Economic Implications of the Nationally Determined Contributions and Goals of the Paris Agreement

Samuel Evan Marginson

Thesis submitted in fulfilment of the requirements for the degree of Doctor of Philosophy

Victoria University, Australia
Institute of Sustainable Industries and Liveable Cities

April 2024

Abstract

The Paris Agreement aims to limit increases in the average global temperature due to greenhouse gas emissions to 2℃ above the pre-industrial average. If we ignore the damages caused by emissions, limiting emissions generally makes economic activity more expensive. Countries signed up to the Paris Agreement because it allows them to propose their own reductions, effectively allowing them to choose the cost they're willing to impose on their own economies. Countries are required to periodically review their commitments to reduce their emissions, known as Nationally Determined Contributions (NDCs). When they do, they compare their targets with those of other countries. Countries often use their economic circumstances to justify their targets, so a key question is, what are the economic consequences of the NDCs? This thesis seeks to address that question through the use of computable general equilibrium modelling.

Most NDCs are focussed on reductions by 2030. Most emissions reductions until then will be the result of changes to the way electricity is generated. To represent those changes, the electricity sector in the Global Trade Analysis Project (GTAP) database has been disaggregated using electricity generation cost data for 2017, the base year for the database. I have modified the dynamic computable general equilibrium model "GDyn-E" by disaggregating its electricity sector and adding more gases to initial greenhouse gas accounts. I simulate economic scenarios to 2030 with and without the NDCs.

The economic impacts of NDCs submitted to date are most significant in regions that are heavily reliant on fossil fuel exports for income. Impacts on the real incomes

of regions with the most ambitious emissions reduction targets are relatively mild, with real incomes with the NDCs being between 0.7-1.1% lower than they are in the base case in the three most ambitious regions (the EU, USA and Japan). To some extent, this is due to reductions in income being offset by additional revenue that is captured by putting a price on emissions. As the economic impacts of climate change are expected to be considerably larger than the reductions in income due to emissions reduction efforts in the most ambitious regions, reducing emissions is good economic policy. At the sectoral level, impacts are mostly limited to changes in electricity generation. Total Final Consumption of most fossil fuels remains relatively unchanged or even increases slightly. This is due to a relative lack of ambition overall - although emissions are likely to peak this decade, they will only decline by approximately 0.3% over the period from 2021 to 2030.

Student Declaration

I, Samuel Evan Marginson, declare that the PhD thesis entitled "Economic implications of the Nationally Determined Contributions and goals of the Paris Agreement" is no more than 80,000 words in length including quotes and exclusive of tables, figures, appendices, bibliography, references and footnotes. This thesis contains no material that has been submitted previously, in whole or in part, for the award of any other academic degree or diploma. Except where otherwise indicated, this thesis is my own work.

I have conducted my research in alignment with the Australian Code for the Responsible Conduct of Research and Victoria University's Higher Degree by Research Policy and Procedures.

Signatur [redacted] Date: July 19, 2024

Acknowledgements

Thanks to my supervisors, Prof. Glyn Wittwer and Dr Michael Jerie, for their patience. Thanks to everyone at the Centre of Policy Studies for their camaraderie, insights and assistance.

For Amami...

Contents

List of Tables

List of Figures

Chapter 1

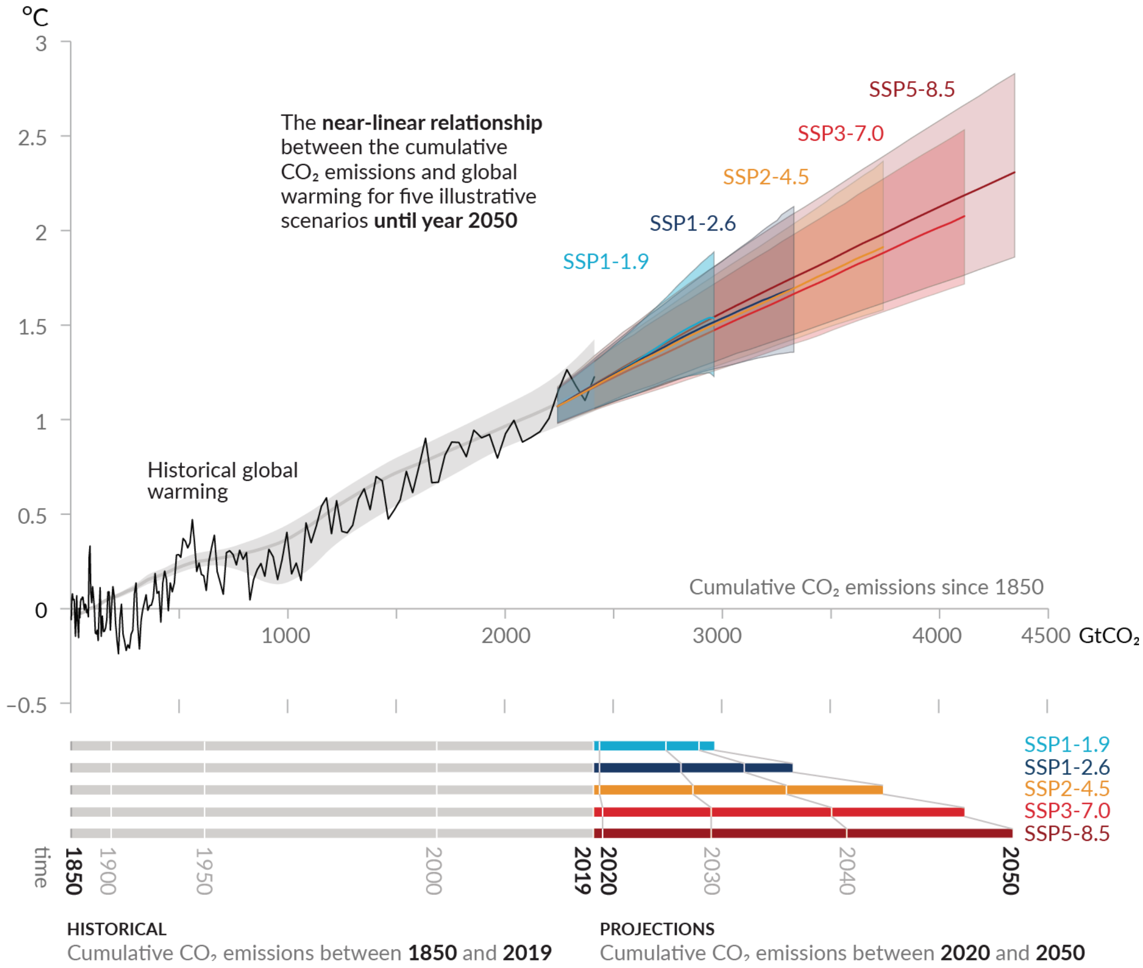
Introduction and research question

Economic development has raised the standards of living for many, but at a cost - human activities have begun to impact the environment in ways that will make life more difficult (Steffen et al., 2015). Climate change is considered a key driver of potentially catastrophic environmental change and politicians have been engaged in negotiations for decades in an attempt to minimise the problem it may cause.

The Paris Agreement (United Nations Framework Convention on Climate Change, 2015) is the latest agreement by parties to the United Nations Framework Convention on Climate Change and it aims to limit increases in the average global temperature to 2℃ above the pre-industrial average, at most (the agreement also contains an aspirational goal to limit the temperature increase to 1.5℃). Figure 1.1 shows the clear relationship between cumulative emissions and temperature, with estimates of temperatures in a number of scenarios considered by the Intergovernmental Panel on Climate Change (IPCC, 2021).

As part of the Paris Agreement, countries must periodically commit to greenhouse gas emissions reductions, known as Nationally Determined Contributions (NDCs).

Figure 1.1: Global surface temperature increase in ℃ since 1850–1900 as a function of historical cumulative carbon dioxide (CO_2) emissions



Source: IPCC (2021)

Throughout this process, countries will inevitably compare the effort required to achieve commitments they are considering with the efforts required by other countries to achieve their commitments. There are a number of ways that these efforts can be compared, but there is often a focus on economic metrics, so a key question is, what are the economic consequences of the NDCs committed to by signatories to the Paris Agreement? This thesis seeks to address that question through the use of Computable General Equilibrium (CGE) modelling. As most NDCs are, at the time of writing, focussed on efforts to reduce emissions up to 2030, the period to 2030 is the focus of this thesis.

The remainder of this document is broken up into six chapters. Chapter 2 covers other literature that has sought to assess the impacts of the Paris Agreement (and earlier climate agreements) in a similar fashion.

Chapter 3 begins with details regarding the initial aggregation of the source data. The five largest emitting countries, China, the USA, India, Russia and Japan, are represented separately. Countries in the European Union (EU) are aggregated into a single region. With the exception of Australia, all other countries are aggregated into regions based on geography. Sectoral aggregation was mostly based on the emissions-intensity of the sectors in the version of the GTAP database that was available at the time (Chepeliev, 2020a, GTAP, 2020a).

My starting point for the model was GDyn-E (Golub, 2013). However, GDyn-E and the GTAP database have a single electricity sector. As much of the climate mitigation efforts over the period relevant to current NDCs will have greatest effect within the electricity sector, it needed to be disaggregated. The work of Peters (2016a) provided a template for doing so, though the exact method of splitting the sector and the costs used to do so are different here. Section 3.1 starts by outlining the components that the electricity sector was split into. The electricity sector in the GTAP database (Aguiar et al., 2023, GTAP, 2020a) includes the costs of transmission and distribution. Those were split out from the remainder of electricity sector costs, which were assigned to electricity generation activities.

The starting point for electricity generation costs are estimates made by the International Energy Agency / Nuclear Energy Agency (IEA/NEA, 2015) for what they would be in 2020. Due to the rapid changes taking place within the electricity sector, costs of generating electricity from the sun and wind were updated using data reported by the International Renewable Energy Agency (IRENA, 2018). These changes were necessary as the cost of generating electricity using methods other than burning fossil fuels will have a significant influence on the economic impacts of emissions mitigation efforts. The methods used to update the costs, fill gaps in data and to address inconsistencies between data sources can be found in detail in Section 3.1. Most importantly, differences between the estimates made by the IEA/NEA (2015) and observations by IRENA (2018) are documented in Section 3.1.3. These are important because many modellers rely on the estimates by the IEA/NEA (2015), despite observed costs already being up to 35% lower by 2017 (the year of interest for this work) than those estimates. More recently, the IEA, NEA and Organisation for Economic Co-operation and Development (OECD) (2020) published estimates of expected generation costs for 2025. Chepeliev (2023) subsequently used those estimates to produce an updated version of the GTAP-Power database for 2017. There is no documentation by Chepeliev (2023) of adjustments made to generation costs to account for "learning rates" used by the IEA, NEA and OECD (2020). Without these, the costs used by Chepeliev (2023) are not applicable to 2017.

Section 3.2 describes how the data discussed in Section 3.1 was used to disaggregate the electricity sector in the GTAP (2020a) database. In general, this was done using simple shares based on unit cost and electricity generation data.

One thing that sets GDyn-E apart from its static version (GTAP-E) is its treatment of investment. The GDyn database (GTAP, 2020b) contains investment data for 2014. However, the economic data in the most recent version of the GTAP database is for 2017. To create investment data for 2017 so that simulations could start then, the investment data for 2014 was scaled using economic data for 2014 and 2017. Section 3.3 discusses the methods used to do so. Subsequent to the database modification process undertaken for this work, Aguiar et al. (2023) published a version of the GDyn database for 2017.

Although GDyn-E only models emissions of carbon dioxide, emissions data for other greenhouse gases is available (Chepeliev, 2020a). Although the majority of greenhouse gas emissions are of carbon dioxide, other gases comprise a significant enough share that they cannot be ignored. As the data is from 2014, it needed to be scaled to be appropriate for 2017. Section 3.4 has the details.

The economic impacts of emissions mitigation are significantly affected by how easy it is for economies to transition away from emitting activities. How easy it is to do so in the model is controlled by various model parameters. The parameters control how easily users of goods and services can respond to changes in the prices they face. CGE models are typically used to estimate changes in use such that an "equilibrium" is achieved for prices and use. However, prices are not only functions of supply and demand. Technological change can result in reductions in prices, whilst taxes and subsidies affect the prices faced by users. The parameters in question are therefore capable of representing the extent of the response to those price changes. What they are not designed to represent are non-market regulations such as bans and moratoria. Section 3.5 begins by discussing the initial sources for parameters introduced into the model used here that were not originally included in GDyn-E, as well as some parameters that needed to be adjusted in order for the model to produce valid solutions. However, just because a solution is valid does not mean it is realistic. A considerable amount of effort went into validation of model parameters using historical data. As the EU was the only region to have an emissions price applied across the entire region during the historical period, it was used as the basis for the parameterisation exercise, which is discussed in Section 3.5.2.

GDyn-E was only set up to simulate the electricity sector as a whole. Model changes were therefore required to enable it to represent changes within the electricity sector. Again, the work of Peters (2016b) provided a template. Section 4.1 outlines the theory involved. GDyn-E was also restricted to carbon dioxide in its representation of greenhouse gases. The model was expanded to allow simulation of changes in emissions of the other greenhouse gases covered by Chepeliev (2020a). This was undertaken following the work of Brinsmead et al. (2019), as mentioned in Section 4.1.

A small number of model variables are calculated outside the model and used to drive changes in the model. These are changes in population, changes in the size of the labour force, economic growth measured as Gross Domestic Product (GDP) from 2017 to 2019 and region-specific technological change from 2020 onwards. Section 4.2 begins by discussing the sources for these calculations.

The combustion of fossil fuels to produce energy is a large source of greenhouse gas emissions. Therefore, trends in the efficiency of energy use are important when estimating the use of fossil fuels and the associated greenhouse gas emissions that causes. Section 4.2.1 presents what changes in energy efficiency were used in this modelling.

During the period from 2017 to 2019, significant changes were taking place not just in the electricity generation sectors, but also in other energy sectors. Additionally, not all changes within the electricity sector were the result of cost alone. Outside the electricity sector, significant reductions in the cost of producing gas were realised due to the application of new technologies in some regions. While reductions in the cost of generating electricity from the sun and wind continued, some regions provided generous subsidies for the uptake of those technologies and so amplified the impact of the cost reductions. Additionally, an expanded set of Organization of the Petroleum Exporting Countries (OPEC) countries, referred to as "OPEC+" by Wingfield et al. (2020), continued to manipulate oil prices. Changes in the production of coal and its use to generate electricity were also observed. All of this was accounted for as much as possible, as discussed in Section 4.2.2. Also discussed are ongoing reductions in the cost of generating electricity from the sun and wind.

Perhaps the most important of all inputs to the modelling are the sources of emissions data after 2017 and interpretation of the NDCs. Those are discussed in Section 4.2.3. The mechanism used by the model to control greenhouse gas emissions by pricing them is also discussed in detail.

The Paris Agreement is not limited to NDCs. It also includes commitments regarding finance. "Annex I" (developed) countries have promised to provide \$100 billion per year to assist developing countries mitigate their emissions. There is also a commitment by all countries to make "finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development" (United Nations Framework Convention on Climate Change, 2015). By supposing this can be translated as a removal of subsidies for fossil fuel production and use, the economic impacts of these commitments have been assessed. The methods that are used to assess them are discussed in Section 4.2.4.

Chapter 5 begins by presenting global emissions with and without the NDCs, as produced by the modelling. Without any constraints placed on emissions (the base case), emissions grow by more than 30% globally over the course of the decade, with higher growth in Asia, the Middle East and Africa. Although the NDCs submitted to date result in considerably lower emissions relative to the base case, the NDCs as they stand result in global emissions in 2030 that are barely lower than they are in the present day. With the current NDCs, model results indicate cumulative emissions of greenhouse gases from 2021 to 2030 will be over 430 megatonnes of CO_2 equivalent ($MtCO_2$-e), which is between the Shared Socioeconomic Pathway (SSP) 2-4.5 and SSP3-7.0 scenarios shown in Figure 1.1. Those scenarios have median warming in the period from 2081 to 2100 of 2.7 and 3.6°C respectively (IPCC, 2021), clearly breaching the goals of the Paris Agreement.

Regional changes are discussed in Section 5.1. China's emissions would be expected to rise by over 40% in the absence of their NDC. Their NDC causes their emissions to remain roughly constant, meaning China will still be by far the largest emitter of greenhouse gases in 2030. Declining emissions in developed countries are largely offset by increases in developing countries. Most notably, NDCs from Russia and the aggregate Rest of Asia and the Pacific region are so weak that they are non-binding. Emissions in those regions rise considerably. India's NDC is also not strong enough to prevent emissions rising significantly, though they are approximately 11% lower in 2030 than they are in the base case. Without their NDC, India's emissions would increase by over 60% over the course of the decade. By 2030, approximately half of global emissions come from Asia. However, in per capita terms, the story is very different. Australia and the USA, the regions with the highest per capita emissions to begin with, are overtaken only by Russia's emissions per capita by the end of the modelling period.

In regions with the most ambitious emissions reduction targets, the majority of emissions reductions are achieved in the electricity generation sector. By 2030, only 3% of the USA's emissions will come from its electricity generation sector. In the EU, that number is 2%. Those numbers are higher in the absence of the NDCs, at 26% and 18% respectively. Those base case numbers are still lower than the shares in 2017, which were 33% in the USA and 24% in the EU. The reductions in the base case are due to ongoing reductions in the cost of wind and solar. That indicates that advances in renewable electricity generation technologies will only produce a reduction in the share of emissions coming from the electricity sector of about a third. This observation makes clear that technological innovation alone is insufficient to produce the level of decarbonisation required to come close to achieving the NDCs, let alone the goals of the Paris Agreement. Government intervention is required to produce sufficient emissions mitigation to achieve our goals.

Economic impacts are worst in regions significantly reliant on sales of fossil fuels for income. The Middle East is the worst affected region in terms of Gross National Income (GNI). It is negatively affected for two reasons: firstly it incurs costs of emissions mitigation and secondly sales of fossil fuels are lower than they would be in the absence of the NDCs. Russia is slightly less affected, as it does not have a binding emissions reduction target and so can use some of the fossil fuels, that it would otherwise sell, as a source of energy. Most regions see their income decline in real terms relative to the case with no NDCs. It should be noted that the base case does not include the economic damages caused by emissions. Compared against the significant growth in incomes in all regions in the absence of the NDCs, the reductions in income due to the NDCs estimated here are relatively minor. Eventually, all negatively affected regions mitigate the impacts of lost income on consumption, to some extent, by saving less. The Rest of Asia and the Pacific region and India see their incomes increase in real terms relative to the case with no NDCs. As mentioned above, the emissions reduction targets in the NDCs of the countries in these regions are weak. As a result, emissions-intensive industries relocate to these regions, providing additional income. Emissions are controlled in the model by putting a price on emissions. Payments to emit become an additional source of income for regions with ambitious emissions reduction targets, which allows mitigation of income loss. Looking at the EU in particular, the pricing of emissions increases costs of commodities produced there, resulting in a decline in economic activity. However, the revenue from payments for emissions more than offsets the nominal income lost from the reduction in economic activity and that limits the impact of the NDCs on real income caused by increases in prices.

Sector-specific global changes are discussed in Section 5.2. For example, the electricity generation sectors undergo significant changes as a result of emissions reduction efforts. Of the ten sectors most affected by emissions mitigion commitments, coal mining is the only one that is not an electricity generation sector. In the regions with the most stringent emissions reduction targets, the vast majority of electricity generation will come from zero- and low-emissions generation technologies by the end of the decade. Those technologies include nuclear, hydro, solar, wind and "other" (most notably geothermal and biofuel / biomass) electricity generation technologies. In the USA, those will generate 97% of electricity by 2030. They will be responsible for 98% of electricity generation in the EU by that time. In the base case, those numbers are 53% and 67% respectively. The shares of electricity generated by zero- and low-emissions technologies estimated here for the case with the NDCs are higher in the EU than the 88% estimated by the European Commission

(2024) and the maximum of 82% estimated for the US in modelling undertaken for the Environmental Protection Agency (EPA, 2023). This is due to the differences in approaches used for the different modelling exercises. The modelling undertaken here simply solves for the least cost way to reduce emissions and assumes that all barriers to implementation will be overcome. It does not, for example, take into account the social resistance to development of any given technology, such as the changes to preferences for nuclear energy discussed by the European Commission (2024).

Globally demand for coal will fall by 12% over the course of the decade, mostly due to reduced coal-fired electricity generation. This results in global coal production being more than 30% less than it would be in the absence of the NDCs. However, the reduction in demand for coal to generate electricity causes a reduction in the price of coal, which incentivises its use by, in particular, energy-intensive industries, though that is very region-specific.

The news for oil producers is not as bad. The NDCs are barely able to make a dent in demand for oil products. Use of oil products continues to grow, particularly by transport sectors and households, who predominantly use it for private transport. However, relative to the case with no NDCs, demand for oil products is slightly lower due to electrification. Additionally, there is significant regional variation. For example, there are considerable negative deviations in the use of oil products by the other transport sector in the USA, EU, Japan and Australia, with declines relative to the base case in the range of 12-33%. This leads to a slight drop in prices relative to the base case, which causes small increases in use by, for example, the other transport sector in Russia, India, the Rest of Asia and the Pacific and the Rest of Europe and former Soviet Union, where increases relative to the base case are in the range

0.4-2.3%. Similar though slightly more muted effects can be seen for household oil products use.

Although important to developing countries, once distributed between all of them, the promised \$100 billion per year represents only a very small increase to investment. Impacts of that additional investment on regional incomes are smaller still. Impacts of the removal of fossil fuel subsidies on income are varied but of a similar magnitude to those of the \$100 billion per year in climate financing. Perversely, subsidy removal in regions with binding emissions reduction targets results in a slight increase in global emissions due to additional relocation of emissions-intensive activities to regions with non-binding targets. Details can be found in Section 5.3.

Chapter 6 begins by discussing how the NDCs, as they currently stand, are not very likely to achieve the goals of the Paris Agreement, then looks at where we might expect to see more ambitious emissions reduction targets announced as countries review their NDCs. As already mentioned, two regions (India and the Rest of Asia and the Pacific) see their incomes increase as the result of new industrial activity spurred by carbon leakage. However, they are both low income and low emissions per capita regions. Some high income countries will still have high emissions per capita, despite having some of the most ambitious NDCs. Low income, low emissions per capita regions may object to being asked to reduce their emissions further by regions that remain high per capita emitters with high incomes. By further reducing their emissions, regions with high per capita incomes and emissions could prevent less developed countries from basing arguments against committing to more ambitious emissions reductions on grounds of emissions per capita. Section 6.1 closes by looking at how carbon leakage limits the impact of the NDCs.

Section 6.2 outlines next steps that could be taken to adapt the model (and the data it uses) to be capable of representing facets of emissions reduction efforts that are likely to become more relevant as time progresses. To begin with, industry-specific marginal abatement cost curves could be incorporated into the model to allow abatement of non-combustion emissions, as discussed in Section 6.2.1. Additionally, the model and database could be modified to represent sectors that may develop in response to climate change mitigation efforts, such as hydrogen production and carbon dioxide capture. That is discussed in Section 6.2.2. Section 6.3 concludes the thesis.

Chapter 2

Literature review

The economic impacts of climate change and the policies that have been or might be implemented to mitigate it have been extensively documented. One significant stream of research utilises integrated assessment models. Chang and Rutherford (2017) provide an update to the commonly referenced Dynamic Integrated Climate Economy (DICE) model, which is a neoclassical growth model with consumption maximised over the timeframe of the model. They concluded that the incorporation of unknown tipping events into the model framework causes the optimal policy to be making emissions reductions larger and sooner. Hänsel et al. (2020) also updated the original DICE model, to better represent the physics of climate change and the economic damages that might be caused by it. They also performed a sensitivity analysis on the social discount rate. There is a trade off between the cost of reducing emissions and the cost of damages from climate change. They concluded that optimality arose from accepting some temperature increases, given the economic cost of abatement, rather than taking immediate and severe measures to limit warming. Pörtner et al. (2022) go into significant detail about projected economic damages, stating, "Severe risks are more likely in developing regions that are already hotter and in regions and communities with a large portion of the workforce employed in highly exposed industries (e.g., agriculture, fisheries, forestry, tourism, outdoor labour)." As the communities that Pörtner et al. (2022) say will be worst affected are not those responsible for the majority of emissions, making a claim regarding what is optimum at the global scale ignores the regional distribution of costs and benefits of mitigation. Neither Chang and Rutherford (2017) or Hänsel et al. (2020) account for the fact that average impacts are not the same as actual impacts. In reality, some regions will experience quite severe impacts in any given year due to extreme events.

Modelling undertaken for the Network for Greening the Financial System (2021) was performed using a number of models with results reported at 5 year intervals. Whilst they did look at the NDCs that had been submitted at the time of writing, the economic structures of the models used do not necessarily provide the sorts of detailed sector level analysis that policy makers might desire. Economic growth in the Global Change Assessment Model, one of the models used, is determined solely by the size and productivity of the labour force (Calvin et al., 2019), while the other two models used only have a single economic sector.

Adams and Parmenter (2013) suggest that CGE modelling is capable of providing the level of detail required by policy makers, whereas economic theory and more stylised analysis cannot. I have therefore limited the scope of the remainder of this chapter to applications of CGE modelling to climate change and some works documenting the development of the model that I chose to use to undertake my analysis.

Fujimori et al. (2016) focussed on the Paris Agreement and the NDCs that had been submitted at the time of their work. They investigated how an emissions trading scheme can help achieve both the NDCs and the temperature limit goal of the Paris Agreement at least cost. They used AIM/CGE, a CGE model with 17 regions and 42 sectors, with economic data from the GTAP database. Although they went to significant effort to verify energy use data (Fujimori and Matsuoka, 2011), no detail is provided regarding the disaggregation of the electricity sector. The authors focussed on overall commitments by countries - where countries have sector-specific NDCs, they were not taken into account. They broke the NDCs down into categories as follows:

- greenhouse gas emissions;
- greenhouse gas emissions intensity; and,
- carbon dioxide emissions intensity.

NDCs reported as emissions intensities were converted to emissions for use in their modelling. They also discuss one of China's NDCs related to the timing of the peak of China's emissions - China have made a commitment that their carbon dioxide emissions will peak by 2030.

It has proven extremely difficult to negotiate a climate agreement covering all countries. Böhringer et al. (2021) made similar findings with regards to the economic efficiency of a global trading scheme, but, if history is anything to go by, an international agreement to implement an all-inclusive emissions trading scheme is unlikely in the timeframes relevant to this work. Since the work of Fujimori et al. (2016), many new NDCs have been submitted (Fenhann, 2022). AIM/CGE was used in modelling undertaken as part of the work summarised by Roelfsema et al. (2020), which assesses some of those new NDCs. The starting year of AIM/CGE simulations is 2005 (Fujimori et al., 2014).

The Economic Projection and Policy Analysis model, developed by researchers at Massachusetts Institute of Technology (Chen et al., 2022) is an 18 region, 22 sector model that is publicly available. It uses economic data from the GTAP-Power database. Primary factors include capital, labour and a variety of energy sources. Simulations span the period from 2015 to 2100 and produce results every 5 years. This final point is most important from the perspective of this study - as NDCs have primarily been submitted for 2030, a model that produces output more frequently is required.

The OECD (2012) undertook CGE modelling for their "Environmental Outlook to 2050", which outlines how the global environmental situation is likely to progress under a baseline scenario with no new policies to address four serious issues – climate change, biodiversity, water and human health. It contains a number of proposals for new policies to address issues that existing policies do not respond to adequately, such as climate change. They used a CGE model called ENV-Linkages for their economic analysis and their Integrated Model to Assess the Global Environment. However, these models are not available to the public.

Another model used extensively to assess climate change policy, most recently by Fernando et al. (2021), is G-Cubed. They include economic damages from climate change. However, they do not focus on Nationally Determined Contributions submitted to date. Deloitte Economics Institute (2021a,b, 2022) also incorporate damages from climate change into a global CGE model. Again, though, their model is not publicly available and their focus is not on currently submitted NDCs. Other global models used to analyse climate change policies include the Global Trade and Environment Model, used by Hatfield-Dodds et al. (2017) to assess the environmental and natural resource impacts of global economic growth, as well as the Modular Applied GeNeral Equilibrium Tool, which Dixon et al. (2016) used to investigate how combining increased biofuels production with limitations on land clearing might impact the price of agricultural commodities.

From an Australian perspective, Adams and Parmenter (2013) give an outline of a model of the Australian economy, which would be perfect to develop a global version of, were it not for the time and data requirements of such an undertaking, in addition to the fact that simulation times would make the use of such a model infeasible. The model they developed, called the Monash Multi-Regional Forecasting model or MMRF, gives the level of detail required by policy makers, with 58 commodity producing industries located in the eight states and territories of Australia, which are further split up into 56 sub-state regions. The representation of the electricity sector in particular is extremely detailed, with a link to an engineering model of the electricity system developed separately by Frontier Economics. Of particular relevance is that emissions from all industries are accounted for, including the source of the emissions (fuel or non-fuel). It is this sort of detail that I aimed to include in a global model. Vandyck et al. (2016) did similar work but before many countries updated their NDCs.

Global Trade Analysis Project (GTAP)

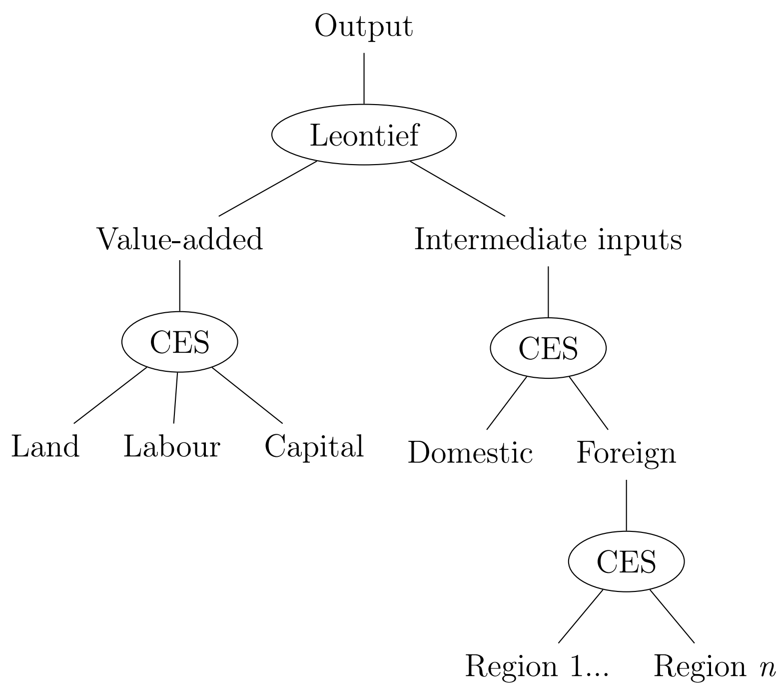
The GTAP data base (Aguiar et al., 2023), which is a widely used source of economic data, is produced by the researchers at the Center for Global Trade Analysis. Additionally, researchers involved in the project have developed (and continually improve) the GTAP model (Hertel and Tsigas, 1997) and its dynamic counterparts. The GTAP model is a global economic model made publicly available and distributed by the Center for Global Trade Analysis. It is written to be solved by the General Equilibrium Modelling PACKage (Horridge et al., 2018). The amount of research associated with the project is large and I limit my focus here to the works either summarising these models, or integrating greenhouse gas emissions into them. Hertel and Tsigas (1997) described the development of the basic GTAP model.

Within GTAP, regions maximise their utility, defined by a Cobb-Douglas function, by allocating their budget to three categories of expenditure: private consumption, saving and government consumption. The expenditure of each region is funded by the sale of endowment commodities, or primary factors, to firms. Endowment commodities include land, natural resources, capital and skilled and unskilled labour. Firms require endowment commodities along with intermediate inputs (tradeable commodities produced by firms) as inputs to production. Firms sell their products to other firms, to government and to households. They also sell investment products to households. Firms operate under a zero pure profits assumption - sales are equal to costs. Global sectors enable flows of goods and finance between regions: trade and transport sectors; and a global bank.

Primary factors and intermediate inputs are complementary in the firms' production function. Substitution is allowed between primary factors. Substitution is also allowed between sources of intermediate inputs at two levels - firstly between imported and domestic sources of each commodity, then between imports from all other countries. A constant elasticity of substitution (CES) is used in the equations for firm demand at each level. This production structure is shown in Figure 2.1.

Ianchovichina and McDougall (2001) built on the work of Hertel and Tsigas (1997) by developing a recursive dynamic version of the GTAP model, which they called GTAP-Dyn. The model treats time as a variable. Doing so has several advantages: how the economy changes over time can be represented; the capital stock is linked to depreciation and time-varying investment; and how regional debt evolves over time due to changes in the trade balance can be tracked. Ianchovichina and McDougall (2001) enabled the movement of capital between regions over time. Their approach

Figure 2.1: Production structure of GTAP



to doing so was outcome-oriented in that they sought only to facilitate the transfer of capital between regions in a way that enforces various accounting identities for stocks and flows related to capital, including income from foreign assets. Their representation of the financial system is therefore "highly stylized" (Ianchovichina and McDougall, 2001, p. 10).

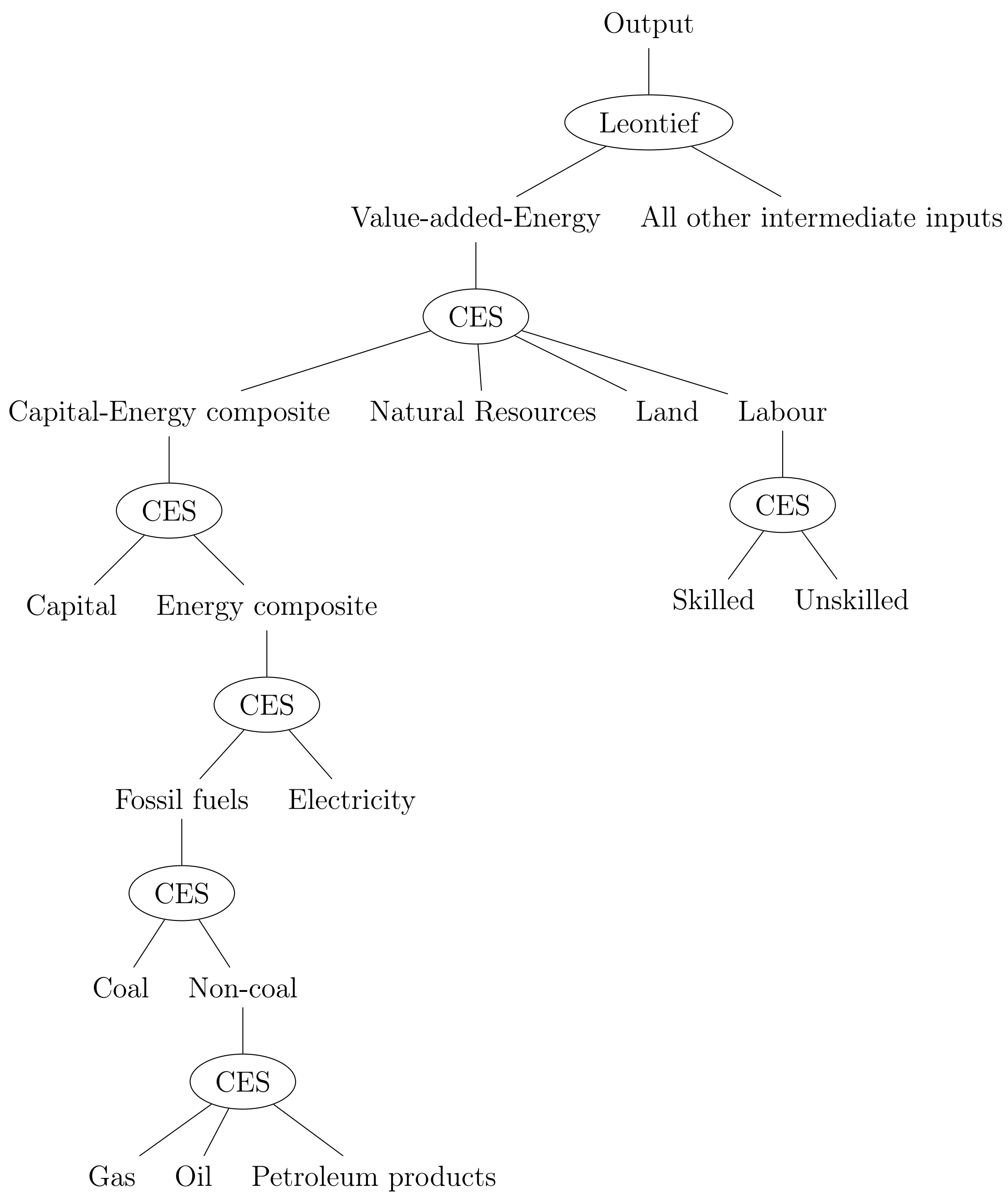
In order to account for financial flows from investment, firms own capital and households invest in the firms, which in turn pay dividends to the households. They account for the fact that rates of return differ across regions by having region-specific risk premia. Additionally, the expected rate of return differs to the actual rate of return and moves towards the actual rate depending on how much the rate of capital growth differs from the "normal" rate, which is region-specific.

