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Working Paper

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DIW Discussion Papers, No. 1880

Provided in Cooperation with:

German Institute for Economic Research (DIW Berlin)

Suggested Citation: Hauenstein, Christian; Holz, Franziska (2020) : The U.S. coal sector between shale gas and renewables: Last resort coal exports?, DIW Discussion Papers, No. 1880, Deutsches Institut für Wirtschaftsforschung (DIW), Berlin

This Version is available at:

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1880

Discussion Papers

Deutsches Institut für Wirtschaftsforschung

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IMPRESSUM

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<http://www.diw.de>

ISSN electronic edition 1619-4535

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The U.S. Coal Sector between Shale Gas and Renewables: Last Resort Coal Exports?

Christian Hauenstein^a and Franziska Holz^b

Abstract

Coal consumption and production have sharply declined in recent years in the U.S., despite political support. Reasons are mostly unfavorable economic conditions for coal, including competition from natural gas and renewables in the power sector, as well as an aging coal-fired power plant fleet. The U.S. Energy Information Administration as well as most models of North American energy markets depict continuously high shares of coal-fired power generation over the next decades in their current policies scenarios. We contrast their results with coal sector modelling based on bottom-up data and recent market trends. We project considerably lower near-term coal use for power generation in the U.S. This has significant effects on coal production and mining employment. Allowing new export terminals along the U.S. West Coast could ease cuts in U.S. production. Yet, exports are a highly uncertain strategy because the U.S. could be strongly affected by changes in global demand, for example from non-U.S. climate policy. Furthermore, coal production within the U.S. is likely to experience regional shifts, affecting location and number of mining jobs.

Keywords: USA; coal; international coal trade; EMF34; numerical modeling; scenarios

JEL Codes: Q02, Q38, Q47, L72, C61

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1 Introduction

In many countries around the world, governments and utility companies have started to engage in coal-phase out processes (Jewell et al. 2019; Rentier, Lelieveldt, and Kramer 2019). Others hold out hope for more prosperous times in the coal sector (Mendelevitch, Hauenstein, and Holz 2019). This paper explores the future of the coal sector in the United States (U.S.). We find that while the politics are different in the U.S. and in Europe, future outcomes may be similar. However, these trends are not yet reflected in many energy scenarios such as those of the U.S. Energy Information Administration (EIA) and of many other models of North American energy markets.

Round 34 of the Energy Modeling Forum (EMF) has dealt with “North American Energy Trade and Integration” and brought together many models from the USA, Canada, and Mexico in a comparative effort (Huntington et al. forthcoming). Our bottom-up study draws on the results of their model-based analyses. We argue that numerical modeling of U.S. electricity, energy and energy-economy relationships need to take into account the vintage structure of the coal-fired power plant fleet as well as the dynamic development of the relative costs of renewables and shale gas compared to coal. In addition, global coal demand trends need to be considered when assessing possible futures for U.S. coal production and coal-industry jobs.

Coal has long been a mainstay of U.S. baseload power generation as well as the U.S. mining sector. However, U.S. domestic coal consumption and production was about halved between 2008 and 2019, with consumption dropping to 520 million tons (Mt) in 2019, the lowest value since 1978. Production declined to 640 Mtpa in 2019.¹ Approximately 93% of domestic coal consumption, relatively constant over the last ten years, goes to the U.S. electricity sector. U.S. coal-fired power generation are directly influencing coal production. Power generation from coal lost large market shares, reaching less than 25% in 2019 (966 TWh). This went along with an increasing number of coal-fired power plants retiring, without new ones being constructed, leaving an aging fleet with a current average age of 41 years in 2020.

¹ EIA energy data browser: <https://www.eia.gov/totalenergy/data/browser/>, last accessed March 30, 2020. Figures in coal tonnage are given in metric tons. Short tons are converted using the IEA conversion factor 0.907184.

U.S. federal government support for continued use of coal remains strong, despite a global trend to “powering past coal” and more and more coal phase-out decisions in developed countries (Blondeel, Van de Graaf, and Haesebrouck 2020). In June 2019, the EPA issued the so-called Affordable Clean Energy rule (ACE), which replaced the Clean Power Plan (CPP) of the previous administration (EPA 2019), despite the negative emission and health effects that must be expected (Thomson, Huelsman, and Ong 2018). In contrast to the CPP, the ACE allows for very soft emission control regulation of coal-fired power generation by the states. On the supply side strict environmental regulations in the ‘Stream Protection Rule’ and the ‘Resource Management Planning’ have been relaxed.

However, economic drivers have led to the continuous decline of U.S. coal mining and power generation. Mendeleevitch, Hauenstein, and Holz (2019), Feaster (2018), Houser, Bordoff, and Marsters (2017), Wang, Li, and Li (2019) and others have documented and analyzed the downward trend of U.S. coal production and consumption in the U.S. electricity sector. They essentially come to four main reasons for this decline: 1) the shale gas boom; 2) an increasing amount of renewable electricity generation; 3) the tightened environmental regulations of the power sector (but with less effect than the previous two reasons); and 4) the very old fleet of coal-fired power plants. And this trend continues. More coal-fired power plants are expected to retire over the next years,² and new builds are very unlikely in the context of low-price (shale) gas and increasingly cheap renewables.³

Yet, these U.S. electricity and coal sector trends are not reflected in many U.S. energy forecast scenarios. In the results of the EMF34 group (Huntington et al. forthcoming) this downward trend of coal-fired electricity generation is only partially reflected. Figure 1 shows that many models still find a share of coal in the electricity mix in 2040 of up to 30%, most of more than 20%. Given the current average age of 41 years of coal-fired power plants, new investments in coal-fired electricity generation would be necessary to achieve this. However, such investments are very unlikely in the current economic circumstances of low-cost competing renewables and gas and, indeed, the industry has no plans for

² EIA 860M January 20120, <https://www.eia.gov/electricity/data/eia860m/>, last accessed March 30, 2020.

³ The Covid-19 crisis, starting in the first quarter of 2020, reinforces the downward trends and shows the vulnerable economic situation of the coal sector (Oei, Yanguas-Parra, and Hauenstein 2020). While power production from other sources, especially renewables, only decreased slightly or even increased, power generation from coal fell drastically (IEA 2020), increasing the strain on coal producers worldwide markedly (Oei, Yanguas-Parra, and Hauenstein 2020).

new coal power plants.⁴ Notwithstanding, the U.S. Department of Energy’s Energy Information Administration (US DOE EIA) forecasted for the year 2040 940 TWh from coal in the Annual Energy Outlook 2019 (EIA 2019), i.e. approximately the level of 2019 (966 TWh).⁵ These – unrealistic – numbers served as input data for several of the models and scenarios in the EMF34 group.

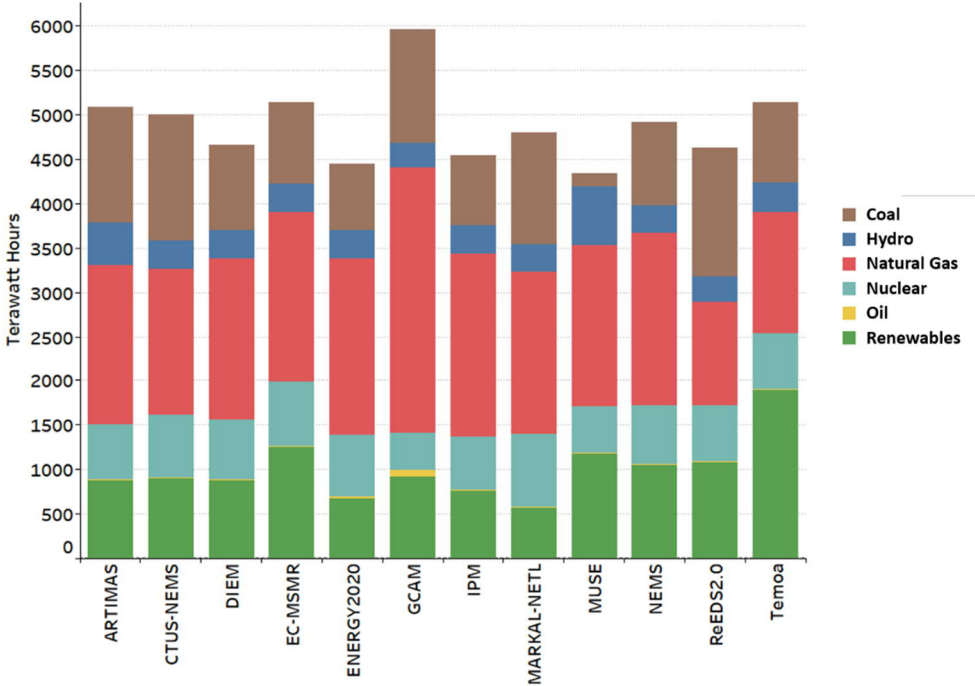


Figure 1: Overview of EMF34 results for U.S. electricity mix in 2040 of various models (“EMF34 Reference Scenario” (Modelers’ Choice Scenario))

Source: (Huntington et al. forthcoming)

In this paper, we investigate how U.S. coal production is affected by current market and policy trends, and whether or not the EMF34 scenarios reflect U.S. coal sector’s trends. Furthermore, we assess to what extent coal exports could compensate for declining domestic demand. Exports have repeatedly been presented by the industry as “savior” of the U.S. coal mining and mining jobs (Cornot-Gandolphe 2015; NCC 2018). Finally, we extend our analysis to also prospects of coal mining employment.

Exports have been only a marginal market for U.S. coal producers of both steam (thermal) and metallurgical (coking) coal. Due to their relatively high supply costs, U.S. coal producers generally act

⁴ See, for example, the power plant tracker at <https://endcoal.org/global-coal-plant-tracker/>

⁵ In the 2018 edition of its Annual Energy Outlook (EIA 2018) it was even higher, with 1,160TWh of net electricity generation from coal in 2040.

as marginal suppliers for the international coal market, strongly following the fluctuations in international coal prices with the size of their supplies to the market. With a shrinking domestic market, the question is whether U.S. coal producers can increase their exports to secure future revenues.

