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Simulating the game-theoretic market equilibrium and contract-driven investment in global gas trade: How supply strategies, demand uncertainties, and trade relationships affect the long-term future

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Submitted for the degree of Doctor of Philosophy

Declaration

I hereby declare that the work presented in this thesis is a product of my own. Everything that is not my work has been appropriately referenced.

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Abstract

Understanding the gas market in the medium and long-term future facilitates political and economic debate on gas business development globally. Existing models commonly simulate the optimal scenario over long time periods, missing insights on how the gas trade business may evolve.

This thesis formulates a new model, Gas-GAME, in an agent-based framework, to study future gas market development and global trade scenarios. It combines a short-term game-theoretical market equilibrium, simulated via a Mixed Complementarity Problem, with the real-world contract-driven investment process in gas assets. The model captures: 1) price fluctuations resulting from investment cycles; and 2) how an individual player's strategy, perspective, and incentives affects the gas market.

Gas-GAME is applied to address the impacts of uncertain North American gas export strategies. An aggressive expansion benefits North America, but the Middle East and Australia see considerable revenue losses. Conversely, tight supply due to North American conservative expansion is observed, where Europe can become over-dependent on Russian supply.

Gas-GAME-Risk extends Gas-GAME by incorporating investors' risk. Its application to unexpected demand changes due to climate constraints shows how real-world investors shift their development focus facing uncertain markets. This work also presents the first systematic and quantitative analysis addressing the impacts of a China-US LNG trade tariff, showing a potential risk in Russian gas export.

Finally, the possibility of asset stranding of gas export facilities is addressed by Gas-GAME-Spot, which advances Gas-GAME by simulating how the theoretical market equilibrium is approached through contract commitment and spot trade. This study improves stranded asset analysis by examining how market signals affect investors' decision making. When markets see a sudden demand reduction, nearly 100 BCM/yr of North American and Australian export capacity will be stranded in 2035, due to their difficulty in competing in spot sales. The effective measures of stranding mitigation are also provided.

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List of publications

Journal publications

Guo Y, Hawkes A. Simulating the game-theoretic market equilibrium and contract-driven investment in global gas trade using an agent-based method. Energy. 2018;160:820-34.

Guo Y, Hawkes A. The impact of demand uncertainties and China-US natural gas tariff on global gas trade. Energy. 2019;175:205-17.

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Conference publications

Guo Y, Hawkes A. Stranded assets caused by near-sighted gas investments during the low-carbon energy system transition. In: 41st International Association for Energy Economics (IAEE) International Conference, 10-13 June 2018, Groningen, Netherlands.

Guo Y, Hawkes A. Global natural gas trade with alternative price expectation and development scenarios. In: 37th International Energy Workshop (IEW), 19-21 June 2018, Gothenburg, Sweden

Guo Y, Hawkes A. Gas export asset stranding: a systematic agent-based simulation. In: 38th International Energy Workshop (IEW), 3-5 June 2019, Paris, France

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Chapter 1. Introduction

This chapter explains the background of this study. The key features of global gas trade are explained, followed by the issues identified in the future gas market. These issues cover different aspects of the gas business, including supply, demand, and trade relationships. A brief overview of the thesis is presented in Section 1.3, and the structure of this thesis is presented in Section 1.4. The research objectives are explained in Chapter 2 in more details, after the literature gaps are identified.

1.1 Global natural gas trade

Natural gas is a mixture of hydrocarbon gases, of which the major component is methane. It also contains a small portion of other higher alkanes like ethane, propane, butane, and some inerts [1]. As shown in Fig. 1 - 1, natural gas contributed to 20% of global primary energy consumption in 2000, and the percentage grew gradually to around 25% in 2018 [2]. According to the US Environmental Protection Agency (EPA), the amount of CO_2 generated during natural gas combustion for one million British thermal units (MMBtu) energy output is around 53 kg [3]. This is approximately half of the amount produced by coal (more than 90 kg), and is much less than oil products (diesel 73 kg and gasoline 71 kg). Hence, natural gas has a crucial role in climate change mitigation and global energy transition.

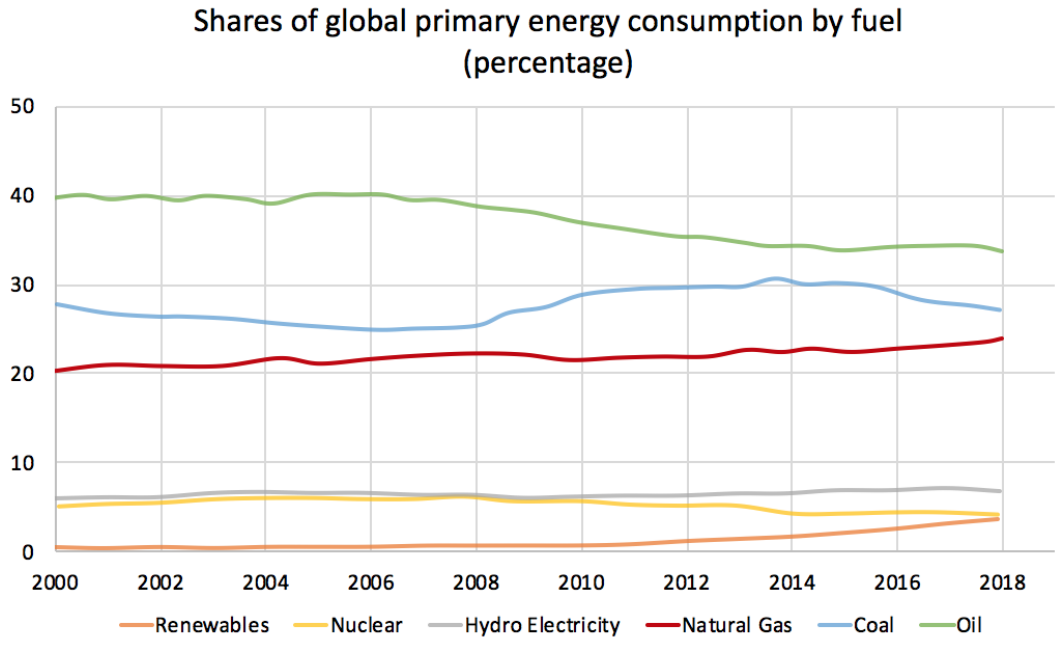


Fig. 1 - 1. Shares of global primary energy consumption [2]

As shown in Table 1- 1, Asia Pacific and Europe are two major gas consumption regions, accounting for 22% and 14% of the global total amount in 2018. However, their domestic production, 16% and 6% of the global amount respectively, is insufficient to satisfy their demand. A considerable amount of the gas consumed in Asia Pacific and Europe is imported. In contrast, the Middle East and

the Commonwealth of Independent States (CIS) own nearly two thirds of the total proved natural gas reserves (see Fig. 1 - 2). Their production accounts for 40% of the global total, and around a quarter of that is sold to other regions. There is no doubt that global trade and transmission plays a significant role in balancing the natural gas supply and demand. The total international trade volumes in each year since 2010, and a steady growth can be seen in Fig. 1 - 3.

Table 1- 1: Shares of natural gas production and consumption in different regions globally [2]

	Europe	**Asia Pacific**	**CIS**	**Middle East**	**Africa**	**North America**	**South & Central America**
Production	6%	16%	21%	18%	6%	27%	5%
Consumption	14%	21%	15%	14%	4%	27%	4%

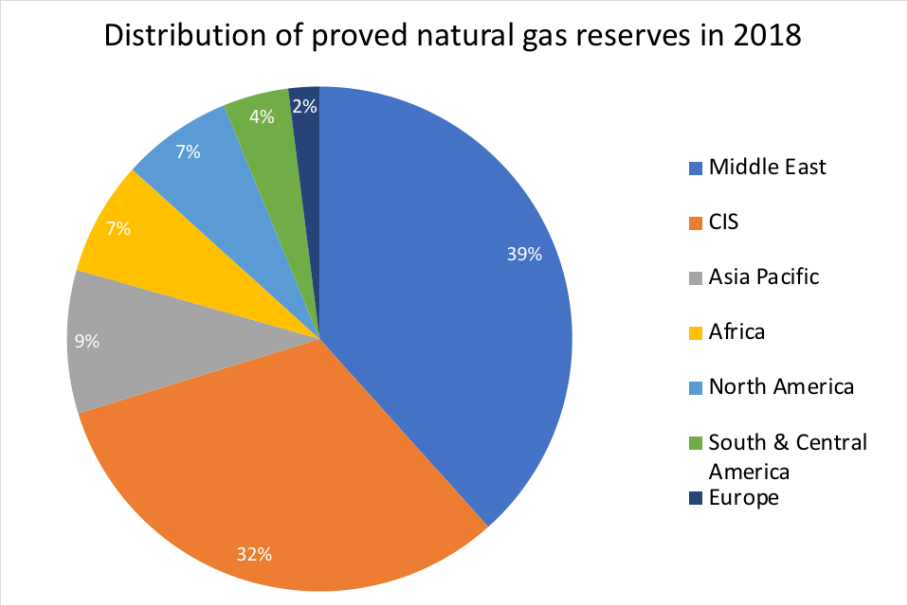


Fig. 1 - 2. Shares of global natural gas reserves in different regions [2]

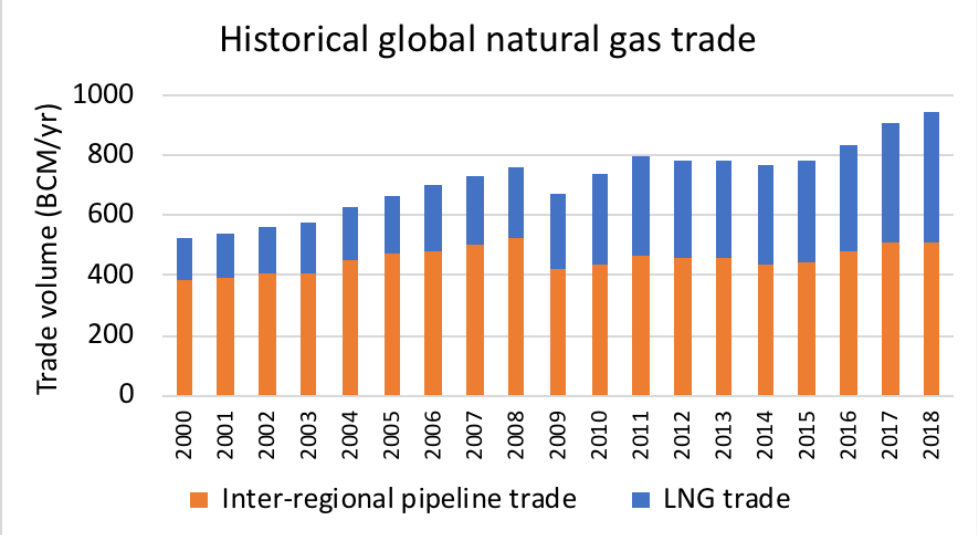


Fig. 1 - 3. Global natural gas trade volumes between 2000 and 2018 [2]

There are two major ways that the natural gas is transmitted between countries and continents; through pipelines and as Liquified Natural Gas (LNG) cargoes. To transmit thorough pipelines, after the pre-processing, natural gas is pumped into the pipeline network through compressor stations. Usually, the compressor stations are located along the entire length of a pipeline in order to maintain a continuous and steady flow of gas. Through the manipulation of compressor stations, the flow rates of gas transmission can be controlled. Every year, around 400 – 500 Billion Cubic Meter (BCM) of natural gas is transmitted via inter-regional pipelines. Around half of this amount is between Russia and Europe, and the Chinese imports from CIS also account for nearly 10%. The remaining amount is mainly between the US and other North American countries, and between Russia and other CIS countries. Pipeline transmission has stayed relatively steady in the past two decades (see Fig. 1 - 3). In contrast, transmission through LNG cargoes has seen a significant increase from 140 BCM/yr in 2000 to 431 BCM/yr in 2018.