Burniaux and Truong (2002) also built on the work of Hertel and Tsigas (1997) by representing the energy sector in more detail. They began by reviewing approaches used by a number of other researchers to represent the energy sector in CGE models. They decided to use a "top-down" approach to modelling the energy sector instead of incorporating a detailed representation of the energy technologies into the model, mainly due to data availability and parameterisation issues.

They then went on to introduce two possibilities for substitution of energy as an input to production in their model, which they called GTAP-E (Burniaux and Truong, 2002). The first is inter-fuel substitution, such as between coal and gas. The second is fuel-factor substitution, such as between energy and capital. To do so, they change energy from being an intermediate input, like the other commodities in the model, to being a factor input, like land, labour and capital. Energy commodities are split into electricity and non-electricity commodities, with some substitution allowed between those two, as well as within the non-electricity group. From there, energy and capital are combined into a single factor, with substitution allowed between the two. The combined capital-energy factor can then be substituted with other factor inputs. The structure is shown in Figure 2.2, with substitution between domestic and imported inputs omitted from the figure, but available for each energy commodity in the same way as shown for intermediate inputs in Figure 2.1.

It is worth noting that, although capital and energy are generally substitutes, depending on the parameters controlling substitution between primary factors and within the capital-energy composite, changes in the demand for energy commodities could be complementary with changes in the demand for capital. For example, a rise in the price of the composite energy commodity might cause the price of the com-

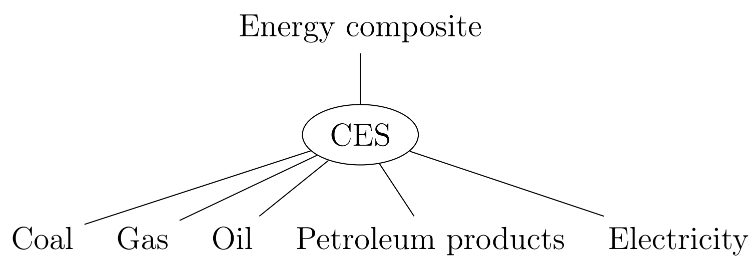
Figure 2.2: Production structure of GTAP-E



bined capital-energy factor to rise by so much that substitution away from it more than offsets the substitution towards capital within the combined capital-energy factor. That results in the use of capital in production falling along with the use of energy.

On the consumption side, the changes Burniaux and Truong (2002) made to the original GTAP model were more straightforward - energy commodities were combined into a composite that can be substituted with other commodities. For government purchases, a CES substitution function controls substitution between energy and non-energy commodity composites. For household purchases, a Constant-Difference of Elasticities form of substitution allows a limited degree of substitution between the energy composite and non-energy commodities. The structure of the energy composite consumed in GTAP-E (Burniaux and Truong, 2002) is shown in Figure 2.3.

Figure 2.3: Consumption of energy commodities in GTAP-E



Burniaux and Truong (2002) concluded that most regions would experience declines in welfare due to the Kyoto Protocol, but that those declines could be significantly offset by allowing trading in emissions. Although they highlighted the importance of time in the response of energy use to price, their model is not dynamic.

McDougall and Golub (2007) provided an update to the work of Burniaux and Truong (2002). They improved the representation of emissions and introduced carbon taxes as a potential control on emissions, whereas Burniaux and Truong (2002) only allowed for trading of emissions. Some errors in the earlier paper were also addressed and the results of the simulations updated.

Hertel et al. (2008) focussed on emissions of other gases. The objective of their work was to assess the emissions mitigation potential of changes in land use, which they attempted by creating a new version of the GTAP model, GTAP-AEZ. It enables such an assessment by splitting the available land into different Agro-Ecological Zones (AEZs), forcing agriculture and forestry to compete for land in each zone (there is also competition within agriculture for land for different types of grazing or crops), whilst accounting for emissions of a variety of greenhouse gases, other than carbon dioxide, from land using sectors. The model also accounts for carbon dioxide storage in forests.

Where agricultural production takes inputs that are emission sources, such as fertiliser use, they calibrated the elasticities of substitution between inputs so that responses to a price on emissions matched observed data. In order to deal with sectors where emissions couldn't be tied to a specific input, they allowed substitution between all inputs and emissions by making emissions an input to the production process.

The production structure for the forestry sector was also modified so that it can substitute between land and forestry products, effectively allowing it to either acquire more land in order to increase carbon stores or to do so by foregoing sales (and hence storing the carbon embodied in those sales). The emissions abatement potential of the sector was calibrated to results from a detailed global timber model.

They found that changes in land use due to a price on emissions vary depending on the length of the growing season (AEZs are classified by climate and length of growing season). Forestry tends to become more dominant due to a price on emissions in AEZs with longer growing seasons, with crop and ruminant production moving to AEZs with shorter growing seasons. They also found that forestry was a more efficient source of emissions reduction than agriculture. However, they note that the ability of a static model, such as theirs, to represent the inherently time-dependent nature of changing forest carbon stocks is limited.

Golub (2013) developed the GDyn-E model based on the earlier GTAP-Dyn model of Ianchovichina and McDougall (2001). Both models account for the way that returns on investment vary over time. That is important because polluting industries in countries implementing carbon prices will become less profitable as NDCs are implemented over time. The dynamic nature of the model is also important because the rate of emissions reductions varies over time for some countries. Golub (2013) investigated the economic consequences of the Copenhagen Accord (United Nations Framework Convention on Climate Change, 2009), focusing on how investment patterns change as the result of emissions reductions.

More recently, Aguiar et al. (2020) developed another dynamic version, GTAP-RD, of the latest GTAP model, which had changed in structure. Subsequently, the energy and environmental accounts of GTAP-E were incorporated into this new dynamic model, with the combined model known as GTAP-E-RD. It was used by Clora et al. (2023) to analyse the impacts of the EU's Carbon Border Adjustment

Mechanism (CBAM). However, GTAP-RD does not have the same accounting for capital ownership as GDyn and is less capable of analysing the capital leakage of interest to Golub (2013).

Peters (2016b) built on the work of McDougall and Golub (2007) to produce the GTAP-E-Power model, which achieves significant disaggregation of the electricity sector. It does so in order to better represent the differences between electricity generation technologies, such as increases in efficiency that are not consistent across technologies. First he reviewed various ways to incorporate substitution between electricity generation technologies into a CGE model, then he applied the most appropriate method for his purposes to the GTAP-E model to create the GTAP-E-Power model. GTAP-E-Power was then used to simulate the NDCs for countries that specified their NDC in terms of a specific reduction in emissions. Other forms of NDCs, such as those made to reduce emissions intensity, for example, were omitted from the analysis. The model is not dynamic though and so cannot represent how the timing of the NDCs affects the economy, whereas GDyn-E can. Chepeliev et al. (2018), after reworking the GTAP Data Base, used GTAP-E-Power to assess the impacts of the removal of fossil fuel consumption subsidies, finding that, in some regions, removing the subsidies resulted in larger emissions reductions than the NDCs.

Kompas et al. (2018) developed an intertemporal version of the GTAP model, which incorporates climate damage functions and allows agents to account for them in their decision-making with perfect foresight. They solve for a number of potential futures that are based on the number of degrees of warming (they have scenarios for 2, 3 and 4 degrees of warming). The modelling does not explicitly account for the NDCs.

Chapter 3

Data

The first pre-release version of version 11 of the GTAP database for reference year 2017 (GTAP, 2020a) was aggregated across regional and sectoral dimensions to limit simulation time. The regional aggregation, which is a more aggregated version of that used by Golub (2013), is shown in Table 3.1.

Table 3.1: Regional aggregation

Region	**GTAP regions**
China	chn, hkg
USA	usa
India	ind
Russia	rus
Japan	jpn
The European Union (EU)	aut, bel, bgr, hrv, cyp, cze, dnk, est, fin, fra, deu, grc, hun, irl, ita, lva, ltu, lux, mlt, nld, pol, prt, rou, svk, svn, esp, swe
Australia	aus

Table continues on next page

Table 3.1: (continued)

Region	GTAP regions
Rest of the Americas	can, mex, xna, arg, bol, bra, chl, col, ecu, pry, per, ury, ven, xsm, cri, gtm, hnd, nic, pan, slv, xca, dom, jam, pri, tto, xcb
Rest of Asia and the Pacific	nzl, xoc, kor, mng, twn, xea, brn, khm, idn, lao, mys, phl, sgp, tha, vnm, xse, bgd, npl, pak, lka, xsa, xtw
Rest of Europe and the former Soviet Union	gbr, che, nor, xef, alb, blr, ukr, xee, srb, xer, kaz, kgz, tjk, xsu, arm, aze, geo, tur
The Middle East	bhr, irn, isr, jor, kwt, omn, qat, sau, are, xws
Africa	egy, mar, tun, xnf, ben, bfa, cmr, civ, gha, gin, nga, sen, tgo, xwf, xcf, xac, eth, ken, mdg, mwi, mus, moz, rwa, tza, uga, zmb, zwe, xec, bwa, nam, zaf, xsc

The 65 sectors in the original database (GTAP, 2020a) for 2017 were aggregated into the 29 sectors shown in Table 3.2 using the GTAP aggregation software GTAPAgg2 (Horridge, 2020), supplied with the database. The aim of aggregation is to preserve project-relevant sectoral detail while aggregating sectors not directly relevant. Mining sectors remain disaggregated and livestock and heavy industry are also relatively disaggregated. Service sectors are aggregated. Following this aggregation the electricity sector was subsequently disaggregated, as discussed in Section 3.2, using TABLO (Horridge et al., 2018) to produce a database with the 38 sectors shown in Table 3.4. Note that in this document italics are used when referring to a named element of the set of sectors or commodities.

Table 3.2: Sectoral aggregation

Sector	**GTAP sectors**
Primary and secondary rice production	pdr, pcr
Wheat, cereal and grain farming	wht, gro
Vegetables, fruit, nuts	v_f
Production of vegetable and seed oils	osd, vol
Farming and processing of sugar	c_b, sgr
Plant-based fibers	pfb
Crops nec	ocr
Grazing and processing of all grazing animals	ctl, cmt
Animal products nec	oap
Raw milk	rmk
Wool, silk-worm cocoons	wol
Forestry	frs
Fishing	fsh
Coal mining	coa
Crude oil	oil
Natural gas extraction, manufacture and distribution	gas, gdt
Other mining	oxt
Meat products nec	omt
Dairy products	mil
Other food, beverage and tobacco products	ofd, b_t
Refined oil products	p_c
Energy-intensive industries	chm, nmm, i_s, nfm
Electricity	ely

Table continues on next page

Table 3.2: (continued)

Sector	GTAP sectors
Water	wtr
Sea transport	wtp
Air transport	atp
Other transport	otp
Services	cns, trd, afs, whs, cmn, ofi, ins, rsa, obs, ros, osg, edu, hht, dwe
Other industry	tex, wap, lea, lum, ppp, bph, rpp, fmp, ele, eeq, ome, mvh, otn, omf

The theory of the model allows households and government to substitute between all commodities but does not allow firms to substitute between intermediate inputs. Many agricultural commodities are sold directly to the household. However, some agricultural commodities are predominantly sold to food and drink manufacturing sectors. Where a sufficiently high share (more than 59%) of the output of an agricultural sector was used by a single food manufacturing sector, the two were aggregated into a single sector.

Unlike many of the agriculture and food manufacturing sectors, the output of the non-food manufacturing sectors is consumed mostly as intermediate inputs by other firms. We want to aggregate as many of these sectors together as possible to reduce simulation times. However, given the objective of this work is to estimate the economic impacts of emissions reductions, we want to choose an aggregation that does not lose significant detail about emissions. Consequently, the only significant aspect that might differentiate between the remaining manufacturing sectors, for the purposes of choosing an aggregation, is their emissions intensity.

To estimate emissions intensities for the purposes of aggregation, emissions from each sector in the fully disaggregated version of the GTAP database were calculated by adding:

- 2017 emissions for CO_2 (GTAP, 2020a); and,
- 2007 emissions of non-CO_2 greenhouse gases (in CO_2-equivalent units) from version 8 of the non-CO_2 greenhouse gas GTAP database (Ahmed et al., 2014). These were used as the author did not have access to non-CO_2 emissions data from any of the more recent versions of GTAP at the time, which, noting that they were only used in the selection of an aggregation, was very early on in the data work and modelling process.

The resulting emissions were divided by sector output for 2017 (GTAP, 2020a) in 2017 United States Dollars (USD) to produce the emissions intensities shown in Table 3.3. The emissions of different gases are taken from different years, but these values were only used for the purpose of selecting an aggregation.

The main source of emissions from non-food manufacturing sectors is energy use, so they have been aggregated into *energy-intensive industries* and *other industry*. A reasonable benchmark for the comparison of emissions intensities were the emissions intensities of the services sectors, as services sectors are generally considered to have low emissions intensities. In version 8 of the GTAP database, the most emissions-intensive GTAP sector within the aggregated *services* sector was the *osg* (public administration, defence, health and education) sector. The *energy-intensive indus-*

Table 3.3: Emissions intensities used to determine emissions-intensive sectors when selecting aggregation (ktCO_2 equivalent / Million USD of output)

Sector	**Intensity**	**Sector**	**Intensity**	**Sector**	**Intensity**
pdr	1.954	omt	0.018	ome	0.016
wht	0.749	vol	0.050	mvh	0.009
gro	0.703	mil	0.036	otn	0.016
v_f	0.766	pcr	0.018	omf	0.032
osd	0.568	sgr	0.093	ely	4.679
c_b	0.536	ofd	0.054	gdt	1.617
pfb	1.026	b_t	0.051	wtr	0.052
ocr	0.636	tex	0.050	cns	0.015
ctl	6.447	wap	0.015	trd	0.020
oap	0.711	lea	0.022	otp	0.840
rmk	1.639	lum	0.032	wtp	0.732
wol	0.031	ppp	0.097	atp	0.596
frs	0.108	p_c	0.285	cmn	0.006
fsh	0.138	crp	0.195	ofi	0.004
coa	1.289	nmm	0.706	ins	0.004
oil	0.260	i_s	0.446	obs	0.013
gas	0.550	nfm	0.127	ros	0.022
oxt	0.173	fmp	0.035	osg	0.113
cmt	0.027	ele	0.079	dwe	0.000

Sources: GTAP (2020a), Ahmed et al. (2014) and author's calculations. Sector codes as used by Ahmed et al. (2014)

tries aggregate is defined to contain manufacturing sectors that are more emissions-intensive than the *osg* sector. The remaining (non-food) manufacturing sectors were combined into the *other industry* sector. The GTAP version 8 sector *crp* (chemical, rubber and plastic products) was split into three sectors by version 11. Of those three, only the *chemical products* sector was emissions-intensive enough for inclusion in the *energy-intensive industries* aggregate. The others, *basic pharmaceutical products* along with the *rubber and plastic products*, were included in the *other industry* sector.

The emissions intensities of the 38 sectors in the database read by the model are shown in Table 3.4.

Table 3.4: Emissions intensity of aggregated sectors ($ktCO_2$ equivalent / Million USD of output)

Sector	**Intensity**
Primary and secondary rice production	1.357
Grain farming	0.768
Fruit and vegetables and nuts	0.312
Production of vegetable and seed oils	0.249
Farming and processing of sugar	0.224
Plant-based fibers	0.505
Crops nec	0.379
Grazing and processing of all grazing animals	2.563
Animal products nec	0.619
Raw milk	1.962
Wool and silk-worm cocoons	0.053

Table continues on next page

(continued)

Sector	**Intensity**
Forestry	0.123
Fishing	0.174
Coal mining	2.394
Crude oil	0.420
Natural gas extraction and distribution	0.889
Other mining	0.167
Meat products nec	0.019
Dairy products	0.036
Other food and beverage and tobacco products	0.052
Refined oil products	0.396
Energy-intensive industries	0.368
Water	1.507
Other industry	0.052
Services	0.017
Transport nec	0.681
Sea transport	0.674
Air transport	1.169
Electricity transmission and distribution	0.109
Coal electricity	13.621
Oil electricity	4.163
Oil products electricity	2.341
Gas electricity	4.682
Nuclear electricity	0
Hydro electricity	0

Table continues on next page

(continued)

Sector	Intensity
Wind electricity	0
Solar electricity	0
Other electricity	0.190

Sources: GTAP (2020a), Chepeliev (2020a) and author's calculations.

3.1 Electricity data

In order to better represent how the electricity sector has evolved over time and how it will be affected by the NDCs, I disaggregated the single sector in the GTAP database into:

- A single transmission and distribution sector; and,
- Nine generation sectors, differentiated by the technologies used to generate the electricity.

It will be useful to define the set of electricity generation sectors GT as follows.

$$GT = \{ce, oe, pe, ge, nuclear, hydro, wind, solar, other\} \tag{3.1}$$

In the notation here, to avoid confusion between the fuel and the sector that generates electricity by using that fuel, the following abbreviations have been used:

- ce uses coal.
- oe uses oil.
- pe uses petroleum products.
- ge uses gas.

The aim of the process is similar to that of Peters (2016a), which is to split a single electricity sector into the sectors listed above. Peters (2016a) split some of the generation sectors up further, into base load and peak load, which has not been done in this work. Additionally, data sources used here, described throughout this section, are more recent. However, at a high level, the method is the same - separate transmission and distribution from generation, then separate generation into generation from different technologies. The method for disaggregating generation used here is the same as that used by Peters (2016a) at a high level - take observations of generation and multiply them by costs per unit of generation to get the value of generation by each technology type in each region. Sum those values to get the total value of electricity generation in each region. The value of generation by each technology divided by the total value of generation in each region then becomes the share used to disaggregate the generation component of the original electricity sector in the GTAP database.

3.1.1 Transmission and distribution

Not all expenditure on electricity goes towards generation. Generation is where the bulk of emissions come from. The first step was to separate expenditure on generation out from expenditure on transmission and distribution. The regional shares going to transmission and distribution are shown in Table 3.5. Data for China and Japan were unavailable for 2017. The value used for China is from 2011. That used for Japan is from 2015, which was the latest year available.

3.1.2 Generation

With the exception of the *wind*, *solar* and *other* generation technologies, i.e. for the set $GT \setminus \{wind, solar, other\}$, I extracted generation data from the Electricity and Heat Output section of tables in World Energy Balances 2018 (IEA, 2018b), where it was available for 2017. I extracted data for *wind* and *solar* from the Summary Time Series section of World Energy Statistics 2018 (IEA, 2018c), where it was available

Table 3.5: Share of electricity costs assigned to transmission and distribution

Region	**Share**
China	32%
USA	23%
EU	38%
India	45%
Russia	20%
Japan	35%
Australia	56%
Rest of Asia and the Pacific	24%
Rest of the Americas	27%
Rest of Europe and the former Soviet Union	23%
Middle East	23%
Africa	20%

Sources:

- China - He et al. (2015)
- USA - Energy Information Administration (EIA, 2019)
- EU - Eurostat (2020)
- India - Central Electricity Authority (2019)
- Japan - Federation of Electric Power Companies of Japan (2020)
- Australia - Australian Competition and Consumer Commission (2018)
- All other regions - Chepeliev (2020b)

for 2017. Where data was not available for 2017 in IEA (2018b) and IEA (2018c), I extracted it from the IEA's online database (IEA, 2021a). Calculating generation by the *other* electricity sector was a two step process:

1. Generation by *wind* and *solar* was subtracted from generation by Geotherm./

Solar/ etc. as reported in the Electricity and Heat Output section of the tables.

2. The result of the step above was added to generation from Biofuels/ Waste in the Electricity and Heat Output section (IEA, 2018b).

Generation by all technologies in the set GT are shown in Table 3.6. Note all values include generation of both heat and electricity, as the GTAP *ely* sector includes the generation of both. Heat values have been converted to TeraWatt hours (TWh).

Table 3.6: Electricity and heat generation in 2017, by source (TWh)

Region	Coal	Oil	Oil Pcts	Gas	Nuclear	Hydro	Wind	Solar	Other
China	5547	0	51	331	248	1190	295	131	104
USA	1324	0	40	1405	839	302	257	71	120
EU	862	0	86	762	761	322	312	103	420
India	1130	0	8	76	38	142	55	26	44
Russia	452	5	50	1530	207	187	0.2	1	142
Japan	361	8	70	403	33	80	6	61	59
Australia	163	0	6	50	0	15	12	8	2
Rest of Asia and the Pacific	834	0	110	723	181	297	12	10	86
Rest of the Americas	163	3	148	529	134	1145	98	8	77
Rest of Europe and former USSR	466	0.002	26	631	209	381	81	20	82
Middle East	44	115	210	890	8	18	1	4	0.2
Africa	253	5	62	323	14	130	12	6	10

Sources: IEA (2018b), IEA (2018c), IEA (2021a) and author's calculations

3.1.3 Levelised cost of electricity

The Levelised Cost Of Electricity (LCOE) is a measure of the cost of generating electricity where the total cost of a facility over its lifetime is divided by the amount of electricity it generates during that lifetime giving the cost of each unit of electricity generated. Since the lifetime of electricity generation facilities are measured in decades, adjustments are needed to bring generation costs into present value terms taking into account the year in which they occur. Similarly, adjustments need to be made to electricity sales. The adjustment is done using a discount rate with the LCOE given in present value terms.

The IEA/NEA (2015) reported estimates of what the LCOE would be in 2020 for a large number of facilities. The IEA, NEA and OECD (2020) undertook a similar exercise, but estimated costs for 2025. As we are interested in costs in 2017, estimates for 2020 by the IEA/NEA (2015) are likely to be closer. The values they reported are denoted here by $C^{IEA}_{cc,fa}$ for cost component cc and facility fa. The set of facilities is denoted FA. The set of cost components CC is defined as $CC = \{k, m, fu\}$ where k is capital; m is operations and maintenance (O&M); and fu is fuel.

The facilities are spread across 22 nations, but not all nations have costs reported for facilities of each type. For example, the only facilities in Brazil that the IEA/NEA (2015) reported costs for were hydropower facilities.

Note that the aim here is to calculate shares of GTAP electricity sector costs for each generation technology using the per unit cost of electricity generation (LCOE), with electricity generation being measured in MegaWatt hours (MWh). For this reason the LCOE costs per unit of generation are appropriate, rather than costs per unit of capacity.

Global average costs of generation, given in Table 3.7, were calculated using various methods. For a subset of technologies

$$GT^{IEA} = \{ce, ge, nuclear, hydro, other\} \subset GT, \tag{3.2}$$

costs for a subset of (non-fuel) cost components $NF = CC \setminus \{fu\}$ reported by the IEA/NEA (2015) were used unchanged, with the capacity shares of each facility used as weights. For these, global averages $\bar{C}_{cc,gt}$ for each cost component cc and generation technology gt were calculated by

$$\bar{C}_{cc,gt} = \frac{1}{\sum_{fa \in FA_{gt}} CAP_{fa}} \sum_{fa \in FA_{gt}} \left(CAP_{fa} C^{IEA}_{cc,fa} \right), \quad cc \in NF,\ gt \in GT^{IEA}, \tag{3.3}$$

where:

- $C^{IEA}_{cc,fa}$ are the costs reported by the IEA/NEA (2015);
- CAP_{fa} are the capacities of the facilities those costs are are associated with; and,
- the set FA_{gt} refers to a subset of the total set FA of facilities reported by the IEA/NEA (2015). The facilities FA_{gt} are of the type of the generation technology gt in question, with GT being the set of all generation technologies, as defined by Equation 3.1.

As discussed later in this section, the global average costs calculated using Equation 3.3 were used for technologies in the set GT^{IEA} in regions shown in Equation 3.7, which are those that the IEA/NEA (2015) did not report any data for those technologies. They were also scaled to estimate costs for technologies in regions where the IEA/NEA (2015) did not estimate them, as discussed later in this section and shown in Equation 3.8.

Estimation of costs of generation from *solar* is discussed in Section 3.1.3.1, *wind* is

Table 3.7: Global average levelised costs of electricity generation (2017 USD/MWh)

Technology	**Capital**	**O&M**	**Fuel**	**Total**
Hydro	$23.01	$10.54	$-	$33.55
Wind	$31.39	$17.59	$-	$48.98
Nuclear	$25.98	$15.87	$10.68	$52.53
Coal	$12.73	$8.54	$36.44	$57.71
Gas	$11.95	$8.79	$62.86	$83.61
Solar	$87.10	$27.60	$-	$114.70
Other	$13.13	$17.38	$96.13	$126.64
Oil Products	$12.42	$26.24	$229.71	$268.37
Oil	$51.54	$25.17	$212.79	$289.50

Sources: IEA/NEA (2015), Power Generation Cost Analysis Working Group (2015), Lazard (2015), Lazard (2017), GTAP (2020a) and author's calculations.

discussed in Section 3.1.3.2, oil *oe* and oil products *pe* are discussed later in this section. Values reported for *wind* and *solar* are weighted averages using generation shares as weights. Values reported for oil and oil products are presented for illustrative purposes only. They were calculated by scaling other global averages, with the exception of the cost of fuel for the oil products electricity *pe* sector, which is a simple average of fuel costs across all regions for generation from diesel reported by Lazard (2017). Values in the Fuel column of Table 3.7 for coal *ce* and gas *ge* have been calculated using data from version 11 of the GTAP database (GTAP, 2020a). In the case of hydropower, global average costs were calculated excluding costs reported for the lone Chinese plant as both the plant's size and cost are outliers, which would have caused the average cost of hydropower to be unrealistically low.

I included decommissioning costs with those of O&M. The reasons for this are twofold:

1. Capital costs are incurred upfront whilst finances for decommissioning are more likely to be set aside over the operating life of a plant; and,

2. Ideally, when the costs per unit of generation (shown in Table 3.6) are multiplied by the amounts of electricity generated, the result should match the values of inputs to the electricity sector in the GTAP database. However, the calculated costs are considerably less than those in the GTAP database. In the comparison to GTAP values, the discrepancy associated with the calculated cost of capital is smaller than the discrepancy associated with the calculated cost of O&M. Therefore, since decommissioning costs need to be allocated, they are included in the O&M costs, which reduces the size of the discrepancy with the value of O&M costs in the GTAP database.

The IEA/NEA (2015) presented capital costs for discount rates of 3, 7 and 10%. We are therefore faced with a decision about what discount rate to choose.

Recall that, at the highest level, our method for disaggregation is to multiply observed quantities of electricity generation by costs per unit of generation to get the value of costs incurred while generating electricity using each generation technology, then to calculate shares associated with each generation technology from those values. Although we are only using those values to calculate shares, it would still be ideal if those values matched the values for electricity sector costs in the GTAP database. Our choice of discount rate should be informed by the proximity of the values our method produces to the values in the GTAP database.

When considering how close the values we calculate are to those reported in the GTAP database, we need to consider how the costs reported by the IEA/NEA

(2015) correspond to those in the GTAP database. The GTAP database includes data for the value of capital use, along with values for the use of many other inputs. The approach here uses each generation technology's share of O&M costs in each region to calculate use of inputs to the electricity sector in the GTAP database other than capital and fuel, as did Peters (2016a). When deciding on a discount rate, the main things we need to consider are, for both capital and O&M cost components, how close are the values we calculate to those in the GTAP database?

The value of capital use by the electricity sector in the GTAP database is approximately 30% higher than that produced by multiplying electricity generation by the capital cost per MWh of generation when the per unit costs assume a 3% discount rate. If instead we use the capital costs that assume a 7% discount rate, the value of capital use in the GTAP database is approximately 30% lower than the value calculated as the product of generation and per unit costs.

The values for O&M costs in the GTAP database are consistently higher than those we calculate no matter what discount rate is used, because O&M costs are less affected by the discount rate. Therefore, for consistency, a 3% discount rate was used, as that results in estimates of capital costs that are lower than those in the GTAP database, which is the same as the estimates for O&M costs. For notational simplicity, all occurrences of the symbol $C^{IEA}_{cc,fa}$ refer to the costs reported for a 3% discount rate.

All costs have been inflated to 2017 US dollars using data from the Bureau of Economic Analysis (2021). Costs for *solar* are discussed in Section 3.1.3.1 and those for *wind* are discussed in Section 3.1.3.2. They include adjustments for advances in technology. It should be noted that the costs reported by the IEA/NEA (2015), with the exception of a very small number of solar thermal generation facilities, do not include the costs of any electricity storage that might be required to facilitate the transition to an electricity sector with a high share of electricity generation from intermittent generating technologies.

Data sources and adjustments are summarised in Table 3.8. Further details can be found below.

Table 3.8: Summary of levelised costs of electricity data sources and adjustments

Technology	**Source**	**Adjustments**
Hydro	IEA/NEA (2015)	N/A
Wind	IEA/NEA (2015)	Adjusted to match IRENA (2018)
Nuclear	IEA/NEA (2015)	N/A
Coal	IEA/NEA (2015)	N/A
Gas	IEA/NEA (2015)	N/A
Solar	IEA/NEA (2015)	Adjusted to match IRENA (2018)
Other	IEA/NEA (2015)	N/A
Oil Products	Lazard (2017)	Regionalised based on costs for coal from the IEA/NEA (2015)
Oil	Power Generation Cost Analysis Working Group (2015)	Regionalised based on costs relative to Japan from the IEA/NEA (2015)

Unfortunately, the IEA/NEA (2015) did not report cost projections for electricity generation from crude or refined oil. I sourced cost structure data for electricity generation from crude oil from Japan's Power Generation Cost Analysis Working Group (2015). The exchange rate used by the IEA/NEA (2015) was used to convert from yen to US dollars. I used the "Levelized Cost of Energy Analysis" version 9 (Lazard, 2015) and version 11 (Lazard, 2017) to account for the change in the price of diesel over time.

The cost of fuel fu required to generate 1MWh of electricity using generation technology gt in region r is denoted $C_{'fu',gt,r}$. The regional variation in the price of diesel reported by Lazard (2017) was used to calculate regional variation in the cost of crude oil per MWh of electricity generated by the oil electricity sector $C_{'fu','oe',r}$ in the following way, based on the assumption that the price of crude oil will be proportional to that of diesel.

$$C_{'fu','oe',r} = \frac{C_{'fu','oe','jpn'}}{C_{'fu','pe','jpn'}} C_{'fu','pe',r}, \quad r \in RL. \tag{3.4}$$

where:

- $C_{'fu','oe','jpn'}$ is the cost of crude oil from the Power Generation Cost Analysis Working Group (2015), inflated by the average change in diesel prices from Lazard (2015) to Lazard (2017);
- $C_{'fu','pe',r}$ is the cost of diesel from Lazard (2017), with $C_{'fu','pe','jpn'}$ being the cost reported for Japan specifically; and,
- RL is the set of regions that Lazard reported a diesel price for.

Some regions are not covered by Lazard (2017). I assumed the fuel costs in the Middle East and Russia were the same as those reported by Lazard (2017) for the USA. I also assumed the costs in Africa and the Rest of the Americas were equal to those reported by Lazard (2017) for Brazil. For other regions not covered by Lazard (2017), I used the average value of the covered countries.

Version 11 of the Levelized Cost of Energy Analysis (Lazard, 2017) contains data regarding the global average costs $CW_{cc,'pe'}$ of cost component cc for electricity generation from diesel (oil products) pe. Those were used to calculate the cost $C_{nf,'pe',r}$ of non-fuel inputs nf for electricity generation from oil products in region r as follows,

$$C_{nf,'pe',r} = \frac{C_{nf,'ce',r}}{CW_{nf,'ce'}} CW_{nf,'pe'}, \quad nf \in NF, \ r \in R, \tag{3.5}$$

where:

- $NF = CC \setminus \{fu\}$;
- $CW_{nf,'ce'}$ is the global average cost of component nf reported by Lazard (2017) for coal electricity generation ce; and,
- $C_{nf,'ce',r}$ are the cost components for coal electricity generation calculated from IEA/NEA (2015) data.

Coal was used as it was the only generation technology reported by both Lazard (2017) and the IEA/NEA (2015) that is used in all regions. The costs of the oil products themselves were assumed to be the same as the costs of diesel reported by Lazard (2017) using the same regional variations discussed above for oil.

Where the IEA/NEA (2015) did not report the costs of generation technologies for a given region, I assigned that region average global costs for capital and O&M. This applied for India, Russia, Australia and the Middle East. Exceptions were made for wind and solar, which are discussed below. Global average costs were also assigned to the Rest of the Americas region for all generation technologies excluding hydropower. The only facilities with costs reported by the IEA/NEA (2015) in the Rest of the Americas were hydropower facilities in Brazil, which were cheap compared to hydropower facilities in other regions. If the average costs in that region for technologies that had data were used to estimate costs for technologies without data, as explained below, the result would be cheap generation costs. In such a large and varied region, the relative costs for a single generation technology, in a country known for the abundance of that technology, are unlikely to be indicative of how the costs of generation from other technologies compare to global averages, so global average costs were used.

Where the cost of only one facility for a given generation technology was reported, that was used as the cost for that generation technology in that region. In regions r where costs were reported for more than one facility fa for a given generation technology gt, a weighted average of facilities was calculated:

$$C_{cc,gt,r} = \frac{1}{\sum_{fa \in FA_{gt,r}} CAP_{fa}} \sum_{fa \in FA_{gt,r}} \left(CAP_{fa} C^{IEA}_{cc,fa} \right), \quad cc \in CC,\ gt \in GT,\ r \in R. \tag{3.6}$$

Here:

- the set $FA_{gt,r}$ is a subset of the set of all facilities FA with costs reported by the IEA/NEA (2015), which includes only facilities of generation technology gt in region r;
- CAP_{fa} is the net generating capacity of the facility in MegaWatts electric (MWe); and,
- $C^{IEA}_{cc,fa}$ are the LCOEs reported by the IEA/NEA (2015).

To calculate value shares to split economic data for the electricity sector into different generation technologies, the three dimensional matrix $C_{cc,gt,r}$ must be fully populated. Costs for *wind* and *solar* are discussed below. Costs for generation from oil and oil products have already been discussed. For the other generation technologies, there are only two regions where data for all of them is available from the IEA/NEA (2015) - the USA and EU. Regions where the IEA/NEA (2015) report no data were mentioned above, as was the fact that they only reported data for one generation technology in the Rest of the Americas. Let us refer to this set of regions as R^{ND}.

$$R^{ND} = \{India, Russia, Australia, Rest\ of\ the\ Americas, Middle\ East\} \tag{3.7}$$

In these regions, global average costs have been assigned, with the exception of hydropower in the Rest of the Americas. In the remaining five regions, i.e. in

$R^{SD} = R \setminus (\{USA\} \cup \{EU\} \cup R^{ND})$, costs are only reported by the IEA/NEA (2015) for a subset of generation technologies. In those regions, the costs for technologies that were reported were used as a basis for calculating how costs in that region compared to global averages, as shown in Equation 3.8. The average ratio between costs in that region for technologies that had data to the average global costs for those technologies was used to estimate costs for technologies that were missing data. In this way, observed ratios of regional costs to global averages were maintained for the costs of capital and O&M. For clarity, costs of generation in regions lacking LCOE data for a given generation technology from the IEA/NEA (2015) were:

$$C_{cc,gt,r} = \bar{C}_{cc,gt} \frac{1}{|GT_r^\star|} \sum_{j \in GT_r^\star} \frac{C_{cc,j,r}}{\bar{C}_{cc,j}}, \quad cc \in CC,\ gt \in GT_r^{est},\ r \in R^{SD}, \tag{3.8}$$

where:

- $\bar{C}_{cc,g}$ is the global average cost of each component of the LCOE for the generation technology in question, as shown in Equation 3.3;
- $GT_r^\star \subset GT$ is the subset of generation technologies that do have cost data reported by the IEA/NEA (2015) in region r;
- $|GT_r^\star|$ is the cardinality of (number of elements in) $GT_r^\star$; and,
- $GT_r^{est} = GT^{IEA} \setminus (GT_r^\star \cap GT^{IEA})$, noting that GT^{IEA} is defined by Equation 3.2.

Costs of generating electricity from solar and wind power in 2020 were estimated by the IEA/NEA (2015) using unspecified "learning rates". As those learning rates are unspecified, there is no way to ascertain whether or not they matched what happened in reality. The IEA/NEA (2015) costs were therefore adjusted to reflect observations documented by the IRENA (2018). Details are below. However, the first thing to note is that the discount rates used differ between the two reports. IRENA (2018) used a discount rate of 7.5%, whereas IEA/NEA (2015) reported costs for discount rates of 3, 7 and 10%, as mentioned earlier. In order to compare like for like, the costs reported by the IEA/NEA (2015) for 7 and 10% discount rates were linearly interpolated to estimate costs for a 7.5% discount rate, referred to in equations below as $\hat{C}^{IEA}_{cc,fa}$. That is,

$$\hat{C}^{IEA}_{cc,fa} = C^{7}_{cc,fa} + (0.075 - 0.07)\frac{C^{10}_{cc,fa} - C^{7}_{cc,fa}}{0.1 - 0.07}, \quad cc \in CC,\ fa \in FA \tag{3.9}$$

where:

- $C^{7}_{cc,fa}$ is the cost reported by the IEA/NEA (2015) assuming a 7% discount rate, adjusted for inflation; and,
- $C^{10}_{cc,fa}$ is the cost reported by the IEA/NEA (2015) assuming a 10% discount rate, adjusted for inflation.