However, coal production in the U.S. is far from uniform. The four coal basins in the U.S. – Appalachia in the East, the Interior region (Center), the Powder River Basin (PRB) in the (North) West and the Rocky Mountains region – have very different characteristics. Most importantly, PRB coal can be produced at much lower costs than in any other region because it comes from large opencast mines. This has led to a continuous increase of the share of PRB coal in total U.S. coal supply in the last decades.⁶ When prospecting the future of the U.S. coal sector, it is a natural question whether this trend in favor of PRB coal will continue and whether there are scenarios – notably those with higher or lower exports – in which this trend is reinforced or attenuated. Due to their geographic location, the coal regions are differently connected to export ports and PRB coal, in particular, can hardly access export markets because of the *de facto* moratorium on West coast export terminals (Mendelevitch, Hauenstein, and Holz 2019).

Furthermore, this affects regional coal-mining employment. In the last years, there has been a significant loss of employment in the Appalachian. We assess how the number of coal jobs will evolve in the different mining regions.

We use the COALMOD-World model (Holz et al. 2016) to quantify our arguments and provide number for future coal production, consumption, exports, and employment. We draw on and complement scenarios from EMF34 on “North American Energy Trade and Integration” (Huntington et al. forthcoming).⁷ Some of the scenarios are parameterized with results of the GCAM model’s EMF 34 scenarios. In other words, we soft-link the sectoral COALMOD-World model with Integrated Assessment Model GCAM (Calvin et al. 2019).

In the remainder of this paper, we describe our method by detailing the modelling approach as well as the scenarios in Section 2. In Section 3, we present an overview of the global and U.S. results of the scenarios. In Section 4, we discuss the impact of exports and include scenario runs with the option of expanding U.S. West Coast export ports. We extend the analysis to investigate the scenarios’ effects

⁶ EIA energy data browser: <https://www.eia.gov/totalenergy/data/browser/>, last accessed March 30, 2020.

⁷ <https://emf.stanford.edu/projects/emf-34-north-american-energy-trade-and-integration>

on the different U.S. coal regions and coal mining employment in the long run in Section 5, before concluding in Section 6. The Appendix includes more details, in particular on alternative U.S. coal power pathways as well as on details of our results.

2 Method

Our approach is typical for an EMF exercise: a) we use a numerical model, here the sectoral global coal market model COALMOD-World (Holz et al. 2016), and b) we run a variety of scenarios with this model. In addition, for some of the scenarios, we soft-link the COALMOD-World with the Integrated Assessment Model GCAM (Global Change Assessment Model; Calvin et al. 2019). Even though both COALMOD-World and GCAM are global models, we focus on the U.S. results, both national and regional results.

2.1. COALMOD-World Model and Data

In the center of our quantitative analysis is a holistic model of the world steam coal market, COALMOD-World. It calculates steam coal production, trade, and prices for the world's regions. It features a detailed representation of domestic and international steam coal supply until 2050 and includes endogenous investment decisions in production, land transport, and export capacity, as well as an endogenous mechanism that updates production costs due to resource depletion (Holz et al. 2015; 2016). For the analysis in this paper, we have updated the model extensively, also compared to Mendeleevitch, Hauenstein and Holz (2019), to include recent data from the International Energy Agency (IEA 2019a; 2019b) and other, mostly national sources, for the U.S.A., China, India, etc. For example, the model is now calibrated for 2015 and we fix 2020 consumption levels to values extrapolated from the 2015 to 2018 trends in order to take into account the development trends of the past years.

Mathematically, COALMOD-World is a perfect foresight equilibrium model that collects the profit maximization problems of the major player types in the global steam coal market, namely producers and exporters, and balances their supply with demand in the coal consumption regions. The model specification has a focus on the supply side of coal (coal extraction, coal transport) and includes extraction costs and extraction constraints, transport costs and transport constraints, investments in mining and transport. Both the seaborne and the overland international trade as well as the national markets are included, with large countries split in regional nodes. We associate each player with one of these nodes.

The U.S. is represented with four supply nodes which represent the major steam coal basins: Appalachia in the East, Interior, Rocky Mountains in the Western coal region, and Powder River Basin in the Northern Great Plains. On the demand side, we split the entire U.S. (Lower 48 plus Alaska) in five consumption nodes: US-North-Central, US-Northeast, US-South-Central, US-Southeast, US-West, see Figure 2).⁸

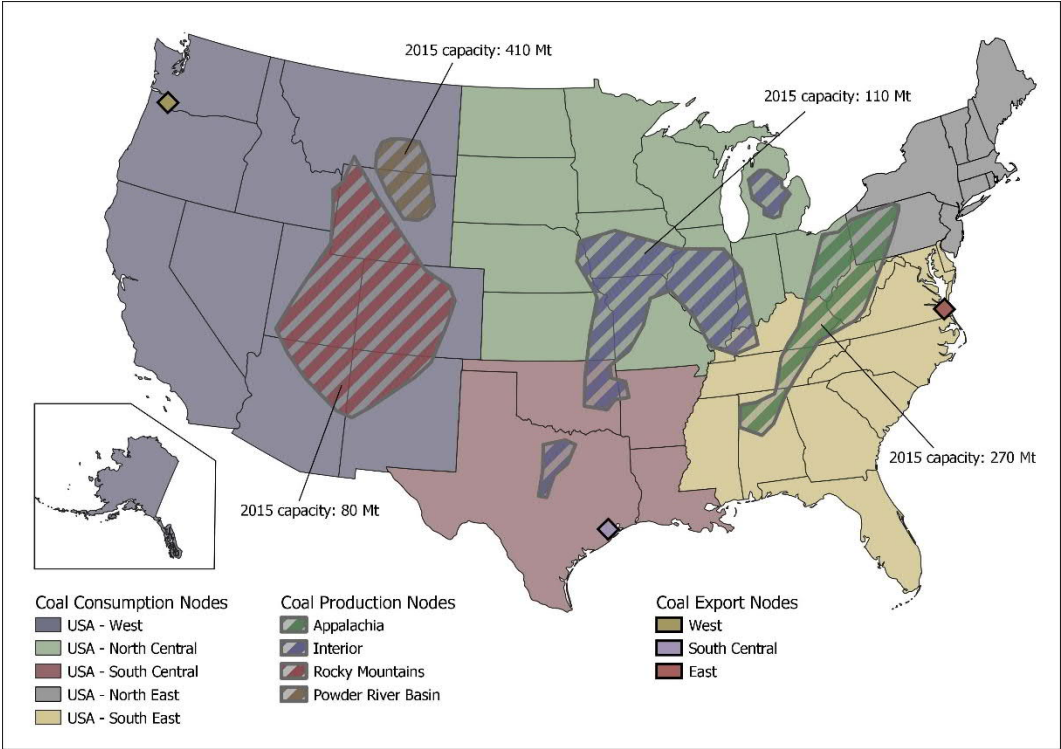


Figure 2: U.S. coal basins, consumption regions and reference export port locations in the COALMOD-World model

Demand is expressed in PJ (i.e. peta joules, a unit of energy), and for each coal producing region its specific average energy content is used to convert from mass (million metric tons, Mt) to energy (PJ). We include future demand trends by applying the regional growth rates from various data sources (see Section 2.2) to our 2020 coal consumption values in each demand node. 2020 values are obtained by extrapolating the trend between 2015 and 2018 from IEA (2019a) to 2020.

⁸ Our definition of the U.S. nodes is based on the EIA disaggregation. The EIA electricity data disaggregates the U.S. in ten regions ('New England', 'Middle Atlantic', etc.). In most cases, we aggregate two EIA regions to obtain the COALMOD-World demand nodes shown in Figure 2.

2.2. Two sets of scenarios, one cross-cutting policy shock

We develop two sets of scenarios in order to, on the one hand, assess the plausibility of the EMF34 coal results shown in Figure 1, and on the other hand, show that alternative futures with more stringent climate policy will have an even stronger effect on the U.S. coal sector than the trends of the past decade. The first set of scenarios are “status quo” scenarios which – generally speaking – assume a sustained, high average global coal demand to 2050 and a continuation of the status quo policies in the U.S. with a substantial role for coal in the power sector. Clearly, we do not assume any climate or coal phase-out policy in any of these scenarios. Except for one, all EMF34 scenarios are status quo scenarios to a smaller or larger extent (Huntington et al. forthcoming).

Our second set of scenarios are climate policy scenarios which assume climate policy measures in place that effectively reduce the role of coal in the global and the U.S. energy system. Only one EMF34 scenario falls into this category, namely the “Carbon Policy” scenario (Huntington et al. forthcoming) which we implement using GCAM’s coal results. Table 1 gives an overview of our five scenarios and their main assumptions.

Table 1: Our scenarios and their main characteristics.

Status quo scenarios	Climate policy scenarios
<p>EIA_ref</p> <ul style="list-style-type: none"> • U.S. coal demand growth rate from EIA AEO 2019 <i>Reference Scenario</i> • Global coal demand growth rate from IEA WEO 2019 <i>Stated Policies Scenario</i> 	<p>1.5°C</p> <ul style="list-style-type: none"> • Based on IPCC “1.5°C” scenarios analyzed by Yanguas Parra et al. (2019), here: median coal consumption without CCS of scenarios fulfilling sustainability criteria (limited BECCS & carbon uptake from AFOLU)
<p>GCAM_ref</p> <ul style="list-style-type: none"> • Coal demand growth rates in the U.S. and all other countries from GCAM EMF34 reference scenario results • “No policy” baseline scenario of GCAM 	<p>GCAM_carb</p> <ul style="list-style-type: none"> • Coal demand growth rates from the GCAM results of the EMF34 Carbon Policy scenario • GCAM runs with global CO₂ price of 35 USD in 2022, and then 5% growth per

	year to 137 USD in 2050 (EMF34 assumption)
<p><i>US_bottom_up</i></p> <ul style="list-style-type: none"> • Future U.S. coal demand is calculated from U.S. coal-fired power generation unit data from EIA with an average lifetime assumption of 60 years and a constant capacity factor of 0.5 • Global coal demand growth rate from IEA WEO 2019 <i>Stated Policies Scenario</i> 	

We distinguish three status quo scenarios, of which two can be considered EMF34 scenarios. The first one of them, the scenario *EIA_ref* uses coal demand growth rates for the U.S. regions from the *Reference case* of the EIA (2019) “*Annual Energy Outlook*” and the coal demand growth rates from the IEA (2019b) *Stated Policies Scenario* (formerly called New Policies Scenario) for the other world regions. EIA (2019, 107–8) assumes a decline of coal-fired power generation by 18% between 2018 and 2035 in the U.S. and a stable level thereafter until 2050. Given the current vintage structure of the U.S. power sector fleet, this implies investments in new coal-fired power plants (or plants of 80 years and more running) as well as an increasing capacity factor of these coal-fired power plants. Both assumptions seem unrealistic in the current market environment of cheap shale gas and low-cost renewables (Mendelevitch, Hauenstein, and Holz 2019), which is why we contrast the *EIA_ref* scenario with the *US_bottom_up* scenario. Both these scenarios are defined with the same international environment, IEA’s *Stated Policies Scenario* (IEA 2019b), which is a conservative scenario assuming only the implementation of the currently committed Nationally Determined Contributions (NDCs) and no further climate action. It, therefore, comes with stable global coal demand until 2050.