Global trade movement as LNG involves three major steps. Firstly, the produced natural gas is liquefied by the compression and heat exchange (cooling to -160 °C) processes; this process takes place in liquefaction plants near export terminals. The volume of natural gas reduces by six hundred times, and the liquefied gas is then stored in double-walled tanks until being loaded on board [4]. Shipping is the second step, and LNG is transported to destinations through canals and oceans. LNG tankers are usually designed with double hulls, and LNG is kept in the inner tanks with an insulation system to keep the temperature at -160 °C [4, 5]. The third step is regasification. When the tankers arrive at import terminals, LNG is discharged into regasification plants, where the liquid gas is vaporised through a warming process [4]. The gas is then transmitted to the consumption sites through pipelines. Most regasification facilities are located onshore, close to densely populated industrial areas. As the safety and security concerns arise in local communities, offshore LNG regasification terminals are constructed. Among all the solutions of offshore regasification, floating storage and regasification units (FSRUs), which install the regasifiers on the deck of ships, are becoming cost-effective [6].

In general, the global gas market is comprised of different regional markets which were historically segregated due to the lack of transoceanic shipping. These regional markets have different levels of domestic production, and often import from a small number of large exporters. The number of natural gas exporters is limited as there are only several regions with abundant natural gas resources (see Fig. 1 - 2). Besides, some of these regions, for example Russia, export via only one state-owned company. Hence, the market structure of most regional natural gas markets, except for the US, is commonly characterised as oligopoly [7, 8].

Nash-Cournot equilibrium is one of the typical models to describe an oligopolistic market and has been widely used to represent the trade condition in natural gas markets by a great number of studies (examples described in Literature review). The equilibrium represents the market condition that none of the suppliers can gain more profit via a unilateral change in supply volumes, given that the other suppliers remain unchanged. It has the fundamental characteristic of a Nash equilibrium in game theory [9]. Additionally, natural gas markets fit the model of Cournot competition, which assumes that firms decide independently (*i.e.* non-cooperatively) and simultaneously on their optimal supply quantities so as to affect the product prices in oligopolistic competition. The reason why Bertrand competition, as compared to Cournot competition, does not suit gas markets is that it assumes firms compete on prices as they all have a constant production cost subject to any demand quantities. Such an assumption only applies when capacity changes are possible at low cost and can easily be achieved [10].

Another important feature in global gas trade is long-term contracts. The suppliers require long-term buyers to mitigate investment risks, primarily because the production and transmission projects are highly capital intensive [11]. A new project can get Final Investment Decision (FID) only if most of its production volumes are contracted with one or several buyers. Buyers also favour long-term contracts for a stable gas supply [12], as this contributes a crucial part of national energy security. The contracts, sometimes also referred as Sale and Purchase Agreement (SPA), incorporates provisions governing pricing, volume commitments, shipping arrangements (for LNG only), payment terms, scheduling, and other related aspects. Take-or-Pay provisions are commonly included in the contracts, obliging buyers to lift a specified volume of gas each year or pay for the shortfall [4].

Besides the contracts, gas is also traded via spot markets. Spot natural gas is bought and sold for delivery usually within 30 days [13]. There are mainly two sources of spot supply. Firstly, production and transmission capacities underpinned by long-term contracts may reserve some extra volumes uncontracted. These volumes will be sold to grab the potentially higher profits in the spot markets. Secondly, the contracted buyers have options to delay or change their delivery schedule based on their actual demand. As storing natural gas for a long period is usually costly, the resulting extra capacities will be sold on a spot basis. Spot demand, on the other hand, usually comes from the buyers who have not contracted enough for their gas consumption, especially in the peak seasons. In general, spot trades via inter-regional pipelines are less common than via LNG. The pipelines have specific limitations on the transmission capacities between sources and destinations. Hence, the spot markets are more likely to develop in a region with numerous pipeline interconnections. In contrast, LNG tankers can deliver gas to any destinations, and therefore balance the supply and demand with more flexibility. The spot and short-term trade accounts for around 30% of total LNG trade in 2018, and is becoming increasingly important [14].

1.2 Key issues in the future gas market

There is not a single scenario of future global gas trade and transmission, because of uncertainties in a variety of factors. Fundamentally, these issues can be categorised into three aspects, namely supply, trade (geopolitical) relationship, and demand. In each aspect, one major uncertain issue is identified and explained.

1.2.1 Uncertain North American gas export

Gas supply in long-term highly depends on the investment in the gas industry. Economically, future technological innovation and resource discoveries may lead to significant changes in natural gas production and transmission costs, thereby affecting the amount of gas available for domestic consumption and exports. Besides, natural gas exporters may have their own strategies on when and where to commercialise their resources. Among all exporting regions, North America is one of the most uncertain supply sources. For the US particularly, projections from the Energy Information Administration (EIA) indicate that the US could become a significant LNG exporter [15]. At the time of writing, several LNG projects have already begun in Sabine Pass in Texas [16]. Yet uncertainty remains regarding whether this trend can continue, and how the US will proceed with natural gas export, and the main reasons are:

1) The suggestion of over-optimistic estimation on technically recoverable resources [17]. The underlying reserve assessment, especially for unconventional natural gas resources, is primarily based on extrapolation from production history. Such historical production data may be unrepresentative of the actual development conditions.
2) Australia, Qatar, Russia, ASEAN countries and several African countries are all investing heavily in natural gas [16]. The potential global gas oversupply, combined with recent oil price drops, may reduce the economic prospects of US LNG projects.
3) The approvals by US Federal Energy Regulatory Commission and public acceptance of hydraulic fracturing may impede the US LNG development.

1.2.2 Uncertain China-US LNG tariff

Since natural gas is a crucial primary energy source, it has a considerable impact on the economies of both importing and exporting countries. The trade of this commodity therefore involves many geopolitical factors. Unstable and uncertain relationships between importing, exporting, and transit regions may significantly affect the future trade decisions. The trading relationship between China and the US became strained in 2018. Alongside this, China may account for a third of global demand growth in the near term [18]. A significant amount of gas needs to be imported via both pipelines and

LNG to satisfy this rapidly growing demand. The US has always been considered as an important LNG supplier to China. However, in August 2018, China stated a potential 25% tariff on the US LNG [19]. This tariff has been changed to 10% and set effective from September 2018. In June 2019, the level is raised to 25% again [20]. Such a tariff will significantly change the natural gas trade between the US and China, and may lead to considerable impacts to other exporters and markets.

1.2.3 Uncertain global natural gas demand

The uncertainties in future natural gas demand are partially attributed to the perception that gas may be a transition fuel [21]. Since gas combustion emits less CO_2 compared to other fossil fuels when generating the same amount of energy [22], in the short term, its demand may escalate to replace coal in many countries to help reach their medium-term climate mitigation targets [18]. However, in the long term, and in the absence of Carbon Capture and Storage (CCS), fossil fuels may be replaced by renewable and nuclear generation to achieve climate targets. Since it is uncertain how and when the energy transition towards a low-carbon economy may happen, future gas demand can vary significantly depending on the pathway of decarbonisation, renewable technology deployment, energy efficiency improvement, and climate legislation.

1.2.4 Asset stranding in natural gas export facilities

The uncertainties in gas demand not only affect future gas trade, but also lead to a threat to the investment in this industry. If demand decreases unexpectedly, many production and transmission projects will no longer earn an economic return prior to the end of their economic life. These investments are defined as stranded assets [23].

The issue of stranded assets in the energy industry rises as a result of climate change mitigation. The Paris agreement has been ratified by most countries with the intention to limit the temperature rise to 2 °C above pre-industrial levels [24]. A global carbon budget of 870 - 1240 Gt CO_2 emission between 2011 and 2050 is therefore suggested [25]. This budget imposes profound limits on the future utilisation of fossil fuels, and around 80% of current coal reserves, 50% of oil, and 30% of gas may never be used [26]. The unburnable carbon may lead to devaluation of listed equities of global fossil fuel producers as their values are based on the commercialisation of their reserves. Many banks, rating agencies, and energy agencies have recognised this risk, and the issue of stranded assets has risen considerably on their agenda [27].

Huge investment has been directed at new gas supplies, and many projects are in the process of obtaining FIDs [28]. These supply infrastructures have lifetimes of over 30 years [29], whereas the gas demand in this period is highly uncertain. Therefore, the potential stranding of the newly developed

and upcoming infrastructures poses significant risks to the returns on these investments. Among the gas supply infrastructures, production and transmission (*i.e.* pipelines, liquefaction plants, and regasification plants) infrastructures are highly capital-intensive. For example, the investment in a production and liquefaction facility development for the Ichthy LNG project in Australia is over US$ 30 billion [30]. Even without highlighting specific assets, it is clear that stranding at such scale could cause a profound impact on economies.

1.3 Research description

It is crucial to understand how global gas trade may look like in the long-term future. Several application aspects that benefit from the understanding are listed below:

- Identify the changes in global trade dynamics

  Historically, natural gas markets have been separated by oceans, and most trades are through pipelines. Increasing LNG trades have been observed. It is worth investigating the respective shares of pipeline and LNG trade in future, which can provide insights on the liquidity of the global gas market. Moreover, the dominant exporters like the Middle East and Russia are facing increasing competition with new suppliers like Australia and North America. Simulating how much each supplier may sell in different import markets helps to address energy security and economic debates around the natural gas business.

- Inform other energy scenario simulation

  Many energy outlooks make simplified assumptions on fossil fuel prices. A detailed simulation of global gas trade can provide better information regarding future gas market conditions and prices, and therefore helps refine the input of other energy systems models.

- Identify the potential risk in the gas industry

  The uncertainties in future global gas trade lead to risks in the multi-billion investment in the gas industry. The simulation helps exporters to identify how much of their export will be affected if the market demand changes. Besides, the simulation also provides insights into how unstable geopolitical relationships may affect the gas prices and market supply security.

- Provide policy insights on decarbonisation pathways and gas business regulations

  The role of natural gas in the decarbonisation pathway can be clarified through simulation. For example, whether a surging gas consumption will lead to tight supply and increasing prices can be addressed by the simulated future gas trade scenarios. By understanding the scenarios, governments of the import countries have better information when deciding their energy policies. Besides, gas trade contributes to a significant share of the economies in many exporting countries. The governments of these countries can use the simulation results to

understand the profitability and risks in their gas export business. Regulations to ensure a stable economic development can therefore be better informed.

This research simulates the global gas trade scenarios in the long-term future, with a time horizon until 2060. A new global gas trade model, named as Gas-GAME, is developed with an agent-based framework. The model has each of the players (*i.e.* exporting regions and importing regions) in the gas market represented to understand the reasoning of their strategies. Moreover, market power, which is crucial in global gas trade, is simulated using the Mixed Complementarity Problem approach. The resulting trade scenario represents a Nash-Cournot market equilibrium. The bilateral contracting process, which influences gas market development significantly, is explicitly modelled. Both import requests and export profitability are taken into account. The endogenously simulated contracts are used to inform production and transmission capacity expansion. A further assumption is that investors make expansion decisions based on existing knowledge and their own perspectives of the future market, instead of perfect information as per many models. Gas-GAME is the first global natural gas model in which such features are combined.

The model is applied to study the four key issues discussed in section 1.2. Firstly, how the uncertain North American export strategy would affect future global gas trade is analysed with Gas-GAME. This illustrates how Gas-GAME can be used to address supply-side uncertainties. Then, regarding the issues of global gas demand uncertainty and the China-US LNG tariff, Gas-GAME-Risk, which advances Gas-GAME by allowing investors to evaluate the alternative demand scenarios in their decision making, is applied. This part of the thesis illustrates how the model can address demand-side and trade relationship uncertainties. Besides, the scale and possibility of potential asset stranding of gas export facilities are studied. To more accurately represent the gas trading mechanism, Gas-GAME-Spot is developed and applied. It extends the Nash-Cournot market equilibrium represented in Gas-GAME, and explicitly simulates how the theoretical equilibrium is approached through contract commitment and spot trade. This work illustrates how the model can address investment-related issues and highlights the advantage of the imperfect foresight assumption.