3.1.3.1 Solar

Solar costs were reported by the IEA/NEA (2015) for two different categories of facilities: photovoltaic (PV) solar and solar thermal (concentrated solar). Adjustments to those costs were necessary to account for the difference between the year that the IEA/NEA (2015) estimated costs for (2020) and the year that the GTAP database (Aguiar et al., 2023, GTAP, 2020a) represents (2017). The adjustments made differed depending on the category of facility. PV solar is broken down into three subcategories, which form the set

$$PV = \{\textit{residential rooftop}, \textit{commercial rooftop}, \textit{utility-scale}\}. \tag{3.10}$$

Let us define two sets of nations for each facility type $pv \in PV$:

- N^{IEA}_{pv}, the set of nations that the IEA/NEA (2015) reported a LCOE and its cost components for; and,
- N^{IRENA}_{pv}, the set of nations that the IRENA (2018) reported a LCOE for.

The set of nations that both the IEA/NEA (2015) and IRENA (2018) reported cost data for is the intersection of those sets,

$$N^{I}_{pv} = N^{IEA}_{pv} \cap N^{IRENA}_{pv}, \quad pv \in PV. \tag{3.11}$$

As these are the nations that the most data is available for, the costs reported by the IEA/NEA (2015) were adjusted for these nations first. As observed by the IRENA (2018), O&M costs were at most 25% of the LCOE. Therefore the adjusted maintenance (m) costs, $C^{7.5}_{'m',fa}$, with a 7.5% discount rate, for each facility reported by the IEA/NEA (2015) are calculated by

$$C^{7.5}_{'m',fa} = \min(\hat{C}^{IEA}_{'m',fa}, 0.25LCOE_{pv,n}), \quad fa \in FA_{pv,n},\ n \in N^{I}_{pv},\ pv \in PV, \tag{3.12}$$

where:

- $LCOE_{pv,n}$ is the LCOE reported by the IRENA (2018) for the nation n and the type of solar PV facility pv; and,
- $FA_{pv,n}$ is a subset of the set of facilities with costs reported by the IEA/NEA (2015) FA, limited to the type of facility pv and nation n.

We now move to a discussion of what the IEA/NEA (2015) and IRENA (2018) refer to as "investment" costs. For this thesis, investment costs are considered to be equivalent to capital costs, following the work of Peters (2016a). This section discusses IEA/NEA (2015) and IRENA (2018) data, so capital costs are referred to as investment costs. As the LCOE for these facilities is simply the sum of investment and O&M costs, the calculation of investment costs $C^{7.5}_{'k',fa}$ is

$$C^{7.5}_{'k',fa} = LCOE_{pv,n} - C^{7.5}_{'m',fa}, \quad fa \in FA_{pv,n},\ n \in N^{I}_{pv},\ pv \in PV. \tag{3.13}$$

The outcome of Equation 3.13 is a reduction in the investment costs reported by the IEA/NEA (2015) of 19% on average.

Now we must consider facilities reported by the IEA/NEA (2015) in nations that did not have any data reported by the IRENA (2018),

$$N^{N}_{pv} = N^{IEA}_{pv} \setminus N^{IRENA}_{pv}, \quad pv \in PV. \tag{3.14}$$

The IRENA (2018) reported an average LCOE for utility-scale facilities across Europe, so the adjustments made to investment costs depended on whether the facilities were rooftop facilities or utility-scale. For both facility types, the method for calculating O&M costs in nations with costs only reported by the IEA/NEA (2015) is

$$C^{7.5}_{'m',fa} = \min\left(\hat{C}^{IEA}_{'m',fa}, C^{7.5}_{'k',fa}/3\right), \quad fa \in FA_{pv,n},\ n \in N^{N}_{pv}. \tag{3.15}$$

Here $C^{7.5}_{'k',fa}$ are the investment (i.e. capital, subscript k) costs after the adjustments shown in Equation 3.16, 3.18 or 3.20, depending on the facility. Note that, because the LCOE for these facilities is the sum of investment and O&M costs, limiting O&M costs to a third of investment costs is equivalent to limiting them to 25% of the LCOE, in line with IRENA (2018) observations.

For rooftop rt facilities reported by the IEA/NEA (2015) in nations without data reported by the IRENA (2018) N^{N}_{rt}, I adjusted investment costs by the average ratio across facilities with costs reported in both publications, as shown in Equation 3.16.

$$C^{7.5}_{'k',fa} = \hat{C}^{IEA}_{'k',fa} \frac{1}{|FA^{I}_{rt}|} \sum_{j \in FA^{I}_{rt}} \frac{C^{7.5}_{'k',j}}{\hat{C}^{IEA}_{'k',j}}, \quad fa \in FA_{rt,n},\ n \in N^{N}_{rt},\ rt \in RT, \tag{3.16}$$

where:

- $RT = PV \setminus \{\textit{utility-scale}\}$;
- FA^{I}_{rt} is the set of facilities of type rt limited to those in nations N^{I}_{rt} where costs have been reported by both the IEA/NEA (2015) and IRENA (2018); and,
- $FA_{rt,n}$ is a subset of the total set of facilities with costs reported by the IEA/NEA (2015) FA, limited to the type of facility rt and nations n.

Note that $N^{I}_{rt} \subset N^{I}_{pv}$ and $FA_{rt,n} \subset FA_{pv,n}$.

Of interest here is that everything on the right of the symbol $\hat{C}^{IEA}_{'k',fa}$ in Equation 3.16 is the ratio of an estimate of the investment component of the LCOE observed by the IRENA (2018) to the investment cost reported by the IEA/NEA (2015), averaged across facilities. If the ratio is less than one, the learning rates used by the IEA/NEA (2015) were not optimistic enough, or, conversely, if the ratio is greater than one, the learning rates used were too optimistic. As a result of these calculations, the following adjustments were made to estimates of investment costs with a 7.5% discount rate based only on IEA/NEA (2015) data $\hat{C}^{IEA}_{'k',fa}$ to calculate investment costs $C^{7.5}_{'k',fa}$ for the rooftop types of solar PV for facilities in nations N^N_{rt} where costs were reported by the IEA/NEA (2015) but not by the IRENA (2018):

- Residential rooftop investment costs were reduced by 17%; and,
- Commercial rooftop investment costs were increased by 1%.

Utility-scale, denoted us, facilities were treated slightly differently, because the IRENA (2018) reported the average LCOE in Europe. Let us define EUR to be the set of nations in Europe. We have previously defined the set N^N_{pv} with Equation 3.14. Let us define $N^N_{'us'}$ as the subset of N^N_{pv} containing only utility-scale facilities. Now let us limit $N^N_{'us'}$ further by restricting it only to nations within Europe,

$$EUR^N_{'us'} = N^N_{'us'} \cap EUR. \tag{3.17}$$

To make the average of the LCOEs across European countries match that reported by the IRENA (2018), investment costs for utility-scale facilities reported by the IEA/NEA (2015) in European nations without data reported by the IRENA (2018) were calculated as

$$C^{7.5}_{'k',fa} = SF^{us,Eur}\hat{C}^{IEA}_{'k',fa}, \quad fa \in FA_{'us',n},\ n \in EUR^N_{'us'} \tag{3.18}$$

subject to:

$$\frac{1}{|FA_{'us',n}|}\sum_{cc\in CC}\sum_{j\in FA_{'us',n}} C^{7.5}_{cc,j} = LCOE^{us,Eur}, \quad cc \in CC,\ n \in EUR. \tag{3.19}$$

Here:

- $SF^{us,Eur}$ is a scaling factor;

- $FA_{'us',n}$ is the set of utility-scale facilities that the IEA/NEA (2015) reported data for, limited to the nations that n ranges over;
- $|FA_{'us',n}|$ is the number of elements in $FA_{'us',n}$; and,
- $LCOE^{us,Eur}$ is the average of the LCOEs across European countries reported by the IRENA (2018) for utility-scale facilities.

The outcome of Equation 3.18 was that investment costs in European countries with facilities reported by the IEA/NEA (2015) but not the IRENA (2018) were increased by 8%, i.e. $SF^{us,Eur} \approx 1.08$.

The only facility with costs reported by the IEA/NEA (2015) in the Rest of Asia and the Pacific region was in Korea. To reflect differences between LCOEs observed by the IRENA (2018) and estimates by the IEA/NEA (2015) for facilities in other nations, investment costs for the utility-scale facility in Korea, denoted $'kor'$, were calculated by Equation 3.20.

$$C^{7.5}_{'k','kor'} = \hat{C}^{IEA}_{'k','kor'} \frac{1}{1 + |FA^{I}_{'us',n}|} \left(SF^{us,Eur} + \sum_{j \in FA^{I}_{'us',n}} \frac{C^{7.5}_{'k',j}}{\hat{C}^{IEA}_{'k',j}} \right), \quad n \in N^{I}_{'us'} \tag{3.20}$$

This scaled $\hat{C}^{IEA}_{'k','kor'}$ by the average amount that other utility-scale facilities were scaled by in nations with costs reported by both the IEA/NEA (2015) and IRENA (2018), including the scaling factor for facilities in $EUR^{N}_{'us'}$ (defined by Equation 3.17), which was given a weight equivalent to that of a single facility. Here $N^{I}_{'us'}$ is the set of nations that both the IRENA (2018) and the IEA/NEA (2015) reported data for utility-scale facilities for, $N^{I}_{'us'} \subset N^{I}_{pv}$.

Finally, costs per unit of generation for each cost component for each facility assuming a 3% discount rate, $C_{cc,fa}$, were calculated by

$$C_{cc,fa} = C^{IEA}_{cc,fa} \frac{C^{7.5}_{cc,fa}}{\hat{C}^{IEA}_{cc,fa}}, \quad cc \in CC, \ fa \in FA, \tag{3.21}$$

where:

- $C^{IEA}_{cc,fa}$ is the cost per unit of generation for each cost component for each facility assuming a 3% discount rate as reported by the IEA/NEA (2015);
- $C^{7.5}_{cc,fa}$ is the cost calculated using the adjustments discussed above; and,
- $\hat{C}^{IEA}_{cc,fa}$ is defined by Equation 3.9.

The averages of $C_{cc,fa}$ across all nations for each of the types of solar PV generation facilities are summarised in Table 3.9.

Table 3.9: Components of LCOE from solar PV (2017 USD/MWh)

	Investment cost	**O&M**	**Total**
Residential rooftop	\$101	\$31	\$132
Commercial rooftop	\$86	\$22	\$108
Utility-scale	\$68	\$24	\$92

Sources: IEA/NEA (2015), IRENA (2018) and author's calculations.

As discussed at the start of this section, there are two different categories of solar facilities: PV and solar thermal. In order to get an average LCOE for the solar sector overall, the costs in Table 3.9 need to be weighted and combined with the costs of solar thermal. Data for the weights comes from three sources. The IEA (2021a) gives the amount of electricity generated by solar thermal and the broad "solar PV" category of generators. The latter provides 98% of the generation by the sector. Within solar PV, the IEA (2018a) report the ratio between utility-scale and rooftop generators to be 57:43. Within rooftop generation, I took the split between commercial and residential rooftop systems from the IEA (2019b), which reports that commercial rooftop is responsible for 73% of rooftop generation.

There is a limited amount of data regarding the LCOE from solar thermal facilities reported by the IRENA (2018) to compare against those from the IEA/NEA

(2015). The IRENA (2018) present data for the range of LCOEs globally and the weighted average of the LCOEs. Upon inspection of their data it is clear that the LCOE at the maximum end of the range is that for a facility in Africa and so the investment cost from the one facility in Africa that the IEA/NEA (2015) reported was adjusted such that the total LCOE for the facility matched that reported by the IRENA (2018). The final global average cost breakdown is shown in Table 3.10, along with the weighted average of the costs for PV shown in Table 3.9.

Table 3.10: Components of LCOE from solar generation (2017 USD/MWh)

	Investment cost	**O&M**	**Total**
Solar thermal	\$108	\$47	\$155
PV solar	\$78	\$24	\$102

Sources: IEA/NEA (2015), IRENA (2018) and author's calculations.

When thinking about the costs in 2017 as shown in Table 3.10, it might be useful to consider changes in LCOEs since then. The IRENA (2022) observed a fall in the LCOE for PV solar of 42% between 2017 and 2021. When considering this reduction, it should again be noted that they assume a discount rate higher than the discount rate of 3% used in the calculations for this thesis. The IEA, NEA and OECD (2020) estimated what LCOEs will be in 2025 for a number of facilities and the average of those for solar PV facilities in 2017 USD is \$68/MWh, assuming a 3% discount rate.

When combining costs for the various types of solar generation technologies into an overall cost for the solar electricity sector, the sources I used for weights were the same as those used when calculating the global average, discussed on the previous page. Region-specific calculations where the IEA/NEA (2015) did not report any data are outlined below.

- India: There was no electricity generated using solar thermal (as opposed to solar PV) generation technologies in 2017 (IEA, 2021a). The IRENA (2018) reported a LCOE for solar PV for China and India as a combined region, along with a LCOE for all categories of solar PV in both countries other than for commercial rooftop solar PV in India. As all LCOEs reported by the IRENA (2018) for solar PV in both countries are above the weighted average across both countries reported by the IRENA (2018), I used the minimum of the range reported across both countries for the LCOE for commercial rooftop in India, in order for the weighted average LCOE of solar PV across both countries to be as close as possible to the value reported by the IRENA (2018). I used the same O&M cost shares and ratios between costs at different discount rates as those in China.
- Russia: I used the ratio between the LCOE for utility-scale solar in Eurasia and the global average reported by the IRENA (2018) to estimate the LCOE of rooftop PV categories. I then applied global average O&M cost shares and ratios between costs at different discount rates from the IEA/NEA (2015).
- Australia: I applied average O&M cost shares reported by the IEA/NEA (2015) for other countries to the LCOE reported by the IRENA (2018) for commercial and residential rooftop solar PV. I also used the average ratios between costs at different discount rates reported for other countries by the IEA/NEA (2015). For utility-scale solar and solar thermal, I used the LCOEs reported by the IRENA (2018) for Oceania. When weighting the various categories of solar generation to produce a LCOE for the solar sector overall, I supplemented data from the IEA (2021a) with data from the Department of the Environment and Energy (2019) and the APVI (2018).
- Rest of the Americas: I applied average O&M cost shares and ratios between

costs at different discount rates from the IEA/NEA (2015) to data from the IRENA (2018). I sourced a LCOE for utility-scale solar for Canada from the IESO (2016) using exchange rates from the OECD (2020).

- The Middle East: I used the ratio between the LCOE for utility-scale solar and the global average reported by the IRENA (2018) to estimate the LCOE of rooftop PV categories. I then applied global average O&M cost shares and ratios between costs at different discount rates from the IEA/NEA (2015).

The costs of generating electricity from solar power that I used to disaggregate the GTAP database are shown in 2017 US dollars for all regions in Table 3.11.

Table 3.11: Costs of solar powered electricity generation in 2017 (2017 USD/MWh)

Region	**Capital**	**O&M**	**Total**
China	$46	$18	$64
USA	$91	$9	$100
EU	$85	$29	$114
India	$45	$18	$63
Russia	$123	$48	$172
Japan	$87	$35	$122
Australia	$55	$17	$72
Rest of Asia and the Pacific	$91	$22	$113
Rest of the Americas	$96	$34	$130
Rest of Europe and rest of the former Soviet Union	$89	$40	$128
Middle East	$118	$39	$157
Africa	$85	$34	$119

Sources: IEA/NEA (2015), IRENA (2018) and author's calculations.

3.1.3.2 Wind

The process for assigning costs for generating electricity from the wind is similar to that for solar PV power, but simpler as there are only two categories: onshore and offshore wind. Furthermore, generation of electricity from offshore wind facilities in 2017 was limited to a small number of nations and almost all generation was in Europe.

The IRENA (2018) reported 2017 O&M costs for facilities in a small number of nations. For O&M costs for facilities in nations where IRENA (2018) did not report O&M costs, the lower of 25% of the LCOE for the facility and the O&M costs reported by the IEA/NEA (2015) was used. As with solar PV, the calculation depended on whether both the IRENA (2018) and the IEA/NEA (2015) reported costs for facilities in that nation, or if it was just the IEA/NEA (2015) that did so. When both organisations reported costs in a given nation, the calculation used was structurally the same as that used for solar PV as in Equation 3.12. In nations where the IRENA (2018) did not report costs, the calculation used was structurally the same as that used for solar PV as in Equation 3.15.

In nations with costs reported by both organisations, investment costs reported by the IEA/NEA (2015) were adjusted such that the LCOE matched that reported by the IRENA (2018), in the same way that investment costs were adjusted for solar PV, as given by Equation 3.13. In nations where the IRENA (2018) did not report a LCOE or where the IEA/NEA (2015) reported costs for more than one facility, repeated scaling was applied, so that the weighted average matched the LCOE reported by the IRENA (2018), as was performed for utility-scale solar PV by combining Equations 3.18 and 3.19. However, this was not possible for offshore wind in Korea, as discussed below.

The region-specific adjustments made were:

- Onshore wind - reduced by 20% in the EU and 35% elsewhere.
- Offshore wind - increased by 71% in the USA and reduced by 19% elsewhere.

Region-specific approaches in regions where the IEA/NEA (2015) did not report any data are outlined below.

- China: In order to deduce a LCOE for offshore wind from that reported by the IRENA (2018) for Asia, I made an assumption about the amount of offshore wind generation in other parts of Asia. This assumption was made based on two facts:

  1. The only regions using this technology in 2017 were Europe, China, the USA and Korea; and,

  2. The IEA (2018a) reported a total of 55GWh generated using this technology worldwide, with 51GWh in Europe, 3GWh in China and 0GWh in the USA.

  As the global total reported by the IEA (2018a) is 1GWh more than the sum of generation in individual countries, let's assume that was equally distributed among the other countries where offshore wind facilities were reported by the IEA/NEA (2015). That is, there were 0.33GWh generated in each of Korea, the UK and the USA. This implies that the 0GWh reported by the IEA (2018a) for the USA has been rounded down. The facility reported for Korea by the IEA/NEA (2015) had the highest LCOE of all offshore wind facilities, which was more expensive than the maximum of the range reported by the IRENA (2018). Consequently, I assumed that the costs in Korea were equal to the maximum of the range reported by the IRENA (2018). These assumptions allowed a cost in China to be estimated.

- India: The IRENA (2018) reported a range for O&M costs but no weighted average. I used the share of O&M costs reported by the IEA/NEA (2015) for China, which resulted in O&M costs well within the reported range. I also took the ratio of investment costs with a 7.5% discount rate to investment costs with a 3% discount rate from those reported by the IEA/NEA (2015) for China.

- Russia: I used the LCOE reported for Eurasia by the IRENA (2018), along with the O&M cost share reported for Turkey (as it is the main producer of electricity from the wind in the IRENA's Eurasia region) by the IEA/NEA (2015). Note that, as both the IEA/NEA (2015) and IRENA (2018) reported costs for onshore wind in Turkey, before using Turkey's costs in calculations for Russia, the costs for Turkey were adjusted using the method for nations with costs reported in both publications, which was discussed earlier in this section.
- Australia: I used the LCOE reported by the IRENA (2018) for Oceania and the LCOE reported by the IEA/NEA (2015) for New Zealand to deduce a LCOE for Australia. I then applied the cost structure reported by the IEA/NEA (2015) for New Zealand. Note that, as both the IEA/NEA (2015) and IRENA (2018) reported costs for onshore wind in New Zealand, before using New Zealand's costs in calculations for Australia, the costs for New Zealand were adjusted using the method for nations with costs reported in both publications, which was discussed earlier in this section.
- Rest of the Americas: I assumed the cost shares in the "North America" region reported by the IRENA (2018) were the same as those reported by the IEA/NEA (2015) for the US.
- The Middle East: I applied average global cost shares, as well as the ratio of investment costs with a 7.5% discount rate to investment costs with a 3% discount rate, to the LCOE reported by the IRENA (2018).

Average global costs used for each category are shown in Table 3.12. These should be considered in the context of further cost reductions observed by the IRENA (2022), who observed the LCOE of onshore wind falling by 42% from 2017 to 2021 and that of offshore wind falling by 34% over the same timeframe, though they used discount rates higher than those used here. The IEA, NEA and OECD (2020) expect the costs of offshore wind to fall considerably by 2025, with the average of their estimates of the LCOE for onshore wind facilities in 2025 being (in 2017 USD, assuming a 3% discount rate) $72/MWh and that for offshore wind facilities being $65/MWh.

Table 3.12: Components of LCOE from wind generation (2017 USD/MWh)

	Investment cost	**O&M**	**Total**
Onshore	$28	$16	$45
Offshore	$92	$39	$131

Sources: IEA/NEA (2015), IRENA (2018) and author's calculations.

The costs of generating electricity from wind power that I used to disaggregate the GTAP database are shown in 2017 US dollars for all regions in Table 3.13.

3.2 Disaggregation

We now have sufficient information to estimate the value of electricity sector costs for each of the cost components, $V^{IEA}_{cc,gt,r}$, based on the electricity generation $G_{gt,r}$ data in Table 3.6 and the costs per unit of generation $C_{cc,gt,r}$ discussed in Section 3.1.3. Here the superscript *IEA* is used to differentiate these values from those used in the final database read by the model, which are denoted $V_{i,s,r}$. Differences in the generation technologies required inputs to the electricity sector to be treated differently depending on what category they fall into: capital; fuel; and all other inputs.

Table 3.13: Costs of wind powered electricity generation in 2017 (2017 USD/MWh)

Region	**Capital**	**O&M**	**Total**
China	$27	$18	$46
USA	$20	$13	$33
EU	$44	$23	$68
India	$31	$21	$52
Russia	$45	$31	$76
Japan	$67	$38	$105
Australia	$39	$21	$60
Rest of Asia and the Pacific	$43	$22	$65
Rest of the Americas	$38	$20	$58
Rest of Europe and rest of the former Soviet Union	$34	$18	$52
Middle East	$43	$25	$68
Africa	$49	$18	$67

Sources: IEA/NEA (2015), IRENA (2018) and author's calculations.

The one input that was treated consistently across all generation technologies was capital k.

$$V^{IEA}_{'k',gt,r} = G_{gt,r} C_{'k',gt,r}, \quad gt \in GT, r \in R \tag{3.22}$$

Capital-use shares $X_{'k',gt,r}$ were calculated directly from the values calculated in Equation 3.22.

$$X_{'k',gt,r} = \frac{V^{IEA}_{'k',gt,r}}{\sum_{j \in GT} V^{IEA}_{'k',j,r}}, \quad gt \in GT,\ r \in R \tag{3.23}$$

These shares were used to calculate values of capital use by the electricity generation subsectors $V_{'k',gt,r}$.

$$V_{'k',gt,r} = V_{'k','ely',r}(1 - X_{'tnd',r}) X_{'k',gt,r}, \quad gt \in GT,\ r \in R \tag{3.24}$$

Here:

- $X_{'tnd',r}$ are the shares of *electricity* sector costs assigned to the *transmission and distribution* sector, shown in Table 3.5; and,
- $V_{'k','ely',r}$ is the value of capital use by the *electricity* sector in the GTAP (2020a) database, which is denoted *ely*.

Next let us deal with a subset of generation technologies that it is problematic to assign fuel costs for:

$$NO = \{nuclear, other\} \subset GT. \tag{3.25}$$

The *nuclear* sector sources its fuel from the *energy-intensive industries*. However, in some cases the cost of fuel calculated simply by multiplying the cost per unit of generation by generation was far greater than the total *electricity* sector use of domestic and imported products of the *energy-intensive industries* according to the GTAP (2020a) database. For the *other* electricity generation technologies, there was insufficient data to assign use of fuel commodities accurately, which for the *other* sector include outputs from the *forestry*, *wood products* and *water* sectors. Consequently, for these technologies, fuel costs $C_{'fu',gt,r}$ were combined with O&M costs $C_{'m',gt,r}$ when calculating values to be used to calculate shares of *electricity* sector input use.

$$V^{IEA}_{'m',gt,r} = G_{gt,r}(C_{'m',gt,r} + C_{'fu',gt,r}), \quad gt \in NO, r \in R \tag{3.26}$$

For all other generation technologies $GTM = GT \setminus NO$, only O&M costs were used.

$$V^{IEA}_{'m',gt,r} = G_{gt,r}C_{'m',gt,r}, \quad gt \in GTM, r \in R \tag{3.27}$$

Now let us treat *electricity* sector inputs other than capital and fuel, denoted NKF. The set of all firm inputs is I and the set of fuel inputs FI is

$$FI = \{coal, oil, gas, p\_c\} \subset I. \tag{3.28}$$

Capital is denoted by k, so $NKF = I \setminus (\{k\} \cup FI)$. We will use $V^{IEA}_{'m',gt,r}$ to calculate electricity generation sub-sector use shares of NKF, denoted $X_{'m',gt,r}$.

$$X_{'m',gt,r} = \frac{V^{IEA}_{'m',gt,r}}{\sum_{j \in GT} V^{IEA}_{'m',j,r}}, \quad gt \in GT,\ r \in R \tag{3.29}$$

To get values $V_{i,gt,r}$ for the use of NKF inputs i by the electricity generation sub-sectors, we have:

$$V_{i,gt,r} = V_{i,'ely',r}(1 - X_{'tnd',r})X_{'m',gt,r}, \quad i \in NKF,\ gt \in GT,\ r \in R. \tag{3.30}$$

The approach to fuel commodities varied by commodity. I assigned the value of *coal* and *gas* consumed by the *electricity* sector in the GTAP database (GTAP, 2020a) directly to the relevant electricity generation sector. Values for fuel use by the sectors generating electricity from *oil* $V_{'oil','oe',r}$ and *oil products* $V_{'p\_c','pe',r}$ were calculated by multiplying the sector output shown in Table 3.6 by the fuel cost for that sector in each region (except when those values exceeded the values of that commodity used by the original *electricity* sector, $V_{'oil','ely',r}$ and $V_{'p\_c','ely',r}$).

$$V_{'oil','oe',r} = \min(V_{'oil','ely',r}, G_{'oe',r}C_{'fu','oe',r}), \quad r \in R \tag{3.31}$$

$$V_{'p\_c','pe',r} = \min(V_{'p\_c','ely',r}, G_{'pe',r}C_{'fu','pe',r}), \quad r \in R \tag{3.32}$$

Values for the *transmission and distribution* sector's use of *oil* $V_{'oil','tnd',r}$ and *oil products* $V_{'p\_c','tnd',r}$ were assigned based on *transmission and distribution* sector cost shares:

$$V_{'oil','tnd',r} = X_{'tnd',r}(V_{'oil','ely',r} - V_{'oil','oe',r}), \tag{3.33}$$

$$V_{'p\_c','tnd',r} = X_{'tnd',r}(V_{'p\_c','ely',r} - V_{'p\_c','pe',r}). \tag{3.34}$$

That still leaves some *oil* and *oil products* use by the original *electricity* sector to be distributed among generation technologies. As use of *oil* and *oil products* produces emissions, their use was restricted to generation technologies that produce emissions.

Those technologies form the set $GE = \{ce, oe, pe, ge, other\} \subset GT$. The *other* sector was included as it produces emissions in many regions through consumption of biomass and biogas. To differentiate between the processes for assigning costs of *oil* and *oil products*, we define two subsets of GE.

$$GXO = GE \setminus \{oe\} \tag{3.35}$$

$$GXP = GE \setminus \{pe\} \tag{3.36}$$

The shares I used to distribute the cost of *oil* and *oil products* among GE were the shares of total O&M costs among those technologies, which included the cost of fuel for the *other* sector. I used the same shares to split emissions from *oil* and *oil product* use by the *electricity* sector in the GTAP database.

$$V_{'oil',gt,r} = (1 - X_{'tnd',r})(V_{'oil','ely',r} - V_{'oil','oe',r})\frac{V^{IEA}_{'m',gt,r}}{\sum_{j \in GXO} V^{IEA}_{'m',j,r}}, \quad gt \in GXO,\ r \in R \tag{3.37}$$

$$V_{'p\_c',gt,r} = (1 - X_{'tnd',r})(V_{'p\_c','ely',r} - V_{'p\_c','pe',r})\frac{V^{IEA}_{'m',gt,r}}{\sum_{j \in GXP} V^{IEA}_{'m',j,r}}, \quad gt \in GXP,\ r \in R \tag{3.38}$$

I split the cost of domestically generated electricity consumed by each sector across the different generation technologies by first calculating the total cost of generation incurred by each technology. I then divided that by the sum of total costs across all technologies to get the share of total generation costs to use for each generation technology. That is, for the non-electricity sectors $NG = S \setminus (\{tnd\} \cup GT)$, where S is the set of all commodities produced in the model, including investment:

$$V_{gt,ng,r} = V_{'ely',ng,r}(1 - X_{'tnd',r})\frac{\sum_{cc \in CC} V^{IEA}_{cc,gt,r}}{\sum_{cc \in CC}\sum_{j \in GT} V^{IEA}_{cc,j,r}}, \quad gt \in GT,\ ng \in NG,\ r \in R. \tag{3.39}$$

The equation to calculate household use was identical to Equation 3.39 but did not range over NG. I based cost shares of imported electricity on the cost shares of generation in the source regions.

3.3 Global trust

In an effort to overcome issues with data availability for holdings of equity in one region by the household in another, Ianchovichina and McDougall (2001) conceptualised a "trust" that holds all foreign-owned equity in each region. Each regional household wishing to invest overseas purchases equity in the trust, which in turn invests in the firms in each region. The firms in each region are then owned partly by the local household and partly by the trust. The household earns income from both the local firms and the trust, depending on their ownership share in each. Details about the household income come from a pre-release version of version 10 of the GDyn database (GTAP, 2020b). As the base year of the version 10 database is 2014, the values in version 10 of the GDyn database needed to be scaled to use in 2017, the base year of version 11 of the GTAP database. Of importance is that the trust's income must be equal to the amount that it pays regional households that invest in it.

Firstly, in line with the calculations in GDyn-E (Golub, 2013), let's assume wealth shares are equal to income shares. Then shares $X^{2014}_{'k',r}$ of global capital ownership for each region r can be calculated based on each region's income from the local firms and the trust in the 2014 data.

$$X^{2014}_{'k',r} = \frac{Y^{d,2014}_r + Y^{t,2014}_r}{\sum_{j\in R}\left(Y^{d,2014}_j + Y^{t,2014}_j\right)}, \quad r \in R \tag{3.40}$$

where $Y^{d,2014}_r$ is the income received by the household from domestic firms or, in the case of $Y^{t,2014}_r$, the trust.

Assuming that household wealth in each region r is equal to that region's share of the capital stock in 2014 K^{2014}_r plus average savings less average depreciation over the period from 2014 to 2017, the wealth of the household in each region in 2017 can be estimated using the share calculated above.

$$H_r^{2017*} = 3\frac{V_r^{s,2014} + V_r^{s,2017}}{2} + X_{'k',r}^{2014} \sum_{j \in R} K_j^{2014} - 3\frac{V_j^{\delta,2014} + V_j^{\delta,2017}}{2}, \quad r \in R. \quad (3.41)$$

Here:

- H_r^{2017*} denotes the wealth of the household (the asterisk indicating it being a preliminary estimate to be scaled in Equation 3.42);
- $V_r^{s,2014}$ is the value of savings in 2014;
- $V_r^{s,2017}$ is the value of savings in 2017;
- $V_r^{\delta,2014}$ the value of depreciation in 2014; and,
- $V_r^{\delta,2017}$ the value of depreciation in 2017.

The GTAP database contains the value of capital in each region in 2017 K_r^{2017}. The sum of household wealth H_r^{2017} across all regions is equal to the total global capital stock. However, the values for household wealth calculated by Equation 3.41 do not sum to the value of the total global capital stock in the GTAP database. Household wealth therefore needed to be scaled accordingly.

$$H_r^{2017} = \frac{\sum_{j \in R} K_j^{2017}}{\sum_{j \in R} H_j^{2017*}} H_r^{2017*}, \quad r \in R \quad (3.42)$$

I assumed that the shares of household wealth invested in the local firms X_r^d were the same as in the 2014 data:

$$X_r^d = \frac{Y_r^{d,2014}}{Y_r^{d,2014} + Y_r^{t,2014}}, \quad r \in R. \quad (3.43)$$

We can now use X_r^d to estimate the household income from the local firm, $Y_r^{d,2017}$. The local household and the trust receive payments for capital use $V_{'k',s,r}$ from each local firm s. Depreciation must be covered, so we subtract it from those payments. The household's share of those payments adjusted for depreciation is the value of household wealth invested locally divided by the total value of capital in the local firms.

$$Y_r^{d,2017} = \frac{X_r^d H_r^{2017}}{K_r^{2017}} \left(\sum_{j \in S} V_{'k',j,r} - V_r^{\delta,2017} \right), \quad r \in R \quad (3.44)$$

Summing up payments for capital use (net of depreciation) across all regions and removing income from local capital received by the household in each region, we get the income of the trust. The amount of household wealth not invested locally, summed across all regions, is the wealth in the trust. I calculated payments to households by the trust $Y_{'t',r,2017}$ based on their share of wealth in the trust.

$$Y_r^{t,2017} = \frac{(1 - X_r^d) H_r^{2017}}{\sum_{j \in R} (1 - X_j^d) H_j^{2017}} \sum_{j \in R} \sum_{s \in S} \left(V_{'k',s,j} - V_j^{\delta,2017} - Y_j^{d,2017} \right), \quad r \in R \quad (3.45)$$

3.4 Non-CO_2 greenhouse gases

The source of data for emissions of greenhouse gases other than carbon dioxide is GTAP's non-CO_2 emissions data (Chepeliev, 2020a). It contains emissions related to the following coefficients in the model:

- the output of each industry;
- each industry's use of inputs; and,
- each regional households' use of commodities.

The emissions intensity of output or use of commodities in 2014 was calculated by dividing the value of output or use by the associated emissions. The source for the economic values and emissions was version 10 of the GTAP database (Aguiar et al., 2019). As the emissions data is not source-specific, emissions-intensity of commodity use was calculated using the sum of commodities from domestic and imported sources. Emissions in 2017 were then calculated as

$$M^{2017} = V^{2017} \frac{M^{2014}}{V^{2017}}, \quad (3.46)$$

where:

- M^{2017} are emissions from input use or output in 2017;
- V^{2017} is the value of input use or output in 2017;
- M^{2014} are emissions from input use or output in 2014; and,

- V^{2017} is the value of inputs use or output in 2014.

The assumption here is that there has been no change in emissions intensity between 2014 and 2017. If we compare non-CO_2 emissions in 2014 of 12.6GtCO_2-e reported by Chepeliev (2020a) to those from the EDGAR database (Crippa et al., 2023) of 14.0GtCO_2-e, we can see there is a slight discrepancy. This discrepancy grows with the estimates of 2017 emissions made here, which total 12.2GtCO_2-e compared to 14.3GtCO_2-e in EDGAR (Crippa et al., 2023). An investigation of the initial discrepancy in 2014 values is beyond the scope of this work, but could be the result of different global warming potential values in the conversion to CO_2-e. The increase in the discrepancy by 2017 is likely the result of changing emissions intensities.

3.5 Parameters

Throughout this document, q is quantity, a is productivity and p is price. σ is a substitution parameter. Note that lower case characters in equations indicate percent change variables.

3.5.1 Initial values and sources

Most parameters came either directly from the GDyn database (GTAP, 2020b) or, in the case of the parameters specific to the alternative method of modelling energy use in GDyn-E, from the work of Golub (2013). There are some exceptions, which are described in this section and summarised in Table 3.14.

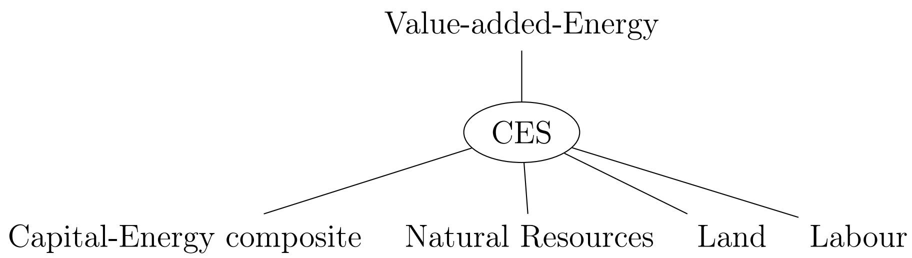
Table 3.14: New and modified parameter values

Parameter	Controls substitution / transformation of:	Range	Equation
ELFVAEN	Non-capital factors and capital / energy	0 to 1.5	3.47
ELFKEN	Capital and energy	0 to 1	3.48
ELFEGEN	Different electricity types	≈1.172	3.49
RIGWQH	Investment locally or abroad	1	3.51
ESUBD	Domestic and imported goods	0.9 to 6.45	3.55
ETRAE	Sluggish endowment use between sectors	-1 to -0.1	3.58

3.5.1.1 Value-added and energy composite

ELFVAEN is the model parameter controlling the rate of substitution between labour, land, natural resources and the capital-energy composite, denoted $\sigma^{vaen}_{s,r}$ in Equation 3.47. This level of the production structure is shown in Figure 3.1.