The second status quo scenario, “*GCAM_ref*”, is based on the results of the GCAM model’s EMF34 Reference Scenario. GCAM’s Reference Scenario results are among the highest coal use results of all EMF34 models and are the highest electricity sector levels (Figure 1). For the “soft link” of COALMOD-World and GCAM, we take the GCAM results for coal demand as input data for COALMOD-World. GCAM is a global integrated assessment model which features a detailed multi-sector representation

that explores both human and earth system dynamics (Calvin et al. 2019). In particular, it includes a detailed energy sector module which distinguishes the major fuels (including coal) and various energy transformation technologies. In its recent update for EMF34, it takes into account the vintage structure of the U.S. coal-fired power sector and restricts expansion of this (as well as the European coal power) sector.⁹ The EMF34 runs go to 2050 and can therefore not report on the temperature development to 2100. In GCAM, the U.S. is one separate node, out of 32 nodes in total. To implement our GCAM scenarios, we map the GCAM nodes to the CMW nodes and apply the regional growth rates of the GCAM results (2020-2050) to our base year demand (2020). EMF34 did not prescribe assumptions for the models' "reference scenarios" but describes them as "modelers' choice". GCAM's reference scenario for EMF34 must be understood as a *no-policy baseline* as is usual in integrated assessment modelling exercises. It is, therefore, clearly a status quo scenario.

For the *US_bottom_up* scenario, we base future U.S. steam coal demand on observable trends regarding retirement age and capacity factor of U.S. coal-fired power plants. We take into account the geographic location, net summer capacity, age, and announced retirement dates of all U.S. coal-fired generation units.¹⁰ In addition to the announced retirements listed in the EIA860M form, we include those retirement announcements reported in the weekly newsletter *CoalWire*, published by Global Energy Monitor, that were not listed in EIA860M yet.¹¹ We assume that coal-fired generation units are retired in the announced year. To all other units we apply the conservative – or, rather, generous – assumption of a 60 years life-time.

While U.S. net electricity generation stayed rather constant around 4,100TWh between 2010 and 2019, the share covered by coal declined by about 48% (from 45%, 1,847TWh, in 2010 to 23%, 966TWh, in 2019). Total coal-fired electric generation capacity peaked in 2011 with about 318 GW, and then

⁹ There is also a U.S. version of the GCAM model (GCAM-USA). While the level of spatial disaggregation of the USA differs significantly between the two model versions, the data is similar. GCAM-USA was recently used in Feijoo et al. (2020) who also find stable U.S. coal consumption levels through to 2050 in a scenario of "National Policies Implemented" (similar assumptions than *EIA_reference*) and almost a doubling of coal consumption in a "NoPolicy" scenario.

¹⁰ Based on data provided in EIA's Preliminary Monthly Electric Generator Inventory EIA860M as of August 2019 (<https://www.eia.gov/electricity/data/eia860M/>). We include all generator units in the sectors 'Electric Utility', 'Industrial CHP', 'Industrial Non-CHP', 'IPP CHP', and 'IPP Non-CHP', in all plant states, except Hawaii (HI), with nameplate capacities of equal to/greater than 50MW, for the technologies 'Conventional Steam Coal' and 'Coal Integrated Gasification Combined Cycle', excluding the energy source 'lignite' (LIG).

¹¹ Global Energy Monitor, *CoalWire*. <https://endcoal.org/category/coalwire/>, last accessed April 1, 2020.

declined to 229 GW in December 2019.¹² Initially, small and very old units retired. But in recent years, more and more plants that were larger and/or younger than the average fleet age were shut down. As of January 2020, the capacity weighted average age of the remaining fleet is 41 years. The capacity factor of coal-fired power generation units dropped from 67.1% in 2010 to 47.5% in 2019.¹³

As of November 2019, the retirement of about 35GW between 2020 and 2030 had been announced publicly, with a current average age of 48 years of the concerned units. Of the remaining capacity, more than 20% are older than 50 years. In other words, they will exit the market – and thereby stop using coal – in year 2030 at the latest. By 2050, only around 70 units (27GW) of the currently existing units will be left in the market. Table 2 shows the regional development of coal-fired power generation capacities. Different age structures and economic conditions of the regional coal-fired power plant fleets lead to differing decline speeds (see Appendix for alternative scenario assumptions). While the capacity in the South Central region remains relatively constant until the year 2035 due to a younger than average fleet, it is reduced by at least around 50% in all other regions by then.

Table 2: Coal-fired power generation capacities in GW in five U.S. consumption regions, 2020-2050, in US_bottom_up scenario

	2020	2025	2030	2035	2040	2045	2050
Consumption Region	GW						
West	25.8	22.1	13.9	12.6	9.7	3.9	3.1
North Central	83	68.4	56.8	42.1	21.8	11.8	9
South Central	24.4	23.1	23.1	23.1	17.4	7.2	3.9
South East	74.1	63.2	56.2	35	28.2	13.9	9.9
North East	11.8	9.9	6.7	2.9	2.3	1.6	1.5
U.S. Total	219.1	186.7	156.7	115.7	79.4	38.4	27.4

Furthermore, we apply a constant capacity factor of 0.5 to all coal-fired power plants. This capacity factor assumption differs strongly from the EIA assumptions. The EIA assumes that in a decade or a little more, when most old power plants will have left the market, the average capacity factor will increase

¹² EIA electricity data: <https://www.eia.gov/electricity/>, last accessed March 30, 2020.

¹³ EIA, Electric Power Monthly, Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a, last accessed April 1, 2020.

again – because fewer but younger power plants are supposed to deliver the same amount of electricity than today (EIA 2019). However, this assumption neglects that the strong rise of renewables of the past decade is likely to continue given the international efforts in further cost decrease in both renewables and flexibility options.

We chose conservative and “pro coal” assumptions for our *US_bottom_up* scenario consistent with the status quo category. Recent trends indicate an even lower capacity factor (47.5% in 2019, 2015-2018 around 53-54%)¹⁴, and earlier shut-down of coal-fired power plants than after 60 years (average, capacity-weighted retirement age of considered U.S. coal-fired generation units in 2019: 46.3 years).¹⁵

We apply the resulting growth (decline) rate of power generation from coal-fired units to the 2020 base demand for steam coal to obtain each future period's reference demand assumption which we need as model input. Figure 3 shows the derived future steam coal demand assumptions in all five U.S. consumption regions in our *US_bottom_up* scenario. Figure 9 in the Appendix shows steam coal demand in U.S. consumption regions based on a range of alternative retirement age and capacity factor assumptions.

¹⁴ EIA, Electric Power Monthly, Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a, last accessed April 1, 2020.

¹⁵ EIA, Electricity, Preliminary Monthly Electric Generator Inventory. <https://www.eia.gov/electricity/data/eia860M/>, last accessed April 1, 2020.

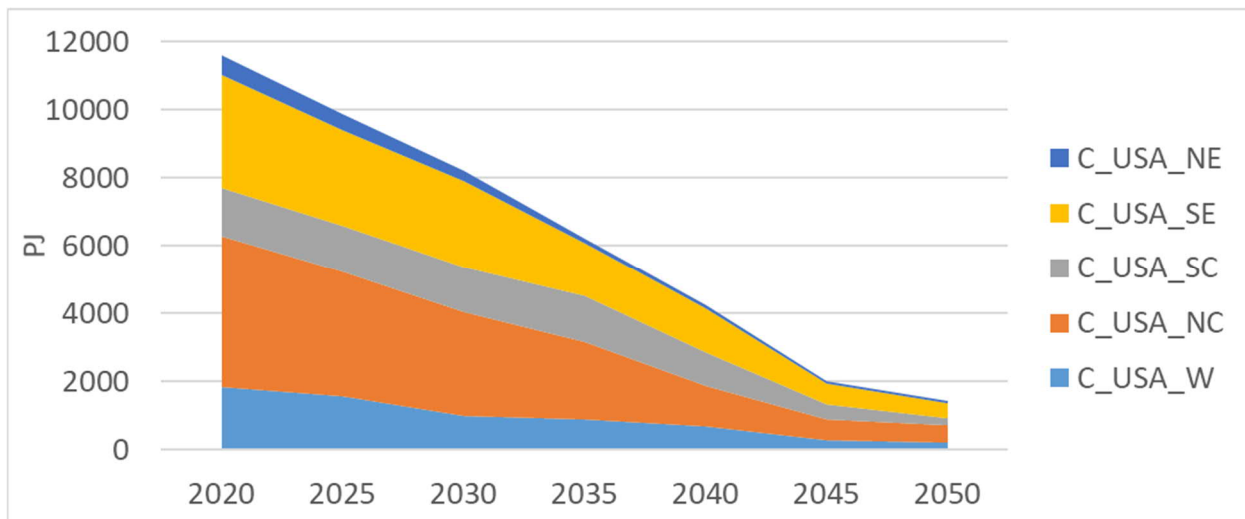


Figure 3: U.S. steam coal demand assumption in the *US_bottom_up* scenario in PJ (disaggregation into five consumption regions), with the life-time assumption of 60 years and constant capacity factor of 0.5

We contrast the three status quo scenarios with two climate policy scenarios, one of them being an EMF34 scenario. The latter one, the “*GCAM_carb*” scenario, is based on the GCAM results for the EMF34 scenario “Carbon Policy”. This scenario assumes a uniform global CO₂ price of 35 USD in 2022 which grows by 5% growth per year until 2050.¹⁶ While this is a climate policy scenario, the effect of these moderate CO₂ price assumptions on the coal sector is limited. Global coal demand in GCAM reduces by only 42% between 2020 and 2050, with the strongest reduction late in the model horizon, after 2045.