Regarding the export capacity stranding issue, a sensitivity analysis is also conducted. The analysis focuses on how the alternative actions by the players in global gas trade will affect the stranding outcomes. Policy insights on how to alleviate the stranding risks are provided.

1.4 Thesis structure

The thesis is structured in the following way:

Chapter 1 provides a general introduction of global natural gas trade. The crucial features of the gas market are explained, followed by the key issues which may affect the gas trade dynamics. In this chapter, the modelling method innovation and model applications are briefly introduced.

Chapter 2 provides a literature review of gas trade analysis. For each of the issues identified in Chapter 1, the existing works, including their research methods and conclusions, are firstly reviewed. Then, the existing models which can simulate future trade scenarios are reviewed, and their weakness identified. The chapter concludes with detailed research objectives in both modelling method development and gas market analysis.

Chapter 3 explains the models developed in this thesis. The formulation of Gas-GAME model, which has a two-module structure, is presented first. The second part of this chapter explains how Gas-GAME-Risk varies from Gas-GAME by allowing supply investors to consider market demand risks. The third part describes the Gas-GAME-Spot model in more details. The additional module which simulates contract-based and spot trade explicitly is explained.

Chapter 4 presents the study on the supply-side issue, which is uncertain North American exporting strategies. The input parameters and assumptions used in Gas-GAME are described first. Then, the base case result is presented and validated. Two alternative cases representing conservative and aggressive North American LNG expansion strategies are examined by comparing with the base case. How the alternative strategies may affect gas market prices and other exporters is discussed.

Chapter 5 presents the study on the uncertain demand and China-US LNG tariff issues. This study applies Gas-GAME-Risk, and the changes in input parameters and assumptions are explained. The discussion firstly illustrates how two different demand scenarios would affect the global trade condition. Then, the impacts of the tariff in both demand scenarios are examined.

Chapter 6 presents the study on asset stranding of gas export facilities. This study applies Gas-GAME-Spot, and how the parameters are updated is explained first. The results show the magnitude of future investments in gas production and transmission capacities. To what extent stranding may occur to these infrastructures is examined. Besides, when the market a face sudden demand decrease, how the scenario may change is also discussed.

Chapter 7 presents a sensitivity analysis on the stranding outcome in the low-demand scenario in Chapter 6. The analysis focuses on five key parameters related to contract structure, supply investor strategy, and demand market strategy. It examines how global export capacity development, trade, and stranding condition are affected by the variation of these parameters. Insights on the effective measures to alleviate regional asset stranding are provided.

Chapter 8 summarises the main innovations and contributions of this thesis. The key insights from individual studies are presented. The chapter concludes with the limitations of this work and future research directions.

Chapter 2. Literature review

This chapter provides a literature review focusing on several aspects. Firstly, the review focuses on the existing works which have addressed the above-mentioned key issues in future gas markets. Both analytical methods and conclusions are discussed, and the literature gaps are identified. Secondly, the modelling methods which can be applied to analyse natural gas markets are reviewed. The existing models are categorised, and the advantages and disadvantages of each category are analysed. Furthermore, the approaches which address uncertainties are reviewed. Based on the review, the research objectives are set and described in details in Section 2.4, explaining both the general objectives of modelling method development and the specific objectives of model applications on the key issues in gas markets.

2.1 Review on gas market analysis

This section presents a review, from the topic perspective, on the studies which discuss how the key issues introduced in Chapter 1 may influence future global gas trade. The review begins by appraising the studies on the supply-side issue of North American gas exports, followed by those focusing on the demand-side market uncertainties and trade relationships. The works addressing stranded asset issues are also discussed in the following Section 2.2.

2.1.1 Analysis on North American LNG supply uncertainties

This section reviews the studies which discuss how supply-side uncertainties will affect future global gas trade. The studies which focus on the uncertain supply from North America are reviewed. Their approaches and conclusions are compared in Table 2- 1, and the literature gap is then discussed.

There are a series of working papers published by Oxford Institute for Energy Studies (OIES) focusing on the changing future of global and regional gas markets. Rogers [31] examined how the uncertainties in American gas production would affect the globalisation of gas market. Further impacts on near-future European gas imports and the pricing structures were also analysed. Four scenarios are simulated, which represent two cases of low/high US production and two cases of low/high Asian demand. The simulation is based on a supply-demand balancing approach with a series of assumptions on how global LNG supply flows to different markets in a pre-defined order. Niche markets like the Dominican republic and South America are satisfied first, followed by Asian markets. The remaining LNG supply is then used to balance North American inventory level and European gas demand.

Another study, by Henderson [32], deepened the above analysis with an assessment of the investment intentions of North American liquefaction projects. The locations, connected reserves, capital costs, and target markets of these projects are evaluated. Based on the evaluation, how likely

each project may be sanctioned and what risks it may face are discussed. Besides the commercial aspect, the author also addressed the political debate over these LNG projects. Finally, the impacts of North American LNG exports in the global gas market are examined. The author studied the elasticities of supply in both the US domestic and other foreign markets. The supply costs to Asia from the North American projects are estimated and compared with other Asian supply sources. The result suggests that North American LNG exports to Asia will push down the high-cost supplies there, and the oil-link LNG contracts will be challenged.

Medlock *et al.* [33] studied the impact if North America-sourced LNG being pushed into the market, using the global gas model BIWGM [34] (referred as RWGTM in the publication). They simulated a scenario in which buyers contract twice the North American LNG import as compared to the base case. The result suggests a decrease in Asian spot gas price and an increase in US domestic price. However, the increasing North American supply does not yield energy security benefits for the European and Asian markets. These markets require further liberalisation to achieve a broader diversification of their supplies.

Moryadee et al. [35] investigated the same issue by applying another global gas model WGM [8]. Besides the base case in which only contracted US LNG will be exported, two alternative scenarios representing medium and high US LNG exports are analysed. The increasing exports lead to an increase in US domestic price by \$0.7 - \$1.53/MMBtu during the period 2020 to 2040. Globally, the production of other exporters, including the Middle East, the Former Soviet Union, and Africa, sees a decrease due to the introduction of US LNG. In addition, Asia-Pacific, Europe, and China exhibit an increase in consumption, and lower prices are observed in these markets.

As shown in Table 2- 1, the studies take different approaches to address the impacts of North American LNG exports. Henderson [32] applies the relative elasticity theory to derive the impacts on domestic and international gas prices. However, the author's estimation on the reaction of other exporters is purely based on existing facts and logic, and there lacks a simulation support. The analysis by Rogers [31] depends on a fixed market structure abstracted from existing global gas trade conditions. Explicit assumptions on the pricing mechanisms and European pipeline supplies are made. Such an approach is applicable to a steady market. However, since the time of publication (*i.e.* 2012), significant changes are observed in global gas trade. Such a fixed-sequential simulation structure is unable to capture the changing dynamics and competition. The other two works, by Medlock *et al.* [33] and Moryadee *et al.* [35], are based on gas market models which represent global trade specifically and systematically. Both models solve the trade scenarios based on intertemporal optimisation, and the solutions reflect the benchmark equilibrium assuming market players have perfect foresight.

However, these equilibrium scenarios may not describe the trades and investments that are likely to happen since they are often suboptimal due to limited knowledge about the future.

All these studies, when representing different North American export scenarios, set specific low or high export volumes. These assumptions are static and hence the studies ignore the reactions of North American exporters to market demand and price conditions. More research is required to link the North American export actions to the market, allowing a more dynamic representation. In addition, systematic modelling which reflects the possible suboptimal development of gas export business, rather than the ideal condition, is required to show a nuanced view of future global gas trade and help both government and industry stakeholders to explore the risks in gas export business due to limited foresight.

Table 2- 1: Summary of the research addressing the impacts of uncertain North American LNG supply

Study	Research question	Method	Scenarios	Conclusion
Rogers [31]	Impact of US domestic gas production to the globalisation of gas market	Fixed structure supply-demand balance. Global LNG supply flows to different markets in a pre-defined sequence.	High/Low US production with High/Low Asian demand	Low US production results in high linkage between the US, European, and Asian markets after 2016. High US production makes Russia export less via pipeline to maintain European price. Global prices are linked later.
Henderson [32]	Impact of North American LNG exports	Analysis including: 1) Commercial logic of North American gas exports 2) Condition of each export project considering the location, connected reserves, and target markets 3) The political debate over LNG exports 4) Supply cost and relative elasticity of supply on domestic and international prices	N.A.	Equilibrium price would be close to sustain US gas production. North American export to Asia will push down the high-cost supplies there, and the oil-linked LNG contracts will be challenged. Short-term impacts will not be dramatic, but there will be long-term impacts on Asian price formation.
Medlock *et al.* [33]	How the US can maximise its emerging position in LNG exports	The Rice World Gas Trade Model (RWGTM) [34] --- A dynamic spatial partial equilibrium model, based on project-specific intertemporal profit maximisation	Status Quo case Liberalisation case: Contracts fully unwind between 2020 and 2025, and drilling and completion costs fall. North American export push case: Double the contracted amount of North American LNG export relative to Status Quo case	Simply accelerating US LNG export does not convey the benefit as successful as promoting liberalisation in the European market.

Moryadee *et al.* [35]	Impact of US LNG exports on global gas markets	World Gas Model (WGM) [8] Mixed complementarity model of global gas markets. Traders can be Nash-Cournot players who can manipulate market prices or price takers Each agent optimises its profit over the simulation horizon.	Base Medium/High US exports: Medium US exports with renewable policy/pipeline projects/low US production	Increased US exports lead to higher prices in US domestic market, but lower prices in importing markets US LNG will displace other more expensive LNG suppliers in the European market.

2.1.2 Analysis on global natural gas demand uncertainties

This section reviews the studies which examine the impacts of demand-side uncertainties on global gas trade. Studies focusing on both regional (*i.e.* China, Asia, and Europe) and global demand uncertainties are discussed. Their simulation methods and conclusions are summarised and compared in Table 2- 2. The literature gap is then identified.

Shi *et al.* examine the impact of uncertain demand in China's gas market on a global scale [36]. The authors review different outlooks and show significant variability in the projected Chinese gas demand between 2020 and 2040. Factors that contribute to the uncertainties are analysed. The authors then applied the commercial Nexant World Gas Model [37] to study four global gas trade scenarios with different Chinese demand levels. While pipeline imports respond to China's demand changes, LNG imports stay steady even when market demand is low. The results suggest that China should create a liberalised LNG market and reduce the Take-or-Pay contract levels for LNG import.

Besides China, other gas importing countries also have uncertain future gas demand. Rogers published an outlook on the Asian LNG market [38]. The study examines three major LNG markets, namely Japan, South Korea, and Taiwan, based on the fundamental contributors in both consumption and supply aspects. Projections until 2030 with different policy and economic growth assumptions are presented and compared. The outlook also covers eight emerging Asian markets, among which the Chinses and Indian markets are addressed with comprehensive details.

Another study conducted by Rogers [31], which has been reviewed in Section 2.2.1 regarding its discussion on uncertain North American production, also explores the scenarios of global gas trade with low and high Asian demand. However, the author assumes that Asian markets are supplied from a single pool of LNG sources, prior to the US domestic and European markets. As a result, the different Asian demand levels only affect the remaining LNG which flows to the US and Europe. How the Asian markets are satisfied by different suppliers in different demand conditions is not discussed. The major insights provided are on the export strategies Russia may exercise. In addition, how the relative prices between North American and European hubs may change subject to Asian demand uncertainties is investigated.

