	Combined Cycle	2017	165
Polk 2 Combined Cycle	Generator: C 2C	SERC + FRCC	Combined Cycle	2017	165
Polk 2 Combined Cycle	Generator: C 2D	SERC + FRCC	Combined Cycle	2017	165
Polk 2 Combined Cycle	Generator: CC 9	SERC + FRCC	Combined Cycle	2017	459
Polk Biomass Generating Facility	Generator: FB 1	SERC + FRCC	Biomass	2016	75
Port Everglades Next Generation Clean Energy	Generator: CC 5A	SERC + FRCC	Combined Cycle	2016	250
Port Everglades Next Generation Clean Energy	Generator: CC 5B	SERC + FRCC	Combined Cycle	2016	250
Port Everglades Next Generation Clean Energy	Generator: CC 5C	SERC + FRCC	Combined Cycle	2016	250
Port Everglades Next Generation Clean Energy	Generator: CC 5ST	SERC + FRCC	Combined Cycle	2016	500
Prease Farm Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Roady Lane Solar Farm	Generator: PV 1	SERC + FRCC	Solar	2016	75
Rutherford Farm	Generator: PV 1	SERC + FRCC	Solar	2016	75

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Sampson County Landfill Facility	Generator: IC GEN7	SERC + FRCC	Landfill	2017	2
Sampson County Landfill Facility	Generator: IC GEN8	SERC + FRCC	Landfill	2016	2
Sarasota County Biomass Plant (Sarasota Energy)	Generator: IC 4	SERC + FRCC	Biomass	2016	2
Sedberry Farm Solar Project	Generator: 1	SERC + FRCC	Solar	2017	5
Snow Camp Solar Project	Generator: 1	SERC + FRCC	Solar	2016	12
Spring Hope Solar 2	Generator: 1	SERC + FRCC	Solar	2016	5
Spring Valley Farm 2 Solar Project	Generator: 1	SERC + FRCC	Solar	2017	5
Spring Valley Farm Solar Project	Generator: PV1	SERC + FRCC	Solar	2017	5
Staley Snow Camp Road Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Statesville Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Thomas Solar Project	Generator: 1	SERC + FRCC	Solar	2016	5
Tiburon Holdings Solar Project	Generator: PV1	SERC + FRCC	Solar	2016	5
Toprak Solar Project	Generator: PV1	SERC + FRCC	Solar	2016	20
V C Summer	Generator: 2	SERC + FRCC	Nuclear	2018	1,100
V C Summer	Generator: 3	SERC + FRCC	Nuclear	2019	1,100
Van Slyke Solar Center	Generator: PV1	SERC + FRCC	Solar	2016	5
Vass Solar 2 Project	Generator: 1	SERC + FRCC	Solar	2016	5
Vogtle (GA)	Generator: 3	SERC + FRCC	Nuclear	2019	1,100
Vogtle (GA)	Generator: 4	SERC + FRCC	Nuclear	2020	1,100
Watson Seed Farm PV 1	Generator: PV 1	SERC + FRCC	Solar	2016	20
Watts Bar Nuclear	Generator: NP2	SERC + FRCC	Nuclear	2016	1,122
Westside Solar Farm	Generator: WEST1	SERC + FRCC	Solar	2016	4
Arbuckle Mountain Wind Farm	Generator: GEN1	SPP	Wind	2016	100
Breckinridge Wind Project (Chisholm View Wind II)	Generator: BWP	SPP	Wind	2016	97
Buffalo Dunes Wind Project	Generator: WT	SPP	Wind	2016	180
Goodman Energy Center	Generator: 10	SPP	Combustion Turbine	2016	9