Figure 3.1: Purpose of ELFVAEN



Use of each component of the value-added-energy composite $q_{vae,s,r}$ responds to the change in price of that input $p_{vae,s,r}$ relative to the change in the value-weighted average price $p^{vaen}_{s,r}$, as shown in Equation 3.47. This is the equation named "VAENFDE-

MAND" in the GDyn-E code (Golub, 2013).

$$\begin{aligned} q_{vae,s,r} = -a_{vae,s,r} + q_{s,r}^{vaen} - \sigma_{s,r}^{vaen}(p_{vae,s,r} - a_{vae,s,r} - p_{s,r}^{vaen}), \\ vae \in VAE,\ s \in S,\ r \in R \end{aligned} \tag{3.47}$$

Here:

- the set *VAE* contains the elements labour, land, natural resources and the capital-energy composite;
- the superscript *vaen* indicates the value-added and energy composite; and,
- the set *S* is the set of all commodities produced in the model, including investment.

For those interested in how the values of *ELFVAEN* vary by sector, they are summarised here. For agricultural and mining sectors, they are less than 1 to prevent those sectors from substituting away from inputs (land and natural resources) that are essential for those sectors. With the exception of the investment sector, which has a value of 1, all other sectors originally had values in the range from 1.12 to 1.68, as used by Golub (2013). Food processing sectors were at the lower end of that range and transport sectors were at the upper end, though, as discussed in Section 3.5.2, values for transport sectors were later adjusted. I used sector output as a weight where necessary during the aggregation process. Values for the *services* and *other industries* sectors are as used by Burniaux and Truong (2002). Values were set to zero for some electricity generation technologies (*nuclear*, *hydro*, *solar* and *wind*) that need increases in capital to increase generation, in line with the work of Peters (2016b). Some parameter adjustments were required to get the model to produce valid (non-negative) results when modelling limits to the emissions of non-CO_2 greenhouse gases: the value for *gas* in China needed to be reduced very slightly from approximately 0.053 to 0.052 and values for *coal* were taken from the alternative parameter file supplied by Golub (2013).

3.5.1.2 Capital-energy composite

The parameter for substitution between the endowment commodity capital and the energy commodity composite is called *ELFKEN*, denoted $\sigma_{s,r}^{keny}$. It controls how the use of capital and the energy composite $q_{ken,s,r}$ change as a function of the difference between the price of that input $p_{ken,s,r}$ relative to the value-weighted average price of the two of them $p_{s,r}^{keny}$, as shown in Equation 3.48. This is the equation named "KENFDEMAND" in the GDyn-E code (Golub, 2013).

$$q_{ken,s,r} = -a_{ken,s,r} + q_{s,r}^{keny} - \sigma_{s,r}^{keny}(p_{ken,s,r} - a_{ken,s,r} - p_{s,r}^{keny}), \qquad ken \in KEN,\ s \in S,\ r \in R \tag{3.48}$$

Here the superscript *keny* indicates the capital-energy composite while the set *KEN* contains the elements capital and the energy composite. Values were the same as used by Peters (2016b): zero for primary energy sources; 0.5 for non-energy commodities; zero for electricity generation technologies that need increases in capital to increase generation, which were defined in Section 3.5.1.1; 0.1 for the *other* electricity generation sector; and 1 for generation sectors that consume fossil fuels, except for the coal electricity sector, which has a value of 0.5.

3.5.1.3 Electricity generation composite

ELFEGEN, denoted $\sigma_{s,r}^{gen}$, is the model parameter governing the ease that sector s in region r can substitute the use of electricity generated by one method for another. The rate of substitution is proportional to the change in price of electricity from each source $p_{gt,s,r}$ relative to the change in the weighted average price of electricity from all sources $p_{s,r}^{gen}$ (where the weights are the amounts of electricity generated), as shown in Equation 3.49. This is the equation named "EGENDEMAND" in the GTAP-E-Power code (Peters, 2016b).

$$q_{gt,s,r} = -a_{gt,s,r} + q_{s,r}^{gen} - \sigma_{s,r}^{gen}(p_{gt,s,r} - a_{gt,s,r} - p_{s,r}^{gen}), \quad gt \in GT,\ s \in S,\ r \in R \tag{3.49}$$

Here:

- the superscript *gen* indicates the electricity generation composite;
- the set GT contains all electricity generation commodities, as defined in Equation 3.1.

The equation governing use of electricity generation commodities by the household is named "EGENPDEMAND" in the GTAP-E-Power code Peters (2016b) and is of the form

$$q_{gt,r} = q_r^{gen} - \sigma_r^{gen}(p_{gt,r} - p_r^{gen}), \quad gt \in GT,\ r \in R. \tag{3.50}$$

The value used for $ELFEGEN$ also comes from the work of Peters (2016b). However, because electricity generation has not been split into base and peak load technologies, a weighted average of the parameters used by Peters (2016b) was taken. As weights I used the shares of the total cost of global electricity generation from the base and peak generation technologies as split by Peters (2016b). For technologies that were split by Peters (2016b) into base and peak components (generation from gas, crude oil and hydro), I used the splits in earlier work by Peters (2016a) to calculate the weights. The value used for the parameter was 1.172.

3.5.1.4 Choice of investment in foreign or domestic assets

$RIGWQH_r$ is the parameter controlling the rigidity of allocation of wealth by the regional household between foreign and domestic equity. It does so via Equation 3.51, which is a combination of the equations named "EQYHOLDFNDHHD", "EQYHOLDHHDLCL" and "EQYHOLDHHDFND" in GDyn-E (Golub, 2013), omitting variables that are set to zero exogenously.

$$(RIGWQH_r + RIGWQ\_F_r)wqhf_r = RIGWQH_r.wqht_r + RIGWQ\_F_r.wqtf_r, \quad r \in R \tag{3.51}$$

$wqhf_r$ is the wealth of the household invested in the local firm, $wqht_r$ is the wealth of the household invested in the global trust and $wqtf_r$ is the wealth of the trust invested in the firm in each region. Note that lower case characters denote percent changes. $RIGWQ\_F_r$ is another rigidity parameter that determines how easily firms can change where they get their financing from. The ratio of the two rigidity parameters in this equation is what ultimately decides capital allocation choices. If $RIGWQ\_F_r$ is low compared to $RIGWQH_r$, firms' preferences to maintain source shares of their funding are stronger than households' preferences to maintain the shares of their wealth invested domestically and internationally. The opposite is also true.

With the original values for $RIGWQH$, a number of regions were substituting local for foreign or foreign for local investments to such an extent that one or the other was going to zero. This is implausible. To avoid this, $RIGWQH$ was set to 1 for all regions. As many of the regions began with values for $RIGWQH$ below 1, increasing those has the effect of making the shares of household wealth invested in the local firm and in the trust more rigid.

3.5.1.5 Armington elasticity parameters

The Armington elasticity parameter (called $ESUBD$ in the model and denoted σ_t^{Arm} below) controls the rate of substitution between domestic products and imports when calculating use of all traded commodities. For all commodities, including energy commodities, this parameter value affects choices between domestic and imported commodities based on the change in the price of the commodity from each source $p_{src,t,s,r}$ relative to the weighted-average price. However, in this work the weights used vary by commodity. The set of energy commodities is defined as

$$E = FI \cup GT, \tag{3.52}$$

where FI is the set of fuel inputs defined in Equation 3.28 and GT is the set of electricity generation technologies defined in Equation 3.1. The corresponding set of non-energy commodities is

$$NE = T \setminus E, \tag{3.53}$$

where T is the full set of traded commodities shown in Table 3.4. For non-energy commodities, the equations for use of domestic and imported commodities remain unchanged. Firm use of imported commodities is calculated by the equation named "INDIMP" and firm use of domestic commodities by that named "INDDOM" in GDyn-E (Golub, 2013). Both equations take the form

$$q_{src,t,s,r} = q_{t,s,r} - \sigma_t^{Arm}(p_{src,t,s,r} - p_{t,s,r}), \quad src \in SRC,\ t \in NE,\ s \in S,\ r \in R, \tag{3.54}$$

where:

- $SRC = \{domestic, imported\}$, the set of sources; and,
- $p_{t,s,r}$ is the value-weighted price of commodity t from domestic and imported sources.

For energy commodities E, weights were calculated using quantities of energy, which is why, in Equation 3.55, the composite price is denoted $p^{vol}_{t,s,r}$.

$$q_{src,t,s,r} = q_{t,s,r} - \sigma_t^{Arm}(p_{src,t,s,r} - p^{vol}_{t,s,r}), \quad src \in SRC,\ t \in E,\ s \in S,\ r \in R \tag{3.55}$$

In the equations for use of non-energy commodities from both sources by government and households are the same as Equation 3.54, except they do not range over S.

$$q_{src,t,r} = q_{t,r} - \sigma_t^{Arm}(p_{src,t,r} - p_{t,r}), \quad src \in SRC,\ t \in NE,\ r \in R, \tag{3.56}$$

where:

- $q_{src,t,r}$ is the percent change in the quantity of commodity t used in region r from source src;
- $q_{t,r}$ is the percent change in the quantity of commodity t used in region r;
- $q_{src,t,r}$ is the percent change in the price of commodity t used in region r from source src; and,

- $p_{t,r}$ is the value-weighted price of commodity t in region r from domestic and imported sources.

The percent change in household use of energy commodities from each source is calculated by

$$q_{src,t,r} = q_{t,r} - \sigma_t^{Arm}(p_{src,t,r} - p_{t,r}^{vol}), \quad src \in SRC,\ t \in E,\ r \in R, \tag{3.57}$$

where $p_{t,r}^{vol}$ is the volume-weighted price of commodity t in region r from domestic and imported sources. As the government does not use energy commodities in the GTAP (2020a) database, the relevant equation is not included here.

To prevent negative values in simulations where greenhouse gas emissions were exogenous, the Armington elasticity parameter for substituting between domestically produced and imported *gas* was reduced significantly to 2.8. This is the value for the *gdt* (gas manufacture, distribution) sector in the GTAP (2020a) database. As most users will get their gas from a distributor, this value was used for *gas* instead of the value for the *gas* sector in the GTAP (2020a) database. Values for other commodities range from 0.9, for the *other mining* commodity, to 6.45 for *wool and silk-worm cocoons*.

3.5.1.6 Transformation of sluggish endowment commodities

The rate of transformation of sluggish endowment commodities currently being used by one sector for use by a different sector is controlled by the parameter named *ETRAE* in the model and denoted σ^{trae} in Equation 3.58. This is the equation named "ENDW_SUPPLY" in GDyn-E (Golub, 2013).

$$q_{lnr,s,r} = q_{lnr,r} + \sigma^{trae}(p_{lnr,r}^{mkt} - p_{lnr,s,r}^{mkt}), \quad lnr \in LNR,\ s \in S,\ r \in R \tag{3.58}$$

Here:

- the set LNR is the set of sluggish endowment commodities, which consists of land and natural resources;
- $q_{lnr,s,r}$ is the percent change in the quantity of lnr used by sector s in region r;
- $q_{lnr,r}$ the percent change in the output of lnr in region r;
- $p^{mkt}_{lnr,r}$ the percent change in the market price of lnr in region r; and,
- $p^{mkt}_{lnr,s,r}$ the percent change in the pretax price paid by sector s to use lnr in region r.

To prevent negative values in simulations where greenhouse gas emissions were exogenous, I increased the magnitude of $ETRAE$ for natural resources significantly, from -0.001 to -0.1. The value of $ETRAE$ for land, the only other commodity that this equation applies to, is -1.

3.5.2 Validation

The purpose of this work is to estimate how the economy will change over time as greenhouse gas mitigation efforts increase. The model would be of limited use if it were unable to reproduce changes in the economy where mitigation efforts have already been significant. We can learn how well the model reproduces the costs of emissions reduction by looking at historical data and we can improve model accuracy by adjusting model parameters such that the results in the in-sample period are a closer match to the data.

The only region in the model where there is an emissions price in the historical period is the EU. As such it can be considered to be representative of regions putting in significant effort to reduce their emissions. Changes in energy use by the household and the *other transport* sector produced by the model in the EU were compared against those documented by Eurostat (2021a,b).

Table 3.15: Change in final energy consumption by EU households, 2017-2019 (%)

Energy source	**CAGR**	**Cumulative**
Oil and petroleum products	-1.9	-3.8
Gas	-1.2	-2.4
Electricity	-0.1	-0.1
Renewables & biofuels	0.4	0.8
Heat	-3	-5.9
Other	-1.2	-2.4

Source: Eurostat (2021b) and author's calculations.

In Eurostat (2021a), over the period from 2017 to 2019, energy use by the transport sector increased by 1.5%, implying a Compound Annual Growth Rate (CAGR) of 0.7%. Electricity use by the transport sector in the EU over the same period increased by 0.3%. The changes in energy use by households in the EU documented by Eurostat (2021b) during that period are summarised by Table 3.15. Note that these do not include use for transportation.

Substitution between energy and factors produced by the model with the parameters discussed in Section 3.5.1 was excessive. For example, with the original parameters and observed changes in energy commodity prices (discussed in Section 4.2.2), household *oil products* use decreased by more than 20% of its 2017 usage by 2019, while *gas* use increased by more than 25%. Meanwhile energy use by the *other transport* sector dropped by almost 8% over the same period, but somehow the sector managed to increase its output by almost 3%. Most notably its use of *oil products* over that period declined by more than 10%. Much of this was achieved by substitution towards labour. That is simply unrealistic.

At the same time, substitution between electricity and other energy sources was insufficient. As households increasingly choose electricity over other energy products and as electric vehicles take up a larger share of the transport fleet, we expect significant substitution towards electricity and away from other energy sources. This can be seen in data from Eurostat (2021b) and the European Environment Agency (EEA, 2023).

To calibrate the model based on the transport sector and household energy use observations discussed above, changes were made to some substitution parameters in all regions. The following parameter values produced changes in energy commodity use roughly in line with those observed by Eurostat (2021a,b).

- To limit substitution of labour for *oil products* in the transport sectors, ELFVAEN for all transport sectors was reduced significantly, to 0.025. It is realistic to apply this to all regions as it is unrealistic that labour will be substituted for capital or energy in almost all transport activities.
- To enhance the electrification of most firms, ELFENY, the parameter controlling the rate of switching by firms between electricity and other energy sources, was increased to 6 for all sectors other than *energy-intensive industries*, *water transport* and *air transport*, which retain the original value of 1. This is most particularly important for the *other transport* sector, given the rapid growth in electric vehicle numbers in the EU (EEA, 2023). It is realistic to apply this to all regions as all sectors other than the three that retain a value of 1 are relatively easy to electrify and will increasingly undertake electrification to make use of the declining costs of renewable electricity relative to fossil fuels. Chen et al. (2022) use a value of 1.5 for this parameter, citing "expert elicitation". For many other parameters, they cite Cossa (2004), who found

that the costs of climate policies were relatively insensitive to this parameter. Given the rapid uptake of electric vehicles documented by the EEA (2023) and the relative insensitivity reported by Cossa (2004), the values used here are considered acceptable.

- To limit the ability of firms to substitute *gas* for *oil products*, ELFNCOAL, the parameter controlling the rate of switching between the use of *gas*, *oil* and *oil products* by firms, was reduced to 0.05. It is realistic to apply this to all regions as substituting between *gas* and the oil commodities requires significant investment in equipment.
- To limit the ability of households to substitute *gas* for *oil products*, ELPNELY, a new parameter controlling the rate of switching between primary energy sources by the household, was set to 0.25. It is realistic to apply this to all regions as substituting between physical energy commodities requires significant equipment purchases by the household.

Finally, ELFEGEN was increased to 6 to facilitate greater uptake of renewables. Chen et al. (2022) used values in the range 1-4 for this parameter, citing "expert elicitation". Winkler et al. (2021) used a value of 12. Used here, a value of 6, which is clearly inside the range used by other modellers, allows the model to produce results for electricity generation and energy use in line with those in the net zero scenario of the IEA (2021f, 2023).

Chapter 4

Modelling

4.1 Model

Starting with the model used by Golub (2013), I first introduced changes made by Peters (2016b) to the GTAP-E model code, modified slightly to combine the base and peak electricity generation nests into a single generation nest. His justification for their separation was that only certain technologies can quickly ramp up generation to meet peaks in demand.

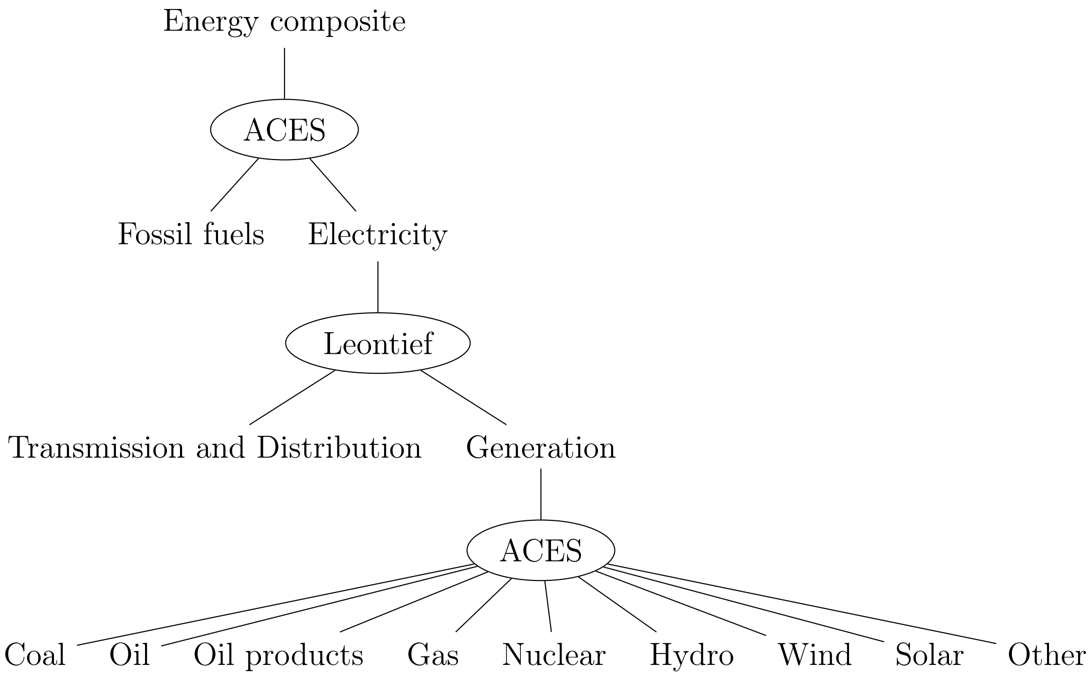
Since the work of Peters (2016b), advances in technology have slowly been making the distinction between base and peak generation technologies less important - if the timing of electricity generation does not match that of demand, it can be stored for later use. Batteries, though still expensive, are rapidly coming down in price. Another option is to use surplus electricity in times of low demand to pump water into a dam, then use that to generate electricity to meet demands later using hydropower. This is referred to as pumped hydro energy storage, or simply pumped hydro. Over 616000 potential off-river sites for pumped hydro have been identified globally (Blakers et al., 2022), "about one hundred times greater than required to support a 100% global renewable electricity system". There is therefore scope for pumped hydro expansion, although it will be constrained by local environmental considerations.

In short, storage can eventually overcome the issue of misaligned timing between generation and demand peaks. This removes the need to separate generation technologies according to load type. The energy nest shown in Figure 2.2 has therefore been modified as shown in Figure 4.1. Substitution between energy sources uses the Additive Constant Elasticity of Substitution (ACES) specification, which is discussed below. Also, given the electricity sector aggregation used in this thesis, some regions do not generate electricity using all available technologies, therefore some minor changes to address divide by zero errors and singular matrices were required.

The next task was to add tracking of emissions of non-CO_2 greenhouse gases to the model. This was achieved in a way similar to the tracking in the model used by Brinsmead et al. (2019).

While validating model parameters as discussed in Section 3.5.2, I decided that it was desirable to be able to control the rate of switching between energy commodities by the household separately for the fossil fuel commodities and electricity. I therefore created a non-electricity energy nest for the household, which is similar to but simpler than that used for firms. The household now uses a non-electricity energy commodity bundle, which is a composite of *oil*, *oil products*, *coal* and *gas*. It can then substitute between that non-electricity commodity bundle and the electricity bundle, which is as described by Peters (2016b) with one exception: as mentioned above, there is no distinction between base and peak electricity generation technologies. This structure is as shown in Figure 4.1. The difference between energy

Figure 4.1: Energy use nest



composites in the production and consumption structures is limited to the fossil fuels composite. On the production side, shown in Figure 2.2, fossil fuel is a composite of coal and the non-coal composite, though in this work substitution uses the ACES specification, whereas GTAP-E uses CES. On the consumption side there is no "non-coal" nest - *coal*, *gas*, *oil* and *oil products* can all be substituted for one another directly. It should be noted that it is much harder to substitute between these fossil fuels, with a substitution parameter of 0.25 as mentioned in Section 3.5.2, than it is for them to substitute towards electricity, with the substitution parameter for substitution between the fossil fuel composite and the electricity composite retaining the value of 1 from the original GDyn-E (Golub, 2013) household energy nest.

Additionally, to facilitate changes in the efficiency of household energy use, I implemented an option for cost-neutral taste changes in the household consumption function. This allows the household to, for example, reduce its use of energy (due to energy efficiency measures) without a reduction in utility and without changing its overall level of consumption, as the money saved on electricity is automatically spent on other commodities according to normalised marginal budget shares. The approach for this is the same as that used in the work of Brinsmead et al. (2019).

Finally, at all levels of the energy nests, I implemented the ACES specification to ensure that an equal amount of energy from one energy commodity must be substituted for another. To do this, I took the setup for the electricity sector used by Peters (2016b) and applied it to all equations governing substitution between energy commodities, including substitution between imported and domestic commodities. As outlined by Peters (2016b), this specification minimises the "disutility of cost":

$$\min_{Q_j} U^E = \left[\sum_{j \in E} (P_j Q_j)^{\rho} \right]^{1/\rho} \tag{4.1}$$

subject to the constraint:

$$Q^E = \sum_{j \in E} Q_j. \tag{4.2}$$

That is, the user of the energy commodities wishes to minimise their costs, which are equal to the price per unit of the energy commodity (or composite) in question P_j multiplied by the volume of energy consumed Q_j in megatonnes of oil equivalent. E is the set of commodities (or composites) being considered for use, which is different at each level within the energy nest. U^E is the disutility of cost of use of the commodities and composites in question. ρ is a parameter. The solution to this problem in percent change terms is:

$$q_e = q + \sigma(p_e - p), \quad e \in E, \tag{4.3}$$

$$p = \sum_{j \in E} \frac{Q_j}{Q} p_j, \tag{4.4}$$

where: q_e is the quantity and p_e is the price of the individual energy commodities or composites that are substitutable at that level of the energy nest; q is the quantity and p is the price of the composite of all energy commodities at that level of the nest; and σ is a substitution parameter.

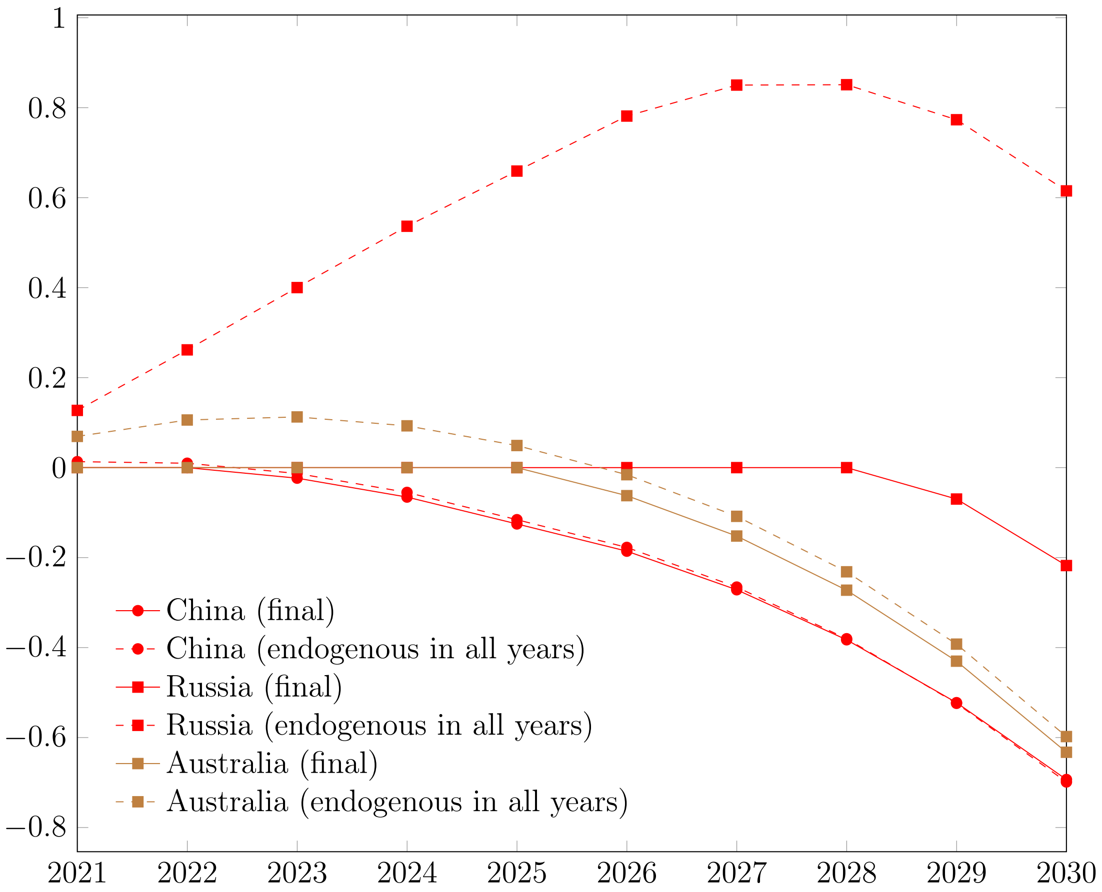
4.1.1 Closure

Golub (2013) provided an alternative savings closure, which implements savings behaviour developed to prevent regions with high rates of household savings owning excessive shares of global wealth as their incomes increase over time. That alternative savings closure was used in this modelling. Initial testing of this resulted in reductions in savings, relative to the base case, in three regions (China, Russia and Australia) that exceeded the reductions in their incomes, causing private consumption to increase in real terms, despite their falling real income. To avoid this, Equation 4.5 was added to the model.

$$ypr_r = yp_r - ppriv_r, \quad r \in R \tag{4.5}$$

Here ypr_r is private consumption in real terms, yp_r is nominal private consumption expenditure and $ppriv_r$ is an index of prices paid for private consumption, weighted by the expenditure on each commodity. In years where, with the alternative savings closure, China, Russia and Australia's real private consumption increased despite falls in real income, their real private consumption ypr_r was made exogenous so that it follows the base case. The model then solved for a level of saving in those regions that resulted in private consumption matching that in the base case, in real terms, as shown in Figure 4.2. The figure shows deviations in real private consumption both in the initial simulation, which had private consumption endogenous in all years, as well as in the final simulation, which produced the results shown in Figure 5.13. The problem is most clearly shown for Russia, where savings declined so significantly that real private consumption, when endogenous in all years, increased by more than 0.8% relative to the base case.

Figure 4.2: Excessive consumption due to reduced savings, compared to final results (%)



Source: model results.

4.2 Exogenous variables

GDP during the period from 2017 to 2019 was exogenous and changes were calculated from data produced by the International Monetary Fund (2021). Population growth is exogenous and sourced from the United Nations (2019). The growth rates I used for the labour force were weighted averages of those used by Golub (2013). Populations from 2017 according to the GTAP (2020a) database were used as the weights. I then adjusted the growth in the labour force to account for the different population growth rates used by Golub (2013). Region-specific change in factor productivity was also taken from Golub (2013), which I aggregated using GDP from 2017, according to the GTAP database (GTAP, 2020a), as weights. These shocks define the base case. Also in the base case are shocks to energy efficiency discussed in Section 4.2.1, as well as to the productivity of capital in the *wind* and *solar* electricity generation sectors, which are discussed in Section 4.2.2.3. The base case represents a scenario where the world takes no further action on climate change, which is what we compare our policy case to. The main difference between the base case and the policy case are the emissions constraints resulting from the NDCs, which are discussed in Section 4.2.3. There are also improvements in energy efficiency in the policy case, as discussed in Section 4.2.1.

4.2.1 Energy efficiency

Energy efficiency changes for industry are as used by ClimateWorks Australia, Australian National University (ANU), Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Centre of Policy Studies (CoPS) (2014), which are roughly in line with the more detailed analysis by Butler et al. (2020). That is:

- 0.55% per year in the base case, except for the EU; and,
- 0.92% per year in the policy case and in the EU during the historical period, as the EU was the only region in the model where an emissions price applied across the entire region over the historical period.

These energy efficiency improvements mean that in the base case, for example, firms can reduce their energy use by 0.55% and still achieve the same level of output. It should be noted that identical changes are applied to all sectors other than energy sectors. Energy sectors do not improve their efficiency of use of energy inputs.

To calculate energy efficiency changes for the household, I created indices of the following series over the period from 1990 to 2018:

- Total Final Consumption (TFC) of energy by the Residential sector (IEA, 2021b);
- TFC of energy by Industry (IEA, 2021b);
- Household final consumption expenditure (World Bank, 2021); and,
- Gross World Product (International Monetary Fund, 2021).

Rates of energy efficiency improvement in household use are slower than those of industry, at approximately 73% of the improvements observed in industrial use in the period after 2005. The improvement applied in the model for the period from 2017 to 2020 outside the EU and for all regions in future periods in the base case was therefore 0.4% per year.

Within the EU, improvements in household energy use were 71% faster after 2005 than during the period from 1990 to 2005. I consider this to be the impact of emissions reduction incentives. Therefore, household energy efficiency improvements were increased to 0.69% per year in the EU for the period from 2017 to 2020 and in all regions in the policy case.

4.2.2 Change in technology and taxes

To solve for technological changes in the energy system, I shocked the prices (International Monetary Fund, 2021) and outputs (IEA, 2021a,e) of fossil fuels in the period from the base year (2017) to 2019. During this period, gas supply increased (Department of Industry, Science, Energy and Resources, 2021, EIA, 2021, IEA, 2019a, 2021c) and prices decreased dramatically due to new production techniques. Also during the same period, oil production limits were imposed beyond the usual OPEC countries (Wingfield et al., 2020), resulting in significant price increases. To facilitate representation of these changes in the model, the following closure changes were made:

- The productivity of the *oil* sector was made endogenous to make global *oil* production exogenous (see Section 4.2.2.1);
- Region-specific productivity of the *gas* sector was made endogenous to make region-specific *gas* production exogenous in major gas producing regions (see Section 4.2.2.1);
- The productivity of the *gas* sector was made endogenous to make the global average price of *gas* exogenous (see Section 4.2.2.1);
- Firm productivity of *gas* use was made endogenous to make the global *gas* production exogenous (see Section 4.2.2.1);
- The productivity of the *coal* sector was made endogenous to make the global average price of *coal* exogenous (see Section 4.2.2.1);
- Firm productivity of *coal* use was made endogenous to make the global *coal* production exogenous (see Section 4.2.2.1); and,
- Export tax rates were made endogenous to make changes in *oil* output in the "OPEC+" regions exogenous (see Section 4.2.2.2).

4.2.2.1 The use of technological changes to target observed prices and output

Equation 4.6 governs the productivity $af_{i,s,r}$ of input i use by each sector s in each region r. To account for region-specific changes in gas production technology, I introduced a sector- and region-specific technological change variable, referred to as

$a_{s,r}$.

$$af_{i,s,r} = a_i + a_s + a_{s,r} + DIFF_{i,s,r} a_r + a_{i,s,r}, \quad i \in I,\ s \in S,\ r \in R, \tag{4.6}$$

where:

- I is the set of all inputs to the firm's production function;
- a_i is the percent change in global productivity of use of each input i;
- a_s is the percent change in global productivity of each sector;
- $DIFF_{i,s,r}$ is a parameter allowing the region-specific productivity growth variable a_r to be scaled in a way that is sector-specific; and,
- $a_{i,s,r}$ is an input-, sector- and region-specific percent change productivity variable.

Technological change variable $af_{i,s,r}$ affects the price paid to the supplier via the zero pure profits condition:

$$p^{sup}_{s,r} + ao_{s,r} = \sum_{j \in I} X_{j,s,r}(p_{j,s,r} - af_{j,s,r}), \quad s \in S, r \in R, \tag{4.7}$$

where:

- $p^{sup}_{s,r}$ is percent change in the supply price received by sector s;
- $ao_{s,r}$ is sector- and region-specific output-augmenting technological (percent) change;
- $X_{i,s,r}$ is the share of total sector s costs for input i in region r; and,
- $p_{i,s,r}$ is percent change in the price of each input paid by each sector in each region.

The supply price interacts with the market price $p^{mkt}_{s,r}$ via the following equation:

$$V_{s,r} p^{sup}_{s,r} + M^{out}_{s,r}(100 dT^g_r + T^g_r(m^{out}_{s,r} - q_{s,r})) = (V_{s,r} + M^{out}_{s,r} T^g_r)(p^{mkt}_{s,r} + t^{out}_{s,r}), \quad s \in S, r \in R. \tag{4.8}$$

Here:

- $V_{s,r}$ is the value of output of sector s in region r;
- $M_{s,r}^{out}$ are emissions in $MtCO_2$-e associated with firm output and $m_{s,r}^{out}$ the percent change in those emissions;
- T_r^g is the price on emissions (g for greenhouse gas) in USD per tonne of CO_2 equivalent in each region;
- dT_r^g is the change in T_r^g;
- $q_{s,r}$ is the percent change in output of each sector in each region;
- $p_{s,r}^{mkt}$ is the percent change in the market price of the commodity produced by s; and,
- $t_{s,r}^{out}$ is the percent change in the power of the tax on output.

Note that the power of a tax is the *ad valorem* tax rate plus 1 (for example, if the *ad valorem* tax rate is 2%, the power of the tax is 1.02).

If required, we could rearrange Equation 4.8 to define $q_{s,r}$ as a function of $p_{s,r}^{sup}$. Doing so would make clear that a desired change in $q_{s,r}$ could be produced by a given change in $p_{s,r}^{sup}$, all else being held equal. In turn, Equation 4.7 could be rearranged to define $p_{s,r}^{sup}$ as a function of $af_{i,s,r}$, which we can already see from Equation 4.6 is a function of $a_{s,r}$. Thus, all else being equal, we can solve for a value of $a_{s,r}$ that produces a desired change in $q_{s,r}$. In this way, region-specific changes in gas output observed during the historical period were used to solve for region-specific technological changes in the *gas* sector. To solve for global technological change, one further equation is required:

$$q_s = \frac{\sum_{j \in R} V_{s,j} q_{s,j}}{\sum_{j \in R} V_{s,j}}, \quad s \in S. \tag{4.9}$$

That is, the percent change in global production for each sector, q_s, is equal to the value-weighted sum of the percent changes in production of that sector in each region. Changes in a_s flow from Equation 4.6 through Equations 4.7 and 4.8. Conversely, if we know that global output of a given commodity changed by a certain amount, the same chain of equations can be used to solve for the global technological change that would produce the target change in output. Similarly, the percent change in the average global price of a commodity can be calculated using an equation similar to 4.9, but being a weighted sum of region-specific prices. I initially solved for the change in a_s that produced observed changes in the world price of *coal*, *oil* and *gas*. However, as discussed in Section 4.2.2.3, only the world prices of *coal* and *gas* were exogenous in the final simulations.

4.2.2.2 The use of export taxes to target output from OPEC countries

To make for changes in *oil* output by the "OPEC+" countries exogenous, export taxes were made endogenous. The reasons for this are twofold. Firstly, the changes in output are not the result of reduced productivity. Secondly, I assume that the regions in question would not cause their own residents and businesses to pay higher prices for oil. To demonstrate the mechanism that is used in the model to solve for the changes in export taxes resulting in the observed change in output, we need to understand another sequence of equations.

For most commodities, the market clearing condition is defined as:

$$q_{i,r} = X^d_{i,r} q^d_{i,r} + \sum_{j \in (R \setminus \{r\})} X^x_{i,j,r} q^x_{i,j,r}, \quad i \in T, \; r \in R, \tag{4.10}$$

where:

- $q_{i,r}$ is the percent change in production of commodity i in region r;
- $X^d_{i,r}$ is the share of domestic sales of commodity i in region r in total sales of commodity i produced in region r;
- $q^d_{i,r}$ is the percent change in the quantity of domestic sales;
- $X^x_{i,j,r}$ is the share of export sales of each commodity (to users in other regions) in total sales of i produced in r;

- $q^x_{i,j,r}$ is the percent change in the quantity of exports of each commodity by each region to each other region; and,
- T is the set of traded commodities.