There is another publication focusing on the gas demand outlook in Europe [39]. Instead of discussing how global trade will be affected by different European gas demand, the study presents the drivers and constraints of gas demand growth, and how gas consumptions may change in different sectors. Different scenarios projected by a variety of agencies are compared. In addition, the author provides country-level insights based on a qualitative analysis involving economic growth, market

structure, the competitiveness of the European industry, the competitiveness of coal and gas in power sector, and the evolving energy mix.

On a global scale, gas demand is also subject to many uncertainties. Holz *et al.* examined global natural gas resources to show that demand growth will not be constrained by the available resources [40]. The authors then use the global gas model WGM [8] (referred as GGM in the paper) to simulate two climate scenarios showing different demand levels until 2040. The result suggests an increase of internationally traded gas being directed to Asia, and the share of LNG in total trade also rises. Moreover, the role of Russia would be strengthened by the growing demand in China, particularly if strict climate policies are implemented.

The review suggests that the number of studies discussing how different demand scenarios will affect the global gas trade is limited. Among the studies shown in Table 2- 2, Rogers [38] and Honoré [39] both focus on market structure and consumption drivers, and they provide no insights on how trade may change. Rogers [31] simulated LNG trade conditions for alternative Asian demand scenarios. However, as discussed in section 2.1.1, the simulation is based on a fixed trading structure, and Asian markets LNG demands are satisfied, ahead of Europe, by a single pool of global LNG supply. Such a structure ignores the heterogeneity of different LNG suppliers, and the competition between pipeline and LNG imports in China is simplified. Shi *et al.* [36] conducted their analysis using Nexant World Gas Model, which is a linear programming model minimising global gas procurement costs. The gas markets are assumed as perfectly competitive, and the results represent the ideal scenarios in which markets are efficient. Holz *et al.* [40] used the World Gas Model [8], which was developed by DIW berlin and university of Maryland. The assumption that gas markets are imperfectly competitive is made, and the results represent the Nash-Cournot market equilibrium However, this simulation, similar to Medlock *et al.* [33] and Moryadee *et al.* [35], which have been discussed in North American supply analysis, takes the approach of intertemporal profit maximisation. Suppliers and investors are assumed to have perfect knowledge about the future, and hence how they may react subject to uncertain demand is not represented. Further research is required to link the uncertain demand to the decisions market players make.

Table 2- 2: Summary of the research addressing the impacts of uncertain natural gas demand

Study	Research question	Method	Scenarios	Conclusion
Shi *et al.* [36]	Global impact of China gas market uncertainties	Analysing factors contributing to the market uncertainties. Simulation based on Nexant World Gas Model	Reference scenario Low demand scenario High demand scenario High Chinese gas production scenario	Global pipeline exports respond to both upside and downside of China's demand uncertainties LNG exports only respond to high demand due to current contract commitment and lack of liberalised markets
Rogers [38]	The uncertainties and outlook of Asian LNG demand	Based on country-level energy mix, gas consumption in different sectors, domestic gas supply, and energy policies. Comparison of different outlooks	N.A.	Asian LNG import by 2030 ranges from 385 to 530 BCM/yr.
Rogers [31]	Impact of Asian gas demand to global gas trade	Fixed structure supply-demand balance. Global LNG supply flows to different markets in a pre-defined sequence.	High/Low US production with High/Low Asian demand	Maintaining the European price by controlling export volume is only possible if Asian demand is high.
Honoré [39]	Gas demand fundamentals in Europe	Reviewing major changes in natural gas industry Analysing the key factors which shape gas demand in different sectors Comparing the demand scenarios by different agencies	N.A.	European gas industry sees a potential for modest future growth
Holz *et al.* [40]	Extensive overview of global natural gas potential	Comparing gas reserves and resources with predicted consumption Identifying main drivers in gas market based on World Gas Model (WGM) [8]	Base scenario Climate scenario following demand projection in World Energy Outlook 450ppm scenario [41]	The Asia-Pacific region faces rapidly rising natural gas demand, and its import dependency is above 40% after 2030. More exports from Russia, the Caspian region, and the Middle East will flow to Asian countries in the climate scenario.

2.1.3 Analysis on transmission and geopolitical uncertainties

Besides the uncertainties on the supply and demand sides, the uncertainties related to the bilateral trade relationships and the transmission routes between exporters and importers also have significant impacts on the future gas market scenarios. For the specific topic of how the China-US LNG tariff may affect future global gas trade, there exists no literature providing any quantitative analysis. Hence, the review here is set more generally to discuss the studies analysing the impacts of different transmission or geopolitical conditions. The focus is on their simulation methods, and the studies are summarised in Table 2- 3.

Some inter-continental LNG trades can be transmitted via certain canals, and the transmission routes and tolls are subject to uncertain inter-governmental relationships. Moryadee *et al.* studied how the varying tolls for LNG cargoes crossing the Panama Canal will affect the global gas trade [42]. The authors applied the WGM [8] and ran six scenarios of possible tariff levels from $ 0/MMBtu to infinitely high. When the canal tariff is low, the gas prices in Japan and South Korea decreases significantly because more gas will be supplied from the Atlantic Basin. When the tariff is high, the LNG exports from the U.S. and Trinidad & Tobago get directed to Europe, where the gas price increases. The resulting LNG flows globally between different scenarios are compared, and how the pipeline gas trades change is also discussed.

Egging and Holz discussed how the geopolitical uncertainty between Russia and Ukraine may affect the investment decisions in natural gas infrastructure [43]. The stochastic version of WGM, named as S-GGM, is used in this study. The scenario tree branches between 2015 and 2020 to represent disrupted or undisrupted Russia-Ukraine transmission conditions. In addition, high/low demand levels and normal/high shale gas production levels are also represented in the scenario tree after 2020. The risk of disrupted Russian supply to Europe leads to investment in European LNG capacities prior to 2020. To hedge the risk, Poland could potentially be developed into a transit hub to supply Ukraine and Germany with Russian imports.

The two studies are based on the similar framework of WGM, and both represent global gas trades with the imperfect competition feature. While Moryadee *et al.* [42] run separate deterministic scenarios each representing a different transmission toll, Egging and Holz [43] assume players anticipate several possible future conditions and simulate the stochastic decisions. Regarding the application of the two approaches on the China-US LNG trade tariff issue, the deterministic scenario comparison has the advantage of providing different development storylines. However, as mentioned in section 2.1.1 and 2.2.2, WGM holds the perfect foresight assumption. Since suppliers may not have perfect information

about future, it is worth investigating how they would use their invested capacities under a changed trade relationship condition.

Table 2- 3: Summary of the research addressing the impacts of uncertain transmission conditions or trade relationships

Study	Research question	Method	Scenarios	Conclusion
Moryadee *et al.* [42]	The influence of the Panama Canal on global gas trade. Will more U.S. gas go to Asia given a shorter distance or to Europe?	Simulation and scenario analysis based on World Gas Model [8]	Reference scenario zero toll for Panama Canal route Regular toll scenario $ 0.35/MMBtu Double toll scenario $ 0.70/MMBtu Scenario 4 toll $ 1.05/MMBtu Scenario 5 toll $ 1.75/MMBtu Infinite toll scenario $9999/MMBtu	The US exports gas regardless of the toll, but there exist differences in the destinations. Higher tolls make the US export less to Japan/S. Korea. The US sells nearly 50 BCM/yr LNG to Europe in 2035 in the infinite toll scenario. The LNG exports from Africa, Australia, and the Middle East decline as the toll decreases.
Egging and Holz [43]	The impacts of a disrupted Ukraine pipeline transmission on Russia gas supplies, the European market, and global gas trade	Simulation and scenario analysis based on Stochastic World Gas Model (S-GGM)	Scenario tree with branches (with equal possibilities) in 2015 with 1) Base case normal Ukraine transit; and 2) Ukraine transit stop case. Different gas demand branches and unconventional US gas production branches are also represented.	Ukraine would construct LNG import terminal to secure its gas supply. European importers may require more transit capacities via Turkey, and they should enhance import capacity from Iraq and the Caspian region.

2.2 Review on stranded asset analysis

This section provides the literature review regarding stranded asset analysis. The discussion around this issue can be classified, in terms of topics, into three major categories. The first category focuses on upstream fossil fuel reserves, examining the quantity of discovered, proven, or listed fossil fuel reserves which may not be used or commercialised. Carbon Tracker Initiative highlighted the risk of stranding by comparing the CO_2 emission potential from the listed reserves globally (762 Gt CO_2) and the carbon budget for the corresponding period (269 Gt CO_2 for 50% probability to achieve the 2°C target) [44]. The report further estimates the potential capital expenditure assuming the same investment level over the next decade. The International Energy Agency conducted a similar comparison for all proven fossil fuel reserves [45]. The reference is the World Energy Outlook (WEO) [46] 450 scenario (2°C climate scenario) and the comparison suggests that over 50% of oil reserves, 50% of gas, and 80% of coal may become stranded. McGlade and Ekins arrived at similar results for oil and coal, though lower for gas at 33%, using the integrated assessment model TIAM-UCL [26]. The study also presents regional-level results, and different scenarios with and without CCS are compared.

The second category focuses on the downstream sectors and the impacts on energy markets. These studies evaluate how the infrastructures using fossil fuels are affected facing the energy transition. In Europe, the stranding of Combined Cycle Gas Turbine (CCGT) power plants has attracted attention. The scale of such stranding of ten major utilities is examined by Caldecott and McDaniels, along with the corresponding impacts on firm value, credit quality, and investment strategy [47]. The study discusses how asset stranding is related to the policies designed to ensure sufficient power generation capacity. It is suggested that governments should carefully value the economic costs of stranded assets when designing "capacity mechanism" policies. The stranding of coal utilities is also analysed by Caldecott *et al.* [48]. On a global scale, the CO_2 commitment of existing electricity generation infrastructure is evaluated by Pfeiffer *et al.* [49]. By assuming a constant development trend, the authors concluded that, to meet the 2°C target, no new emitting electricity infrastructure should be built after 2017. Not only generators that have already been built, but also those under construction or in the planning process, are all included in their analysis, where a minimum of 20% global capacity stranding is suggested. The International Renewable Energy Agency (IRENA) [27] estimated that delayed policy action may cause significant stranding of over US$ 10 trillion assets in the building sector and US$ 2 trillion in the power sector. The study suggests that companies and investors, because of their cognitive biases, may not take initiatives to tackle the forthcoming stranded assets, and strong policy signals are needed to prevent further commitment of capital where stranding is likely.

The third category is related to financial assets like equities and bonds. These studies quantify the investments related to fossil fuels and estimate how the global economy can be affected by climate change and decarbonisation. Dietz *et al.* [50] studied climate Value at Risk (VaR) in global financial assets with the DICE model [51]. The result suggests a substantial write-down in the assets' fundamental values (expected value US$ 1.7 trillion and 1% possibility US$ 13.2 trillion) if the 2°C target is met. The climate VaR is also calculated in [52], and the resulting expected mean losses are US$ 4.2 trillion in present value terms for all manageable assets. Other works include [53] which evaluates the risks in UK insurance sector and [54] which discusses the potential impacts of fossil fuel divestment campaigns.

The works reviewed above have a broad coverage on the asset stranding issue. However, the number of studies, which focus on the process of transferring upstream fossil fuel reserves to downstream end-use sectors, is limited. It is controversial, especially under the climate constraints, how much investment in infrastructures are still required to produce reserves and transport them to end-users. Carbon Tracker Initiative examined all existing and planned fossil fuel production projects and their corresponding investments [55]. They compared the volumes listed by these projects to the low-carbon demand [56], and estimated that further investment is not required under the assumption of global cost minimisation. Based on the same method, a more detailed study with a specific focus on natural gas projects has also been published [28]. The study concludes that the structure of the gas industry is less prone to waste of capital when compared with other fossil fuels, but the LNG projects requiring a break-even price of over US$ 10/MMBtu are exposed to higher risks. In addition, any new gas plants being approved at the time of writing may become stranded, as there is strong policy support to significantly reduce greenhouse gas emissions by 2050.