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Goodman Energy Center	Generator: 11	SPP	Combustion Turbine	2016	9
Goodman Energy Center	Generator: 12	SPP	Combustion Turbine	2016	9
Goodwell Wind Project	Generator: 1	SPP	Wind	2016	200
Grand River Energy Center Unit 3 (Chouteau)	Generator: 3CT	SPP	Combined Cycle	2017	495
Grant Wind Farm	Generator: 1	SPP	Wind	2016	150
Kingfisher Wind Farm	Generator: KNG1	SPP	Wind	2016	298
Marshall (Summerfield) Wind Farm	Generator: RPMA	SPP	Wind	2016	37
Marshall (Summerfield) Wind Farm	Generator: WT 1	SPP	Wind	2016	37
Ozark	Generator: 10	SPP	Hydro	2016	20
Riverton CC	Generator: 1	SPP	Combined Cycle	2016	250
Roosevelt Wind Ranch	Generator: GEN1	SPP	Wind	2016	250
Slate Creek Wind Project	Generator: 1	SPP	Wind	2016	150
Stillwater IC Plant	Generator: 1	SPP	Combustion Turbine	2016	19
Stillwater IC Plant	Generator: 2	SPP	Combustion Turbine	2016	19
Stillwater IC Plant	Generator: 3	SPP	Combustion Turbine	2016	19
Western Plains Wind Project	Generator: WT 1	SPP	Wind	2018	400
Alta Wind Energy Center	Generator: WT567 620	WECC	Wind	2016	153
American Solar Greenworks Solar Plant	Generator: 1	WECC	Solar	2016	35
Anderson Facility	Generator: GEN2	WECC	Biomass	2016	31
Antelope Valley I Solar Project	Generator: PV1	WECC	Solar	2016	309
Antelope Valley II Solar Project	Generator: PV1	WECC	Solar	2016	270
Arlington Valley Solar Energy Project	Generator: SS	WECC	Solar	2016	125
Avalon Wind Project	Generator: WT1 127	WECC	Wind	2017	300
Beacon Photovoltaic Project	Generator: PV1	WECC	Solar	2016	88
Beacon Solar (Hectate)	Generator: PV1	WECC	Solar	2016	112
Beacon Solar (Hectate) 2	Generator: PV1	WECC	Solar	2016	50
Beacon Solar Plant Site 2 (SunEdison)	Generator: BEAC2	WECC	Solar	2017	48
Beacon Solar Plant Site 5 (SunEdison)	Generator: BEAC5	WECC	Solar	2017	40
Blackwell Solar Park Project	Generator: 1	WECC	Solar	2016	20
Boise Airport Solar Project	Generator: PV 1	WECC	Solar	2016	10
Carty Generating Station	Generator: 2	WECC	Combined Cycle	2019	460
Carty Generating Station	Generator: GEN1A	WECC	Combined Cycle	2016	272

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Carty Generating Station	Generator: GEN1B	WECC	Combined Cycle	2016	168
Centinela Solar Energy	Generator: PV3	WECC	Solar	2016	105
Cheyenne Power Plant	Generator: CT3	WECC	Combustion Turbine	2018	80
Clark Canyon Hydro	Generator: HY	WECC	Hydro	2017	4
Clark Canyon Hydro	Generator: HY2	WECC	Hydro	2017	4
Copper Mountain Solar IV	Generator: 1	WECC	Solar	2016	94
Del Sur Solar	Generator: PV1	WECC	Solar	2016	19
Del Sur Solar	Generator: PV2	WECC	Solar	2016	19
Frank Bowerman Landfill Project	Generator: 1	WECC	Biomass	2016	20
Gibson Dam	Generator: HY5	WECC	Hydro	2019	8
Gibson Dam	Generator: HY6	WECC	Hydro	2019	8
Glenarm Repowering	Generator: GT5	WECC	Combined Cycle	2016	71
Haxtun Wind Farm	Generator: WT1 20	WECC	Wind	2016	30
Headworks Reservoir	Generator: HY1	WECC	Hydro	2018	4
Hecate Energy Beacon Solar 1	Generator: BEAC1	WECC	Solar	2017	56
Huntington Beach Repowering	Generator: B	WECC	Combined Cycle	2018	487
Huntington Beach Repowering	Generator: E	WECC	Combined Cycle	2020	487
Imperial Solar Energy Center West	Generator: PV1	WECC	Solar	2016	150
K Road Moapa Solar Facility	Generator: PV2	WECC	Solar	2016	100
La Luz Energy Center	Generator: 1	WECC	Combustion Turbine	2016	40
Lake Tahoe Biomass Project (Cabin Creek)	Generator: 1	WECC	Biomass	2016	2
Liberty Energy Center	Generator: ST 1	WECC	Biomass	2017	5
Liberty Energy Center	Generator: ST 2	WECC	Biomass	2017	5
Liberty Energy Center	Generator: ST 3	WECC	Biomass	2017	5
Lincoln Alamosa County Solar	Generator: PV	WECC	Solar	2016	37
Lotus Solar Farm (Borden Solar)	Generator: 1	WECC	Solar	2020	51
McCoy Solar Energy Project	Generator: PV1	WECC	Solar	2016	250
McCoy Solar Energy Project	Generator: PV2	WECC	Solar	2019	500
Midway Solar Farm I	Generator: PV 1	WECC	Solar	2016	50
Neal Hot Springs	Generator: GE 4	WECC	Geothermal	2017	28
Nellis Solar Project - II	Generator: 1	WECC	Solar	2016	15
Newberry Demonstration EGS Project	Generator: EO 1	WECC	Geothermal	2018	30
Newberry Demonstration EGS Project	Generator: EO 2	WECC	Geothermal	2018	30
Newberry Demonstration EGS Project	Generator: EO 3	WECC	Geothermal	2018	30