Demand for imports from any given region is determined by the following equation.

$$q^x_{i,j,r} = -a^{im}_{i,j,r} + q^{im}_{i,r} - \sigma^{im}_t(p^{im}_{i,j,r} - a^{im}_{i,j,r} - p^{im}_{i,r}), \quad i \in T,\ j \in R \setminus \{r\},\ r \in R \quad (4.11)$$

Here:

- $a^{im}_{i,j,r}$ is a commodity-, source- and destination-specific percent change variable representing technological change;
- $q^{im}_{i,r}$ is the percent change in total imports of commodity i into region r;
- σ^{im}_i is a parameter controlling the ease of substitution between imports from different regions;
- $p^{im}_{i,j,r}$ is the percent change in the price of imports of commodity i from region j to r; and,
- $p^{im}_{i,r}$ is the percent change in the average price of imports of commodity i into region r.

The price of imports of commodity i from region j to r is determined by Equation 4.12.

$$p^{im}_{i,j,r} = t^{im}_{i,r} + t^{im}_{i,j,r} + p^{cif}_{i,j,r}, \quad i \in T,\ j \in R \setminus \{r\},\ r \in R \quad (4.12)$$

That is, the percent change in the price of any given import is the sum of the percent change in the Cost, Insurance and Freight (CIF) price ($p^{cif}_{i,j,r}$) and the taxes applied to imports of that commodity, both source region-specific ($t^{im}_{i,j,r}$) and generic ($t^{im}_{i,r}$).

The CIF price in turn is the weighted sum of percent changes in the Free On Board (FOB) price $p^{fob}_{i,j,r}$ and the price of shipping:

$$p^{cif}_{i,j,r} = \frac{V^{fob}_{i,j,r}}{V^{fob}_{i,j,r} + V^{trn}_{i,j,r}} p^{fob}_{i,j,r} + \frac{V^{trn}_{i,j,r}}{V^{fob}_{i,j,r} + V^{trn}_{i,j,r}} p^{trn}_{i,j,r}, \quad i \in T,\ j \in R \setminus \{r\},\ r \in R, \quad (4.13)$$

where:

- $V_{i,j,r}^{fob}$ is the FOB value of the commodity being shipped;
- $V_{i,j,r}^{trn}$ is the value of payments made for transportation of the commodity
- $p_{i,j,r}^{fob}$ is the percent change in the FOB price of the commodity; and,
- $p_{i,j,r}^{trn}$ is the percent change in the price of transportation.

The final link in the chain connecting export taxes to the output of a given commodity in a particular region is the equation for the FOB price of a given commodity being exported from one region to another:

$$p_{i,j,r}^{fob} = p_{i,j}^{mkt} - t_{i,j}^{x} - t_{i,j,r}^{x}, \quad i \in T, \ j \in R \setminus \{r\}, \ r \in R. \tag{4.14}$$

Here:

- $p_{i,j}^{mkt}$ is the market price, in the source region j, of the commodity i being traded;
- $t_{i,j}^{x}$ is the destination-generic tax on exports of each commodity from the source country; and,
- $t_{i,j,r}^{x}$ is the destination-specific tax.

We can see from Equation 4.14 that an increase in export taxes increases the FOB price. An increase in the FOB price causes an increase in the CIF price via Equation 4.13. That in turn increases the cost of imports by other regions from the region where the tax was increased, as a result of Equation 4.12. All else being equal, that will cause a reduction in imports of that commodity by all regions as a result of Equation 4.11. Finally, Equation 4.10 shows us how that will affect the output of the commodity in question in the region that increases its export tax. The corollary of this is that we can solve for the change in export tax that will produce an observed change in output.

4.2.2.3 Comparison to observations

Imposing the observed output and price changes resulted in excessively large changes in energy commodity use in the model. One of the reasons behind these large changes in energy commodity use is the difference between the changes in global price indices of the commodities and the prices faced by users. Eurostat (2021c,d) data shows that reductions in gas prices were not passed on to users in the EU. Although petroleum price rises were largely passed on to consumers (European Commission, 2021), prices faced by users in the model rose by considerably more than those observed. Leaving the average global *oil* price endogenous made little difference to user prices, whereas doing so for *gas* caused a significant drop in user prices. Average global *coal* prices, when left to the model, increased significantly, whereas in reality they declined. Consequently, during the period from 2017 to 2019, using region-generic, sector-specific technological change, the average global prices of *coal* and *gas* were forced to follow those observed, but those for *oil* were not. This, rather fortuitously, resulted in changes to user prices of *oil products* in line with those observed (European Commission, 2021).

The decline in the costs of generating electricity from *wind* and *solar* technologies observed by the IRENA (2020) have been applied by improving the productivity of capital for those sectors during the historical period. By my calculations, productivity of capital improved by 7.5% per year for solar and 4.7% per year for wind. These values are based on the aforementioned changes documented by the IRENA (2020) and the ratios of capital costs for different discount rates documented by the IEA/NEA (2015). For the years 2020 to 2030, I assume improvements in the productivity of capital of 4.6% per year for *solar* and 4.0% per year for *wind*, which are based on IRENA (2019a, 2019b) projections, again adjusted for assumptions about discount rates based on costs reported by the IEA/NEA (2015).

The closure of facilities generating electricity from coal in the EU, as documented by Carbon Brief (2021) and Global Energy Monitor (2021), have been represented as an annual reduction of 1.8% in the productivity of capital use by the *coal electricity* sub-sector for the years 2017 to 2019. Otherwise, changes in electricity production by technology have been controlled by allowing output taxes or subsidies to adjust over the period from 2017 to 2019. The mechanism for this is entirely captured by Equation 4.8 - all else being equal, an increase (decrease) in the tax on output must be offset by a reduction (increase) in output. This creates differences in the output tax rate between electricity generation sectors. The procedure outlined in Section 3.2 for disaggregating the electricity sector does not distinguish between values at market and agent prices, meaning that the output tax rate is identical for all electricity generation sectors. However, renewable electricity generation sectors have been the recipient of significant subsidies in recent years, so we know that the output tax rate should vary between electricity generation sectors. Allowing the model to solve for output taxes or subsidies over the historical period creates the differentiation between taxation on output by the electricity generation sectors that we know exists.

4.2.3 Emissions

Historical emissions and emissions proposed as NDCs were calculated based on those documented by Fenhann (2022), with the exception of the following regions, where other data sources were used:

- The European Union (EEA, 2021);
- China's emissions in 2019 (Larsen et al., 2021) and 2025 (World Economic Forum, 2022);
- Australia's emissions in 2017 and 2019 (Department of Climate Change, En-

Table 4.1: Annual changes in emissions quotas (%)

Region	**2021-2025**	**2026-2030**
China	0.5	-0.6
United States	-2.3	-7.5
European Union	-4.3	-5.5
India	4.1	3.4
Russia	3.3	2.8
Japan	-4.6	-5.9
Australia	-3.6	-4.4
Rest of Asia and the Pacific	3.2	4.3
Rest of the Americas	0.2	-0.5
Rest of Europe and former Soviet Union	1.2	1.0
Middle East	1.2	1.1
Africa	-0.1	-0.5

Sources: Fenhann (2022), EEA (2021) and author's calculations.

ergy, the Environment and Water, 2022); and,

- Aggregate regions, where a small number of other sources were used where necessary.

I calculated linear emissions paths consistent with the NDCs. The average year on year changes during the periods 2021-2025 and 2026-2030 are shown in Table 4.1. Note that these were non-binding (i.e. they exceed emissions in the base case) for the following regions:

- Russia; and,
- Rest of Asia and the Pacific.

In those regions, emissions therefore remained endogenous in the policy case, which allows for carbon leakage to occur. In other regions, emissions reductions were exogenously imposed in the model by making the emissions price endogenous. Emissions were exogenous and emissions prices endogenous prior to 2021 where countries' base case emissions were in excess of their commitments under the Copenhagen Accord (United Nations Framework Convention on Climate Change, 2009). It should be noted that revenues from emissions pricing have not been offset by reductions in taxes. This assumption ensures that estimates of economic impacts are conservative (i.e. more severe than if assuming the alternative of recycling the revenues).

Non-zero emissions prices in 2020, used to enact Copenhagen Accord targets, have been left as they are from 2020 onward in the base case, which should therefore be interpreted as a "no new policies" scenario. Where countries have submitted a range of emissions (such as a target contingent on actions taken by other countries, along with a non-contingent target), I used the less ambitious end of that range. Sectoral goals and reductions compared to future baseline emissions, when those baseline emissions levels have not been submitted, have been ignored.

By making the emissions price endogenous and the emissions exogenous, we get the model to solve for the emissions price that results in the desired change in emissions. To see how this works, note that emissions are determined by the following mechanisms in the model, which are functions of emissions prices as shown in the equations as indicated:

1. Household use of domestically produced fossil fuels (Equation 4.15);

2. Household use of imported fossil fuels (Equation 4.15);

3. Use of some endowments by some industries (Equation 4.16);

4. Use of some domestically produced commodities by industry (Equation 4.17);

5. Use of some imported commodities by industry (Equation 4.17); and,

6. Output by some industries (Equation 4.8).

The equation governing the price each household pays for domestic and imported goods is:

$$
\begin{aligned}
V^h_{src,i,r} p^h_{src,i,r} = & (V^h_{src,i,r} - M^h_{src,i,r} T^g_r)(p_{src,i,r} + t^h_{src,i,r}) \\
& + M^h_{src,i,r}(100 dT^g_r + T^g_r(m^h_{src,i,r} - q^h_{src,i,r})), \\
& src \in SRC,\ i \in T,\ r \in R.
\end{aligned}
\tag{4.15}
$$

Here:

- $V^h_{src,i,r}$ is the value of purchases by the household h, from both domestic and imported sources ($src \in SRC$), of traded commodities ($i \in T$) in each region ($r \in R$);
- $p^h_{src,i,r}$ is the percent change in the price paid by the household;
- $M^h_{src,i,r}$ are the emissions from the use of the commodities;
- $m^h_{src,i,r}$ is the percent change in emissions from the use of the commodities;
- T^g_r is the price on greenhouse gas (g) emissions;
- dT^g_r is the change in the emissions price;
- $p_{src,i,r}$ is the percent change in the source-specific price of commodity i (the market price for domestic commodities or the average import price for imported commodities);
- $t^h_{src,i,r}$ is the percent change in the power of the source-specific tax on household purchases of commodity i; and,
- $q^h_{src,i,r}$ is the percent change in the quantity of commodity used from source src.

The equation for the price each firm pays for its use of endowment commodity w is:

$$
\begin{aligned}
V_{w,s,r}p_{w,s,r} =& (V_{w,s,r} - M_{w,s,r}T_r^g)(p_{w,s,r}^{mkt} + t_{w,s,r}) \\
& + M_{w,s,r}(100dT_r^g + T_r^g(m_{w,s,r} - q_{w,s,r})), \\
& w \in W,\ s \in S,\ r \in R,
\end{aligned} \tag{4.16}
$$

where:

- $V_{w,s,r}$ is the value of endowment w used by sector s;
- $p_{w,s,r}$ is the price sector s pays for its use of endowment w;
- $M_{w,s,r}$ are emissions from the use of endowment w by sector s
- $m_{w,s,r}$ is the percent change in those emissions;
- $p_{w,s,r}^{mkt}$ is the percent change in the pretax price paid by s for use of w;
- $t_{w,s,r}$ is the percent change in the power of the tax on each firm's use of each endowment;
- $q_{w,s,r}$ is the percent change in the quantity of each endowment used by each firm; and,
- W is the set of endowment commodities.

The equation governing the price each firm pays for domestic and imported goods ($p_{src,t,s,r}$) is:

$$
\begin{aligned}
V_{src,i,s,r}p_{src,i,s,r} =& (V_{src,i,s,r} - M_{src,i,s,r}T_r^g)(p_{src,i,r} + t_{src,i,s,r}) \\
& + M_{src,i,s,r}(100dT_r^g + T_r^g(m_{src,i,s,r} - q_{src,i,s,r})), \\
& src \in SRC,\ t \in T,\ s \in S,\ r \in R,
\end{aligned} \tag{4.17}
$$

where:

- $V_{src,i,s,r}$ is the value of use of commodity i from source src by sector s;
- $M_{src,i,s,r}$ are the emissions from that use;
- $m_{src,i,s,r}$ is the percent change in the emissions from that use;
- $t_{src,i,s,r}$ is the percent change in the power of the tax on that use;

- $q_{src,i,s,r}$ is the percent change in the quantity of each commodity used by each firm from each source; and,
- $p_{src,i,r}$ is the percent change in the market price for domestic commodities or the average import price for imported commodities, as in Equation 4.15.

We can see from Equations 4.15, 4.16 and 4.17 that an increase in the emissions price raises the price paid for use of any emissions-intensive commodity. All of these equations have a similar form:

$$Vp = (V - MT^g)(p^{mkt} + t) + M(100dT^g + T^g(m - q)). \tag{4.18}$$

Dividing both sides by the value of use, we get:

$$p = \frac{V - MT^g}{V}(p^{mkt} + t) + \frac{M}{V}(100dT^g + T^g(m - q)). \tag{4.19}$$

The two terms on the right-hand side of Equation 4.19 are: firstly, the impact of changes in the market price and taxes on the user price; and, secondly, the impact of the emissions price on the user price. The second term shows that the price of more emissions-intensive commodities is more significantly affected by changes in the emissions price, as $\frac{M}{V}$ is the emissions-intensity.

As taxes comprise the difference between market and user prices, as shown in Equation 4.19, increases in them cause increases in production costs. Due to the assumption of zero pure profits, these flow through to market prices as shown in Equation 4.20.

$$P^{sup}Q + T^g M = P^{mkt}T^{out}Q \tag{4.20}$$

Here:

- P^{sup} is the price paid to the supplier;
- Q is the quantity of production;
- P^{mkt} is the market price; and,

- T^{out} is the power of the tax on output.

Note that Equation 4.8 is derived from Equation 4.20. An increase in the emissions price will result in an increase in the market price of any emissions-intensive good, which flows through to the user prices via Equations 4.15, 4.16 and 4.17. Demand for energy commodities is particularly affected by these mechanisms, as energy commodities are substitutable, as discussed in Section 4.1. For other commodities, the degree of substitutability depends on the user.

Firms cannot substitute between intermediate inputs, so increases in the cost of non-energy inputs to a firm's production processes flow through to the price of the commodity it produces. The government substitutes between non-energy commodities (it does not use energy commodities) using a standard CES form:

$$q_{t,r}^{gov} = y_r^{gov} - p_r^{gov} - \sigma_r^{gov}(p_{t,r}^{gov} - p_r^{gov}), \quad t \in T, \ r \in R, \tag{4.21}$$

$$p_r^{gov} = \frac{\sum_{j \in T} V_{j,r}^{gov} p_{j,r}^{gov}}{\sum_{j \in T} V_{j,r}^{gov}}, \quad r \in R. \tag{4.22}$$

Here:

- $q_{t,r}^{gov}$ is the percent change in demand by government for commodity t in region r;
- y_r^{gov} is the percent change in government expenditure in region r;
- p_r^{gov} is the value-weighted average percent change in the prices the government in region r pays for commodities;
- σ_r^{gov} is a substitution parameter; and,
- $V_{t,r}^{gov}$ is the value of use of each commodity by each government.

The household demand equation has a constant difference of elasticities form:

$$q_{t,r}^h + a_{t,r}^h - pop_r = \sigma^y(y_r^h - pop_r) + \sum_{j \in T} \sigma_{t,j,r}^p (p_{j,r}^h - a_{j,r}^h), \quad t \in T, \ r \in R, \tag{4.23}$$

where (again, all percent changes except for the substitution parameters):

- $q^h_{t,r}$ is household demand for each commodity;
- $a^h_{t,r}$ is a variable allowing for cost-neutral taste changes;
- pop_r is the population;
- σ^y is a substitution parameter controlling how consumption changes with income;
- y^h_r is household income;
- $\sigma^p_{t,j,r}$ is a substitution parameter controlling how consumption of each commodity changes as its price changes relative to the prices of each commodity (all parameter values are negative or effectively zero); and,
- $p^h_{t,r}$ is the price paid by each household for each commodity.

We can see from Equations 4.21 and 4.23 that increases in the price of one commodity, relative to others, due to the emissions price, results in declines in demand for that commodity. This causes a reduction in emissions related to the production and use of that commodity. This mechanism is in addition to substitution between energy commodities (and the resulting decline in emissions), which is also driven in part by the emissions price. The model solves for a value of the emissions price in each region that results, via these mechanisms, in the target change in regional emissions.

4.2.4 Policies consistent with the Paris Agreement

Under the Paris Agreement, parties committed to "Making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development" (United Nations Framework Convention on Climate Change, 2015). I investigated two ways that would contribute to such consistency:

1. The provision of 100 billion USD per year by developed countries "for climate action in developing countries" (United Nations Framework Convention on Climate Change, 2019); and,

2. The removal of subsidies for the production and consumption of fossil fuels.

4.2.4.1 Climate finance

The Independent Expert Group on Climate Finance (2020) indicate that a significant share (likely more than half) of the \$100 billion was provided in 2017 and so is in the database. However, they also state that value should "be seen as a floor and not as a ceiling." Therefore a highly stylised approach was employed. Firstly, the financing is to be provided by "Annex I" countries and the recipients are therefore not Annex I countries. The model regions considered to be potential recipients of funding are therefore:

- China;
- India;
- The Rest of Asia and the Pacific;
- The Rest of the Americas;
- The Middle East; and,
- Africa.

I assumed that, from 2022, on top of the investment in the case with the NDCs as they stand, an additional \$100 billion per year will be divided up amongst the regions above in proportion to each region's share of emissions reductions below the base case. That is:

$$INV_{r,y}^{fi} = INV_{r,y}^{n} + 100 \times 10^3 \frac{\min(0, M_{r,y}^{n} - M_{r,y}^{b})}{\sum_{j \in NAI} \min(0, M_{j,y}^{n} - M_{j,y}^{b})}, \quad r \in NAI, 2022 \leq y \leq 2030 \tag{4.24}$$

where:

- $INV_{r,y}^{fi}$ denotes investment in millions of dollars in region r in year y in the case with \$100 billion (i.e. \$100 $\times\ 10^3$ million) of climate financing;
- $INV_{r,y}^{n}$ denotes investment in millions of dollars in region r in year y in the

case with Nationally Determined Contributions as committed to date but no additional climate financing;

- $M^n_{r,y}$ denotes emissions in megatonnes of CO_2 equivalent ($MtCO_2$-e) in the case with Nationally Determined Contributions as committed to date but no climate financing;
- $M^b_{r,y}$ denotes emissions in the "no new policies" case; and,
- the set NAI is the set of non-Annex I countries listed above, with the exception of the Rest of Asia and the Pacific, because, as discussed in section 4.2.3, emissions from that region were higher in the scenario with the NDCs.

The target levels of investment are achieved by endogenising the variable *srorge* (which is a shift variable for the expected rate of return), as suggested by Ianchovichina and McDougall (2001), in order to make exogenous the variable *qcgds*, the percent change in investment in each region.

4.2.4.2 Fossil fuel subsidies

This simulation involved calculating the power of taxes (excluding emissions pricing) on the production and consumption of all fossil fuels. The powers of those taxes were calculated from use values in the GTAP database (GTAP, 2020a). When those powers were less than 1, an annual shock was calculated such that the power of the taxes in 2030 was 1, i.e. that all subsidies are removed by 2030. Policy shocks began in 2022, using the simulation of the NDCs as the base case. It should be noted that this constitutes a narrow definition of a subsidy and does not allow for subsidies in the form of tax credits. As the power of taxes are calculated at sector level, they are net subsidies and will miss any subsidies for sectors that pay both a tax and receive subsidies if the tax revenue is greater than the subsidies. For a more detailed treatment of fossil fuel subsidies, see Chepeliev et al. (2018).

Chapter 5

Results

Given the aim of the Paris Agreement is to limit global average temperature increases and therefore greenhouse gas emissions, its success can be judged by the emissions reductions achieved. NDCs submitted to date now appear to be sufficient to result in a peak in greenhouse gas emissions this decade. However, model results show emissions in 2030 will only be 0.3% lower than they were in 2021 and cumulative emissions during the period from 2021 to 2030 are over 430 gigatonnes of CO_2 equivalent greenhouse gases, which only includes non-land use emissions covered by the GTAP database (GTAP, 2020a). The method that produces these emissions reductions in the model has been outlined in Section 4.2.3.

As mentioned in Section 4.2.3, the base case should be considered a "no new policies" scenario. Emissions in the base case are driven by economic growth, along with continued reductions in the cost of wind- and solar-powered electricity. Note that gross emissions figures show only emissions covered by the model, which are those in the GTAP database (GTAP, 2020a), with the exception of land use emissions.

5.1 Regional changes

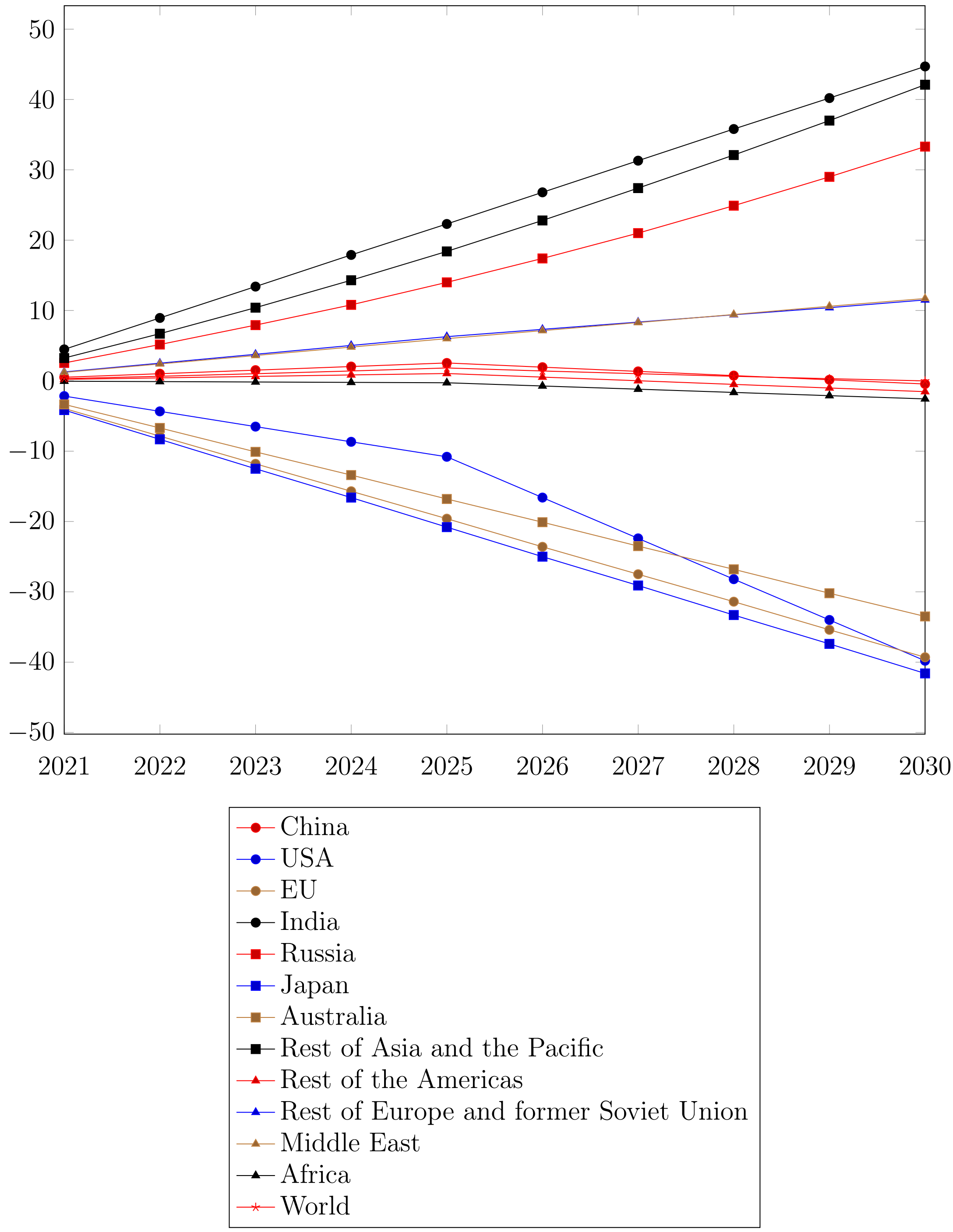
In the absence of their NDCs, emissions from China grow by over 40%, those from the USA by over 10%, those from the EU by almost 5% and emissions from Japan grow by over 17%. Globally emissions grow by over 30% in the base case, with highest growth in Asia, the Middle East and Africa.

The cumulative changes in emissions from their level in 2020 by each region with their NDCs are shown in Figure 5.1. By the end of the decade, approximately half of all global emissions will come from Asia.

Figure 5.2 shows the difference between emissions in the base case and in the case with the NDCs as percent changes relative to the base case. In the two regions where quotas are non-binding (Russia and the Rest of Asia and the Pacific), emissions increase slightly due to emissions reduction policies elsewhere.

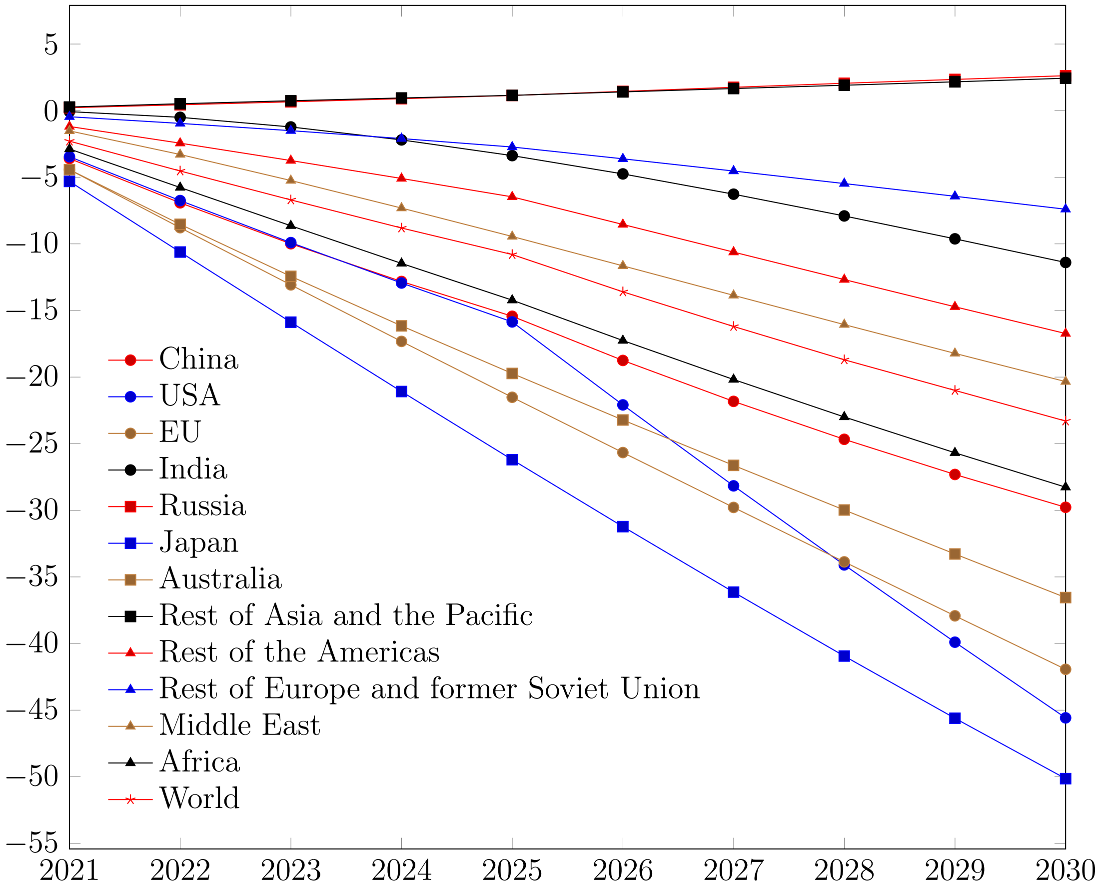
Figure 5.3 shows changes in per capita emissions over time with the NDCs. In Africa, per capita emissions are already the smallest and only decline further. India has the next smallest, though slightly increasing, emissions per capita throughout the period. Perhaps most notably, Australia, which currently has the highest emissions per capita of all regions modelled, despite its binding emissions reduction target, takes until 2028 for its per capita emissions to drop below those of Russia, which does not have a binding target.

Figure 5.1: Cumulative change in emissions from 2020 by region with NDCs (%)



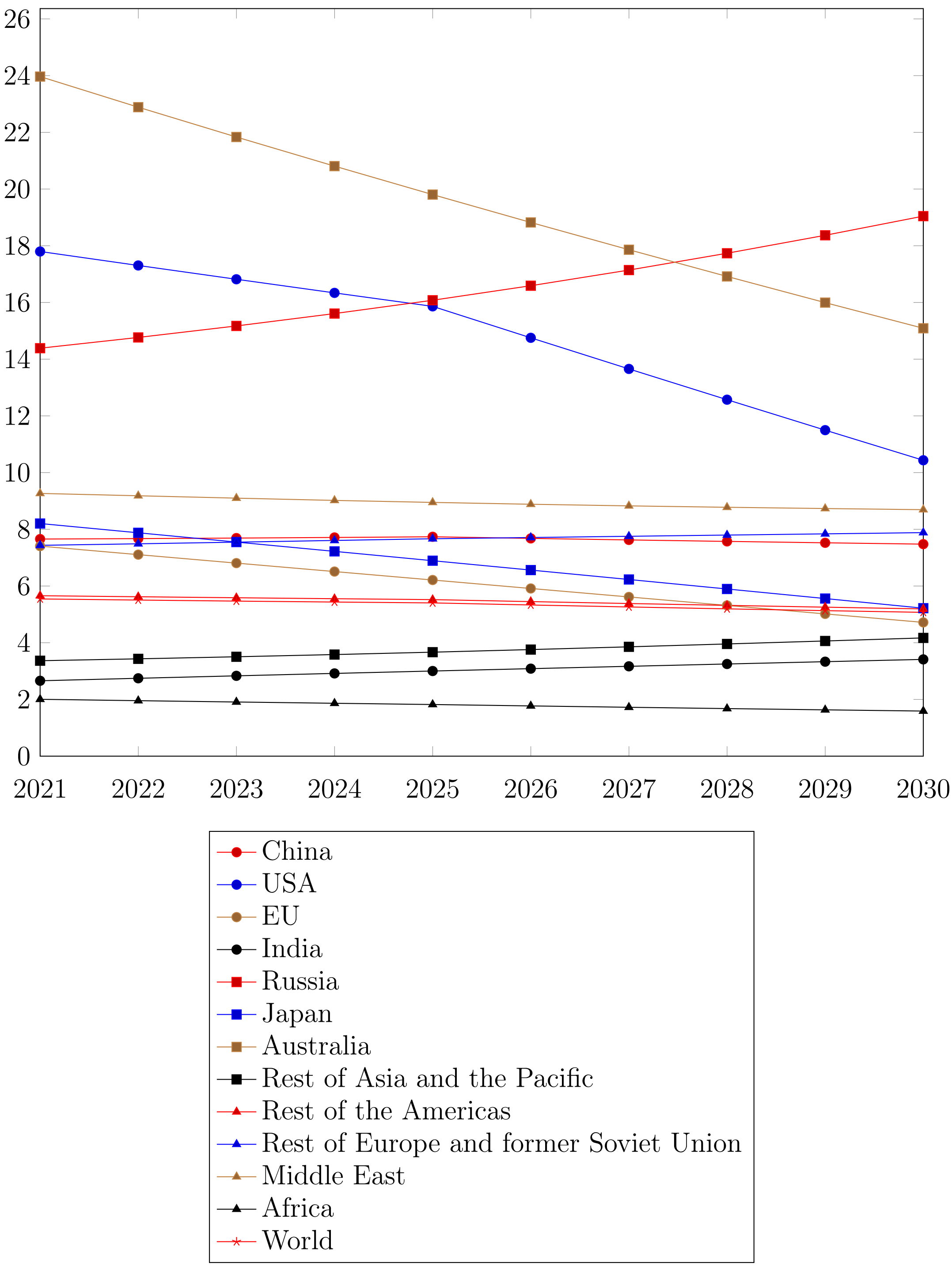
Source: model results.

Figure 5.2: Deviation in emissions (%)



Source: model results.

Figure 5.3: Emissions per capita with NDCs (tonnes CO_2 equiv.)



Source: model results.

Regions with the largest emissions reductions achieve most of those reductions by changes in their electricity sector. Table 5.1 shows how the share of total regional emissions that came from the electricity sector changes over time with and without the NDCs. Without the NDCs, changes are driven by technological change - improving energy efficiency and continued cost reductions in renewable electricity generation sectors.

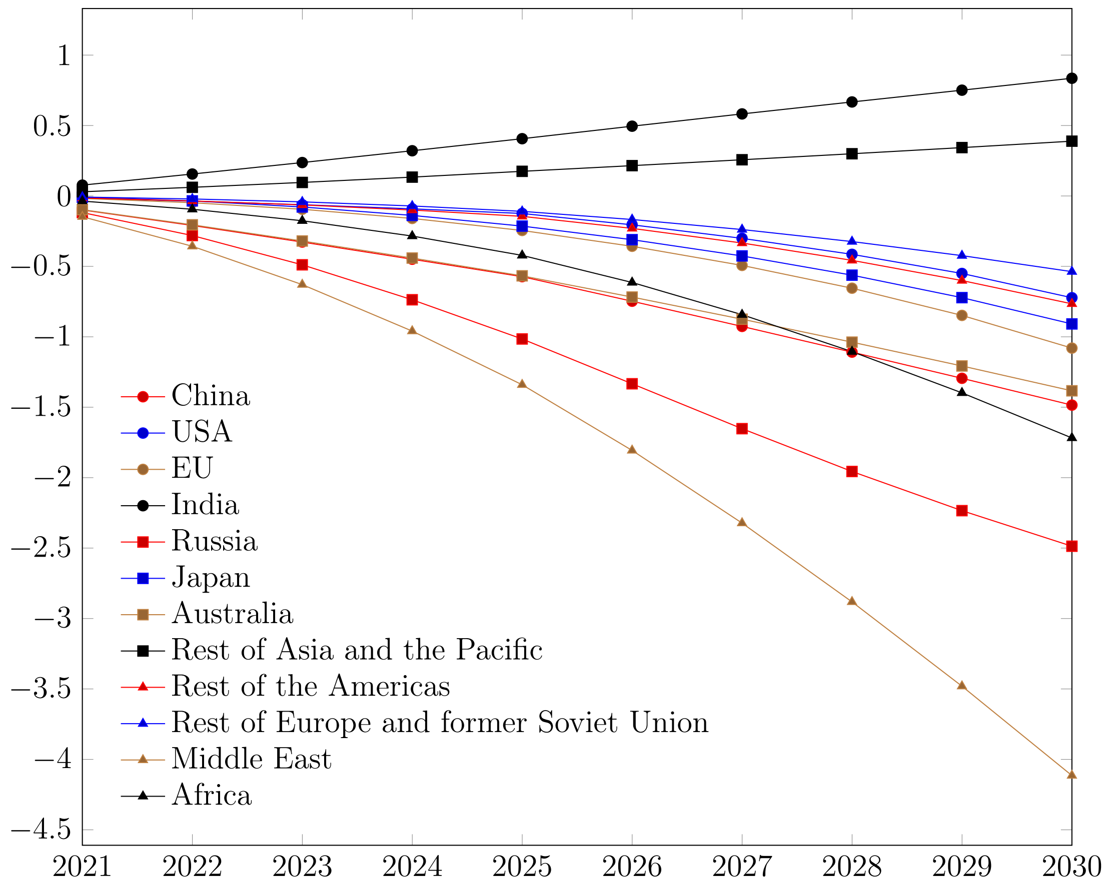
Table 5.1: Electricity sector share of emissions (%)

Region	**2017**	**2030 (Base)**	**2030 (Policy)**
China	39	38	20
United States	33	26	3
European Union	24	18	2
India	30	31	30
Russia	41	41	41
Japan	44	41	14
Australia	27	20	5
Rest of Asia and the Pacific	24	26	25
Rest of the Americas	13	11	7
Rest of Europe and former USSR	25	24	18
Middle East	27	29	29
Africa	17	17	9
World	30	28	19

Sources: GTAP (2020a) and model results.

What effect do these changes have on the economies of each region? Figure 5.4 shows the deviations in real GNI in the policy case relative to the base case.