These studies provide an overview of the risks to capital expenditures in fossil fuel production. However, they overlook the interactions between upstream producers and downstream customers. For example, the dynamic process of investment (*i.e.* investors evaluate price and market size before the final decision), and demand changes subject to fluctuations in fuel price, are simplified.

2.3 Review on modelling methods

Sections 2.1 and 2.2 provide a review on the existing works which address the four key issues in global gas markets. The review suggests that there lacks a systematic modelling method which link suppliers' long-term investment behaviours to the market conditions they face. However, besides the methods and models discussed above, there are a wide range of models built to project the future energy system. Though many of them have not been applied to study specific gas market issues, it is worth reviewing their capability of simulating future global gas trade. This part of the literature review therefore focuses on what methods these models apply. Firstly, energy systems modelling is introduced, and basic concepts in modelling methods are explained. Some models cover many energy sectors, and their simulation of the gas sector is simplified. The methods these models apply to represent global gas trade are briefly reviewed. Then, models which represent the gas sector in great details are reviewed. As this thesis is set out to examine gas trade conditions, the models which focus solely on gas supply or demand are not reviewed. Thirdly, the review examines the methods to address uncertainties in energy systems models. The advantages and disadvantages of these methods are discussed.

2.3.1 Energy systems modelling

This section starts by defining energy systems models and discussing what aspects these models simulate. How the modelling methods are classified is then introduced, with examples of different models in each category. Moreover, a simulation concept which is crucial in this thesis is explained. After that, the review discusses how the existing models simulate global natural gas transmission and trade. In this section, the review focuses on the relatively simplified methods used by multi-sector energy systems models, as the gas sector models are separately discussed in section 2.3.2.

2.3.1.1 Definition and coverage

To capture the interaction of multiple sectors of the energy market and quantitively evaluate potential transitions, mathematical modelling on the energy system is the primary approach in the literature. Here, "energy system" is defined as the process-chain (or a subset of it) from the extraction of primary energy to the use of final energy [57]. Since there are many components in an energy system, the models vary in their focus areas depending on their target questions. Here, three categories of models are identified based on the simulation topic.

Firstly, there are sector-specific models, which represent one specific subset of the energy system. A sector can be a primary energy source like oil, an energy consumption sector like power, or a transformation technology like combined-cycle gas turbine (CCGT). These models are often detailed

in sector representation and capture the features which are unique in the sector. Regarding the links in energy system between the simulated sector and other sectors, assumptions are made exogenously.

Secondly, there are models simulating more than one sector or represent the whole energy system. These models, by representing multiple sectors, can capture 1) the interaction between upstream production and downstream end-use; and 2) the competition between different primary energy sources and transformation technologies.

Thirdly, there are Integrated Assessment Models (IAM) which cover not only the energy sector, but also other related areas such as economy, climate system, agriculture and land use. These models can be used to evaluate the broader impacts of energy development in human society and assess how climate change mitigation activities link to other sustainable development goals.

2.3.1.2 Classification of modelling method

Regarding the modelling method, there are mainly two categories of energy systems models: 1) optimisation models; and 2) simulation models. They take different approaches to represent the actual system and the assumptions vary depending on the modelling purposes.

An optimisation model conducts minimisation or maximisation of an objective function, and thereby finds the optimal configuration or pathway to achieve a specific goal. The model also has a set of constraints specifying the requirements in different sectors or physical realities. Models in this category usually have a detailed bottom-up representation of the technical components in the system, and are commonly used to evaluate the regional or global least-cost decarbonization pathways. They provide insights for the questions regarding the feasibility of energy transition targets and at what cost the targets can be achieved.

An important example of models in this category is MARKAL/TIMES. MARKAL is a widely used general-purpose simulation framework, and with the addition of EFOM (Energy Flow Optimisation Model), TIMES (The Integrated MARKAL-EFOM System) energy model generator is developed by the IEA-ETSAP (Energy Technology Systems Analysis Program) [58]. Each individual IEA member country has built its regional application of TIMES, such as UK TIMES [26, 59], TIMES-France [60], TIMES-DK [61], for the exploration of possible energy futures and the assessment of technologies. TIMES has also been further developed in to TIAM (TIMES Integrated Assessment Model) with alternative functionality for climate response simulation [58, 62], and it has a wider application in the discussion of climate change mitigation. For example, Gambhir *et al.* used TIAM-UCL to study India's long-term mitigation options and how the economy is influenced by carbon trading permissions [63]. Selosse and Ricci applied TIAM-France to evaluate the viability of using Bioenergy with Carbon Capture and Storage (BECCS) to help decarbonize in the power sector [64].

Another important model family in this category is MESSAGE [65-67]. Developed by IIASA (International Institute for Applied Systems Analysis), the MESSAGE modelling framework is used to identify the optimal portfolio of mitigation technologies by minimizing total system costs given demand levels for commodities and services. Similar to TIMES, rich details in energy transformation technologies are represented. However, compared to the TIMES family, MESSAGE models focus more on greenhouse-gas emissions. Emissions from not only energy, but also agriculture, forestry, industrial sources, and other radiatively active gases are all included in the simulation. MESSAGE is also used in conjunction with MAGICC (Model for Greenhouse gas Induced Climate Change)[68] for detailed climate impact (e.g. atmospheric concentrations, global surface air temperature) evaluation.

Another recent development in the regime of optimisation models is OSeMOSYS [69]. It is an open source modelling system for long-run energy planning, and is designed as an analytical toolbox for the energy research community in developing countries. OSeMOSYS runs with the objective of minimising the total net present cost of an energy system, and can represent different technologies in the manner similar to TIMES and MESSAGE. The framework has a pre-defined algebraic formulation for the components (e.g. operating cost, energy balance, capacity constraints) and a plain English description of model inputs and structure. This allows researchers to have a less significant learning curve and time commitment to build and operate models. An example application of OSeMOSYS is TEMBA, which is an African electricity supply and transmission model [70]. TEMBA was presented at the African Pavilion at UNFCC (United Nations Climate Change Conference) COP21 to assist national energy planning discussions by the attending governmental officials and policymakers.

In parallel to the optimisation models, a second major category of models are based on simulation methods. A simulation model focuses on predicting the likely evolution of a system and does not assume optimal behaviour. The specific methods can vary depending on the sector that the model targets to simulate and have the flexibility to represent the particular features specific to the sector. In addition, simulation models can be built modularly so that different methods can be applied to different sectors.

One important example of simulation models is NEMS (National Energy Modelling System) built by the US EIA [71]. NEMS is used to compute the equilibrium production, imports, conversion, consumption, and energy prices for the US Annual Energy Outlook. There are over ten modules, covering energy supply, electricity and petroleum markets, different demand sectors, and macroeconomic activity. One central integrating module controls the solution process as it iterates to determine the economic equilibrium across all modules. Each module has its own design. For example, the Commercial Demand Module projects the floorspace and required energy service first, and then define the type and efficiency of equipment to meet different service demands. Based on the two

aspects, the total energy consumption by fuel is calculated. In contrast, the Electricity Market Module (EMM) takes a cost-minimisation approach to simulate the power dispatch. There are also other submodules in EMM which simulate capacity planning, electricity finance and pricing, and demand-side management.

PRIMES (Price-Induced Market Equilibrium System) is another modular simulation model [72], which is adapted by the European Commission to provide analysis for EU's Energy Roadmap 2050 [73]. Similar to NEMS, it has multiple modules which are linked together, and the equilibrium prices and volumes are determined when the balancing and constraints are met. PRIMES features behavioural modelling and agent representation, and how factors like perceived costs and uncertainty influence decisions by private entities are simulated. Because of these features, PRIMES can evaluate how policy measures may induce higher uptake of advanced technologies by reducing uncertainty and decreasing perceived costs.

In the category of simulation models, besides the modular ones which take different approaches to simulate different sectors, there are Computable General Equilibrium (CGE) models which simulate core economic interactions based on elasticities and social accounting matrix. These models take top-down methods as they, instead of emulating the real-world processes, aggregate variables such as energy, capital, and labour to represent production functions. These top-down methods are in contrast with other bottom-up approaches since the detailed input materials, output products, costs and techno-economic parameters are not represented. However, one of the advantages of the CGE models is that they can cover all aspects (*e.g.* commodities, activities, household, government, and capital) in a national or international economy.

There is a further aspect that can categorise energy systems models, which is the amount of information on future results the decision makers have. Some models assume perfect foresight, which means that decision makers know all the information (*e.g.* demand, prices, costs, and policy constraints) within the modelling time horizon and make the optimal decisions. The perfect foresight assumption describes an ideal condition but does not represent the reality which decision makers face. In contrast, some models assume that decision makers do not know the future changes and the decisions are therefore made adaptively with the best available information at the time of decision making. These models are categorized as imperfect foresight models (also named as myopic and recursively dynamic models). The result scenarios produced from these models are sub-optimal, but may better represent the real world mechanics.

In summary, the two major categories of modelling methods: optimisation and simulation, are both widely used with different purposes. While optimisation models address the feasibility of decarbonization targets and find the optimal energy transition pathway, simulation models project the

possible futures with high likelihood. Since this research targets to project the possible evolution of global gas trade and investigate how the supply and demand strategic decisions may affect the future scenarios, simulation models are more suitable to be adopted. Moreover, the modelling assumptions of perfect and imperfect foresight are introduced, and the following review will examine this aspect in different models to further explain why this work takes the imperfect foresight assumption.

2.3.1.3 Representation of gas market in multi-sector models

This section discusses how global gas transmission and trade is simulated in multi-sector energy systems models. Here the multi-sector models refer to both the energy models covering more than one sector and the IAMs. Since the methods adopted by multi-sector models often simplify the gas market features, the discussion here is separated from the following section which discusses gas sector models. Generally, in the multi-sector models, the capacity constraints on gas export production, transmission, and import are often not simulated. Furthermore, the assumption of a global united gas price is often made.

The gas trade simulation in most multi-sector models can be categorised into three major branches: system optimisation, economic equilibrium methods, and multinomial logit equations.

For optimisation models, gas import and export decisions are simulated as the outcomes of the system optimisation problems. The inter-regional trades make the global energy demand satisfied in the most cost-effective way. Regarding the objective function, all the costs related to the process of gas production and transportation are included. In addition, mass balance constraints, which link import volumes to export volumes and the transport losses, are also applied. Typical examples of this category are TIAM [74] and MESSAGE [67].

For the simulation models which represent general economic equilibrium, methods based on elasticity are used to solve inter-regional commodity trade. Elasticity represents the rate at which a rational profit-maximizing firm changes its production or consumption quantities in response to the change in price ratio of different goods or services. In these models, the values of elasticity are assumed constant and the Armington specification, which suggests imperfect substitutions of imports/domestic and exports/domestic goods [75-77], is applied. Nested Constant Elasticity of Substitution (CES) and Constant Elasticity of Transformation (CET) is used to determine the flow of commodities (*e.g.* gas, oil, electricity). CES functions are used to compute aggregated domestic output, which is then allocated between exports and domestic sales based on CET functions. It is assumed that demands in the international markets are infinitely elastic at the given world prices, and the prices received by exporters are the world prices converted to the domestic currency and adjusted for transaction costs and export taxes. If there is commodity import in a region, the demand there is computed with another

CES aggregation function considering both import and domestic production of the commodity. A typical example model in this category is GEM-E3 [78].