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Newberry Demonstration EGS Project	Generator: EO 4	WECC	Geothermal	2018	30
Newberry Volcano	Generator: GE1	WECC	Geothermal	2018	45
Newberry Volcano	Generator: GE2	WECC	Geothermal	2019	45
Newberry Volcano	Generator: GE3	WECC	Geothermal	2020	90
North Lancaster Ranch Solar PV Plant	Generator: 1	WECC	Solar	2017	20
Oakley Generating Station	Generator: CC1	WECC	Combined Cycle	2018	624
Potrero Hills Landfill	Generator: 1	WECC	Landfill	2016	8
RE Tranquillity 1 Solar Generating Facility	Generator: 1	WECC	Solar	2016	200
RE Tranquillity 2 Solar Generating Facility	Generator: 1	WECC	Solar	2016	15
RE Tranquillity 3 Solar Generating Facility	Generator: 1	WECC	Solar	2016	15
RE Tranquillity 4 Solar Generating Facility	Generator: 1	WECC	Solar	2016	35
RE Tranquillity 5 Solar Generating Facility	Generator: 1	WECC	Solar	2016	40
RE Tranquillity 6 Solar Generating Facility	Generator: 1	WECC	Solar	2016	35
RE Tranquillity 7 Solar Generating Facility	Generator: 1	WECC	Solar	2016	20
RE Tranquillity 8 Solar Generating Facility	Generator: 1	WECC	Solar	2016	40
Rice Solar Energy Project	Generator: SS1	WECC	Solar	2016	150
Rio Bravo Solar I	Generator: PV1	WECC	Solar	2017	20
San Emidio South Project Phase I-II	Generator: 2	WECC	Geothermal	2016	11
San Luis Solar	Generator: PV1	WECC	Solar	2016	20
Scattergood Repowering CC	Generator: 4	WECC	Combined Cycle	2016	367
Scattergood Repowering CT	Generator: 6	WECC	Combustion Turbine	2016	104
Scattergood Repowering CT	Generator: 7	WECC	Combustion Turbine	2016	104
Searchlight Wind Energy Project	Generator: WT1 87	WECC	Wind	2016	200
SEPV Mojave West Solar Project	Generator: 1	WECC	Solar	2016	20
Silver State South	Generator: SSS	WECC	Solar	2016	250
South Kern Industrial Center (SKIC Solar 1-2)	Generator: SKI10	WECC	Solar	2016	10
Springbok Solar Farm I Project	Generator: 1	WECC	Solar	2016	150
Stateline Solar Project	Generator: STL	WECC	Solar	2016	300
Summit Ridge I Wind Farm	Generator: SRWF	WECC	Wind	2019	194
Utah Red Hills Renewable Park	Generator: 1	WECC	Solar	2016	80
Victorville 2 Hybrid Power Project	Generator: PV1	WECC	Solar	2018	49

Plant Name	Unit Name	Region Name	Capacity Type	Online Year	Capacity (MW)
Watson Cogeneration	Generator: GN97	WECC	Combustion Turbine	2016	80
Western Antelope Blue Sky Ranch B	Generator: B	WECC	Solar	2017	20
Western Antelope Dry Ranch Project	Generator: WADR	WECC	Solar	2017	10
Wildwood Solar Project	Generator: PV1	WECC	Solar	2016	20