We also design a climate policy scenario with an effective coal exit, the “1.5°C scenario”. It is based on the IPCC (2018) report on 1.5°C scenarios. Yanguas Parra et al. (2019) selected those 1.5°C scenarios that also fulfil other sustainability criteria such as reasonably limited use of biomass with CCS (BECCS) and limited carbon uptake from afforestation or land use. For each model year (i.e. 2025, 2030, 2035, and so on), we take the regional growth rates of the median global coal consumption of these scenarios.

We consider the scenarios *EIA_ref*, *GCAM_ref*, and *GCAM_carb* as EMF34 scenarios which are either based on common input used by the EMF34 group or directly on results of EMF34 scenarios. In contrast, the scenarios *US_bottom_up* and 1.5°C are our “modelers’ choice” scenarios.

¹⁶ These CO₂ price assumptions are implemented by GCAM. COALMOD-World cannot implement a CO₂ price because it only includes coal and no other energy vector (emission source).

In all scenarios, the baseline assumption is that U.S. exports via the West Coast are only possible via the existing – small – capacities (in total five Mtpa); no investments in U.S. West Coast export terminals are allowed. There currently is a *de facto* ban on creating new coal export capacity (from new terminals or expansion of existing ones) in California, Oregon, and Washington. A number of new projects have been introduced in the past two decades but none has been granted permission, due to complex permitting and strong environmental concerns by local policy makers (Cornot-Gandolphe 2015; Mendelevitch, Hauenstein, and Holz 2019). West coast ports might still be possible, for example by constructing for new terminals on federal land (e.g., former military ports). Even though their realization is questionable because railroad transportation to the ports is also a big issue of contention in the U.S. West Coast states, we want to analyze with our counter-factual policy shock whether new export capacities would make a difference to the export chances of U.S. coal suppliers, and if yes, to which extent.

We apply a policy shock that allows for endogenous investments in U.S. West Coast export capacities in the scenarios “_ports” of up to 50 Mtpa per 5-year period.^{17,18} In other words, we may then see an expansion of U.S. West Coast export capacities when it is economically rational, for example because of strong demand in Asia and idle production capacities in the U.S., in particular in the Powder River Basin and the Rockies. With this, we want to analyze whether a coal phase-out by domestic power generation can be compensated by the U.S. coal producers by exporting more to the world markets.

3 Five scenarios for U.S. and global coal demand trends

In this section, we want to provide an overview of the global and U.S. results from the five COALMOD scenarios introduced in Section 2.2, and to highlight three main lessons that can be learnt from these results:

¹⁷ Investments in all other export capacities, including U.S. Gulf Coast and East Coasts are equally allowed in all scenarios. Costs, capacities, and maximum expansions are not varied between scenarios.

¹⁸ Coal terminals vary in size. For example, each of the two coal terminals in the Baltimore ports has a size of approx. 14 Mtpa. The unrealized projects Millenium Bulk Terminal (WA) and Gate Pacific Terminal (WA) were approx. 44 Mtpa each (<https://www.eia.gov/todayinenergy/detail.php?id=32092>). This means that 50 Mtpa can be expected to be one very large or more smaller ports.

1. There is significant uncertainty on the outlook for the U.S. coal sector, even in the absence of explicit climate policies. It depends strongly on the assumptions for the U.S. power sector development and, to a lesser extent, the access to global markets.
2. The current assumptions by the U.S. Energy Information Agency – which has been the source for most EMF34 models and scenarios – are biased towards coal given the vintage structure of the U.S. coal-fired power plant fleet and recent market trends. These assumptions have a very strong influence on the future level of U.S. coal demand and production and must be viewed critically. They can be called “pro-coal” scenarios and implicitly rely on further support mechanisms for coal power in the U.S.
3. If the global success of renewables continues in combination with effective climate policy, the U.S. loses its option to shift a share of its coal production to the world markets. This option is already limited now and in the status quo future scenarios because of the U.S. suppliers’ high relative supply costs which make them the marginal suppliers in the import markets.

In Section 4, we delve deeper into the topic of exports of U.S. coal. There, we also include scenarios with West coast ports. In Section 5 we analyze the details of these scenarios for the different U.S. coal regions, including the mining employment.

Looking first at the global coal use trends to 2050 (Figure 4), we can easily discern the five scenarios. We see that *GCAM_ref* is an extreme no-policy scenario in which “status quo” leads to a strong increase of global coal demand, about 37% above 2020 levels and well above 7000 Mtpa. This can well be interpreted as an upper bound of future coal demand. The other status quo scenarios exhibit rather constant demand over time, with a moderate increase until the 2030s when they peak below 6000 Mtpa and then a return to approximately 2020 levels around 5400 Mtpa. *GCAM_carb* is a “middle-of-the-road” scenario with only moderate climate policy assumed. The global demand reduction between 2020 and 2050 is only 37%, to about 3400 Mtpa. In contrast, the 1.5°C scenario leads to a strong and early fall of global coal demand: by 2030 coal demand is already 73% lower than in 2020, and 99% lower by 2040.

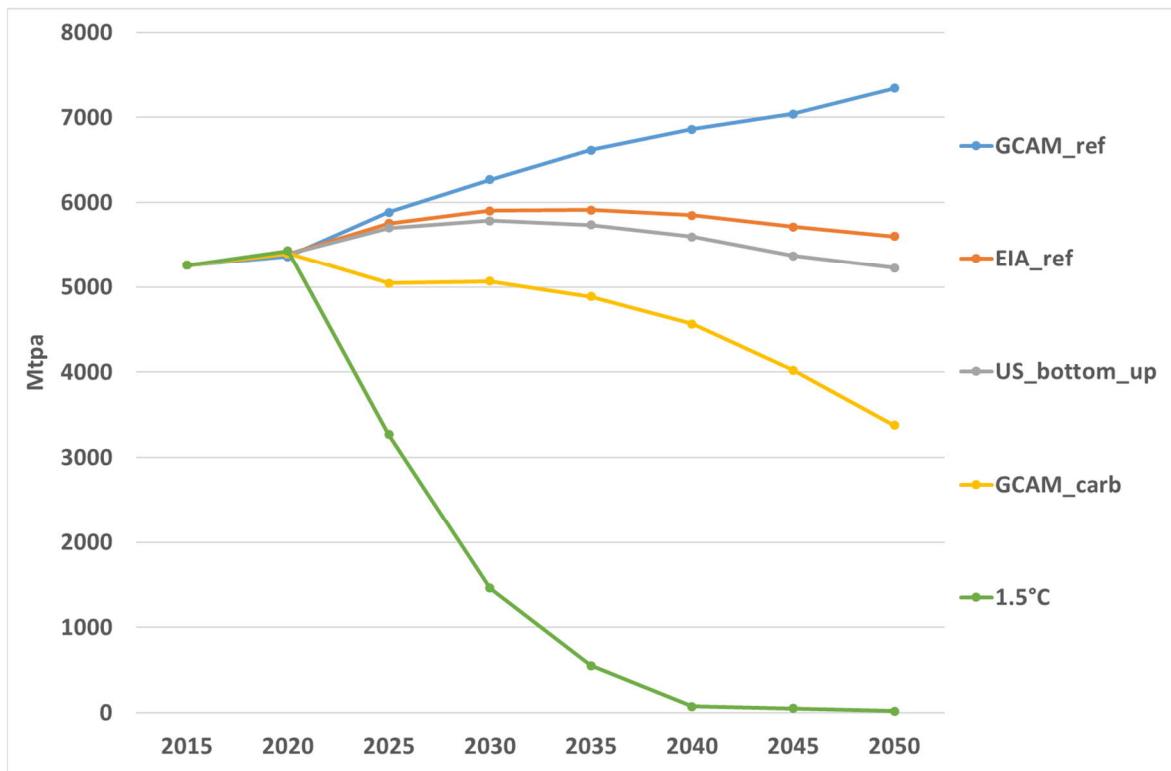


Figure 4: Global steam coal consumption in Mt per year in all scenarios

Main consumers in all scenarios are China (between 48% and 52% of cumulative global consumption between 2020 and 2050) and India (between 18% and 23%), but the US also is a major coal consumer (between 6% and 9% of cumulative coal consumption, with the smallest share in the *US_bottom_up* scenario). These countries' shares in global coal demand stay rather constant over time in most scenarios, i.e. their demand evolves similarly to the global trend. An exception, amongst others, is the U.S. demand in the *US_bottom_up* scenario, which reaches a share of only 1% of global demand in 2050. India's demand generally increases to around 30% of global demand in most scenarios by 2050.

We see already in the global numbers of the *status quo* scenarios that adjusting the U.S. consumption expectations has a notable effect on the total coal consumption: in our scenario *US_bottom_up*, global coal consumption 2050 is almost 7% lower than in the scenario "*EIA_ref*". Turning to the U.S. numbers (Figure 5), this result is even more obvious: while the scenario "*GCAM_ref*" contrarily forecasts an increase between 2020 and 2050 by 15% and the scenario *EIA_ref* only a slight decrease by 12%, the scenario *US_bottom_up* comes with a strong decrease by 87%. We need to keep in mind that the observed decrease of U.S. coal use only between 2015 and 2020 was more than 20%.¹⁹ The strong

¹⁹ EIA Coal Data Browser: <https://www.eia.gov/coal/data/browser/> (last accessed June 4, 2020)

decrease in the *US_bottom_up* scenario reflects the exit of more and more coal-fired power plants, either because of economic and other retirement decisions, or that reach 60 years of age (our assumed maximum lifetime).