Another economic equilibrium method that is used to address global trade is the Heckscher-Ohlin theorem [79]. The model that applied this method is Global Change Assessment Model (GCAM) - an IAM simulating the interactions between the energy system, water, agriculture and land use, the economy, and the climate [80]. In GCAM, gas is treated as a commodity traded in a single global market. Instead of using elasticity, the Heckscher-Ohlin theorem decides import and export based on the relative capital and labour intensities for commodity production in different countries. Based on this theorem, capital abundant countries export capital intensive products while importing labour intensive products, and vice versa for labour abundant countries. This theorem assumes factor (i.e. capital, labour) immobility and identical technology of production between different countries. It therefore leads to the equilibrium where factor prices are equalized throughout the world

Besides the optimisation and economic equilibrium methods, another commonly-applied method for inter-regional gas trade simulation in multi-sector models is multinomial logit function (MNL) [81, 82]. The MNL method is often used to compute shares and decisions in a choice set of multiple alternatives. In energy systems models, each region has a historically calibrated utility function, which is related to costs and analysts' random variables like geographical and political barriers. The gas demand in the region is satisfied by a choice set, which consists of domestic production and imports from different other regions. The shares of different choices are calculated with MNL function trying to optimise the region's utility function, and the sum should equal to 1. One example of the models taking this approach is TIMER (the Targets IMage Energy Regional model) [83], which is the energy submodule of an IAM named as IMAGE[84].

As explained above, the commonly applied methods in multi-sector models often simplify the transmission capacity constraints and the expansion of capacities are not considered. In addition, most of these models lack the details on supply chain and spatial characteristics due to their targeted broad coverage. However, there are two modular simulation models – NEMS and PRIMES – which have gas-sector modules that are specially designed to represent gas trade and transmission features.

The module that addresses inter-regional gas trade in NEMS is Natural Gas Transmission and Distribution Module (NGTDM) [85] before 2018. It links the producers and consumers by taking an iterative heuristic approach to determine the flow of natural gas and regional market clearing prices. Since NEMS is a national-scale (the US) model, natural gas only flows between regions via pipelines. The transmission capacity constraints, as well as the transmission and storage expansions, are explicitly modelled. The tariffs for transmission services are also determined endogenously. After 2018, NGTDM is replaced by the Natural Gas Market Module (NGMM), which maximises total

surplus minus transportation costs to simulate monthly state-level production, transmission, and price results [86]. Both modules focus on the domestic activities, and the algorithm is only applicable to the liberalised American gas market. For the PRIMES model, the gas trade module named as GSM (Gas Supply Model) explicitly represents the gas infrastructures and trades in Europe [72]. GSM represents a detailed supply chain structure, with the relationships between different market players (*i.e.* gas field producers, LNG importers, transmission system operators, traders, and storage) simulated. Its market representation is typical to European gas sector models, and its application to global gas trade and transmission is limited. Hence, no further discussion is presented here.

2.3.2 Gas sector models

The previous section discusses the methods used by multi-sector energy systems models to simulate the international or inter-regional gas transmission and trade. This section discusses the models that solely focus on the natural gas sector, and reviews only the models that generate long-term gas transmission and trade scenarios. Those simulating short- to medium-term business decisions are not discussed. Generally, these gas sector models often simplify the competition between natural gas and other primary energy sources (*e.g.* crude oil, coal, renewables). The demand is not represented in the final energy form (e.g. electricity, heat), but is direct natural gas quantity. There are two reviews which compare different natural gas models. Busch did a general review to support the redesign effort of the EIA NGTDM module [87]. Comparison on modelling method, regional aggregation, temporal representation and several other aspects is presented. However, the focus is mainly on the North American gas market. Goryachev also published a review on global gas models to identify the prospects to develop a Russian world gas model [88]. The advantages, disadvantages, and key features of the four reviewed models are analysed.

There are some gas-sector models which were developed for commercial purposes. These models include ArrowHead Global Gas Model (AGGM) [89], and Nexant global gas model [37]. Moreover, Deloitte MarketPoint is a commercial software which is used in the Baker Institute World Gas Model (BIWGM) [34]. There is limited publication regarding the methodologies applied in these models, and therefore they are not discussed.

In this review, the gas-sector models are categorised based on their assumptions on perfect or imperfect competition. The perfect competition assumption suggests that there are many gas suppliers who are price-takers, and market price equals the marginal supply cost. The imperfect competition assumption suggests that the market is oligopolistic, duopolistic, or monopolistic, and the suppliers or other players in supply chain exert market power to manipulate or control the prices. These two assumptions lead to different approaches in simulation, which will be explained below. Finally, the

review focuses on how decisions on capacity expansion are simulated and how long-term contracts are represented in these models.

2.3.2.1 Gas models with perfect competition assumption

Table 2- 4 summarises the natural gas models which assume a perfectly competitive market. These models take a single-objective system optimisation approach to simulate gas flows and prices. The International Natural Gas Model (INGM) [90] developed for EIA World Energy Projection System Plus (WEPS+) project tries to maximise the cumulative discounted total surplus (*i.e.* consumer surplus plus producer surplus) over a period, based on the economic market efficiency theory. It covers, from production to consumption, 61 nodes globally. Multiple activities at different locations are optimised with linear programming to generate the equilibrium for each year within the simulation period. The results, including global natural gas production, consumption, trade, and regional prices are published in the EIA's International Energy Outlook. The model assumes perfect foresight, and capacity investment and expansion activities are part of the optimisation. The endogenously simulated capacity decisions should allow the overall system to operate in the most effective way. Contracted trades and term prices are not simulated, as the model assumes that contracts only have a short-term impact on the market and the long-term global trades will only be based on marginal prices.

MAGELAN is another global natural gas model which simulates the optimal long-term gas supply through 2030 [91]. It takes the perfect competition assumption because it tries to avoid further assumptions on the type of market structures and the degree of market inefficiency. The results are not to be interpreted as a simulation of reality, but the best benchmark of possible future conditions. Unlike INGM, which simulates the most efficient market equilibrium with the demand calculated endogenously, MAGELAN has fixed demands in different regions, and the objective is to minimise the cost to satisfy the gas demand globally. Both capital and operational costs for production and transportation are included in the objective function, and the results shows the gas production, trade, and investment when the market is efficient. The gas world is represented as a grid with 139 interconnected points, and its result suggests a continually expanding global gas market. Similar to INGM, the assumption of perfect foresight is made, and long-term gas contracts are not represented in MAGELAN.

Table 2- 4: Summary of gas models with perfect competition assumption

Model name	Region (market)	Optimisation objective	Foresight assumption	Capacity expansion	Long-term contracts
INGM [90]	Global	Maximise cumulative discounted total surplus	Perfect foresight	Endogenous optimal expansion	No
MAGELAN [91]	Global	Minimise total cost to satisfy the fixed demand	Perfect foresight	Endogenous optimal expansion	No
TIGER [92, 93]	Europe	Minimise total cost to satisfy the fixed demand	Perfect foresight	Exogenously specified	Not simulated; Result comparison conducted
InTraGas [94]	Europe	Maximises total surplus	Perfect foresight	Exogenously specified	No
Eser *et al.* [95]	Europe	Two-layer structure: 1) minimise annual import cost; 2) minimise hourly operational cost	Operational 1-year perfect foresight	Exogenously specified	No
GSAM [96, 97]	North America	Maximises total surplus with the transportation costs deducted	Perfect foresight	Transport constraints not accounted; Production expansion endogenously simulated	No
APGM [98]	Asia-Pacific LNG market	Minimise total import cost	Perfect foresight	Exogenously specified	Exogenously specified

Besides the global models, there are several regional gas models based on the perfect competition assumption. For the European market, TIGER is a cost-minimisation gas dispatch model with high temporal and regional granularity [92, 93]. All gas infrastructures are represented at a high level of detail. For example, the characteristics of each pipeline, including location, nodes connection, capacity,

length, directionality, and availability are all represented. However, as the model is designed to investigate European energy supply security issues, it takes exogenous assumptions on regional gas demand, domestic production, import, and price. The expansion projects of LNG import terminals, pipelines and storage are also exogenously specified. Though the model does not account for contracts, how the European long-term gas contracts deviate the simulation from the actual gas flows is discussed.

Another model simulating the European gas market is InTraGas [94]. It differs from TIGER as it does not assume a fixed demand to be satisfied, but maximises total surplus (social welfare) to generate the market equilibrium. The model is designed to examine the existing bottlenecks in European gas transmission infrastructure, and therefore provide incentives to pipeline investment. It runs from the reference case in 2005 with monthly granularity until future scenarios in 2015. All infrastructure developments are specified exogenously, and long-term contracts are not represented as the model focuses on the gas flow in transmission infrastructure.

To represent the European market with high spatial and temporal resolutions, Eser *et al.* developed another model [95]. All physical components of the system, including pipelines, compressor stations, and storages, are modelled individually. Furthermore, the system is simulated with an hourly resolution. The model is designed with a two-step solving procedure. Firstly, the annual sourcing of gas is determined by minimising the total import cost of all countries. Then, the hourly operation is simulated by minimising the short-term operational cost. The infrastructure expansions are specified exogenously based on ENTSOG's ten-year network development plan [99], and the changes in the maximum import capacities from different sources are pre-defined. No long-term contract is represented.

For the North American market, the Gas Systems Analysis Model (GSAM) is an intertemporal spatial price equilibrium model with high-level details in both supply and demand sides [96, 97]. The model maximises the total surplus with the transportation costs deducted to simulate the exploration and production activities of individual reservoir operators. The rich reservoir-level production details make the optimisation problem hard to solve because of the large problem size, nonlinearities, and the lack of closed-form supply curves. To address this problem, GSAM takes a heuristic method named as successive linear programming (SLP). The simulation period is between 1998 to 2020, with seasonal details for each year. Focusing on gas production in North American, GSAM does not account for the transportation capacity constraints. Similarly, no contracts are simulated in this model.

Kompas and Che developed the Asia-Pacific Gas Model (APGM) to simulate the interactions and dynamics of the Asia-Pacific LNG market [98]. The model minimises the total costs of LNG imports in the region with control variables as the trade flows between import and export nodes. APGM is formulated as a non-linear problem because the unit LNG production cost is assumed as a function of

the production volume. The simulation horizon is from 2015 to 2030. During this period, the LNG production capacity is assumed based on existing projects and other company reports. The model features its specific representation of the long-term LNG import contracts with the oil-linked pricing scheme. However, besides the existing contracts, other long-term contracts are exogenously specified based on projected crude oil prices and the term pricing structure.

As presented in Table 2- 4, perfect foresight is commonly assumed in the above-mentioned gas-sector models. While some models, including INGM, MAGELAN, and GSAM, endogenously simulate capacity expansions, they do not represent the impact of long-term contracts on these investment decisions. APGM is the only model which represents contracted gas trade. However, the model specifies future contracts based on other analysis and therefore does not capture the link between market condition and contract formation. All gas-sector models which take the perfect competition assumption provide insights on an efficient market, but there are two aspects that cannot be simulated with these models. The first aspect is the market power exerted by major suppliers, and the second one is the heterogeneity of players in the supply chain. Hence, many models holding the imperfect competition assumption have been developed.

2.3.2.2 Gas models with imperfect market competition assumption

Gas models of the second category assume imperfect competition and take a game theoretic approach to represent gas markets. Such an assumption is based on the fact that regionally segregated gas markets can only be supplied by a limited number of major exporters because of the uneven distribution of gas reserves [4]. The method of Mixed Complementarity Problem (MCP) is commonly applied in these models. This method decomposes multiple interdependent optimisation problems and solves them simultaneously, thereby generating the Nash Equilibrium in which all stakeholders are in their optimal condition. A detailed explanation of MCP is presented in Chapter 3 Methods.

These models are firstly developed to discuss the impact of market structure to regional gas trade. Therefore, regional gas models are reviewed first, followed by global gas models. Table 2- 5 summarises the features of these models.