Table A2-2. Planned Retirements for 2016 through 2020

Plant Name	Unit Name	Region Name	Capacity Type	Retirement Year	Capacity (MW)
GADSDEN	1	SERC + FRCC	Coal	2019	64
GADSDEN	2	SERC + FRCC	Coal	2019	66
Greene County (AL)	1	SERC + FRCC	Coal	2016	254
Greene County (AL)	2	SERC + FRCC	Coal	2016	243
Browns Ferry	2	SERC + FRCC	Nuclear	2035	1,104
Browns Ferry	3	SERC + FRCC	Nuclear	2037	1,105
COLBERT	1	SERC + FRCC	Coal	2016	177
COLBERT	2	SERC + FRCC	Coal	2016	177
COLBERT	3	SERC + FRCC	Coal	2016	177
COLBERT	4	SERC + FRCC	Coal	2016	173
JOLIET 29	7	PJM	Coal	2016	518
JOLIET 29	8	PJM	Coal	2016	518
MCKEE RUN	1	PJM	Oil/Gas	2017	17
MCKEE RUN	2	PJM	Oil/Gas	2017	17
TURKEY POINT	3	SERC + FRCC	Nuclear	2032	802
TURKEY POINT	4	SERC + FRCC	Nuclear	2033	802
AVON PARK	P1	SERC + FRCC	Combustion Turbine	2016	24
AVON PARK	P2	SERC + FRCC	Combustion Turbine	2016	25
CRYSTAL RIVER	1	SERC + FRCC	Coal	2018	372
CRYSTAL RIVER	2	SERC + FRCC	Coal	2018	494
G E TURNER	P1	SERC + FRCC	Combustion Turbine	2016	11
G E TURNER	P2	SERC + FRCC	Combustion Turbine	2016	11
HIGGINS	P1	SERC + FRCC	Combustion Turbine	2016	27
HIGGINS	P2	SERC + FRCC	Combustion Turbine	2016	26
HIGGINS	P3	SERC + FRCC	Combustion Turbine	2016	28

Plant Name	Unit Name	Region Name	Capacity Type	Retirement Year	Capacity (MW)
HIGGINS	P4	SERC + FRCC	Combustion Turbine	2016	32
Suwannee	2	SERC + FRCC	Oil/Gas	2018	28
Suwannee	3	SERC + FRCC	Oil/Gas	2018	71
LANSING SMITH	1	SERC + FRCC	Coal	2016	162
LANSING SMITH	2	SERC + FRCC	Coal	2016	195
ARVAH B HOPKINS	GT2	SERC + FRCC	Combustion Turbine	2017	24
Dresden	2	PJM	Nuclear	2030	883
Dresden	3	PJM	Nuclear	2031	867
JOLIET 9	6	PJM	Coal	2016	314
Quad Cities (EXELON)	1	PJM	Nuclear	2032	908
Quad Cities (EXELON)	2	PJM	Nuclear	2032	911
H T Pritchard/Eagle Valley	2	MISO	Oil/Gas	2016	39
H T Pritchard/Eagle Valley	3	MISO	Coal	2016	43
H T Pritchard/Eagle Valley	4	MISO	Coal	2016	56
H T Pritchard/Eagle Valley	5	MISO	Coal	2016	62
H T Pritchard/Eagle Valley	ST1	MISO	Oil/Gas	2016	39
WABASH RIVER	4	MISO	Coal	2016	85
BIG SANDY	1	PJM	Coal	2016	260
R A Reid	GEN1	MISO	Coal	2016	65
Dale (KY)	3	SERC + FRCC	Coal	2016	74
Dale (KY)	4	SERC + FRCC	Coal	2016	75
CHALK POINT	1	PJM	Coal	2018	334
CHALK POINT	2	PJM	Coal	2018	335
DICKERSON	2	PJM	Coal	2018	178
DICKERSON	3	PJM	Coal	2018	178
DICKERSON	ST1	PJM	Coal	2018	178
B C COBB	4	MISO	Coal	2016	156
B C COBB	5	MISO	Coal	2016	156
Palisades (MI)	1	MISO	Nuclear	2032	782
J C WEADOCK	7	MISO	Coal	2016	155
J C WEADOCK	8	MISO	Coal	2016	151
J R WHITING	1	MISO	Coal	2016	102
J R WHITING	2	MISO	Coal	2016	102
J R WHITING	3	MISO	Coal	2016	124
TRENTON CHANNEL	7	MISO	Coal	2016	110
TRENTON CHANNEL	8	MISO	Coal	2016	100
Twin Falls (MI)	1	MISO	Hydro	2017	1
Twin Falls (MI)	2	MISO	Hydro	2017	1
Twin Falls (MI)	3	MISO	Hydro	2017	1