Figure 5.4: Deviation in real GNI (%)



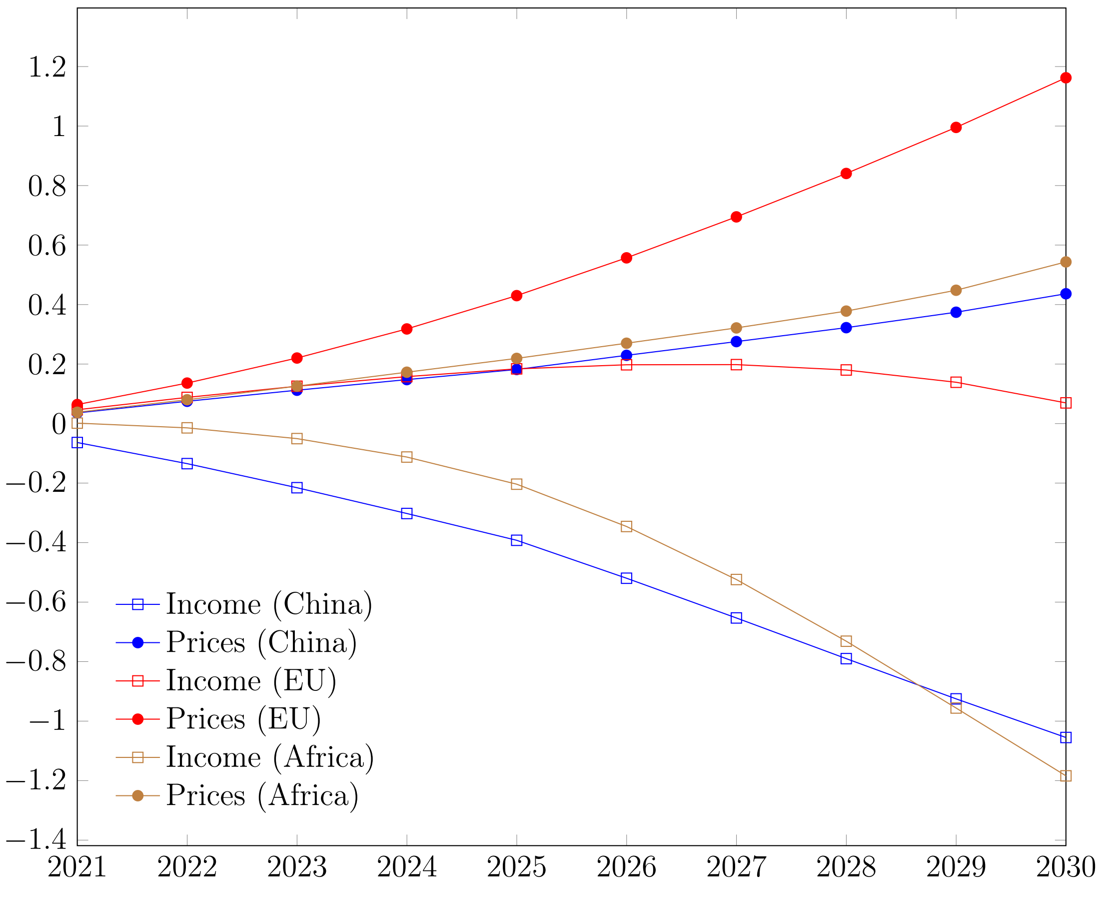
Source: model results.

The negative deviations shown here are the result of a mixture of income sacrificed in order to achieve emissions reductions and, in the case of fossil fuel exporters, the result of emissions reductions elsewhere. At a global level, the results appear to be slightly more severe than those summarised by Böhringer et al. (2021), but it should be noted that a number of more stringent NDCs (most notably that of the USA) were submitted after their work. Two regions see their GNI increase in real terms as the result of the policy - India and the Rest of Asia and the Pacific. Emissions-intensive industries increase their output, relative to the base case, in the Rest of Asia and the Pacific due to its lack of a binding emissions reduction target. Emissions-intensive industries are similarly attracted to India, as its target is relatively weak. The biggest impacts are in the two regions that have the largest share of their economies dedicated to the production of fossil fuels. Russia's GNI declines in real terms despite not having a binding emissions target and the Middle East fares even worse, as not only do its exports decline, but it must also reduce its emissions below those in the base case, in line with its NDC. Note that no regions see their GNI actually decline. All reductions are only relative to the base case. Incomes in both Russia and the Middle East grow by 45% in the base case, so the deviations shown here should be considered in that context.

Interestingly, the regions with the three largest reductions in emissions below the base case (Japan, the USA and the EU) see their GNI decrease by less than China and Africa. To understand why, let us compare impacts in China and Africa to those in the region that has the most similar emissions profile of those three most ambitious regions. China and Africa have relatively large shares of their emissions coming from primary and food processing sectors. Of the three regions with the largest emissions reductions, the EU has the largest share of its emissions coming from those sectors. Impacts in the EU are therefore compared to those in China and Africa below.

Figure 5.5 shows deviations in nominal GNI and prices. The prices are weighted sums of the prices of the three categories of regional expenditure: consumption, savings and government purchases. For real income to decline by less in the EU than in China and Africa, it must be that nominal incomes decline by less, or prices go up by less. We can see from Figure 5.5 that prices in China, the EU and Africa all go up, with prices in the EU increasing by more than in the other two. The main reason that real GNI declines by less in the EU than in China and Africa is that its nominal GNI actually increases slightly, whereas it declines by more than 1% in the other two regions.

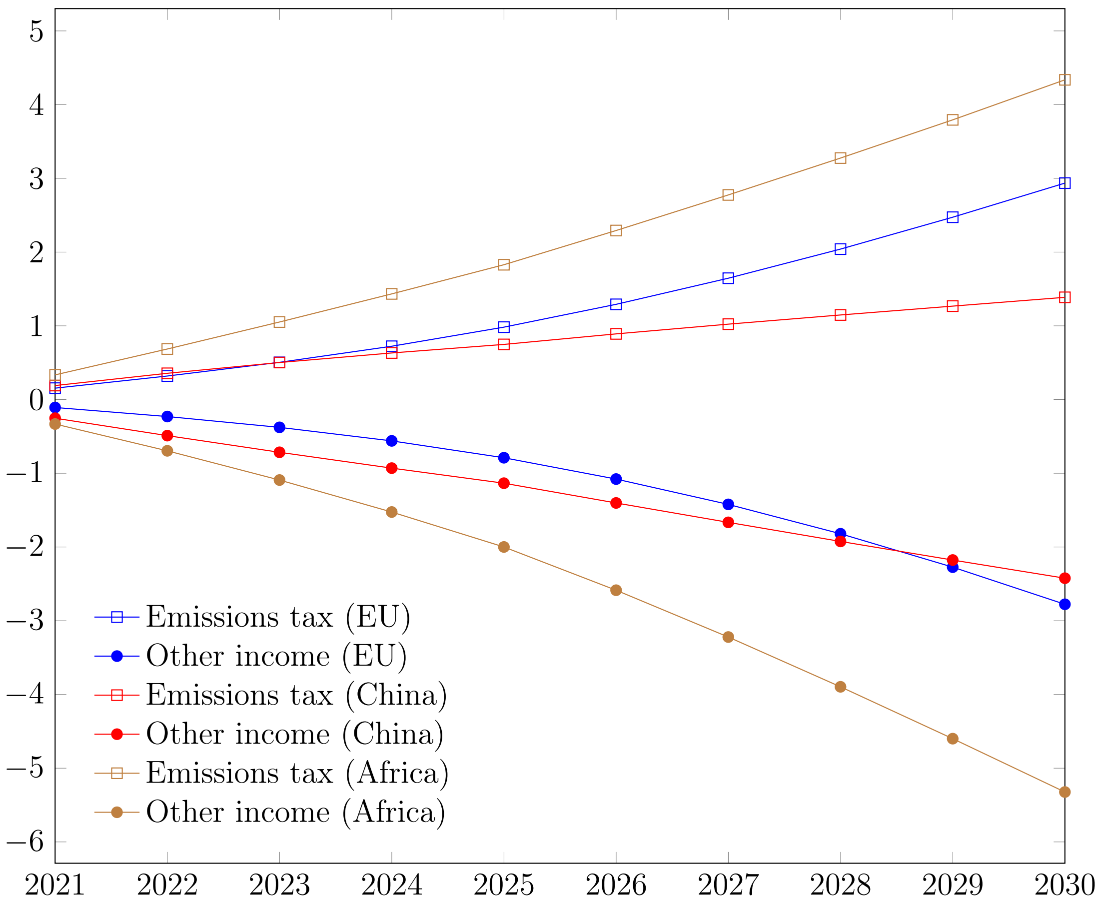
Figure 5.5: Deviation in nominal GNI and prices (%)



Source: model results.

We can see from Figure 5.6 that the main difference between China and the EU is the amount of revenue received from the emissions tax. This is, quite simply, due to the large discrepancy between the emissions price in those two regions, shown in Figure 5.7. One conclusion we could possibly draw from this is that China's income is significantly more sensitive to domestic emissions reduction efforts than the EU's is.

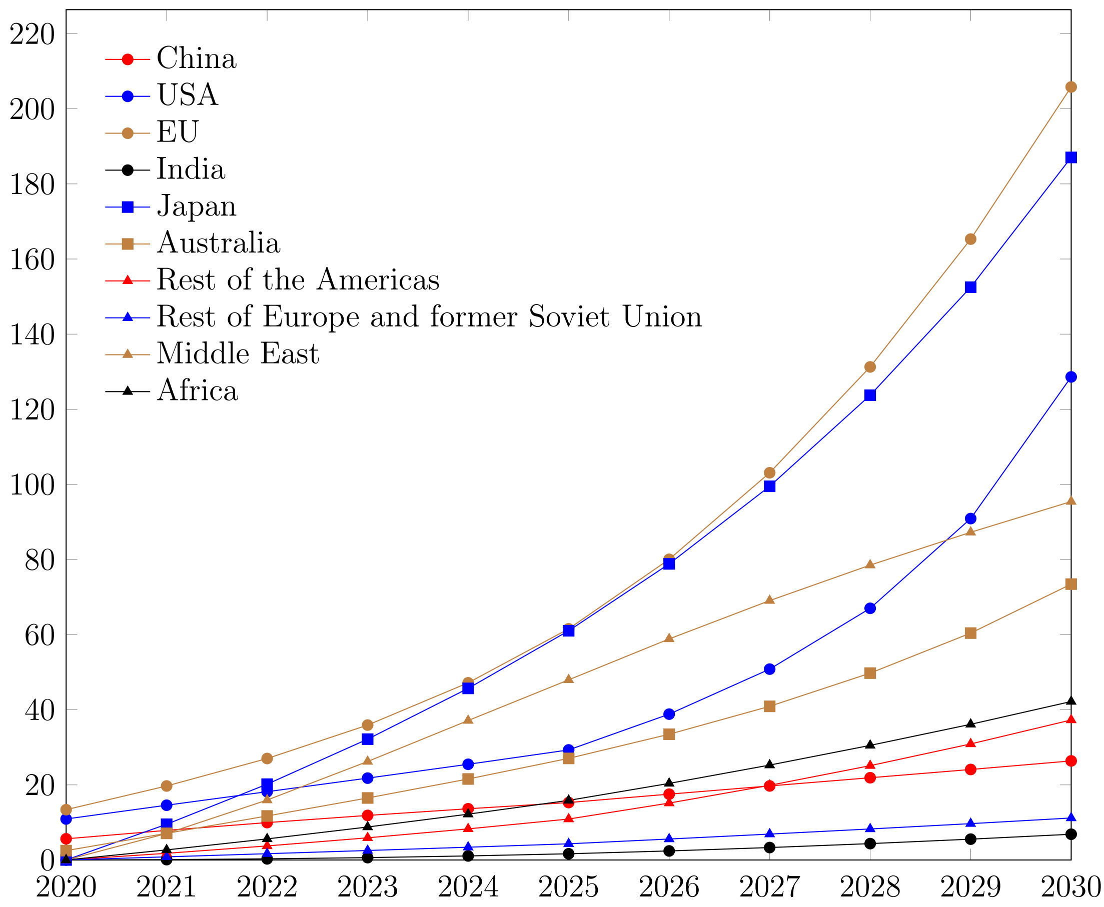
Figure 5.6: Contribution to deviation in income by source (%)



Source: model results.

Figure 5.7 shows the emissions price in each region with a binding emissions quota. China, the USA, the EU and Australia have non-zero emissions prices in 2020. That is because those regions made commitments to reduce their emissions as part of the Copenhagen Accord and a price on emissions was required to get emissions in those regions to meet their targets.

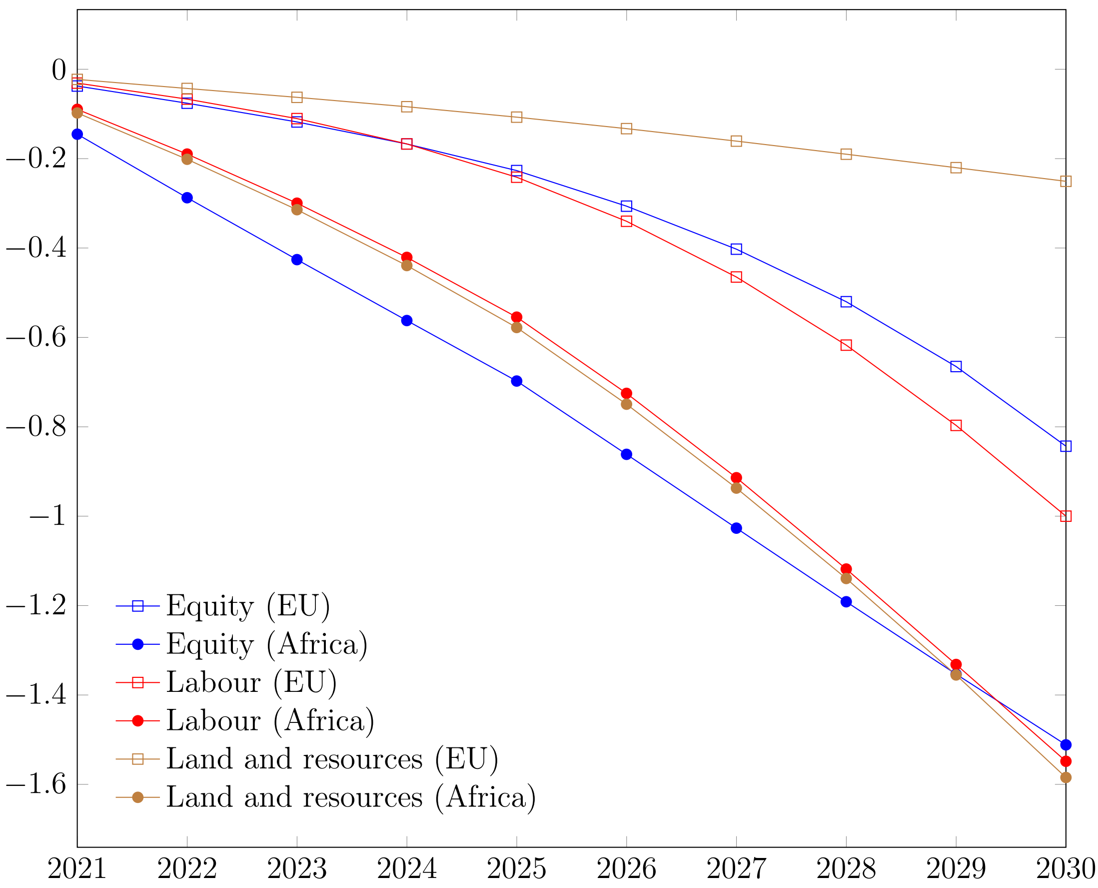
Figure 5.7: Real emissions prices with NDCs (2017USD/tCO_2-e)



Source: model results.

The question that remains is, why does Africa's income excluding emissions tax revenue decrease by so much? Figure 5.8 shows contributions to factor income by groups of factors. Contributions from equities and labour both decline by more in Africa than in the EU. However, the largest difference is in the decline in income from land and natural resources, which contributes almost 1.6% to the 5.3% decline in Africa's income excluding emissions tax revenue, but only approximately 0.25% to the 2.8% decline in the EU's. In Africa, these income losses will be concentrated in countries where revenue from fossil fuel exports comprises a significant share of income, such as Nigeria.

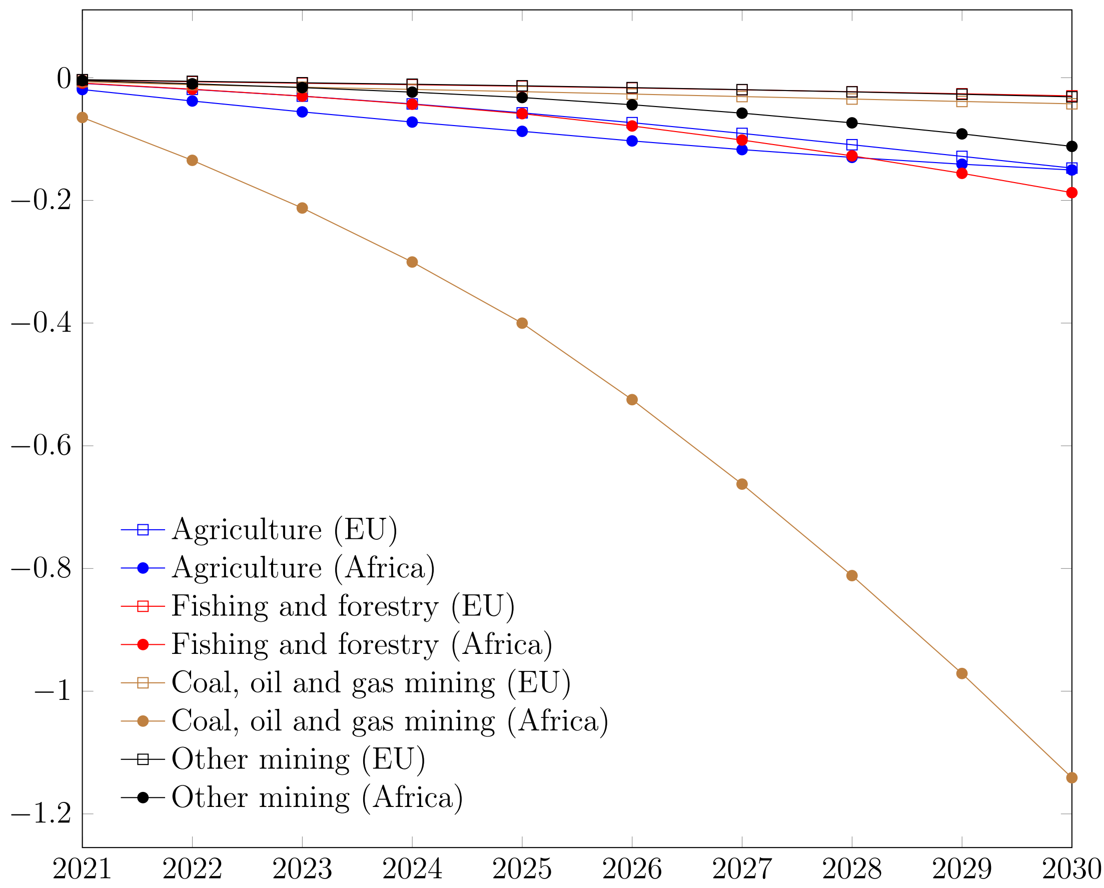
Figure 5.8: Contribution by groups of factors to deviations in factor income (%)



Source: model results.

Figure 5.9 breaks down the contributions to deviations in income from land and natural resources by sector. It is clear that the largest difference comparing impacts on regional income in the EU and Africa is from payments for natural resources by the fossil fuel mining sectors.

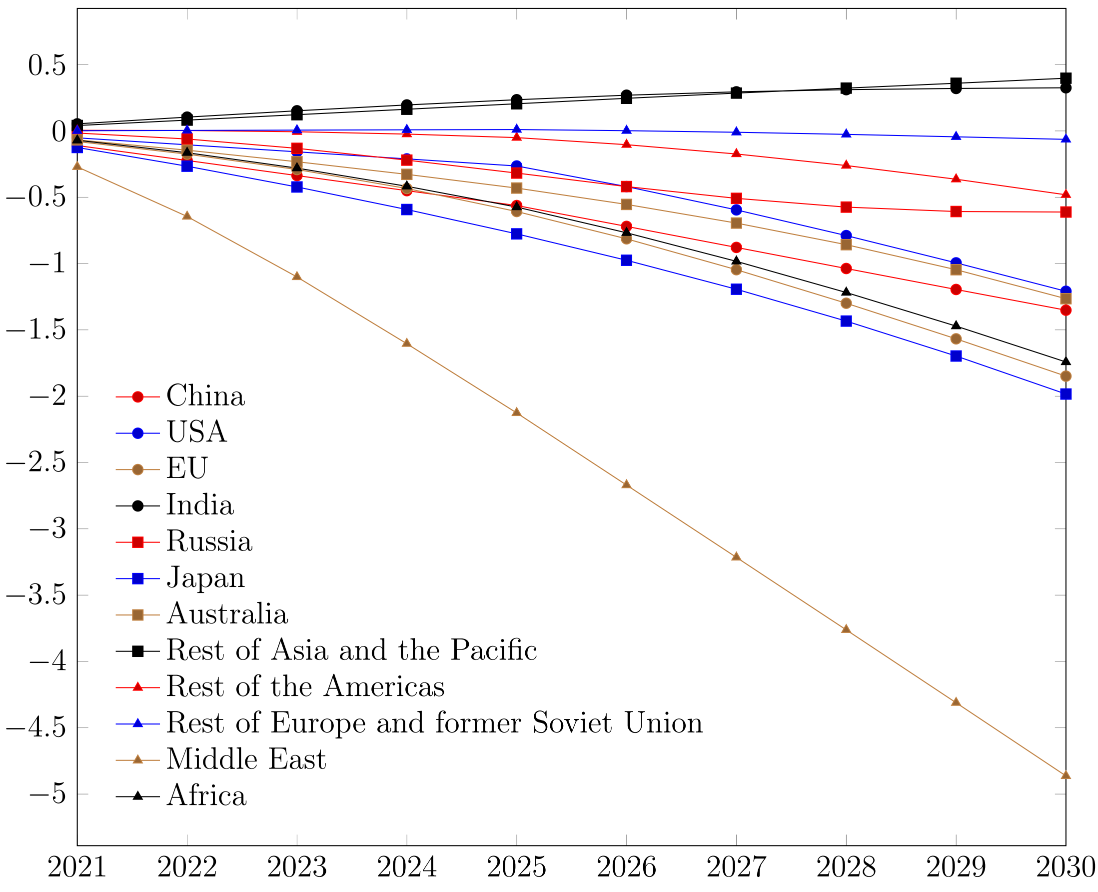
Figure 5.9: Contribution to deviation in land and natural resources income (%)



Source: model results.

With those sorts of reductions in payments for resources by *coal*, *oil* and *gas* mining firms elsewhere in the world, it is perhaps unsurprising to see the relative decline in GDP in the Middle East shown in Figure 5.10. Given the structure of its economy, we might also expect Russia's output to follow a similar path. The difference between Russia and the Middle East, though, is the absence of a binding emissions reduction target in Russia. This allows Russia to take advantage of lower energy commodity prices due to reduced demand in most other regions. Although savings decline in Russia as a result of the negative deviation in their income, foreign capital fills the void, allowing output to be less affected than income.

Figure 5.10: Deviation in real GDP (%)



Source: model results.

Again, these deviations should be considered in the context of growth over the decade in the base case, which is sufficiently strong that, even with these deviations, there is still significant growth in economic activity. Looking at growth in the base case for the three regions most affected by emissions reduction efforts as shown in Figure 5.10, GDP grows by over 45% across the Middle East, in Japan it grows by 24% and the growth in GDP across the EU is 10%, so despite these deviations, growth continues in all regions even when emissions are restricted.

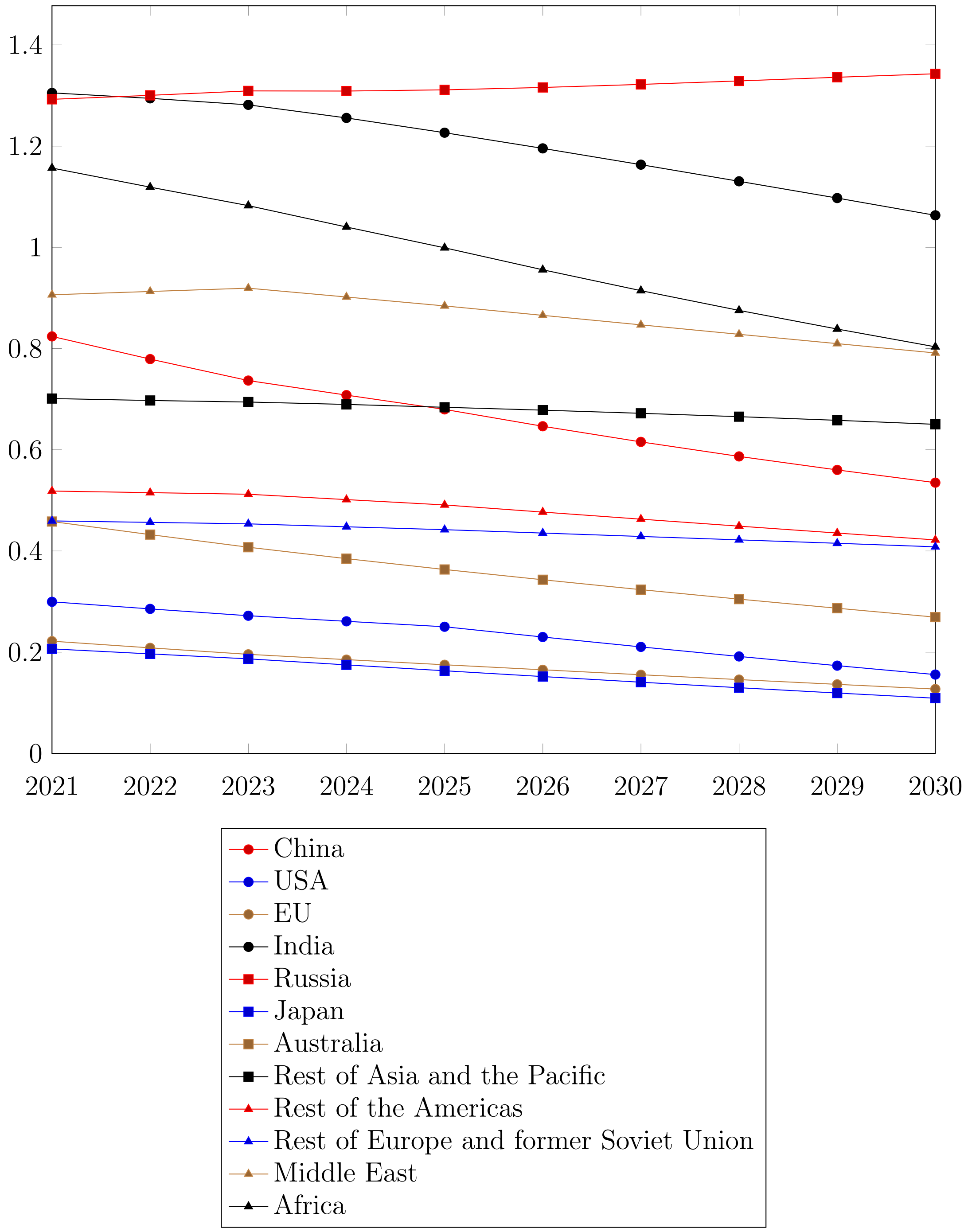
Figure 5.11 shows the emissions intensity of each region with the NDCs, in units of megatonnes of CO_2-equivalent per billion 2017 USD of GDP. It can be seen that developed countries generally have low emissions intensity. This is largely because they have outsourced their manufacturing to developing countries over recent decades. The challenge is now for those developing countries to reduce their emissions intensities.

As a considerable share of Russia's exports are energy commodities, the lower energy commodity prices, due to reduced demand in most other regions, affect Russia's terms of trade, shown in Figure 5.12. Interestingly here we see that regions with high emissions prices often see their terms of trade improve - despite reductions in export volumes due to their less competitive pricing, the increase in the prices of their exports offsets the impacts on regional income to some extent.

Impacts on real private consumption, shown in Figure 5.13, are more muted than those on real regional income, as reductions in income affect savings more than consumption in most regions.

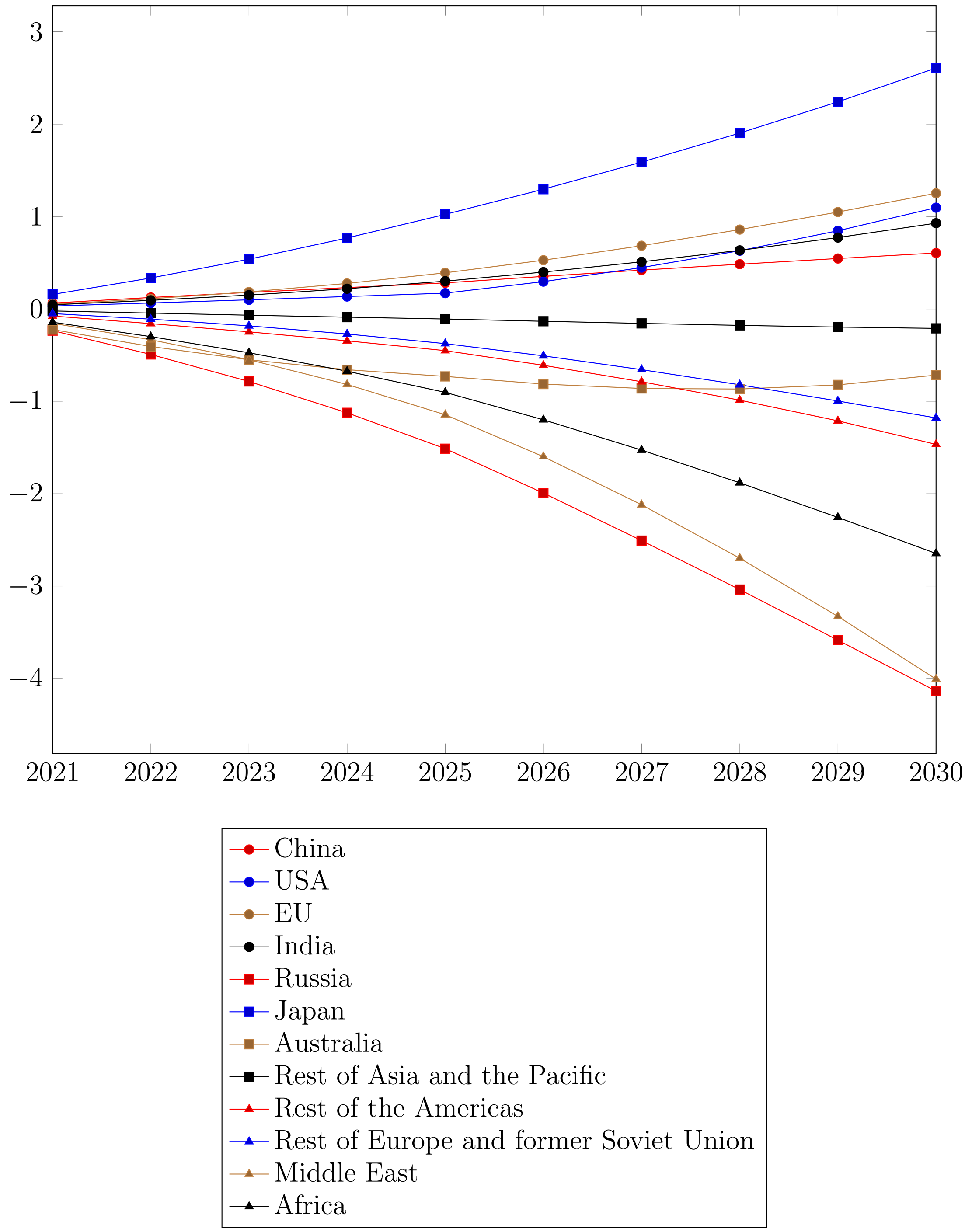
In the USA, EU and Japan, prices faced by private consumers go up by more than they do in the economy more broadly, causing, in real terms, a reduction in private

Figure 5.11: Emissions Intensity of GDP with NDCs ($MtCO_2$-e/billion USD)



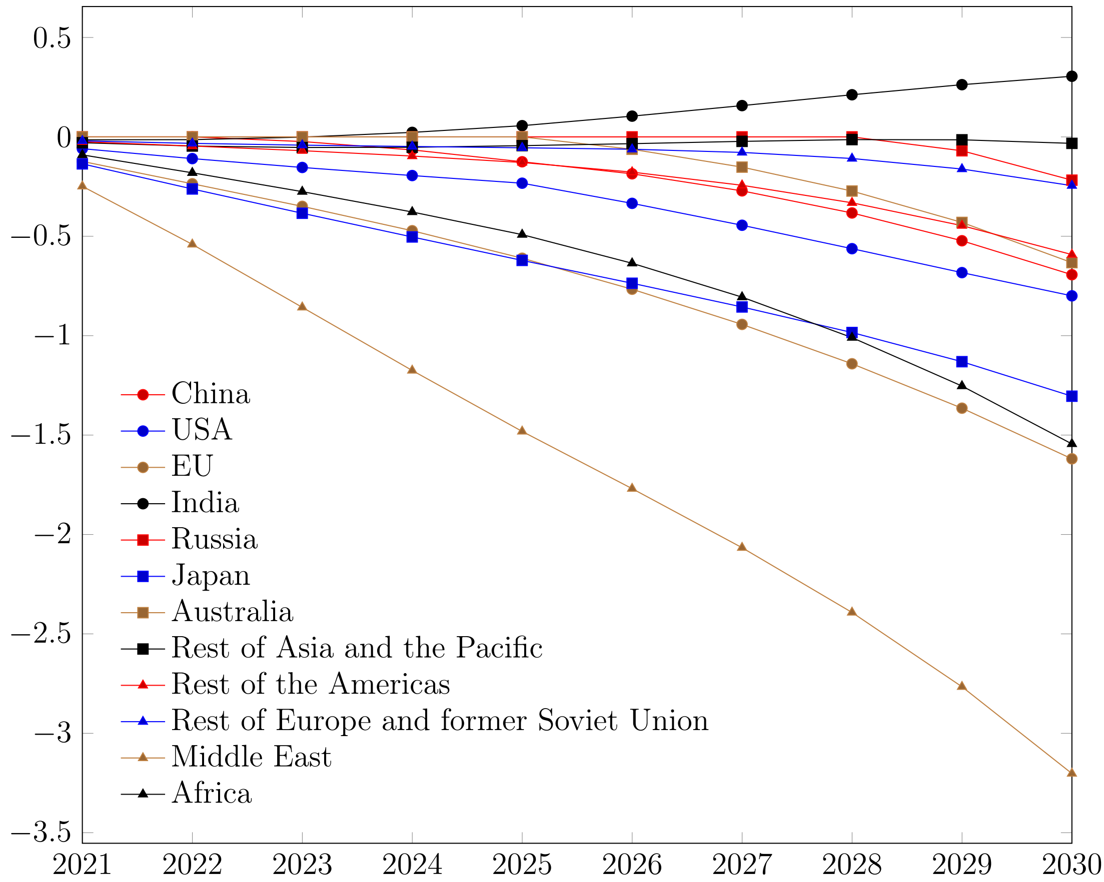
Source: model results.

Figure 5.12: Deviation in terms of trade (%)



Source: model results.

Figure 5.13: Deviation in real private consumption (%)

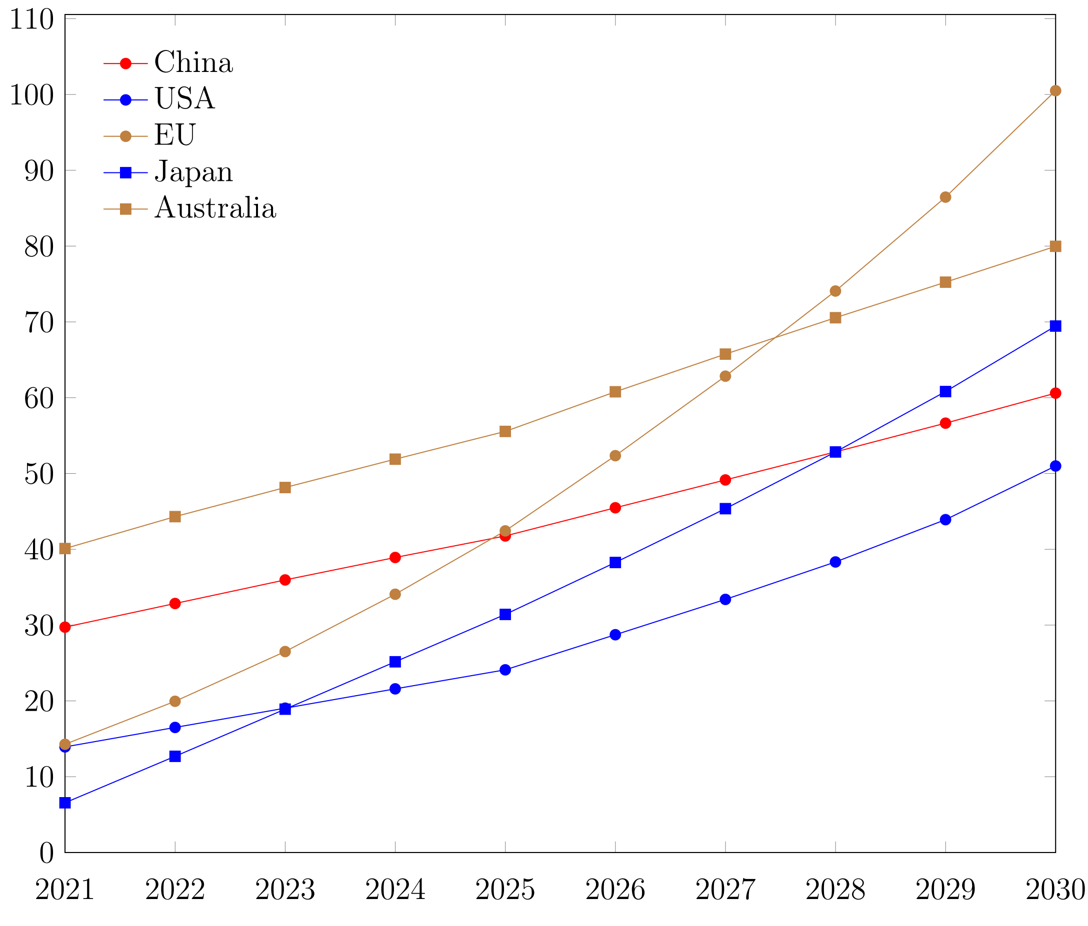


Source: model results.

consumption in excess of the reduction in regional income. Note that for China, Russia and Australia, real private consumption was exogenous initially, with changes from year to year equal to those in the base case until later in the modelled period, as discussed in Section 4.1.1.