Table 2- 5: Summary of gas models with imperfect competition assumption

Model name	Region (market)	Research target	Represented players	Strategic players	Foresight	Capacity expansion	Long-term contracts
Gabriel *et al.* [100]	North America	Investigate market restructuring and deregulation strategy	Producers, storage reservoir operators, peak gas operators, pipeline operators, marketers, and consumers	Marketers act as Nash-Cournot players when selling to consumers	Perfect foresight	Not simulated	No
GASTALE Boots *et al.* [101]	Europe	Examine the impact of market structure and market power in the European gas market	producers, within-country marketers, consumers	A two-level successive oligopoly structure is simulated. Both upstream producers and within-country marketers are Cournot players	Perfect foresight	Not simulated	No
GASTALE Egging and Gabriel [7]	Europe	Analyse the extent of market power by producers; Analyse importance of pipeline and storage capacity	Producers, transmission system operator, storage system operator, consumers	Producers act as Cournot players	Perfect foresight	Endogenous optimal expansion	No
GASTALE Lise and Hobbs [102]	Europe	Analyse how strategic behaviour by producers would affect future gas prices and investments in the European Union	Producers, transmission system operator, storage system operator, consumers	Producers act as Cournot players	Imperfect foresight	Endogenously simulated based on heuristic method; Capacity operators decide the investment once every 5-year period	No

GASMOD [103] & GASMOD-Net [104]	Europe	Examine the market power condition in Europe	Domestic producers, export producers, wholesale traders (marketers) For GASMOD-Net, network operator is also simulated	Three scenarios: 1) both upstream producers and downstream traders are Cournot players 2) only upstream producers are Cournot players 3) both producers and traders are price-takers	Perfect foresight	Not simulated	No
GASMOD-Dynamic [104]	Europe	For economic assessment of investment in European inter-country gas transport capacity	Domestic producers, export producers, wholesale traders (marketers), network operators	Both upstream producers and downstream traders are Cournot players	Perfect foresight	Endogenous expansion with open-loop optimisation	No
EPRG-Gas Market Model [105]	Eurasia	Analyse the strategic export policy by Russia, with a specific focus on the South Stream project	Producers, suppliers, transmission system operators (pipelines & LNG facilities), transit countries	All producers act as Cournot players; Bilateral market power between the Russian producer and the transit countries (*i.e.* Ukraine) is also simulated	Perfect foresight	Not simulated	No
World Gas Model [8]	Global	Explore the future global gas trade; Analyse the supply shares of pipeline and LNG in different regions over time	Producers, traders, pipeline operators, liquefiers, LNG shipping vessels, regasifiers, storage operators, transmission system operators, marketers, consumers	Traders and regasifiers, both of whom sell to the consumers, act as Cournot players	Perfect foresight	Endogenous optimal expansion	No

To assist the discussion of market restructuring and deregulation in North America, Gabriel *et al.* developed a regional gas model to examine the market power in the gas supply chain [100]. The model analyses inter-seasonal competition and storage seasonal arbitrage using the MCP approach. Different participants in the supply chain are simulated in different ways. For example, marketers compete against each other to sell to final end-use sectors with gas procured from producers, storage operators, and peak gas operators. These marketers are assumed to be strategic players who are capable of altering the market price by selling different volumes. In contrast, the players who sell to marketers are assumed to operate in a perfectly competitive way. Every participant maximises its operating profit. The model represents production and inter-state transmission capacities as the operational constraints, but the expansion of these capacities is not simulated. The global long-term import-export contracts have insignificant impacts on the operation of the North American regional market, and therefore are not included in this model.

For the European market, Boots *et al.* [101] simulated a two-level successive oligopoly structure using GASTALE (Gas mArket System for Trade Analysis in a Liberalising Europe). Both upstream producers and within-country marketers are assumed to compete in the manner of Cournot in oligopolistic markets. In addition, upstream producers anticipate the reactions of marketers while making their decisions. The model solves the second level downstream marketers' optimisation problems analytically, deriving the border prices as functions of marketers' decision variables and market-related parameters. The border price functions are then substituted into the upstream producers' optimisation problems, which are then transformed into the MCP format to be solved by a specific solver. Neither capacity expansion nor contracts are represented in the initial version of GASTALE. Egging and Gabriel [7] extend GASTALE by also considering more operational and capacity details like storage, LNG terminals, and seasonally varying demand. However, when investigating the strategic behaviour of producers, the authors abolish the assumption of successive oligopoly and only allow producers to exert market power. Endogenous investment activities in capacities are simulated with the perfect foresight assumption, and each operator maximises its total profit with capacity addition modified in constraints and appropriate cost terms deducted from the multiyear objective.

Later, a variant version of GASTALE was developed by Lise and Hobbs [102], in which capacity investment is simulated in a recursive and heuristic way. The investment activities cover four types of capacities: liquefaction, regasification, storage, and pipeline, whereas production capacity changes are defined exogenously as the model focuses on the congestion issue in the transmission network. The capacity operators decide the investment once every 5-year period based on a mathematically derived heuristic rule. The rule suggests that, if the shadow price of an infrastructure in the short-term market equilibrium exceeds the annualised cost of the investment project, the investment will take place. To

implement this rule, the single period (*i.e.* short-term) profit objective of each infrastructure operator would have the annualised capacity expansion costs deducted, and the expanded capacities are added to the corresponding constraints. In each period, the model solves both the short-run equilibrium and the incremental capacity commissioning in that period. The capacity parameters in the subsequent period are updated, and the model runs recursively until the final period. By implementing this method, the model captures the myopic feature of infrastructure investment. However, the underlying assumption that investors do not look further ahead than 5 years significantly simplifies the decision-making process. Regarding the long-term contracts, no versions of GASTALE has a specific representation.

Another European gas model, GASMOD, has also been developed to address the market power issue [103]. Similar to GASTALE, GASMOD simulates the European gas market as a two-stage-game. It examines three possible market scenarios: perfect competition in both upstream and downstream markets; Cournot competition in both markets; and perfect competition in the downstream with Cournot competition in the upstream market. The optimisation problems of both upstream producers and downstream marketers are formulated, and the different competition assumptions are reflected in the parameter named as market power factor. If the player is in perfect competition and behaves like a price taker, the factor is set as 0. In contrast, if the player is in Cournot competition and knows that its sales will directly affect customer purchases and the prices, the factor is set as 1. The result suggests that Cournot competition in both markets is the most accurate representation of the European gas market at that time. Besides the market structure study, GASMOD is also applied to examine the scenario of European gas trade if Russian supply via Ukraine is disrupted [106]. Neither capacity expansion nor contracts are represented in the basic version of GASMOD.

Based on GASMOD, Holz further developed GASMOD-Net and GASMOD-Dynamic to study the European transmission network problem [104]. GASMOD-Net expands the modelling efforts in two aspects. Firstly, it enables multiple players to use a single pipeline link simultaneously. Secondly, pipeline counterflows in two directions, which are observed in Europe at multiple cross-border points with bilateral transmission capacities, are also represented. However, GASMOD-Net is a "static" model in which capacity expansions are specified exogenously. To endogenously simulate the transmission capacity expansions, Holz developed GASMOD-Dynamic in which investment decisions are included in the formulation. The decisions on transmission routes are made by network operators, who maximise the Net Present Value (NPV) of the expansion projects over the entire time-horizon. The NPV includes capital investment at the beginning of each expansion and congestion profits from the transmission service in every time-period. The investment decisions in production capacities are fixed exogenously as the model's focus is to study the European gas network. The model is developed

to be driven by economic factors as opposed to trading relations, and therefore the long-term contracts are not represented.

Chyong and Hobbs extend the above-mentioned European market simulation with a detailed representation of the Former Soviet Union gas sectors [105]. The model is referred to as EPRG-Gas Market Model and is used to provide insights on the South Stream pipeline project which will supply gas from Russia via the Black Sea to South Europe. Horizontal oligopolistic relationships are assumed among producers, and the market power of transit countries, namely Ukraine and Belarus, is also represented. While the model specifies detailed production and transmission constraints, the capacities are assumed to stay constant over a 20-year time horizon. Similarly to other European gas models, long-term contracts are not represented.

Regarding the global gas models which represent imperfect competition in market, World Gas Model (WGM) developed by Egging *et al.* [8] is the only one with methods fully documented and peer-reviewed. It has been used to study the impacts of potential gas cartels [8], and scenarios representing different production conditions in North America, Russia, and the Middle East are also generated [107]. WGM is a large multi-period complementarity model and simulates nine types of players covering different sections in the supply chain. As the model was developed based on the structure of GASMOD and GASTALE, the setting of these players is similar to the European market. However, the assumption that such representation is applicable to global gas trade is hypothetical and needs further justification. Two types of participants are allowed to exert market power to consumers. The first type is traders, who purchase gas from producers and sell to markets where pipelines are connected. The second type is regasifiers who purchase gas from liquefiers and sell to markets with LNG import capacity.

WGM allows endogenous investment in pipelines, storage capacities, regasification plants, and liquefaction plants. The perfect foresight assumption is made, and expansion activities are decided to generate the maximum accumulated profits for their investors. For pipeline capacities, the expansion algorithm is the same as GASMOD-Dynamic [104], where transmission system operators maximise the congestion revenues minus capital costs. For liquefaction capacities, the model adds incremental capacities and corresponding investments into each liquefier's optimisation problem, which is to maximise the total discounted net profit over the simulation horizon. Similarly, the storage and regasification capacity expansions are embedded in the optimisation problem of storage operators and regasifiers. Regulatory, technical, or budget restrictions are also applied to limit the incremental capacities for each period. Production capacities are defined exogenously by fixed growth rates, which are derived from the projection by PRIMES model for Europe [108] and POLES for other countries

[109]. Long-term LNG and pipeline contracts are used to set the minimum trade constraints initially. After all initial contracts in the database expire, the model assumes that all trades are in the spot market.

In summary, most of the gas-sector models have a relatively simplified representation of export (including production and transmission) capacity expansion. While some directly make exogenous assumptions on future investment, the rest take a perfect foresight approach to simulate the optimal expansion condition which leads to the maximum future profit. One exception, which is the variant version of GASTALE developed by Lise and Hobbs [102], takes a recursive approach and the investment decisions are made following a heuristic rule considering only 5 years into the future. As these models are expected to provide neutral insights for the market structure related policies, they do not explore how the perspectives and strategies of investors may affect the gas trade development. Long-term contracts are seldom represented in the reviewed models.

2.3.3 Methods to address uncertainty

Since this study aims to analyse the impacts of uncertain supply, demand, and trade conditions, the methods that have been applied to address uncertainty issues in the regime of energy systems modelling are also reviewed. Five methods, namely scenario analysis, Monte Carlo analysis, stochastic programming, robust optimisation, and modelling to generate alternatives, are explained in this section.

Scenario analysis is the most common approach used by modellers to examine different possible futures subject to technological, economic, and political uncertainties. For each study, a base case scenario is created and treated as a reference. Alternative scenarios are then simulated with changes in constraints, parameters, and assumptions. These changes reflect the plausible exogenous conditions which cannot be determined at the time of simulation, and the impacts of the changes are examined through scenario comparison. Besides the direct scenario results, the development paths leading to alternative outcomes also help researchers to understand the mechanism and rationale behind the changes. As reviewed in section 2.1, most gas market studies have adopted the scenario analysis approach when examining the impacts of some uncertain factors. This approach is easy to implement and communicate. Furthermore, with the small-ensemble of what-if scenarios explicitly represented, researchers can explore the detailed storyline of each possible future. However, this method is criticised for underestimating the range of possible outcomes [110]. Since the number of scenarios that can be examined and explained is limited, such analysis may lead to cognitive bias by highlighting certain scenarios. In addition, this method cannot show how probable and plausible the alternative scenarios are, and the deterministic approach of modelling reference scenarios does not reflect the uncertainties of input parameters and assumptions.