Plant Name	Unit Name	Region Name	Capacity Type	Retirement Year	Capacity (MW)
Twin Falls (MI)	4	MISO	Hydro	2017	1
Twin Falls (MI)	5	MISO	Hydro	2017	1
JAMES DE YOUNG	3	MISO	Coal	2020	11
JAMES DE YOUNG	4	MISO	Coal	2020	21
Key City	1	MISO	Combustion Turbine	2017	15
Key City	3	MISO	Combustion Turbine	2017	15
Key City	4	MISO	Combustion Turbine	2017	16
Monticello (MN)	1	MISO	Nuclear	2031	633
Prairie Island	1	MISO	Nuclear	2034	521
Prairie Island	2	MISO	Nuclear	2034	519
JACK WATSON	1	SERC + FRCC	Oil/Gas	2019	76
JACK WATSON	2	SERC + FRCC	Oil/Gas	2019	76
JACK WATSON	3	SERC + FRCC	Oil/Gas	2019	107
MONTROSE	2	SPP	Coal	2016	164
MONTROSE	3	SPP	Coal	2016	176
Sibley (MO)	1	SPP	Coal	2019	54
Sibley (MO)	2	SPP	Coal	2019	54
MERAMEC	1	MISO	Coal	2022	120
MERAMEC	2	MISO	Coal	2022	120
MERAMEC	3	MISO	Coal	2022	268
MERAMEC	4	MISO	Coal	2022	347
Fort Calhoun	1	SPP	Nuclear	2033	479
NORTH OMAHA	4	SPP	Coal	2023	138
NORTH OMAHA	5	SPP	Coal	2023	224
REID GARDNER	4	WECC	Coal	2017	265
FORT CHURCHILL	1	WECC	Oil/Gas	2018	113
Oyster Creek (NJ)	1	PJM	Nuclear	2019	615
RIO GRANDE	6	WECC	Oil/Gas	2017	45
RIO GRANDE	7	WECC	Oil/Gas	2017	46
SAN JUAN	2	WECC	Coal	2018	320
SAN JUAN	3	WECC	Coal	2018	495
Indian Point 2	2	NYISO	Nuclear	2033	1,020
Dunkirk Generating Station	DUN2	NYISO	Coal	2016	78
Nine Mile Point Nuclear Station (NY)	1	NYISO	Nuclear	2029	531
AVON LAKE	7	PJM	Coal	2016	92
St Marys (OH)	7	PJM	Combustion Turbine	2018	12
MUSKOGEE	4	SPP	Coal	2019	511