One way that we might consider the cost of emissions reductions is in terms of the loss of income per unit of abated emissions. However, as shown in Figure 5.9, some regions lose income from natural resources as a result of reduced sales of *coal*, *oil* and *gas*, rather than due to the cost of domestic emissions reductions. Figure 5.14 shows the deviation in real GNI in dollar terms per deviation in emissions in tonnes of CO_2 equivalent for selected regions. Regions where the main contribution to losses in income are made by lost factor income due to reduced sales of *coal*, *oil* and *gas* have been omitted.

Figure 5.14: Per unit cost of emissions reductions (2017 USD / tonne CO_2 equiv.)

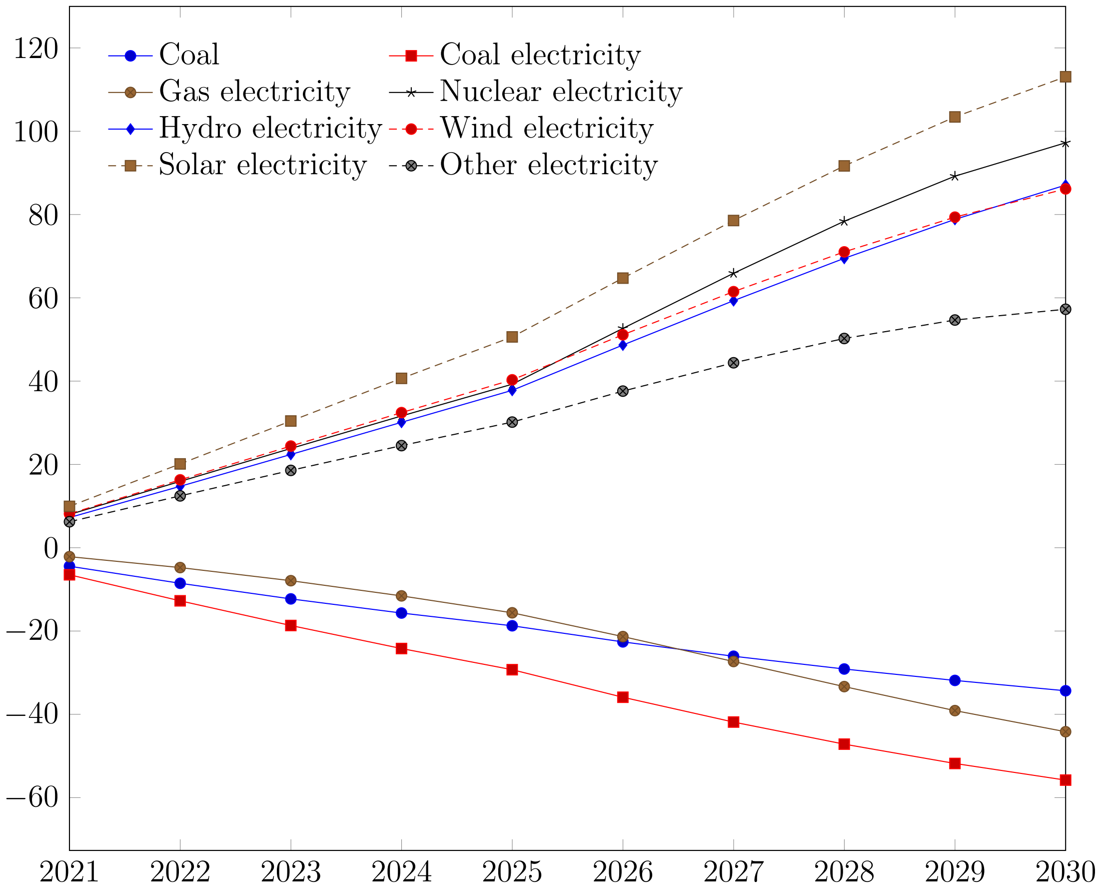


Source: model results.

5.2 Sectoral changes

In percent change terms at the global level, the major impacts of the NDCs on sectoral output in the model are on the various methods of electricity generation. Deviations in the output of the most significant sources of electricity generation are shown in Figure 5.15. The only sector in the top ten most affected that is not an electricity generation sector was *coal* mining.

Figure 5.15: Deviation in global sector output (%)



Source: model results.

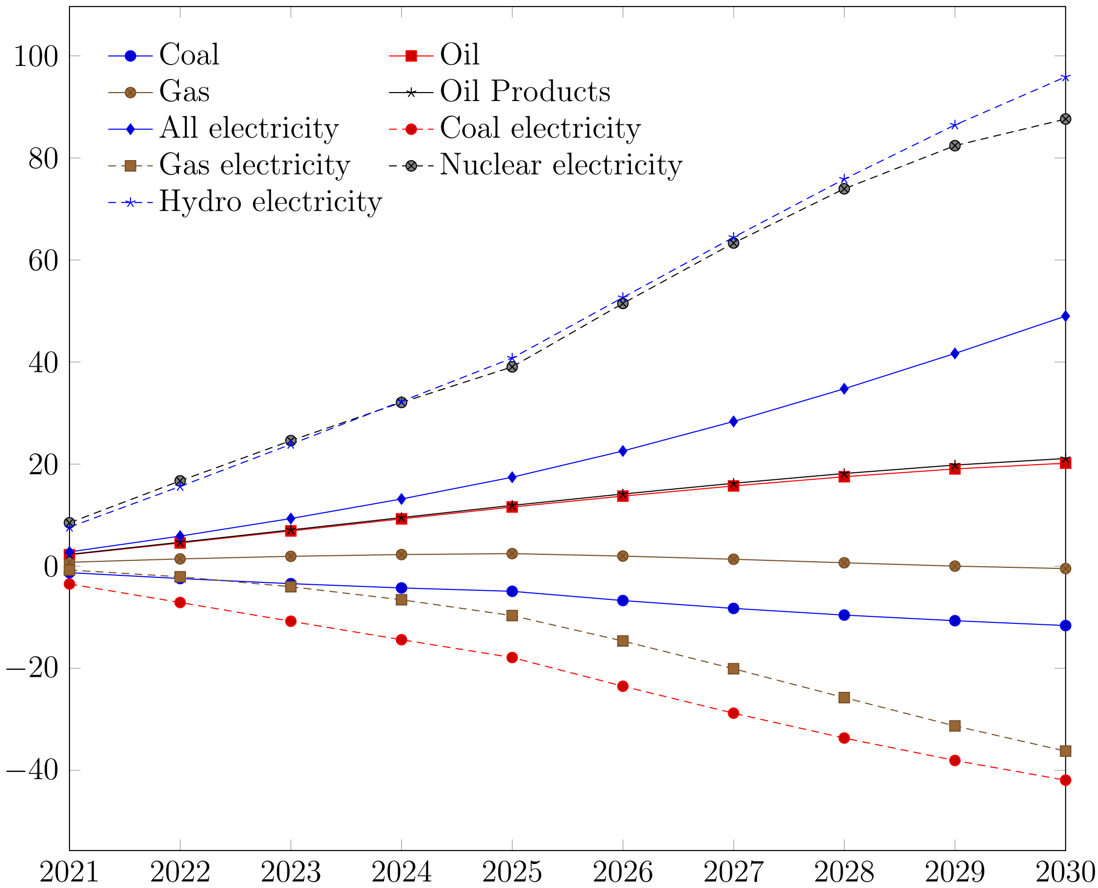
The positive deviations for hydro electricity can be considered to be the impact of pumped hydro. As discussed in Section 4.1, substantial opportunities exist to construct pumped hydroelectric facilities, which do not suffer the same resource constraints as facilities built on rivers. In many jurisdictions where generation from solar is abundant during the day, pumped hydro can make generation from wind more productive by removing the need for curtailment when generation from solar results in low (or negative) electricity prices during the day.

Figure 5.16 shows how the deviations shown in Figure 5.15 translate into cumulative changes. The -30% deviation in the output of the global *coal* sector is only equivalent to a 12% reduction below 2020 levels. Despite declines of 42% for the coal electricity sector and 36% for the gas electricity sector globally, generation of electricity increases 49% over the course of the decade. That is largely driven by the *solar* and *wind* electricity sectors, which have been omitted from the graph as the scale of their changes dwarfs all others.

The changes shown in Figure 5.16 are in some cases quite different to those expected to occur in the absence of the NDCs. Without the NDCs, *nuclear* electricity generation actually declines slightly over the decade - the only sector that has declining output in the base case. Increases in the output of hydropower are the next lowest, growing by less than 5% over the decade. The NDCs clearly have a significant effect on the output of those two sectors. Generation of electricity from coal and gas continue to grow in the base case.

With or without the NDCs, the growth of generation of electricity from the sun and wind far surpasses the growth of all other sectors. In the absence of the NDCs, the output of the *solar* electricity sector still more than quadruples over the decade and that of the *wind* sector more than doubles.

Figure 5.16: Cumulative change in global output with NDCs (%)



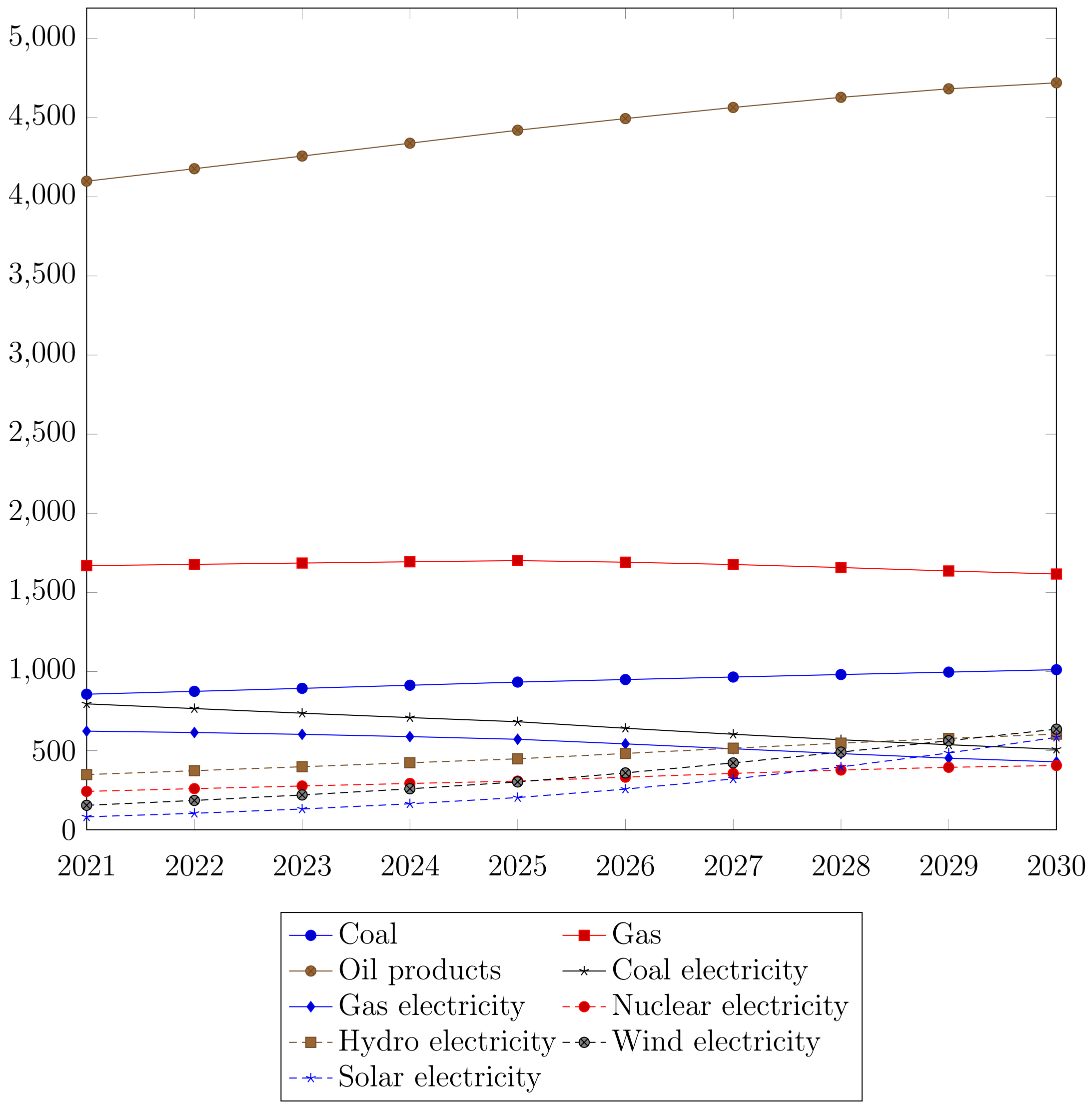
Source: model results.

Although global *coal* output drops due to the NDCs, it is only the use of *coal* to produce electricity that declines significantly. Figure 5.17 shows TFC of energy in megatonnes of oil equivalent (Mtoe).

The decline in the use of *coal* to generate electricity causes the price of *coal* to decline, which in turn results in increased use by other (non-electricity) sectors. The increase in use of *coal* by non-energy sectors is primarily driven by *energy-*

intensive industries, which find it more difficult to substitute away from than most other sectors and hence, as discussed in Section 3.5.2, have a lower substitution parameter. The dramatic rises in output of the *wind* and *solar* electricity sectors are clearly visible in Figure 5.17.

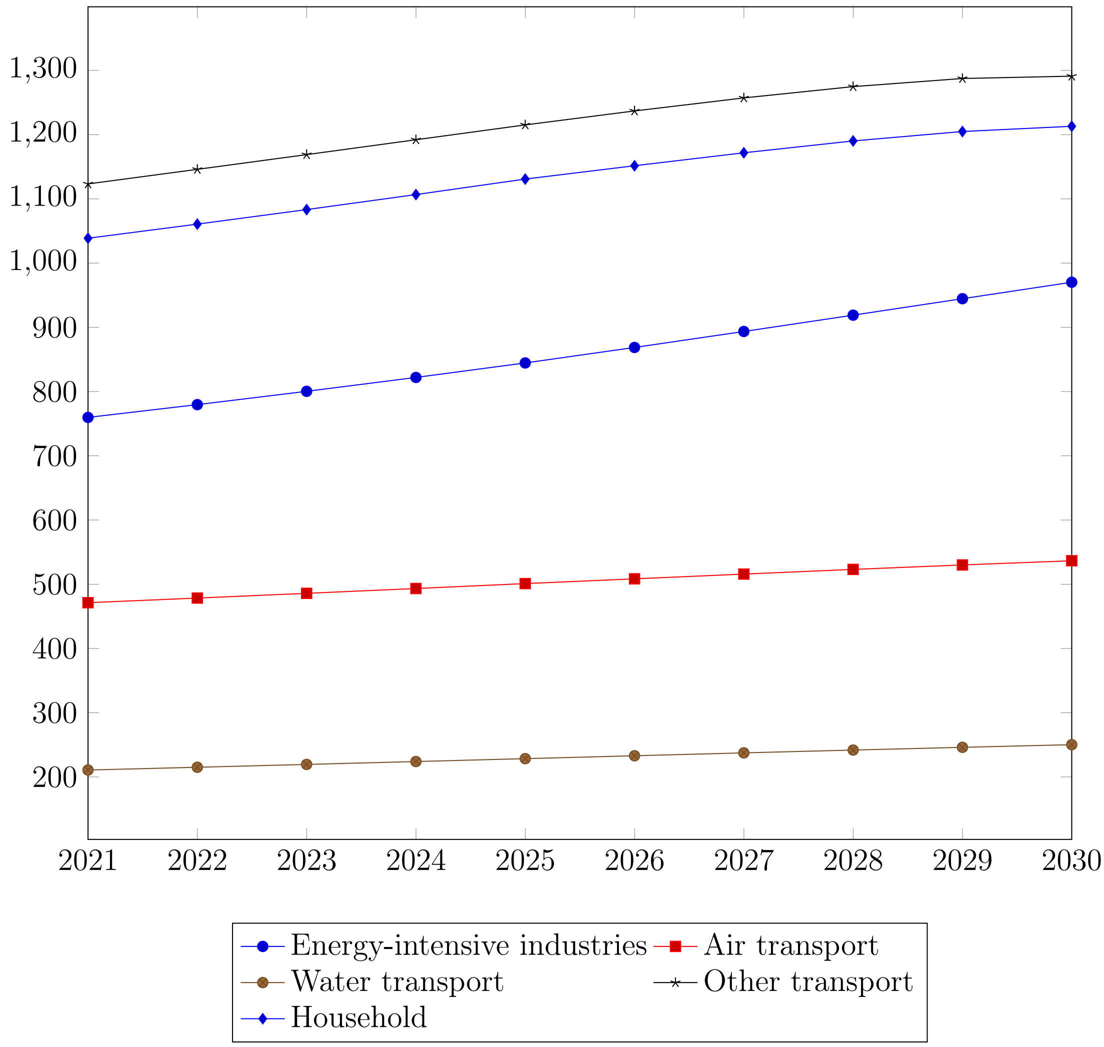
Figure 5.17: TFC of energy by commodity with NDCs (Mtoe)



Source: model results.

More than anything, what is clear from Figure 5.17 is that the NDCs, as they stand, are not ambitious enough to prevent further rises in the use of *oil products*, which will continue to provide a major share of TFC of energy out to 2030. As shown in Figure 5.18, the largest users of *oil products* remain the transport sectors and the household, which also primarily uses them as fuel for cars.

Figure 5.18: TFC of oil products by sector with NDCs (Mtoe)



Source: model results.

Although use of *oil products* by non-energy sectors and households grows in absolute terms, its share declines very slightly due to the rise in use of emissions-free electricity generation, as shown in Table 5.2. We can see that the NDCs cause the shares of zero-emissions energy sources to roughly double relative to the base case.

Table 5.2: Shares of TFC of energy (%)

Commodity	**2020**	**2030 with no NDCs**	**2030 with NDCs**
Coal	9.4	10.4	9.3
Oil	0.1	0.2	0.1
Gas	18.6	17.8	14.9
Oil products	45.2	44.4	43.6
Coal electricity	9.3	9.2	4.7
Oil electricity	0.1	0.1	0.2
Oil products electricity	0.7	0.6	0.8
Gas electricity	7.1	6.2	4.0
Nuclear electricity	2.5	1.9	3.8
Hydro electricity	3.7	3.0	5.6
Wind electricity	1.4	2.9	5.9
Solar electricity	0.7	2.4	5.4
Other electricity	1.2	1.0	1.7

Source: model results.

Table 5.3 shows the changing nature of the electricity sector over time, both with and without any new policies to address climate change. Shares shown there are the shares of generation from *nuclear*, *hydro*, *solar*, *wind* and *other* electricity generation technologies. As there are some emissions from the *other* electricity generation technologies, we will refer to these as low-emissions sources of generation. Although there is a noticeable increase in generation from low-emissions sources in the absence of new policies, the difference with the current NDCs is marked. Of note is that there is very little emissions-intensive electricity generation in any of the three major emitters with strong emissions reduction targets (the USA, the EU and Japan) by 2030 with their current NDCs, which is roughly in line with what the IEA (2021d) is saying will be necessary in their "Net Zero by 2050" scenario. Although the low-emissions shares in those regions may seem high, it is worth noting that they are already higher in the USA and EU than in most regions due to the use of *nuclear* power. The same would be said of Japan if their *nuclear* reactors were not still mostly idle.

Figure 5.19 compares the rise in the use of *oil products* by *energy-intensive industries*, also shown in Figure 5.18, with their use of other energy commodities. Increases in the use of *coal* and *oil products* are larger than increases in the use of electricity. *Energy-intensive industries* are harder to electrify and decarbonisation efforts in other sectors make fossil fuels cheaper, resulting in greater use.

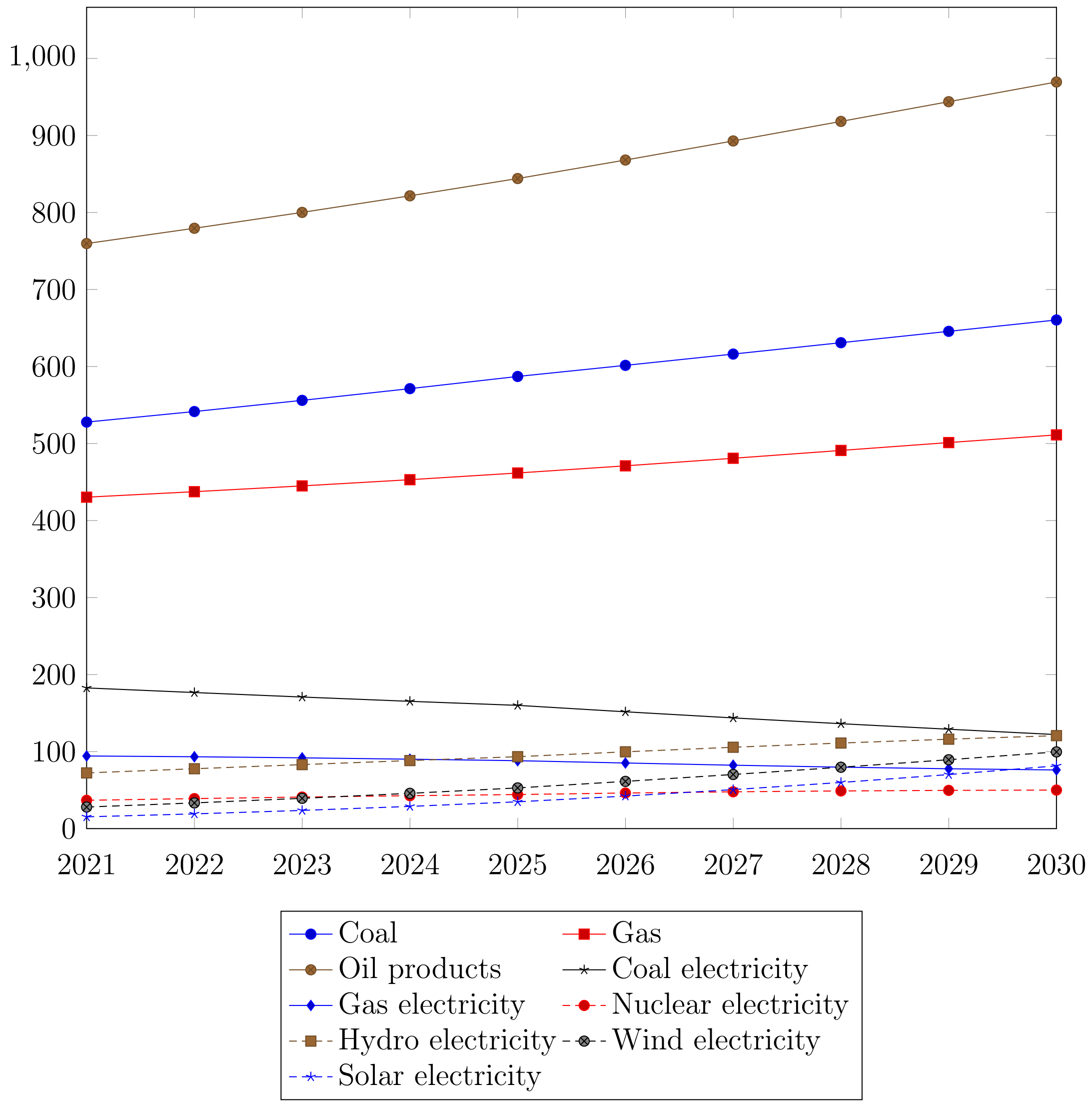
The rising use of *coal* by *energy-intensive industries* is not consistent across regions. As shown by Figure 5.20, there is a large amount of regional variation, with more ambitious NDCs resulting in reduced use.

Table 5.3: Electricity generation (TWh) and low-emissions shares (%)

	Generation			Share		
		2030			2030	
Region	**2019**	**Base**	**Policy**	**2019**	**Base**	**Policy**
China and Hong Kong	9057	13686	13214	27	34	70
United States	4515	5758	7743	37	53	97
European Union	3898	4300	5837	57	67	98
India	1624	3150	2989	23	28	35
Russia	2600	3271	3294	22	17	17
Japan	1051	1324	1578	28	34	93
Australia	264	302	353	20	42	90
Rest of Asia and the Pacific	2432	4004	3824	25	35	33
Rest of the Americas	2311	2952	3276	65	72	88
Oth. Europe and former USSR	1920	2489	2453	44	50	60
Middle East	1344	2037	2045	3	5	32
Africa	855	1322	1516	22	30	67
World	31870	44594	48121	34	40	69

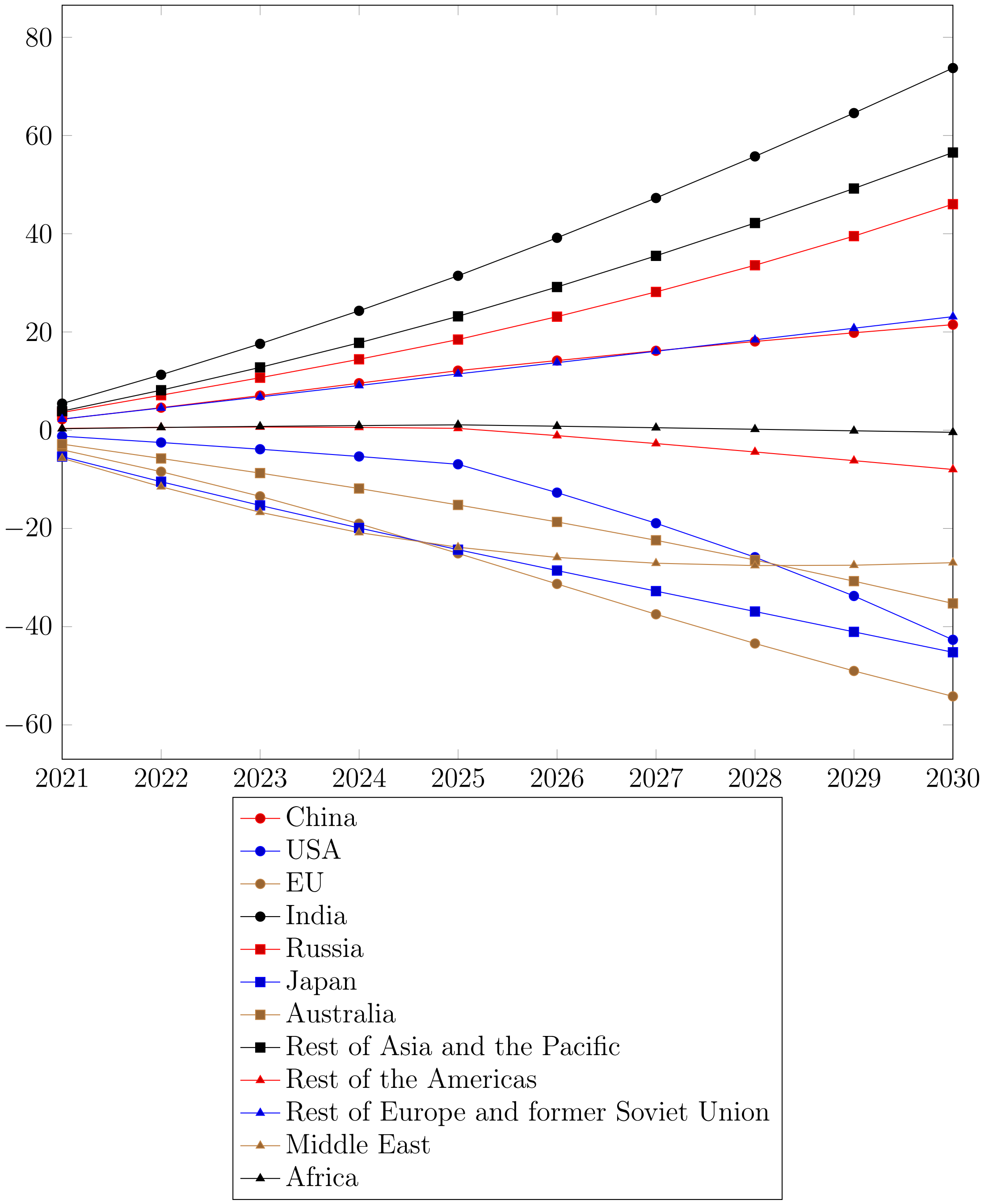
Sources: IEA (2021b) and model results.

Figure 5.19: TFC of energy by *energy-intensive industries* with NDCs (Mtoe)



Source: model results.

Figure 5.20: *Energy-intensive industries*’ *coal* use, cumulative change with NDCs (%)



Source: model results.

5.3 Policies targeting finance flows

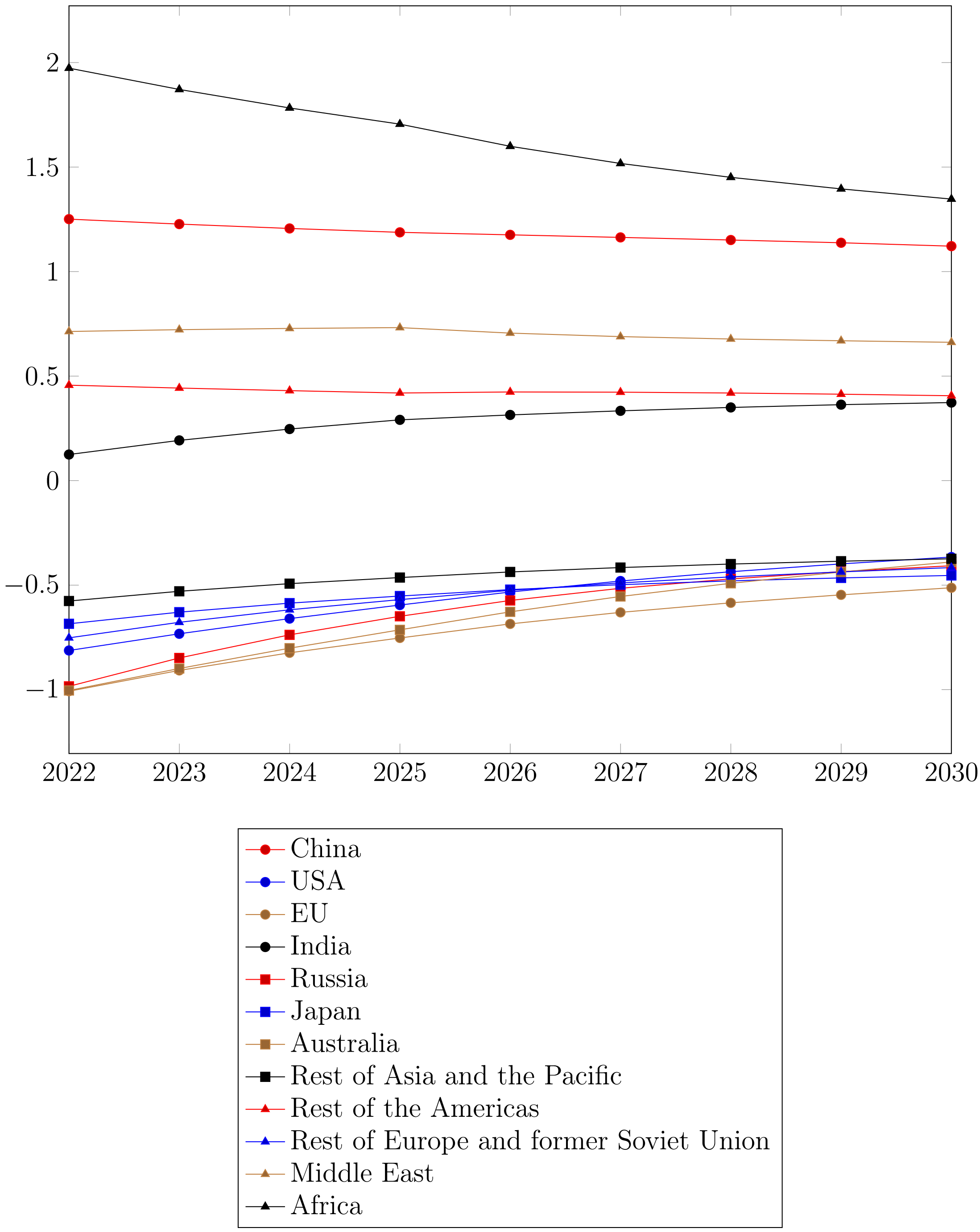
5.3.1 Climate finance

This section presents the results of the policy discussed in section 4.2.4.1, which, in summary, involves the distribution of 100 billion USD per year from developed to developing countries. Deviations are relative to the case with the NDCs, which was made the base case for this simulation. Figure 5.21 shows the deviations in total regional investment that are the result of exogenously imposing the investment calculated in Equation 4.24. Those regions with negative deviations did not receive climate finance and investment was endogenously determined.

As a result of this increase in investment in developing countries, there is an increase in output of wind electricity globally. As the cheapest form of zero-emissions electricity, it is the first choice for regions seeking to increase access to energy. However, as a capital-intensive industry, investment is the main constraint on its development. The additional investment in developing countries due to this policy results in increases in output of wind and solar electricity in Africa in particular, with deviations of over 1% by 2030.

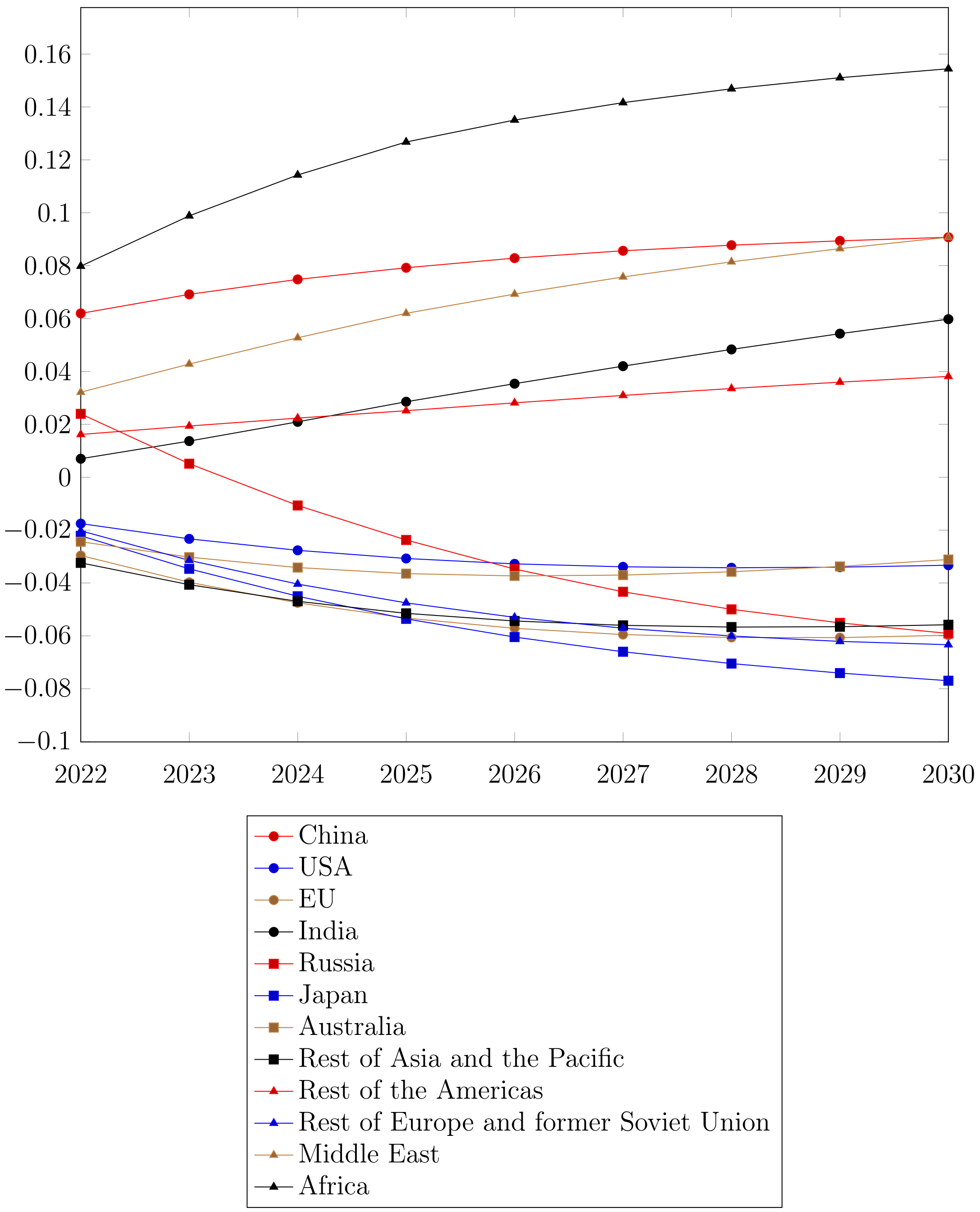
As shown in Figure 5.22, all regions that were not recipients of the additional financing saw their incomes decrease slightly in real terms. Russia's income increases in real terms in 2022 and 2023 because the average prices paid for consumption, government expenditure and the savings commodity decline by more than nominal income. This, in turn, is because those prices decline by more than the prices paid for Russia's exports, as shown in Table 5.4.