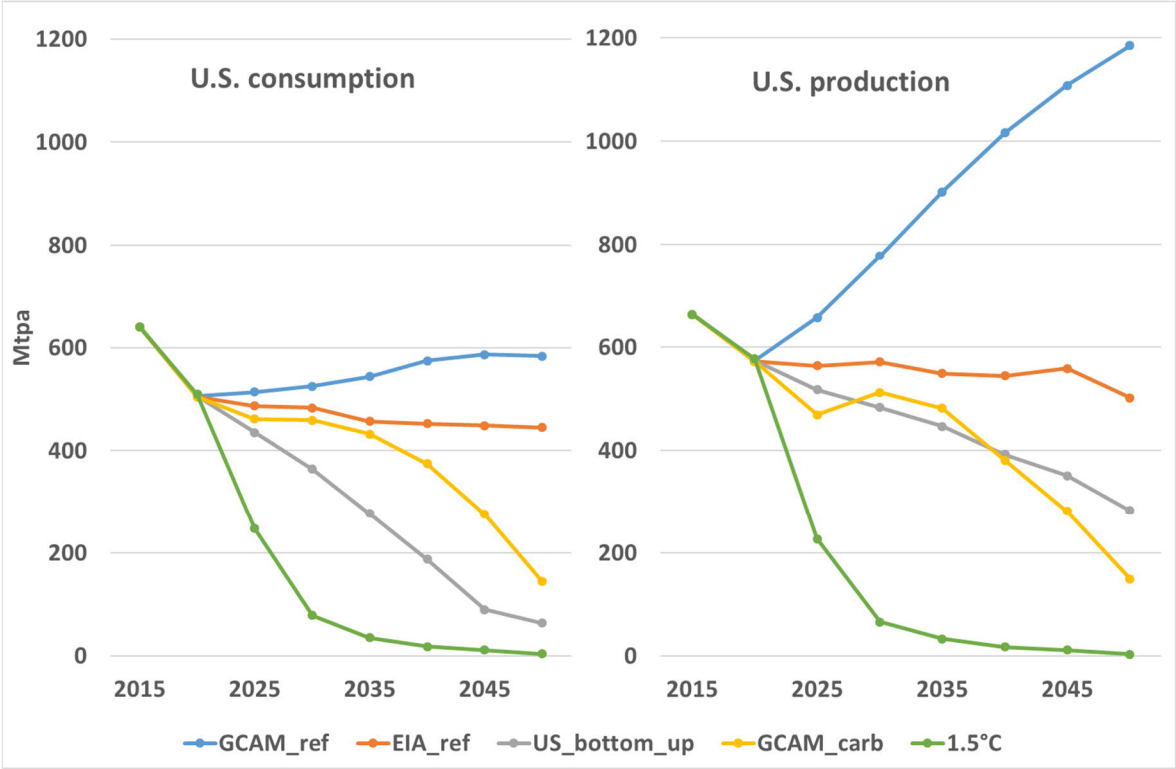


Figure 5: U.S. steam coal consumption (left) and production (right) 2015-2050 in Mt per year in all scenarios

The U.S. coal supply has traditionally served primarily the domestic demand and has exported only a small share of the U.S. coal production. In other words, U.S. production levels are usually close to U.S. consumption levels. Figure 5 shows that the various scenarios have somewhat diverging perspectives on this. The congruence of domestic production and consumption continues to be largely the case in the *EIA_ref*, the *GCAM_carb* and the *1.5°C* scenarios. In contrast, the *GCAM_ref* scenario forecasts such a strong growth in production that even consumption cannot keep up the pace. Production levels well above 1000 Mtpa would exceed the all-time peak level of U.S. production of 2008.²⁰ Yet another picture is given by the *US_bottom_up* scenario in which the bleak outlook for coal-fired power generation leads to the consumption fall outpacing the – slow – production decline. In both scenarios, U.S.

²⁰ In 2008, U.S. production of bituminous and sub-bituminous, the two coal categories included in our analysis, was 1063 million short tons, which is equivalent to 993 Mtpa (<https://www.eia.gov/coal/annual/pdf/tableES1.pdf>, last accessed April 26, 2020).

production net of domestic consumption leaves considerable volumes of 120 Mtpa and more for exports (also see Section 4).

4 Increasing U.S. coal exports – A realistic option?

In this section, we investigate whether a coal phase-down by domestic power generation can be compensated by the U.S. coal suppliers exporting more to the world markets as suggested by Knittel, Metaxoglou, and Trindade (2016). We do this by analyzing the export volumes in the different scenarios, including the scenarios with the policy shock of West coast terminals being allowed (scenarios named “_ports”). Clearly, such a shock is very unlikely because of the strong and effective local opposition to coal ports, but it is still helpful to analyze their potential effects (see section 2.2).

Exports were in the range of 4% to 15% of U.S. coal production (54 Mt – 114 Mt) in the period 2006 to 2018.²¹ About 50% to 70% of U.S. coal exports are metallurgical coal. U.S. steam coal has relatively high supply costs – production and transport costs summed up – and is the marginal supplier in most international markets.²² Therefore, the possibility for U.S. coal suppliers to deliver to other markets is very price-sensitive and varies considerably over time and between scenarios (Figure 6).²³ Generally, U.S. exports are higher when global demand is higher (status quo scenarios) and when domestic demand is lower, such as in the *US_bottom_up* scenario.²⁴ The 1.5°C scenario shows the fundamental importance of sufficiently high global demand for U.S. exports to realize: the generalized global coal phase-out brings the import demand down to zero despite a lot of U.S. supply capacity being idle and able to export. In contrast, in the *US_bottom_up* scenario, a scenario with both sustained global demand and idle U.S. coal supply capacities, exports are multiplied by more than three between 2020 and 2050.

²¹ EIA coal data browser: <https://www.eia.gov/coal/data/browser/>, last accessed March 26, 2020.

²² In the COALMOD-World model structure, we assume a different demand (function) in each model node (country). Hence, an exporter addresses different nodal demands for (imported and/or domestically produced) coal. In other words, there is not a single “world market” and prices differ between demand nodes.

²³ In some years in the past, the U.S. even were net importer of coal. In some of the future scenarios, too, we see some imports, mostly small volumes from Columbia.

²⁴ Also see Table 3 in the Appendix for the share of exports of U.S. production in each scenario.

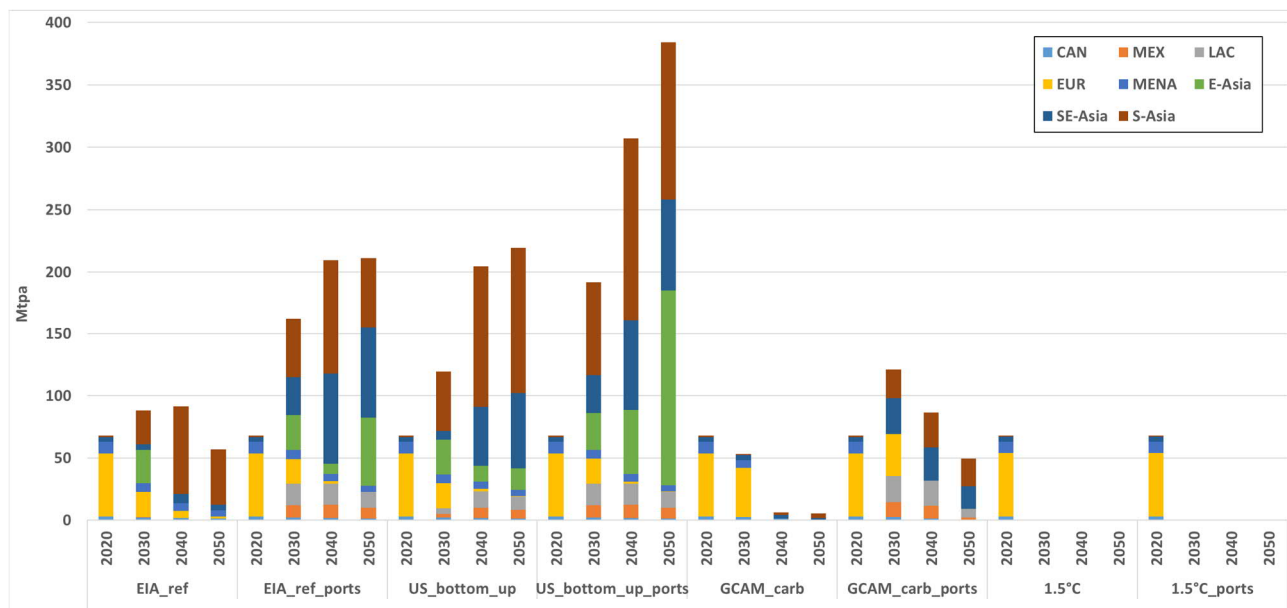


Figure 6: U.S. coal exports 2020-2050 and their destination in Mt per year

Note: Countries represented in importing regions: CAN = Canada; MEX = Mexico; LAC = Brazil, Chile; EUR = Belgium, Denmark, Finland, France, Germany, Italy, Netherlands, Portugal, Spain, United Kingdom; MENA = Israel, Morocco, Turkey; E-Asia = China, Japan, South Korea, Taiwan; SE-Asia = Malaysia, Philippines, Thailand, Vietnam; S-Asia = Bangladesh, India, Pakistan.

The role of the U.S. as marginal supplier to the world’s import markets is also reflected in its diversified importer portfolio (Figure 6). At first, the large number of importers may be puzzling given the (perfectly) competitive nature of the global steam coal market. However, it is due to the marginal position of the U.S. in the importers’ supply curve,²⁵ and to the fact that the graphs show an aggregation of several U.S. exporters. While Europe has traditionally been a major market for U.S. coal, the importance shifts to the Asian-Pacific market (even in scenarios without West Coast ports, assuming Panama Canal utilization), reflecting the general strong demand push in Asia and the shrinking coal demand in Europe. U.S. exports will benefit from limited Indonesian reserves and can increase the volumes sent to South Asia and Eastern Asia over time. These demand regions are in the Pacific basin, so opening new terminals on the Pacific Coast of the U.S. would potentially have a further increasing effect.