Plant Name	Unit Name	Region Name	Capacity Type	Retirement Year	Capacity (MW)
MUSKOGEE	5	SPP	Coal	2019	517
SHAWVILLE	1	PJM	Coal	2016	122
SHAWVILLE	2	PJM	Coal	2016	125
H B ROBINSON	2	SERC + FRCC	Nuclear	2031	741
Oconee	1	SERC + FRCC	Nuclear	2033	846
Oconee	2	SERC + FRCC	Nuclear	2034	846
Oconee	3	SERC + FRCC	Nuclear	2034	846
MCMEEKIN	1	SERC + FRCC	Coal	2016	125
MCMEEKIN	2	SERC + FRCC	Coal	2016	125
Johnsonville (TN)	2	SERC + FRCC	Coal	2017	106
Johnsonville (TN)	3	SERC + FRCC	Coal	2017	106
Johnsonville (TN)	4	SERC + FRCC	Coal	2017	106
Plant X (TX)	1	SPP	Oil/Gas	2019	48
Plant X (TX)	2	SPP	Oil/Gas	2019	102
Plant X (TX)	3	SPP	Oil/Gas	2020	103
CLINCH RIVER	1	PJM	Coal	2016	230
CLINCH RIVER	2	PJM	Coal	2016	230
Surry	1	PJM	Nuclear	2032	872
Surry	2	PJM	Nuclear	2033	872
Point Beach	1	MISO	Nuclear	2030	591
Point Beach	2	MISO	Nuclear	2032	591
Edgewater (WI)	4	MISO	Coal	2018	320
Fox Lake	1	MISO	Oil/Gas	2016	12
Milford (IA)	1	MISO	Combustion Turbine	2018	1
AES Beaver Valley Partners Beaver Valley	GEN2	PJM	Coal	2017	32
Brunswick (NV)	1	WECC	Combustion Turbine	2019	2
Brunswick (NV)	2	WECC	Combustion Turbine	2019	2
Brunswick (NV)	3	WECC	Combustion Turbine	2019	2
Milford (IA)	4	MISO	Combustion Turbine	2018	1
Rolling Hills Generating LLC	CT2	PJM	Combustion Turbine	2016	165
Rolling Hills Generating LLC	CT3	PJM	Combustion Turbine	2016	165
Rolling Hills Generating LLC	CT4	PJM	Combustion Turbine	2016	165
WABASH RIVER	2	MISO	Coal	2016	85
WABASH RIVER	3	MISO	Coal	2016	85

Plant Name	Unit Name	Region Name	Capacity Type	Retirement Year	Capacity (MW)
WABASH RIVER	5	MISO	Coal	2016	95
NAVAJO	NAV1	WECC	Coal	2019	750
Donald C Cook	1	PJM	Nuclear	2035	1,009
Donald C Cook	2	PJM	Nuclear	2038	1,060
Joseph M Farley	1	SERC + FRCC	Nuclear	2037	874
Brunswick (NC)	1	SERC + FRCC	Nuclear	2037	938
Brunswick (NC)	2	SERC + FRCC	Nuclear	2035	932
Beaver Valley	1	PJM	Nuclear	2036	921
St Lucie	1	SERC + FRCC	Nuclear	2036	981
Edwin I Hatch	1	SERC + FRCC	Nuclear	2035	876
Edwin I Hatch	2	SERC + FRCC	Nuclear	2039	883
Boardman (OR)	1	WECC	Coal	2020	585
James A FitzPatrick	1	NYISO	Nuclear	2036	716
Ginna	1	NYISO	Nuclear	2030	490
Davis Besse	1	PJM	Nuclear	2037	894
North Anna	1	PJM	Nuclear	2038	943
North Anna	2	PJM	Nuclear	2040	943
Three Mile Island	1	PJM	Nuclear	2034	805
Cooper	1	SPP	Nuclear	2034	766
Arkansas Nuclear One	1	SERC + FRCC	Nuclear	2034	836
Arkansas Nuclear One	2	SERC + FRCC	Nuclear	2040	992
Indian Point 3	3	NYISO	Nuclear	2036	1,041
AES Beaver Valley Partners Beaver Valley	GEN3	PJM	Coal	2017	114
Lake Road (MO)	4	SPP	Coal	2019	97
Suwannee	1	SERC + FRCC	Oil/Gas	2018	30
Broadway (CA)	B3	WECC	Oil/Gas	2016	65
Rolling Hills Generating LLC	CT1	PJM	Combustion Turbine	2016	165
Paradise (KY)	1	SERC + FRCC	Coal	2017	628
Paradise (KY)	2	SERC + FRCC	Coal	2017	602
VALMONT	5	WECC	Coal	2017	186
Cherokee (CO)	4	WECC	Coal	2017	352
REDONDO BEACH	GEN5	WECC	Oil/Gas	2019	179
REDONDO BEACH	GEN6	WECC	Oil/Gas	2019	175
REDONDO BEACH	GEN7	WECC	Oil/Gas	2019	480
REDONDO BEACH	GEN8	WECC	Oil/Gas	2019	480
Allen Steam Plant (TN)	1	SERC + FRCC	Coal	2018	245
Allen Steam Plant (TN)	2	SERC + FRCC	Coal	2018	245
Allen Steam Plant (TN)	3	SERC + FRCC	Coal	2018	245
GEORGE NEAL NORTH	1	MISO	Coal	2016	135