Figure 5.21: Deviation in real investment due to climate financing (%)



Source: model results.

Figure 5.22: Impact of climate financing on real regional income (%)



Source: model results.

Table 5.4: Deviations in selected variables for Russia due to climate financing (%)

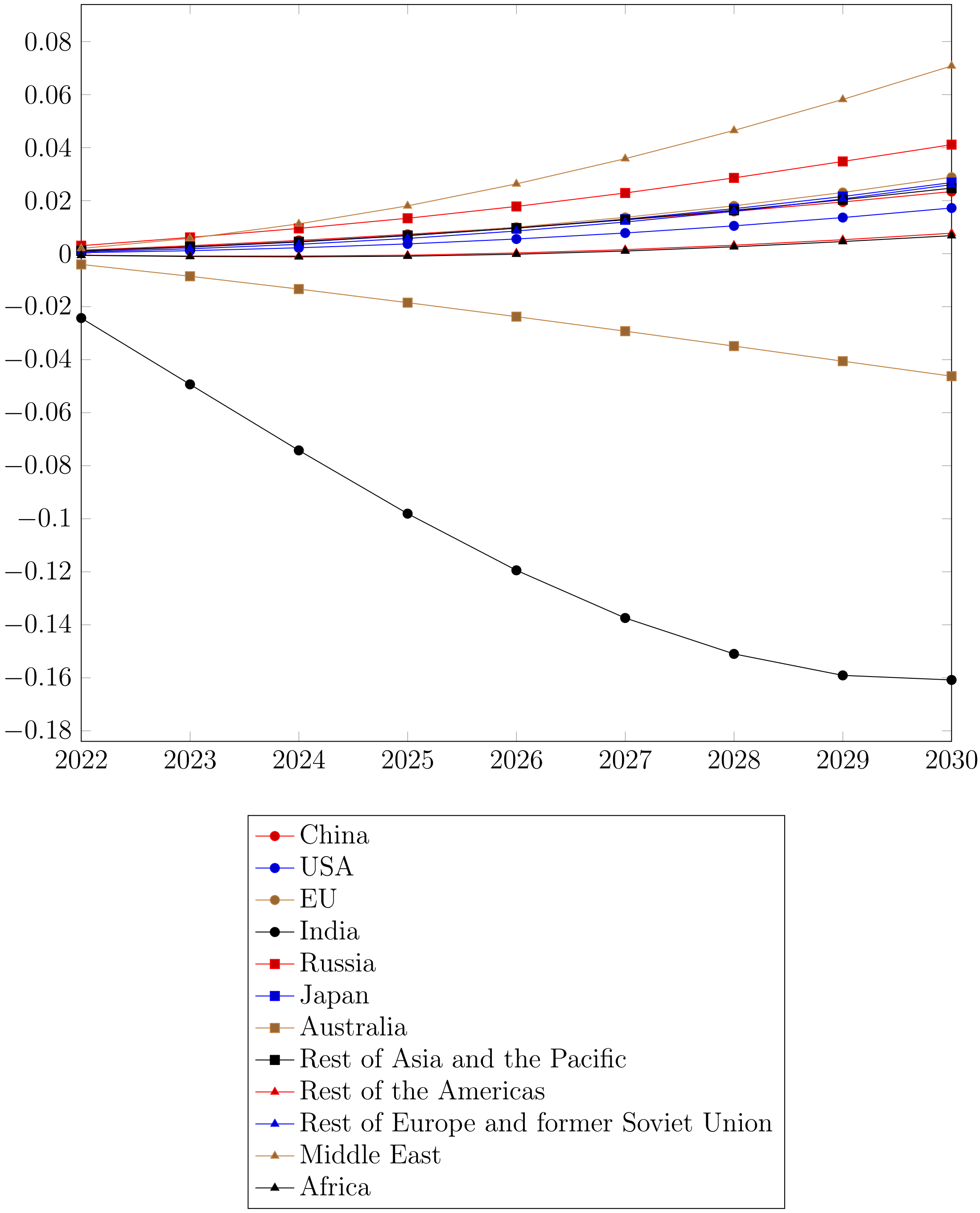
Variable	**2022**	**2023**
Nominal income	-0.063	-0.059
Prices	-0.087	-0.064
Export prices	-0.051	-0.037

Source: model results.

5.3.2 Fossil fuel subsidies

This section presents the results of the policy discussed in section 4.2.4.2. Figure 5.23 shows deviations in real regional incomes as a result of the removal of fossil fuel subsidies, compared to the case with the NDCs. Comparing Figure 5.23 to Figure 5.22, we see that the improvements in real regional incomes that can be achieved through the removal of fossil fuel subsidies are relatively modest, at least when compared to those resulting from $100 billion per year in additional investment. Conversely, in regions where real income declines, the declines are larger from the removal of fossil fuel subsidies than from the provision of climate financing. However, there are only two regions that do not benefit from the removal of fossil fuel subsidies: India and Australia. The regions that benefit the most are Russia and the Middle East, the two major fossil fuel producers. As the subsidies removed here comprise only a subset of what might be considered "subsidies", these results should be considered conservative. Impacts on income are in the same direction as those reported for welfare by Chepeliev et al. (2018) for regions that they reported results for, with the exception of India, where they reported positive impacts. Chepeliev and van der Mensbrugghe (2020) also report welfare declines in Russia as the result of the removal of fossil fuel subsidies, which is the opposite of the result here.

Figure 5.23: Impact of removal of fossil fuel subsidies on real regional income (%)



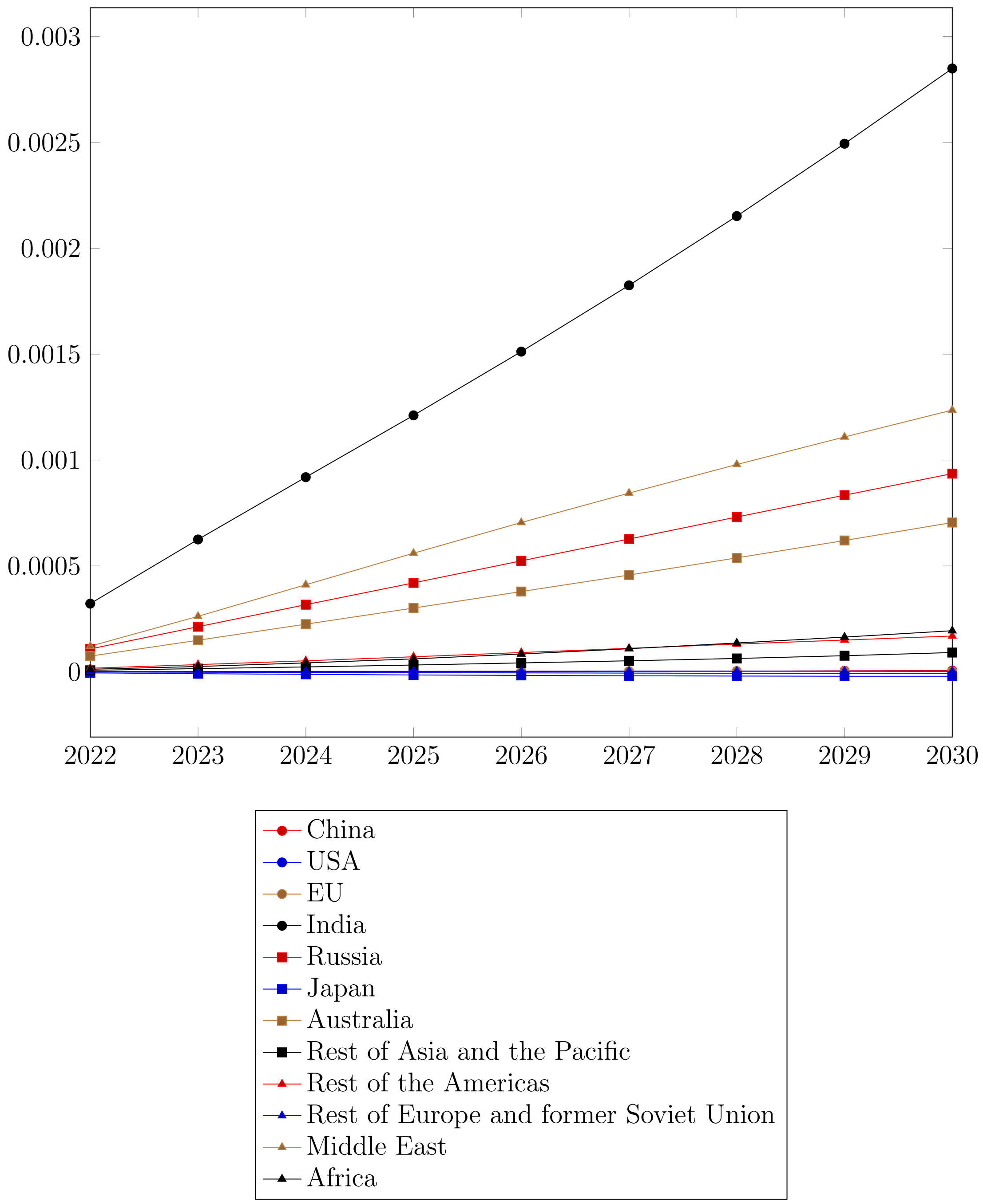
Source: model results.

The removal of fossil fuel subsidies has the effect of increasing the total amount of tax revenue retained for government expenditure. We can see this by looking at the deviations in the ratio of tax to income in the case due to the removal of the subsidies relative to the case with the NDCs, shown in Figure 5.24. Those deviations are of the variable del_ttaxr in GDyn-E (Golub, 2013).

Governments often use these subsidies to alleviate cost of living pressures on households. Their removal will therefore increase the cost of living and it is worth noting such increases can be met with resistance from the public. Consequently, in reality governments may choose to reduce other taxes such that the impact of the overall policy is revenue-neutral.

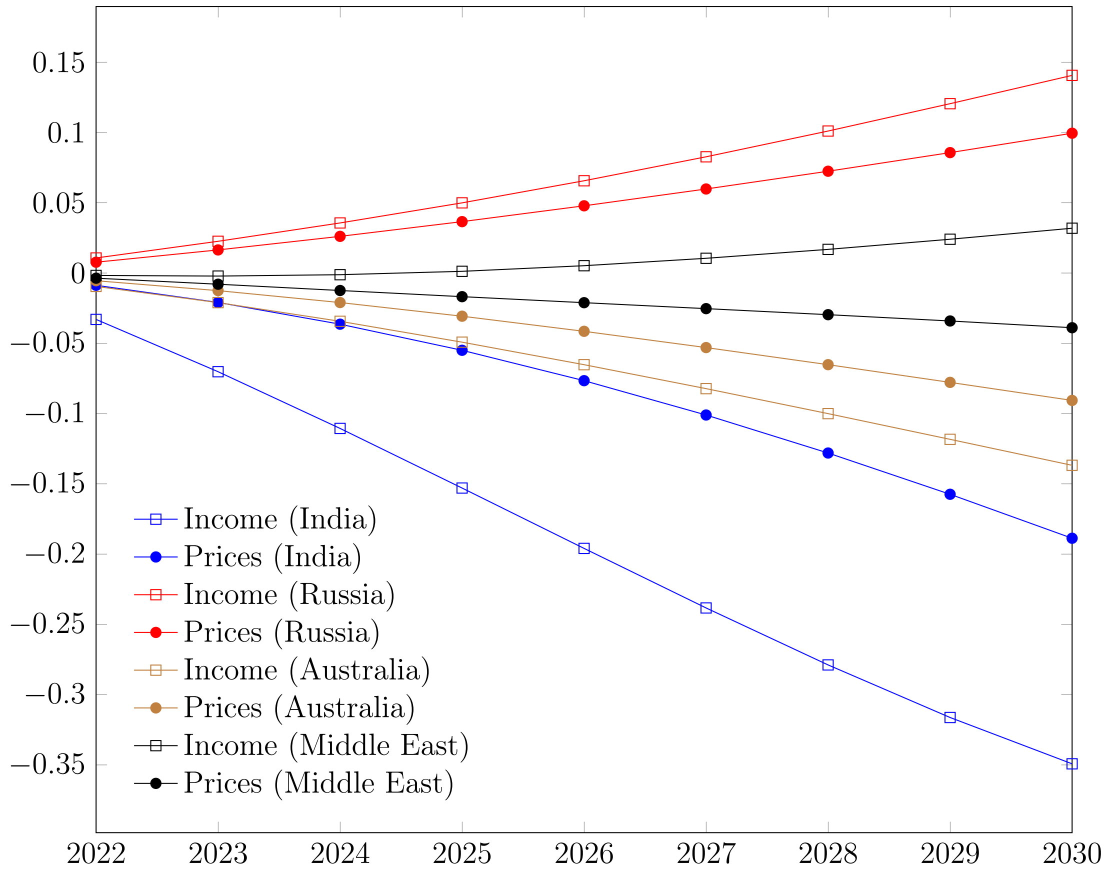
Looking at Figure 5.23 and Figure 5.24, we see that the regions where the tax to income ratio increases the most are the regions with the largest impacts on real income. We can see in Figure 5.25 how the components of real income change, relative to the case with the NDCs, in the two regions that benefit the most from the removal of subsidies and in the two regions that see their incomes decline. In three of the four cases, the largest impact is on income. In the Middle East, the fourth case, prices and income move in opposite directions, both contributing to an increase in real income.

Figure 5.24: Change in tax to income ratio due to removal of fossil fuel subsidies



Source: model results.

Figure 5.25: Deviation in income and prices as fossil fuel subsidies are removed (%)



Source: model results.

India provides significant subsidies for the use of electricity. As this simulation removed those from electricity generated by burning fossil fuels, the effect is similar to an emissions tax, but limited to the electricity sector. Shares of electricity generation in India change significantly as a result. The drop in output of emissions-intensive electricity generation as a result of the removal of these subsidies means that the economy-wide emissions price, already the lowest of any region due to the weak nature of India's NDC, is approximately a third of what it is with the NDCs when the subsidies remain in place. Other sectors then increase their output in response to this lower emissions price. However, the lower emissions price also results in less tax revenue, which isn't fully compensated for by the removal of the subsidies. In addition, factor income also falls, largely due to reduced labour income from the electricity sector. This reduction in income causes a relative decline in aggregate demand, in turn causing a reduction in prices, but the latter is insufficient to fully offset the reduction in income. Also of note is that the increase in electricity prices results in some substitution towards the use of fossil fuels by the household.

The removal of subsidies for emissions-intensive electricity generation sectors in India is also responsible for the decline in Australia's income. As shown in Table 5.5, exports of Australian *coal* to India decline significantly as a result of the removal of fossil fuel subsidies, resulting in less value added by the *coal* industry in Australia. To establish the impact of the removal of fossil fuel subsidies in Australia on Australia's income, an additional simulation was run. In that simulation, which only has fossil fuel subsidies removed in Australia, Australia's income increases slightly in real terms, though by less than the increases shown for other regions in Figure 5.23.

Table 5.5: Australia's *coal* sector in 2030 (billion USD, nominal)

	Current subsidies	**No fossil fuel subsidies**
Value added	16.2	14.9
Domestic sales	0.9	0.9
Exports	43.7	41.1
Exports to India	13.3	10.7

Source: model results.

In the Middle East, as in India, the emissions price declines when these subsidies are removed, as shown in Table 5.6. Consequently, there is less revenue from emissions pricing. There are also subsidies for electricity use for a number of sectors and the household, but no other fossil fuel subsidies. The removal of those subsidies causes a slight reduction in emissions from the three largest sources of electricity generation in the Middle East - from burning gas, crude oil and petroleum products.

Table 5.6: Emissions and emissions prices in the Middle East in 2030

	Emissions price (2017 USD)	**Electricity sector emissions ($MtCO_2$-e)**		
		Gas	**Oil**	**Oil products**
Current subsidies	95.33	267	189	315
No fossil fuel subsidies	92.49	266	185	306

Source: model results.

The emissions reductions shown in Table 5.6 create room within the Middle East's emissions quota to increase the output of other emissions-intensive industries. This flows through to an increase in income from the *services* industry in particular, as shown in Table 5.7. The largest user of *services* in the Middle East is the capital goods (investment) sector and investment in the Middle East increases by more than twice the largest change in any other region due to the removal of these subsidies, though still by less than 1%. This uplift in investment is driven by increased demand for capital by the sectors that fill the gap in the emissions quota left by the reduction in emissions from the electricity sectors.

Table 5.7: Economic activity in the Middle East in 2030 (billion USD, nominal)

	Current subsidies	**No fossil fuel subsidies**
Services sector value added	1821	1825
Investment	612	617

Source: model results.

Russia, in contrast to the regions discussed above, does not have a binding emissions target. The only subsidy of significance that it provides for fossil fuel use or production is for consumption of domestically produced *gas* by the household. Domestic *gas* consumption drops slightly as a result of the removal of that subsidy, while exports are relatively unchanged, as shown in Table 5.8.

Table 5.8: Russia's *gas* sector in 2030 (billion USD, nominal)

	Current subsidies	**No fossil fuel subsidies**
Value added	54.8	54.5
Domestic sales	126.8	126.3
Exports	12.9	12.9

Source: model results.

Output also drops in Russia's *coal* mining sector as the result of the removal of subsidies in other regions. In particular, exports of Russian *coal* to India are significantly lower in relative terms by 2030, due to the removal of subsidies for the use of *coal electricity* in India, discussed above. However, smaller relative changes in *coal* exports to regions that import more in absolute terms, most notably to China, Japan and the Rest of Asia and the Pacific, shown in Table 5.9, are responsible for more of the decline in Russia's *coal* production due to the removal of fossil fuel subsidies globally. The slight drop in factor income due to slightly reduced output by some sectors is more than offset by the size of the subsidy itself, the removal of which allows government spending to increase slightly.

Table 5.9: Russia's *coal* sector in 2030 (billion USD, nominal)

	Current subsidies	**No fossil fuel subsidies**
Value added	9.5	9.4
Domestic sales	14.4	14.4
Exports		
Total	14.9	14.6
To China	3.3	3.2
To Japan	0.78	0.76
To India	0.56	0.44
To rest of Asia and the Pacific	5.6	5.5

Source: model results.

Finally, of note is that in the two regions where emissions quotas are non-binding, we see diverging environmental outcomes. While emissions decline in Russia, they increase in the Rest of Asia and the Pacific. The overall effect is of a very slight increase in global emissions. This suggests that when removing fossil fuel subsidies in regions with binding emissions quotas, there is a possibility that it will exacerbate carbon leakage when there are regions where quotas are non-binding. However, in the simulation that had the removal of fossil fuel subsidies limited to Australia, the deviation in global emissions due to the removal of the subsidies was slightly negative, so the impact at a global level appears to depend on exactly what subsidies are removed and where.

Chapter 6

Closing remarks

Here I first discuss the relevance of the results of the modelling to the aims of the Paris Agreement. In the further work section I outline issues not covered by the modelling such as transitions in sectors other than electricity that will become more important after 2030.

6.1 Discussion

As shown in Figure 5.1, emissions reductions by 2030 are limited with NDCs as they stand. The results indicate that cumulative emissions of greenhouse gases from 2021 to 2030 will be over 430MtCO_2-e. That is between the SSP2-4.5 and SSP3-7.0 scenarios shown in Figure 1.1. Temperature rises in both those scenarios exceed 2°C, so although, when compared to the emissions trajectory in the absence of the NDCs, a flattening of the curve could be considered an achievement, it appears that the temperature goal of the Paris Agreement will not be met, based on the NDCs as they stand.

Where might we most likely see more ambitious emissions reductions? Figure 5.4

suggests perhaps we might expect India and countries in the Rest of Asia and the Pacific region to commit to more stringent targets, as their targets are currently so weak that they see their incomes increase as the result of global emissions reduction efforts. By 2030, those two regions combined will account for over 25% of global emissions, although on a per capita basis, only Africa will generate less emissions per capita than the Rest of Asia and the Pacific region.

India, in its updated NDC (Government of India, 2022), has committed to "achieve about 50 percent cumulative electric power installed capacity from non-fossil fuel-based energy resources by 2030". As shown in Table 5.3, in this modelling India is expected to reach 35% of electricity generated by low- and zero-emissions sources. 50% of "installed capacity" cannot be directly compared to 35% of generation. The difference between capacity and generation is accounted for by the capacity factor. The capacity factor for a facility is 100% if that facility is generating as much electricity as it can all the time. Conventional generation technologies usually have quite high capacity factors, whereas renewable technologies have lower capacity factors due largely to their reliance on weather conditions. Consequently, India could realistically have 50% of their installed generating capacity be in facilities that don't use fossil fuels but still have only 35% of their electricity be generated by those facilities. For example, in the month of October 2022, non-fossil fuel sources of generation comprised 42% of capacity (Central Electricity Authority, 2022a), but, in the six months ending September 2022, only 28% of electricity was generated from non-fossil fuel sources (Central Electricity Authority, 2022b,c). Additionally, India's means of achieving the 50% capacity target is dependent on climate financing, which, as discussed in Section 4.2.4.1, remains below levels committed to by developed countries. The updated NDC (Government of India, 2022) does not state what impacts any shortfall on the committed funding levels will have on this target.

Whilst on the topic of electricity generation, it is worth noting that the one thing that this work makes abundantly clear is that the cheapest way to decarbonise the global economy is to construct zero-emissions electricity generation facilities as quickly as possible. In the near term, governments should be focussing on policies that enable that construction, especially for overcoming non-market barriers such as community opposition, which are not represented here but would make the energy transition less efficient. Communities should be made aware, when objecting to such developments, that they will result in cheaper energy prices, which benefit everyone. Local communities, who might perceive negative externalities of such developments, may need to be compensated.

Back on the topic of where we might see more ambitious commitments to reduce emissions, Russia will account for 6% of global emissions by 2030 and, unlike India, will have the highest emissions per capita of all the regions modelled here. However, given the impacts of global emissions reduction efforts on their income reported in Section 5.1, it is perhaps unlikely that they will commit to a binding target.

Australia has the highest emissions per capita of all regions modelled until Russia finally overtakes it in 2028 after 8 years without a binding emissions reduction target. However, impacts on Australia's real income, in relative terms, are the worst of all Annex I regions other than Russia, so Australia may also be loathe to commit to more ambitious emissions reductions. Additionally, Australia's emissions reductions come at a cost per tonne higher than three of the other four regions shown in Figure 5.14. Although some of Australia's income is lost due to reductions in sales of *coal* (most notably), *oil* and *gas*, most impacts on Australia's income are caused by domestic emissions reductions.

Whilst looking at Figure 5.14, it is worth noting that the region with the smallest income losses per tonne of abated emissions is the USA, who also have the third highest emissions per capita in 2030 and are a high income country. If we also consider that the USA is responsible for the largest share of historical cumulative emissions to date (IPCC, 2022), it would be reasonable to suggest that the US should perhaps be even more ambitious with their emissions reductions.

As countries such as the US and Australia bring their per capita emissions into line with other regions, countries that have lower emissions per capita, but higher overall emissions, will cease to be able to use the fact that their per capita emissions are relatively low as a reason for weak targets. Although they may continue to use historically low emissions as a reason, that too will be a less viable option the longer their emissions remain elevated.

As discussed in Section 5.3.1, keeping promises for climate finance results in more electricity generation from wind and solar in developing countries. That will result in reduced emissions, so developed countries should not limit improvements to their ambition to reducing their own emissions.

Recent measures put in place to limit exports of Russian fossil fuels, in response to the war in the Ukraine, are unlikely to make a significant dent in their emissions. Although Russian *coal*, *oil*, *gas* and *oil products* sectors are responsible for approximately 19% of Russia's emissions, excluding household emissions, reductions in demands for exports do not necessarily flow through to reduction in output. What they do cause is a drop in prices, which, in the absence of a binding emissions reduction target, results in increased domestic use. With the NDCs as assessed in this work, export volumes of Russian fossil fuels fall by the following amounts by 2030, relative to the base (no NDCs) case:

- *Coal* - 18% lower
- *Oil* - 25% lower
- *Gas* - 49% lower
- *Oil products* - 10% lower

These results do not take into account the aforementioned recent sanctions on Russia. Although the sanctions will likely accelerate the changes shown above, they may also cause Russia to find new export destinations that might have less stringent NDCs.

Despite the reductions in export volumes listed above, the most affected of these sectors in Russia, in terms of output, is *coal*, which is 8% lower relative to the base case. The output of Russia's *oil* sector declines by a similar amount in relative terms. The output of Russia's *gas* sector declines by less than 3% and the *oil products* sector actually increases output slightly (by a bit more than 1%), again, relative to the base case. One way that it makes use of the relative abundance of domestic fossil fuels is by increasing the output of its *energy-intensive industries* by almost 20% and by generating more electricity from fossil fuels, especially coal - Russia's coal electricity sector increases output by 7% by 2030, relative to the no NDCs case.

There are probably limits to the extent that the Russian economy can make productive use of cheap fossil fuels - although the deviation in GDP, shown in Figure 5.10, is relatively small, the deviation in their income, shown in Figure 5.4, is more significant. As a result, foreign capital is required to make up for the decline in Russian savings. This sort of carbon leakage, via an investment channel, is one of the motivations for the development of GDyn-E (Golub, 2013). As the result of relative price drops driven by cheap fuel, exports of electricity generated by the burning of fossil fuels in Russia surge. In particular they more than double to the Rest of Europe and the former Soviet Union region. By 2030, Russian exports of energy-intensive commodities increase to all destinations relative to the no NDCs case, by almost 38% on average. Worthy of consideration are measures to limit imports of energy-intensive commodities and electricity from Russia. This brings us to the topic of Carbon Border Adjustment Mechanisms (CBAMs).

CBAMs are a way to address carbon leakage. They work by getting importers to pay for emissions generated in the production of the commodities they're importing if the source region has a lower emissions price than the importing region. Complicating matters are regional differences in the emissions-intensity of production, meaning the region implementing the mechanism needs information about the specific production processes of the exporting region to calculate the required payment. The only region to have passed legislation to implement them to date is the EU, where they will come into force in 2026. Chepeliev (2021) analysed the impact of a hypothetical EU CBAM on its trading partners, finding that the Ukraine would suffer the most significant negative impacts, with impacts on other regions limited to their exports of particular commodities, such as iron, steel, chemicals and electricity, to the EU.

6.2 Further work

The current model setup cannot dynamically incorporate the effects of the EU's CBAM. This represents an opportunity for improvement in the future. Other opportunities for improvement include:

- The incorporation of industry-specific Marginal Abatement Cost (MAC) curves;

and,

- The inclusion of nascent industries.

However, due to the relatively short time frame considered in this work and the emissions prices shown in Figure 5.7, the omission of these mechanisms for emissions reduction is unlikely to make a substantial impact on the results presented here. In the short term, the cheapest method to reduce emissions is by the conversion of the electricity sector to one based on technologies that do not produce emissions. However, in reality this transition is being driven by subsidies in most regions, not by pricing emissions. One alternative to the approach taken here is to allow the model to solve for the subsidies required to produce the emissions reductions that have been committed to. However, without the changes to the model mentioned above and discussed below, that would limit emissions reductions to energy commodities use, as the only means to decarbonise currently represented in the model is to increase the use of zero-emissions electricity in the place of emissions-intensive energy sources. Whether emissions are priced or zero-emissions alternatives are subsidised, the way that decarbonisation is achieved is effectively the same - the prices of the zero-emissions options end up being below those of the emissions-intensive ones. The approach used in this work, pricing emissions, was selected as being the most effective way of assessing the likely impacts of decarbonisation efforts given the available data and model structure. Pricing emissions allows for a homogenous approach to reducing emissions in the model, avoiding the complications of the much more detailed proposals in each country's NDC. It is for this reason that this work focussed on the emissions reduction commitments in the NDCs, rather than the much broader set of mitigation policies that they contain, which would have different economic effects.

Economic effects would also be different if co-benefits, such as improved health outcomes due to less pollution, had been accounted for. Similarly, the highly aggregated nature of the global economy in this modelling masks what would be highly differentiated effects on different countries within regional aggregates (for example those in Africa that do or don't export fossil fuels) and different household types within countries.

Another limitation of this work is that the significant changes to the electricity sector shown in the results are driven by prices - both the declining costs of generating electricity from renewable technologies and the increasing costs, as a result of emissions pricing, of emissions-intensive generation methods. Those prices do not account for issues such as barriers to development of renewable electricity generation facilities that include things like delays in obtaining permits due to local opposition to projects. Similarly, the model does not account for supply chain issues that might affect the process of decarbonisation, such as physical (as opposed to economic) limits on the production of minerals critical to battery manufacture. Additionally, the GTAP database and models do not have sector-specific capital, so this modelling assumes that, effectively, if the zero-emissions electricity sectors are willing to pay more for capital than the other sectors, the capital they require will be available. Should capital be made sector-specific, delays in the construction of generation facilities could be represented and the uptake of zero-emissions electricity could be slower.

The database construction process outlined in Chapter 3 began with the first pre-release version of version 11 of the GTAP Data Base, as that was what was available at the time the work was being undertaken. Subsequent developments in the database, prior to its official release, include updates to CO_2 emissions, energy data and energy subsidies.

6.2.1 Industry-specific MAC curves

With the current model structure, there are only two ways to reduce emissions: substitution away from emissions-intensive factor and energy commodity use; and reduction in output. For emissions related to the use of some factors, the ability of sectors to substitute away from emissions-intensive factor use in the model is limited. For emissions related to the output of a given industry, the only way to reduce emissions in the model is to reduce output. In these cases, incorporating MAC curves into the model would allow industries to become less emissions-intensive, at a cost.

The largest sources of emissions in most regions are the use of fossil fuels and so the lack of mechanisms to reduce emissions from other sources is not a major issue in most regions. However, in some regions, such as Africa and the Rest of the Americas, that is not the case, so estimates of economic impacts should be considered conservative in the absence of MAC curves for the emissions-intensive industries in those regions (most notably *grazed meat* in both regions, along with *water* in Africa). Methane emissions from agriculture, for example, come from a range of sources and mitigation options are source-specific. Smith et al. (2021) catalogued many of the sources and mitigation options in detail. What is common to the mitigation options is that they will add to industry costs, with the most obvious example of dietary additives to abate emissions from livestock raising the cost of production by the cost of the additives. These could be modelled as negative productivity shocks, which could be made either input-specific or generic, as relevant.

6.2.2 New industries

A vast number of new companies have been formed to make the most of the opportunities that the emissions-reduction challenge presents. Some are focussed on storing electricity generated during times when generation from renewable sources are high, such as through the use of batteries or pumped hydro energy storage. For heating, even simpler solutions are being developed (Eronen, 2017). Many companies are focussed on creating new fuels that either produce no emissions when burnt, such as hydrogen, or the emissions are offset during the production process, such as biofuels.

Hydrogen, in particular, has been the focus of considerable attention. The basic idea is that electricity can be used to create hydrogen from water. That hydrogen can then be burnt with no greenhouse gas emissions to produce energy. If the electricity used to produce the hydrogen is generated by a technology that does not produce emissions, then there are no emissions caused as a result of the use of hydrogen for energy. It can therefore, without producing emissions, fill the role of traditional energy commodities, as it can be compressed and transported in a similar way to natural gas. Furthermore, in steel manufacture, hydrogen can act as the reducing agent, allowing the production of liquid steel at costs that might, in Australia, be as little as US$55 per tonne more than those of traditional manufacturing methods, when considering the low end of the range of green steel costs and the high end of the range of traditional steel costs (Wang et al., 2022). That gap is likely to narrow, given that capital costs will decline (Bruce et al., 2018) and there is scope to dramatically improve the efficiency of production (Hodges et al., 2022). Biofuels can also fill the role of traditional energy commodities without producing emissions, because, if they are produced using agricultural commodities, those commodities remove carbon dioxide from the atmosphere as they grow, making the process carbon neutral. However, one advantage that hydrogen has over biofuels is that hydrogen is not reliant on agricultural land. Neither of these commodities currently appear in the GTAP database as energy commodities, but they can be split out from the sectors that their production is currently recorded in.

Other ventures are focussed simply on removing carbon dioxide from the atmosphere. A large number of countries have submitted NDCs that include negative emissions when Land Use, Land Use Change and Forestry (LULUCF) are taken into account. Where legislation permits, other countries can purchase these to offset emissions in their own country, rather than reducing their own emissions. This presents a potentially important source of revenue for the countries with potential for significant negative emissions from LULUCF. The model, as it currently stands, is incapable of representing this. However, modifying it to rectify that issue is a non-trivial exercise. Rates of carbon dioxide uptake by forests vary greatly depending on circumstances. Not only must the model be modified, but a great amount of data must be incorporated into the database to account for those circumstances. Pant (2010) proposed a framework for analysing the problem in a recursive-dynamic CGE model. However, he found that significant assumptions were required to facilitate the modelling and to extend the GTAP database for use with that framework. Those assumptions included the area of land used to provide offsets in the first year of simulations and that the rotation length of commercial plantation forests will remain constant. He described such assumptions as "extreme".

Finally, there are variations and combinations of these two broad categories (creating zero-emissions alternatives and removing emissions) of response to the emissions reduction challenge. There are a variety of other negative emissions technologies being developed that are not reliant on agricultural land. Some of these also produce fuel from the carbon dioxide they remove from the atmosphere. The absence of all these emissions reduction options from the model results in higher emissions prices than will occur in reality. Where the cost of removing a tonne of carbon dioxide from the atmosphere is cheaper than paying the price to emit one tonne of carbon dioxide equivalent of a greenhouse gas, it follows that any profit-maximising company will choose the former. The inclusion of these industries will therefore result in more realistic estimates of future emissions prices, as well as the consequential economic impacts. However, in the time frame considered here, the difference made by the inclusion of these industries is likely to be minor, as the emissions prices remain relatively low in most regions. Industries with harder to abate emissions, such as *energy-intensive industries*, *water transport* and *air transport*, will only be significantly affected beyond the horizon of this modelling. The new industries discussed in this section are the ones that will facilitate mitigation of these hard to abate emissions. Consequently, the omission of these new industries from the model will only cause the cost of mitigating emissions presented here to be slightly overestimated.

6.3 Conclusion

The focus of this thesis has been on the electricity sector, as that is where emissions reductions can be achieved at the lowest cost in the short term, due to reductions in the cost of generating electricity from the sun and wind over the decade from 2010 to 2020. This has been accounted for by disaggregating the electricity sector of the GTAP database. Attention has been paid to productivity gains in electricity generation technologies since 2014, with costs used to calculate electricity sector cost shares for renewable generation technologies being more accurate than those used in previous studies. The GDyn-E model has been adapted to use this additional data, as well as to account for a larger set of greenhouse gases.

The economic impacts of NDCs submitted to date are most significant in regions that are heavily reliant on fossil fuel exports for income. Impacts on the real incomes of regions with the most ambitious emissions reduction targets are relatively mild, with real incomes with the NDCs being between 0.7-1.1% lower than they are in the base case in the three most ambitious regions (the EU, USA and Japan). To some extent, this is due to reductions in income being offset by additional revenue that is captured by putting a price on emissions. As the economic impacts of climate change are expected to be considerably larger than the reductions in income due to emissions reduction efforts in the most ambitious regions, reducing emissions is good economic policy. At the sectoral level, impacts are mostly limited to changes in electricity generation. Total Final Consumption of most fossil fuels remains relatively unchanged or even increases slightly. This is due to a relative lack of ambition overall - although emissions are likely to peak this decade, they will only decline by approximately 0.3% over the period from 2021 to 2030.

Questions about opportunities for emissions reductions outside the electricity sector remain. How much can we expect the costs of negative emissions and alternative fuel technologies to decline by? Can regions, such as Africa, where some countries are proposing contributions of negative emissions due to enhanced storage in forests, use sales of offsets to claw back income from lost fossil fuel exports? These questions will be the subject of future investigations.

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