²⁵ In other words, as formulated by an analyst, the U.S. “come in when there are problems in the market” (<https://foreignpolicy.com/2018/04/04/trump-makes-american-coal-great-again-overseas/>, last checked April 28, 2020).

We indeed observe a – relatively strong – effect of increasing exports when U.S. West Coast ports are allowed (Figure 6). The effect is almost the same in the *US_bottom_up* and *EIA_ref* scenarios, with exports more than 150 Mtpa higher in the ports scenarios than in the baseline scenarios. This is the effect of the global demand assumptions, which in these two scenarios are based on the “Stated Policies Scenario” (IEA 2019b) coal demand trends – which include a stable coal demand over time. In contrast, even a moderate global climate policy scenario such as the *GCAM_carb* scenario forecasts only a low level of U.S. exports, even when West Coast ports are allowed (about 50 Mtpa in 2050). In the ambitious climate policy scenario *1.5°C*, the U.S. also cease exporting after 2020 when West Coast terminal investments are allowed.

For a marginal supplier as the U.S., prudence on investments in the coal value chain is a good idea in times of high uncertainty. The breadth of our scenarios – which are all more or less realistic and plausible (except probably for the “no-policy” scenarios *GCAM_ref* and *GCAM_ref_ports*) – gives an indication of the wide range of possible outcomes for the U.S. coal sector. Between an extensive phase-out of coal in the *1.5°C* scenario which complies with the commitments in the Paris Agreement and a stability of U.S. coal production at 2018 levels above 600 Mtpa with high domestic consumption and exports in the *EIA_ref_ports* scenario, there is a spread of more than 300 Mtpa in exports and 600 Mtpa in production. However, the strong spread in outcomes between the different scenarios shows that assets in the U.S. coal value chain continue to be at risk of becoming stranded if a lower demand scenario realizes than envisaged at the moment of the investment decision.

Export dependency on world regions with uncertain demand development is only reinforcing the uncertainty on domestic demand (Shearer et al. 2020). As marginal suppliers, the U.S. exporters do not have much of a choice where to export to. However, markets such as India, Vietnam, or Pakistan that only recently still counted an impressive pipeline of coal power plant projects have recently considerably reduced their project numbers, mostly under the influence of lower renewable costs.²⁶ Moreover, the Corona pandemic – and the accompanying energy demand reduction – is likely to reinforce the trends of increasing renewable use and phase-down of coal use (Oei, Yanguas-Parra, and Hauenstein 2020). This means that coal import requirements may well be considerably lower than the status quo demand

²⁶ Also see a recent short analysis by Feaster and Cates in <https://ieefa.org/ieefa-u-s-why-exports-wont-save-american-coal/> and Wamsted, Feaster, and Cates (2020).

that we model, and closer to demand in the climate policy scenarios, which eventually come with a phase-out of coal before 2050.

5 Competition between U.S. coal regions?

In the last two decades, the U.S. coal sector has seen a shift of importance away from Appalachian coal to a dominance of PRB coal. While both regions had an equal share of U.S. coal production in 2002 (36%), the Powder River Basin now supplies almost half of the U.S. coal (43% in 2018) and Appalachia only a quarter (26%). Appalachia has also suffered from the rise of coal from the Interior region (from 13% in 2002 to 20% in 2016 and 18% in 2018). The shift was due to a multitude of factors such as the location of demand, the low sulfur content of PRB and Interior (Illinois) coal, but importantly also the low costs of production in very large opencast mines in the PRB compared to smaller mines and many (inherently expensive) underground mines in the Appalachia region. This long-run trend was reinforced by a pronounced relative production cost increase in Appalachia which was mainly due to declining labor productivity (Jordan, Lange, and Linn 2018).

However, there starts to be an understanding that PRB will not be safe from the mine closure trend that started in Appalachia – which comes hand in hand with job losses which mean not only wage losses but also health and pension benefit losses.²⁷ In this section, we look at regional changes of production, as well as their effects on direct jobs in coal mining.

5.1. Regional coal production and demand

Total U.S. coal production varies over different scenarios as shown above. However, these different trends do not unfold evenly in all four U.S. steam coal production regions. Figure 7 shows exemplarily the production in the four production regions for the *EIA_ref*, the *US_bottom_up*, and the *1.5°C* scenarios. Furthermore, it shows where the produced coal goes to, i.e. the five U.S. consumption regions and exports.

²⁷ See, for example, <https://www.vox.com/energy-and-environment/2019/7/9/20684815/coal-wyoming-bankruptcy-blackjewel-appalachia>

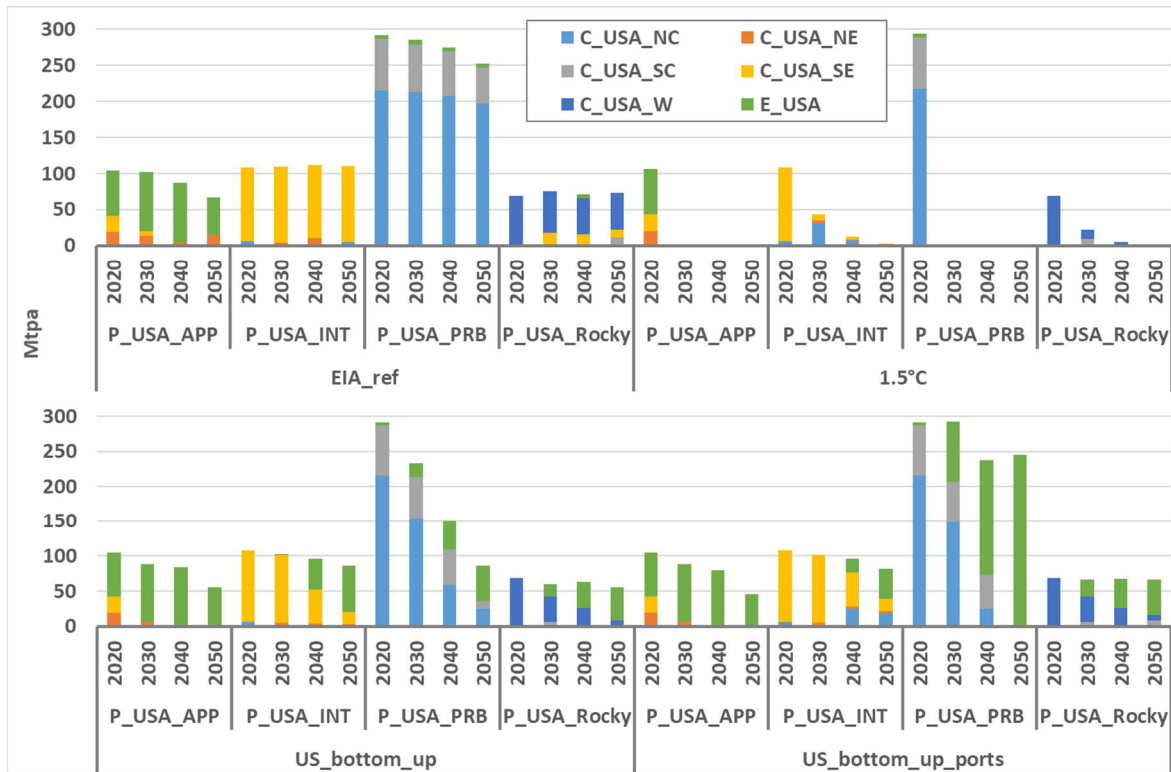


Figure 7: Disaggregation of supplies by U.S. coal regions to domestic consumption regions and exports 2020-2050 in Mtpa (in scenarios *EIA_ref*, *1.5°C*, *US_bottom_up*, and *US_bottom_up_ports*)

In the *EIA_ref* scenario, coal production in the Interior and the Rockies remains relatively constant between 2020 and 2050, while it declines steadily in Appalachia and PRB. PRB coal goes mainly to the North and South Central demand regions where demand declines somewhat over time. However, PRB still produces as much as all the other regions together by 2050. U.S. Appalachia loses more and more of its domestic customers and depends largely on coal exports to the international market.

The *US_bottom_up* scenario shows a drastically different picture, especially for PRB. Production declines in all basins due to significant domestic demand reductions, but PRB cannot compensate the immense decline of demand in North and South Central by similar amounts of exports due to its landlocked location. For Appalachia, the Rockies, and the Interior exports play a significant role to prevent larger production cuts. Already by 2030, Appalachia produces almost solely for the international market. This shows the importance of taking the vintage structure of the power plants into account, as in the *US_bottom_up* scenario. Figure 11 in the Appendix shows the differences in regional U.S. coal consumption for the years 2020-2050 between the scenarios.

In the *US_bottom_up_ports* scenario with West Coast export expansion possibilities, additional U.S. production comes from PRB (compared to scenario *US_bottom_up*). Production levels in Appalachia, Interior and the Rockies are similar to the baseline scenario. PRB even reduces its domestic sales (to North Central) to export more, while Interior and Rockies shift some of their domestic sales to North Central and South Central.

In case of stringent global climate policies (*1.5°C scenario*), reducing coal demand in the U.S. and globally, coal production ceases in Appalachia and PRB as early as 2030. International demand will not compensate for domestic decline in this case. Thus, betting on increasing exports in the future might be a risky game for U.S. coal producers, in particular in the Appalachia region which is highly export-dependent.

Altogether, we find three drivers of regional production trends:

1. Differences in regional U.S. demand (due to differing assumptions on coal power plant fleet development) lead to substantially different regional supply mixes.
2. Allowing for new West Coast ports leads to a different regional allocation of supplies and, generally, comes with a higher production by PRB.
3. The development of demand in the export destinations, determined i.a. by climate policy, leads to a different regional supply structure in the U.S. because the regions do not have equal access to export capacities (different costs and capacities).