Plant Name	Unit Name	Region Name	Capacity Type	Retirement Year	Capacity (MW)
GEORGE NEAL NORTH	2	MISO	Coal	2016	289
Duane Arnold	1	MISO	Nuclear	2035	601
Dubuque	IC2	MISO	Combustion Turbine	2016	2
Sutherland (IA)	3	MISO	Coal	2016	79
NORTHEASTERN	3	SPP	Coal	2026	460
NORTHEASTERN	4	SPP	Coal	2016	470
Calvert Cliffs Nuclear Power Plant	1	PJM	Nuclear	2035	866
Calvert Cliffs Nuclear Power Plant	2	PJM	Nuclear	2037	850
Bridgeport Station	2	ISONE	Oil/Gas	2017	130
Centralia Complex	BD21	WECC	Coal	2020	703
Centralia Complex	BD22	WECC	Coal	2025	703
Peach Bottom	2	PJM	Nuclear	2034	1,125
Peach Bottom	3	PJM	Nuclear	2034	1,125
Browns Ferry	1	SERC + FRCC	Nuclear	2034	1,101
HOOT LAKE	2	MISO	Coal	2020	60
HOOT LAKE	3	MISO	Coal	2020	84
New Castle Plant	5	PJM	Coal	2016	137
Millstone	2	ISONE	Nuclear	2035	869
Pilgrim	1	ISONE	Nuclear	2032	677
Bar Harbor	1	ISONE	Combustion Turbine	2017	1
Bar Harbor	3	ISONE	Combustion Turbine	2017	1
Brayton PT	GEN1	ISONE	Coal	2017	244
Brayton PT	GEN2	ISONE	Coal	2017	244
Brayton PT	GEN3	ISONE	Coal	2017	612
Brayton PT	GEN4	ISONE	Oil/Gas	2017	435
Brayton PT	IC1	ISONE	Combustion Turbine	2017	3
Brayton PT	IC2	ISONE	Combustion Turbine	2017	2
Brayton PT	IC3	ISONE	Combustion Turbine	2017	3
Brayton PT	IC4	ISONE	Combustion Turbine	2017	3
E C GASTON	1	SERC + FRCC	Coal	2016	254
E C GASTON	2	SERC + FRCC	Coal	2016	256
E C GASTON	3	SERC + FRCC	Coal	2016	254
E C GASTON	ST4	SERC + FRCC	Coal	2016	256
Harding Street	3	MISO	Oil/Gas	2016	35
Harding Street	4	MISO	Oil/Gas	2016	35
Harding Street	5	MISO	Coal	2016	106

Plant Name	Unit Name	Region Name	Capacity Type	Retirement Year	Capacity (MW)
Harding Street	6	MISO	Coal	2016	106
Harding Street	7	MISO	Coal	2016	435
Encina Carlsbad	ST2	WECC	Oil/Gas	2017	104
Encina Carlsbad	ST3	WECC	Oil/Gas	2017	110
Encina Carlsbad	ST1	WECC	Oil/Gas	2017	106
AVON LAKE	9	PJM	Coal	2016	625
James M Barry Electric Generating Plant	1	SERC + FRCC	Coal	2019	138
James M Barry Electric Generating Plant	2	SERC + FRCC	Coal	2019	137
James M Barry Electric Generating Plant	3	SERC + FRCC	Coal	2016	249
Johnsonville (TN)	1	SERC + FRCC	Coal	2017	106
New Castle Plant	3	PJM	Coal	2016	98
New Castle Plant	4	PJM	Coal	2016	98
SHAWVILLE	3	PJM	Coal	2016	175
SHAWVILLE	4	PJM	Coal	2016	175
YORKTOWN	1	PJM	Coal	2017	159
Polk Station	2	SERC + FRCC	Combustion Turbine	2017	159
Polk Station	3	SERC + FRCC	Combustion Turbine	2017	164
PSEG Salem Generating Station	1	PJM	Nuclear	2037	1,168
Polk Station	GT4	SERC + FRCC	Combustion Turbine	2017	149
Polk Station	GT5	SERC + FRCC	Combustion Turbine	2017	149