Overall, we see a continued decline of production in Appalachia across the different scenarios. The future of PRB production could be bleak if domestic demand continues to decline, especially in U.S. North Central and South Central consumption regions. Additional export terminals along the U.S. West Coast could ease production cuts in PRB, provided global demand is sustained. However, they are very unlikely in the regional context of strong opposition by the population, the regulators, and policy makers (Mendelevitch, Hauenstein, and Holz 2019).

5.2. Coal mining employment

According to the EIA, around 50,000 direct employees worked in coal mining in the years 2016-2018, down from 92,000 in 2011.²⁸ Large regional differences exist in numbers of jobs per region, as well as the productivity (output of coal per working hour). More than 50% of the jobs were in Appalachia, around 20% in Interior, and around 10% each in the Rockies and PRB. Labor productivity in Appalachia, where coal is mostly produced in underground mines, is only about half of the value in the Interior basin and the Rockies. It is only 10% of the productivity in PRB where very large opencast mines operate.²⁹ Table 3 in the Appendix summarizes the information on regional coal mining job characteristics used in our calculations.

Figure 8 depicts the development of direct mining jobs in the U.S. coal regions for different scenarios, assuming constant labor productivity over time. In all scenarios, the number of jobs declines significantly over the modeling horizon, hand in hand with the decrease of production. In absolute terms, Appalachia sees the highest number of job losses. In the *US_bottom_up* scenario, the number of jobs declines faster than in the *EIA_ref* scenario. However, the difference is less pronounced than in terms of coal produced, due to production cuts mostly in PRB with its high productivity in the *US_bottom_up* scenario (compare Figure 7). This also explains why the total number of jobs is only slightly higher when allowing for additional West Coast ports (*US_bottom_up_ports*), as this leads to less production cuts in PRB while reducing job-intensive production in Appalachia even further.

While we conclude that coal mining employment is likely to decrease in the major U.S. coal regions because it does so across all our scenarios, this does not necessarily have to induce negative long-run consequences for these regions. Much in contrast, other authors found that U.S. coal regions, in particular but not exclusively Appalachia, have suffered from a resource curse with lower education levels and lower long-run economic growth than comparable regions without coal (Douglas and Walker

²⁸ EIA coal data browser, „Aggregate coal mine average employees“; <https://www.eia.gov/coal/data/browser/>, last accessed May 10, 2020. This includes jobs in lignite and coking coal mining, which we estimate to account for about 10-15% of all coal mining jobs, based on shares of production and productivity in different mine types. There is no data on subcontractor employment from this source, and data from other sources is incomplete.

²⁹ However, labor productivity in PRB was 64% higher in 2001 than 2014-2018. A generalized labor productivity decrease was observed in all U.S. coal mining basins in that period: by 49% in Appalachia, 17% in Interior, and 35% in the Rockies. This is somewhat surprising given the global trend to improvements in labor productivity due to increased automation.

2017).³⁰ In any case, the prospect of job losses in the next decades could be mitigated if economic policies helped mine workers compensate for losses of income, and health and pension benefits on the one hand, and convert to other jobs on the other hand. The experience in Appalachia has shown that without compensation policies, income losses and political radicalization may be lasting (Weber 2020).

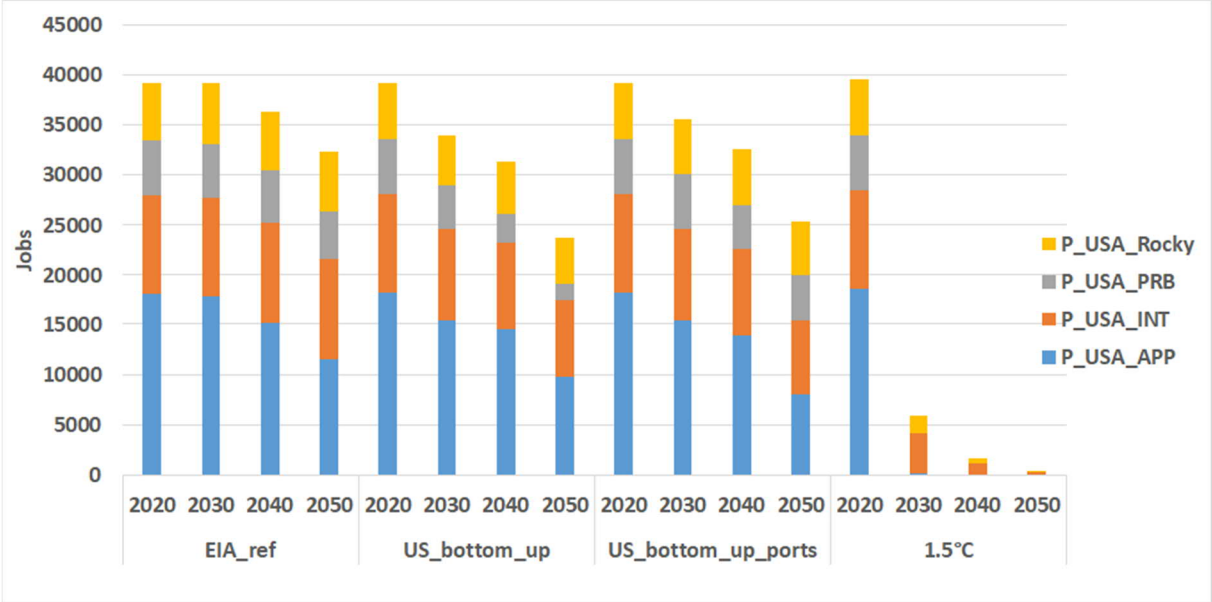


Figure 8: Direct coal mining jobs in the four U.S. coal regions, 2020-2050 (in scenarios *EIA_ref*, *US_bottom_up*, *US_bottom_up_ports*, and *1.5°C*)

6 Conclusion and Policy Implications

While In many countries around the world, governments and utility companies have started to engage in coal-phase out processes, the U.S. are still mourning the heydays of its coal sector. In this paper, we put into perspective the coal sector assumptions of EMF34 and the U.S. Energy Information Administration. We show that the current downward trend is insufficiently taken into account in their scenarios. However, the “downward spiral” of U.S. coal is triggered by drivers that lie outside the coal sector – mostly competition from cheap shale gas and renewables – and will, therefore, not be stopped. Our scenario results show that it can, at most, be delayed. Moreover, the Corona pandemic may well lead to speeding up the downward trend in the U.S., too.

³⁰ Betz et al. (2015) do not find a negative effect on per capita income of coal mining regions, but a significant negative on entrepreneurship which is a factor of long-term economic growth.

We show that a status quo scenario that takes realistic – and even conservative – assumptions on lifetime and capacity factor, as well as investments of U.S. coal power plants, leads to a considerably lower U.S. coal production and consumption than a scenario based on EIA assumptions. Moreover, scenarios with U.S. and global climate policy efforts, lead to even lower U.S. coal production and consumption. However, there is a noticeable difference in the exact levels depending on the climate policy stringency and only an ambitious climate policy such as a 1.5°C scenario would lead to a phase-out of U.S. coal by 2050. A moderate climate policy such as the one suggested by EMF34, would still see around 300 Mtpa coal production in the U.S. by 2050.

The decline of U.S. coal production can be delayed by increasing exports, and most prominently if exports to the energy-hungry Asian economies via the U.S. West Coast were possible. In the – unlikely – case of U.S. exports via the West Coast, U.S. coal production can increase in the long run by up to 150 Mt per year. However, betting on exports is a risky strategy for U.S. producers because they are the marginal suppliers to the world's import markets due to their comparatively high costs. Asian coal expansion plans are becoming more and more uncertain because these countries can benefit from cheap renewables, too. “The myth of export-market expansion” (Wamsted, Feaster, and Cates 2020) has given hope and artificial respiration to parts of the U.S. coal sector for more than a decade but it is becoming ever more unlikely.

Yet, the breadth of our scenarios gives an indication of the wide range of possible outcomes for the U.S. coal sector. Between a Paris-compatible 1.5°C scenario and a scenario with stable U.S. coal production at 2018 levels with high domestic consumption and exports in the *EIA_ref_ports* scenario, there is a spread of more than 300 Mtpa in exports and 600 Mtpa in production. However, the strong spread in outcomes between the different scenarios shows that assets in the U.S. coal value chain are at a substantial risk of becoming stranded if a lower demand scenario realizes than envisaged at the moment of the investment decision. In fact, such stranding – and subsequently mothballing – of mines has been seen across the USA in the past decade, as the upstream effect of shutting down more and more domestic coal-fired power plants. The loss of value of previously high priced assets such as coal mines has caused multiple bankruptcies in the U.S. coal sector – and our results, in addition to the increasing funding problems, suggest that the series of bankruptcies may well continue.

Recent political attention focused on the Appalachian coal region. This region lost most coal jobs, both in relative and in absolute numbers in the last decades due to the hard mining conditions in small and

underground mines. Our numerical results show that the Powder River Basin region – where large opencast mines allow for much higher productivity – similarly will be strongly affected by the decline of U.S. coal consumption in the next decades. This is due to the regional supply structure within the country: PRB delivers to regions where coal power plants are nearing the end of the lifetime. The two other basins, Interior and Rockies, are more resilient because they supply regions with a younger coal power plant fleet.

Our results are a warning for policy makers in the U.S. to start action. The decline of U.S. coal is inevitable and actions must be taken to guarantee a fair and just transition out of coal to the mining communities. The experience of the last decades was that coal mine bankruptcies led to income and pension losses for miners, while company owners could escape from their entrepreneurial responsibilities.

The Energy Modeling Forum and the U.S. Energy Information Agency provide important input to U.S. energy policy-making. Credible and realistic scenarios are necessary to guide policy decisions that can be sustaining in the long-run. The EIA therefore needs to put an increased effort in updating its own scenario assumptions to the reality of the U.S. power sector. It is not helpful for the affected communities to provide the illusion of hope for a recovery of the U.S. coal sector when adaptation to the new reality is needed instead. The EIA has made small steps in adjusting its AEO scenario assumptions in the last few years, however, it now needs to be more ambitious.

Acknowledgements

We would like to thank John Weyant and Hill Huntington for giving us the opportunity to discuss the EMF 34 results. Special thanks go to Jonathan Huster and Jae Edmonds for data provision and comments on an earlier draft. We thank Philipp Herpich, Lennart Rathje, Catharina Rieve, and Akira Schroth for excellent research assistance. We also thank Roman Mendelevitch, Pao-Yu Oei, Paola Yanguas Parra and the participants of the PEGASOS workshop on coal modeling at the Potsdam Institute for Climate Impact Research in February 2020 for helpful comments. Christian Hauenstein gratefully acknowledges funding from the Heinrich-Böll-Foundation. This work was supported by the German Ministry for Education and Research (BMBF) under grant numbers 01LN1704A ('CoalExit' project) and 01LA1811B ('FoReSee' project). All remaining errors are ours.

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Appendix

Sensitivities of U.S. coal demand: retirement age & capacity factor

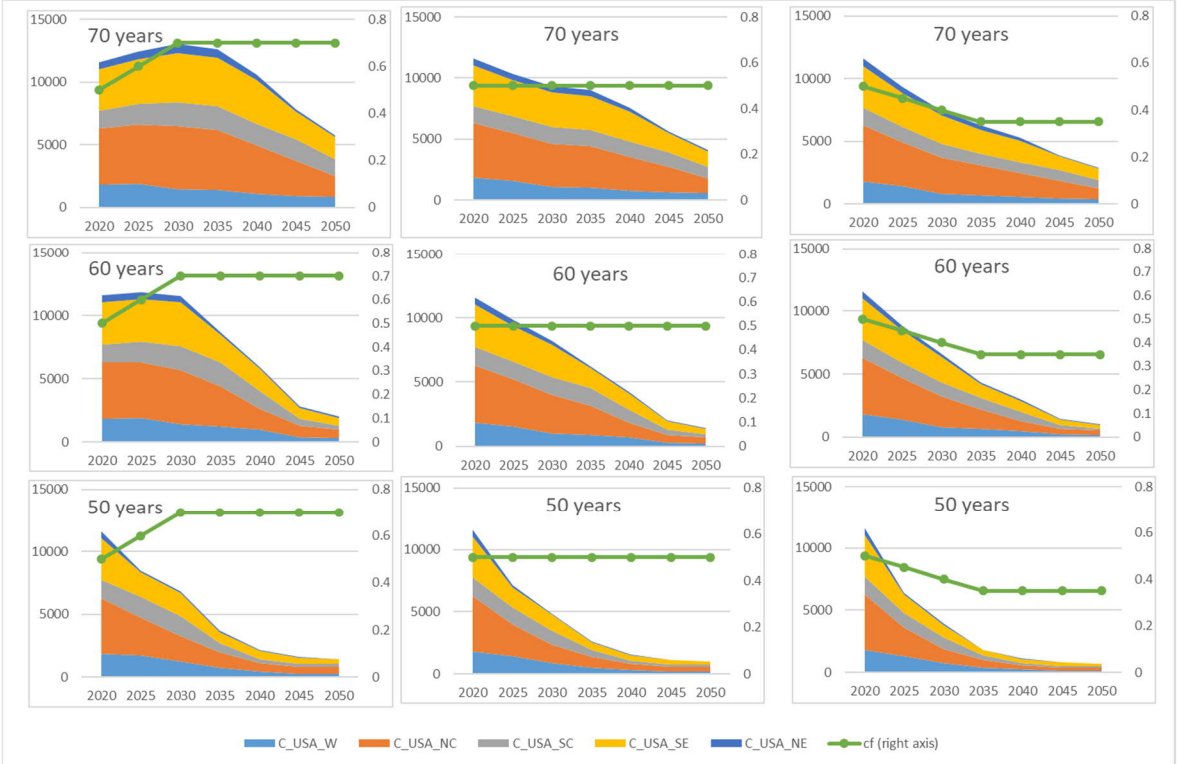


Figure 9: Coal power plant fleet development for alternative assumptions on retirement age and capacity factor (green line, right scale) by region between 2020 and 2050

Effect of West coast ports on U.S. coal production

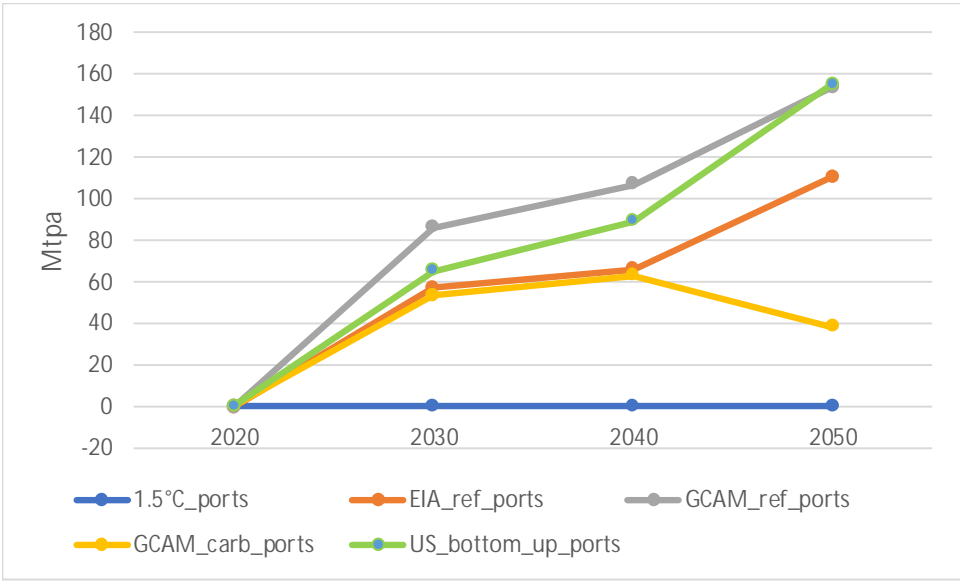


Figure 10: Difference in U.S. coal production 2020-2050 in Mtpa per year between scenarios without and with new coal ports allowed on the U.S. West Coast

Table 3: Share of exports in U.S. steam coal production

	EIA_ref	EIA_ref_ports	US_bottom_up	US_bottom_up_ports	1.5°C	1.5°C_ports
2020	12%	12%	12%	12%	12%	12%
2025	14%	20%	16%	23%	-9%	-9%
2030	15%	26%	25%	35%	-19%	-19%
2035	17%	31%	38%	48%	-5%	-5%
2040	17%	34%	52%	64%	1%	1%
2045	20%	41%	74%	83%	1%	1%
2050	11%	35%	78%	88%	1%	1%

Varying speed of regional coal demand decline

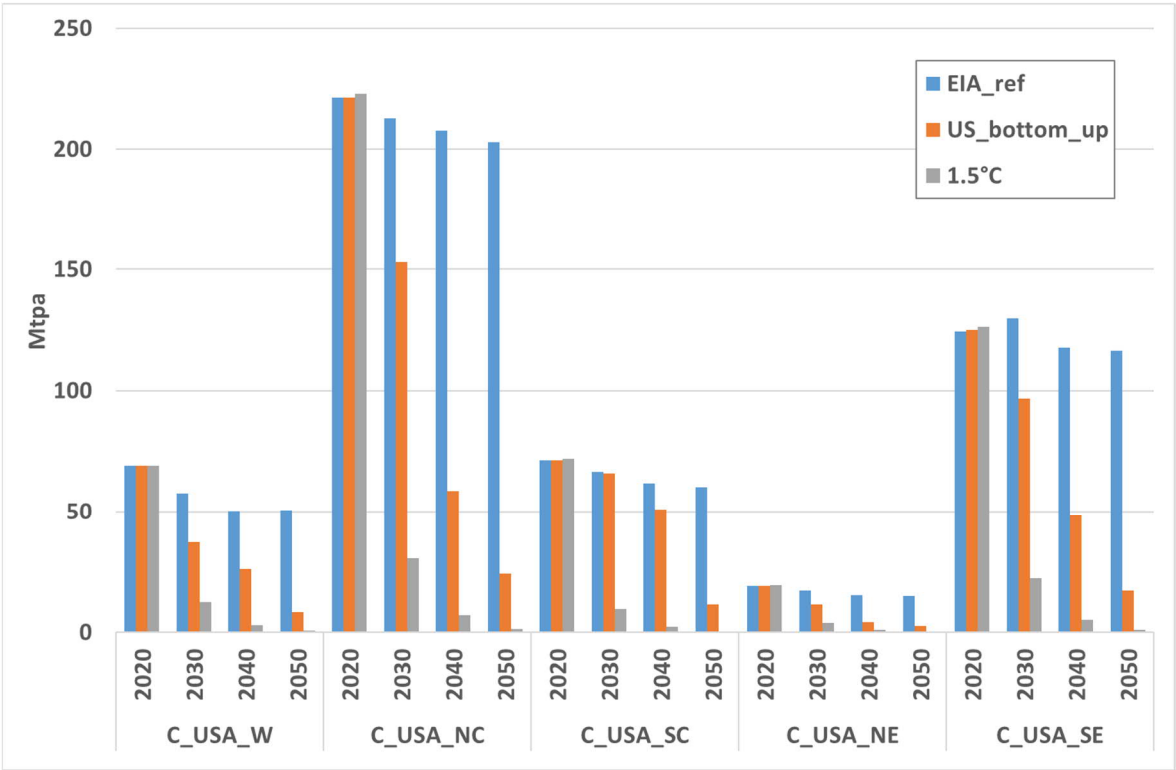


Figure 11: Regional U.S. coal consumption 2020-2050 in Mt per year in various scenarios

Regional coal mining employment characteristics

Table 4: Average (2014-2018) productivity, annual working hours per employee, and jobs per Mtpa coal produced in the four U.S. coal regions

Average data for 2014-2018	Appalachia	Interior	Rockies	PRB
Productivity [Mtpa/hour]	2.59	4.74	6.61	26.05
Annual working hours per employee	2219	2319	1832	2049
Jobs per Mtpa	174.04	90.93	82.56	18.74

Source: Own calculations based on data from EIA coal data browser: <https://www.eia.gov/coal/data/browser/>, last accessed May 05, 2020.