Monte Carlo Analysis (MCA) is a systematic approach to address uncertainties in parameters. The first step of this approach is to assign probability distributions to the uncertain input parameters. Then, one set of random parameters needs to be generated based on the distributions, and the set is then fed into the model to produce an output. The random parameter generation and model feeding processes are then repeated for hundreds to thousands of times, thereby generating thousands of outputs. Statistical analysis is then conducted on the results to show the different likelihoods of different scenarios. The capability to simulate the scenario likelihoods is a major advantage of MCA as compared to scenario analysis. MCA has been applied to assess the likelihood in reaching a particular policy target [111], and to evaluate the robustness of different technologies are in an uncertain future [112, 113]. However, one of the major challenges of MCA is to obtain reliable probability distributions for the uncertain inputs. In many cases, the probability distributions cannot be derived from historical or published data, and modellers' judgement or expert elicitations [114] are used. Some studies even

simplify this process to make the parameters vary within a specific range across the deterministic values in the base case scenarios [112, 115]. Since the accuracy of the output probability highly depends on the reliability of the input probability distributions, this method is more applicable to the sectors where the uncertainties have rich supportive data to build an effective statistical representation. In contrast, for the uncertainties with unknown ranges and probabilities, it is not suitable to apply MCA. The European gas model developed by Eser *et al.* [95] applies MCA in the annual gas sourcing simulation. Optimisation is repeated thirty times with the hourly gas prices varying stochastically relative to the reference. The average of the optimised import profiles is taken as the resultant import strategy which accounts for uncertain prices. However, the number of simulations is limited, and the resulting probabilities of different outcome scenarios are not discussed. Besides this example, no other literature in gas-sector modelling has used MCA to address the uncertainty issue.

The method of stochastic programming is commonly used for multi-stage problems, in which actors need to make decisions at earlier stages and the uncertainties are revealed at later stages. The actors explicitly consider the distribution of uncertain aspects and determine the optimal strategy by striking a compromise between multiple outcomes. Strategies simulated with stochastic programming often provide a hedging decision at an early stage to account for all possible future instances. When the uncertainties are revealed in the later stages, the method also generates recourse actions which should be taken in response to the random outcomes. The method was originally proposed by Dantzig [116], and has been applied to TIMES and MESSAGE models for a variety of applications. For example, Keppo and van der Zwaan assessed how climate target uncertainties could impact the implementation of CCS technologies on a global scale [117]. Seljom and Tomasgard examined the effect of wind power availability and electricity price uncertainties on long-term heat and electricity system in Denmark [118]. As compared to scenario analysis and MCA, stochastic programming has the advantage that it can identify the "super-hedging" actions that are more robust than the strategies simulated based on perfect foresight assumptions. Though this approach also requires the probability distribution of uncertainties, many studies are carried out by simply assigning equal probability weighting for different future outcomes. Such simplification, known as the Laplace criterion, is based on the principle of insufficient reason and should result in the strategies that hold no bias across all possible outcomes.

While the gas-sector models reviewed in Section 2.1.2 are all deterministic, several of them have been extended by applying the stochastic programming approach. The Stochastic-Natural Gas Equilibrium Model (S-NGEM) [119] was developed based on the market structure proposed in the North American gas model developed by Gabriel *et al.* [100] to further examine market activities. The model explicitly represents the uncertain consumer demand over the time horizon. Four seasons are

represented in each year, and after the first season, two possible demand conditions, representing low and high levels, can branch from the scenario tree. The marketers who procure gas from suppliers and sell to end-use consumers take stochastic inverse demand functions in the scenario tree when maximizing their profits. Marketers' decision variables include 1-year-ahead purchase contracts with producers and storage operators, and supply contracts with industrial and electric power sectors. Furthermore, spot trades when the actual demand levels are revealed in the following seasons are also simulated as recourse actions. This model focuses to examine the value of stochastic solutions in the gas market structure, and therefore instead of representing the large scale North American gas network, it only simulates a sample network with two production and two consumption nodes. The result shows that a stochastic solution for such model generally improves the profits of strategic players and consumer surplus, and perfect information does not bring a significant return increase.

Another regional stochastic natural gas model, named S-GaMMES, represents the major gas chain players in the north-western European market. The model has no determinant version. It relates gas demand functions to oil prices, whose uncertainty is simulated [120]. A total of seven periods are defined from 2000 to 2035, and for each 5-year period after 2010, two branches representing increase and decrease of oil prices are represented in the scenario tree. The objective function of each player is the total expected profit over the entire simulation horizon, with costs and revenues at all nodes in the scenario tree multiplied by the corresponding probabilities. For example, producers are assumed to take stochastic solutions by maximising the expected profits with the options of capacity expansion considering all uncertain future scenarios. Long-term contracts between producers and independent traders are simulated via equality constraints describing supply and demand balances in-between. The term prices are represented as the dual variables of the constraints, and the contracts decided at early stages cannot be changed at later stages. The model also endogenously simulates the expansion of production, transportation, and storage capacities. Instead of holding the perfect foresight assumption, each investor decides the capacity expansion to reach a maximum expected profit considering all future uncertain scenarios. Such way of simulating capacity expansion assumes that the investors know the results of future scenarios but do not anticipate which future scenario may happen. The conclusion is that considering stochasticity in decision making benefits the players on an average basis, whereas some players may suffer losses in utility.

For the global trade of natural gas, Egging and Holz extend the World Gas Model (WGM) [8] to the Stochastic Global Gas Model (S-GGM) [43]. As mentioned in section 2.1, the scenario tree branched between 2015 and 2020 on whether Ukrainian transit is disrupted, between 2020 and 2025 on low and base-case gas demand levels, and between 2025 and 2030 on two conditions of unconventional gas production developments. In a similar way to S-GaMMES, S-GGM addresses

stochasticity by representing the objective function of each player as the maximum expected profit over the entire simulation horizon. Production and transmission capacity expansions are included in the players' optimisation problems, whereas contracts are not simulated in this model. The study discusses the potential development of major infrastructure projects in Europe under different scenarios and the stochastic solution illustrates how the inter-temporal hedging behaviour of players may affect the timing of these investments.

Besides the above-mentioned methods, robust optimisation and Modelling to Generate Alternatives (MGA) are also developed approaches to address uncertainty. However, as the number of related studies in the field of energy systems modelling is limited, and there is no application in gas-sector models, the review on these two methods is brief. The principle of robust optimisation is to find a solution which is always feasible with the given uncertain parameters and constraints, and the optimality is obtained for the worst-case realisation [121]. Only the ranges of uncertain parameters are required to apply this method, and the main application area is energy security [122]. MGA is a modelling technique that can address structural uncertainties. It searches the near-optimal solution space to identify alternative solutions that are maximally different as compared to the optimal decision. This method alleviates the cognitive bias, and the possible future options that may be otherwise overlooked can be identified [110].

To conclude, among the five methods which can address the uncertain issues in energy systems modelling, scenario analysis is the easiest to apply. While MCA can simulate the possibilities of different scenarios, the reliability of result depends highly on the accuracy of probility distributions of uncertain parameters. Stochastic programming is often used to generate hedge decisions which account for many different futures. This approach has been applied in several gas-sector models and the stochastic solutions generally benefit the players and the system.

2.4 Research objective

Based on the literature review, the objectives of this thesis are explained in this section. Sections 2.1 and 2.2 highlight the literature gaps of existing works on the four key issues in global gas markets. Some works rely on a fixed global gas trade structure, and the potential changes in supply and demand competition cannot be captured. Other works simulate the ideal benchmark scenarios where market players hold perfect foresights and make optimal development decisions. However, to understand the possible future gas market developments and to identify the risks the gas industry may face, it is crucial to analyse how suppliers and investors may make decisions and develop based on their limited knowledge, the past market conditions, and their perspectives of future markets. Based on the review of modelling methods in section 2.3, it is identified that existing models, to various extents, lack the capability of capturing the suboptimal behaviours of market players. As a result, this thesis aims to make improvements in modelling methods to better address, in a systematic and close-to-reality manner, how the uncertainties in supply, demand, and trade relationship may affect the development of gas markets. More specifically, the uncertain issues addressed by this thesis include North American export strategies, global gas demand levels, and the China-US LNG trade tariff.

2.4.1 General objectives: Development of the modelling method

This thesis aims to develop a global gas model which simulates gas trade scenarios in the medium and long-term future (*i.e.* to 2060). The review suggests that there lacks a gas-sector modelling method which endogenously simulates the formation of long-term contracts between suppliers and consumers. Furthermore, the process that long-term contracts underpin the development of future production and transmission capacity has never been represented. Hence, the primary objective of this thesis is to develop a model which explicitly simulates the contracting process and connects the long-term contracts with capacity development.

Besides the contract-related features, the desired model aims to represent each player in global gas trade with its own rules of behavior, and an agent-based modelling framework shall be used. This framework allows a heterogeneous representation of the market participants. Such a design enables the model to examine the impact of each participant's strategy.

The review on gas market analysis suggests the lack of scenarios which represent potential suboptimal market development. Most existing gas-sector models assume players, especially the production and transmission capacity investors, have perfect foresight. In reality, investor perspectives may focus more on near-term issues. Such myopia may lead to negative consequences because of the long lifetimes and high capital requirements in the natural gas business [66]. Hence, another objective of the thesis is to mimic the practical environment where investors do not have perfect information

and make expansion decisions based on existing knowledge and their own perspectives of the future market. With this feature, the model helps to understand how gas market may evolve alternatively as a result of different investors perspectives.

Moreover, imperfect competition in natural gas markets has been represented in many models. This thesis follows the existing approach based on the Mixed Complementarity Problem (MCP) to capture the market power in global gas trade. The simulated result reflects the game-theoretical Nash-Cournot market equilibrium.

To sum up, this thesis targets to develop a global gas model with a unique combination of features:

- An agent-based framework
- Explicit representation of the contracting process, which mimics the real-world interaction between import and export agents
- Endogenous capacity expansion underpinned by long-term contracts
- Imperfect foresight in decision making, with flexibility in investors' perspectives
- Market power simulation using an MCP approach

The basic version of the model is named as Gas-GAME (Gas Global Agent-based Market Expansion), and the thesis aims to use the developed model to analyse the key issues in global gas supply, demand, and trade relationship aspects.

Modelling method improvements are also made to enhance the range of issues that the model is capable of analysing, and two extended models are developed. Firstly, when market demand shows a certain level of uncertainty, investors should assess that uncertainty before making their decisions. Hence, Gas-GAME-Risk is developed to better mimic this risk evaluation process of real-world investors when they face market demand uncertainties. In this case, demand uncertainties not only affect future market conditions, but also influence how supply investors decide on capacity expansion. Gas-GAME-Risk is applied to analyse the uncertain global demand and uncertain China-US LNG tariff issues. Detailed objectives of the study will be explained in section 2.4.2.

Secondly, contract constraints will affect the utilisation of production and transmission capacities. While Gas-GAME simulates the Nash-Cournot market equilibrium, the practical gas trade condition may deviate from the theoretical equilibrium because of the long-term contracts. Such a deviation may significantly affect the evaluation of gas supply asset stranding. As a result, Gas-GAME-Spot is developed. In every time-period, how the import markets purchase gas based on contracts is simulated. Moreover, the model explicitly simulates spot gas trade, which complements contract-based trade and enables trade flows to move closer towards a Nash-Cournot equilibrium. With both of these trading

mechanisms represented, the model is more appropriate to examine the stranding risks of gas production and transmission investment.

It is clarified that the models developed in this thesis focus solely on global import and export relationships. Trade in the domestic market is not simulated. In addition, the model developed is a simulation model (in contrast to an optimisation model). Hence, the results do not provide insights on the most efficient market scenario.

2.4.2 Specific objectives: Impacts of key uncertainties on future gas market

The four key issues introduced in Chapter 1 will be analysed by three studies. These studies will demonstrate how the developed models can provide insights regarding the uncertain development of future gas market. The first one focuses on the supply-side uncertain strategies of North America. The second addresses both the market demand uncertainty and the geopolitical uncertainty of the China-US LNG trade tariff. The third one focuses on the capacity stranding issue in different market demand conditions. In addition, a sensitivity analysis on the stranding result is conducted, aiming to provide insight on how stranding risks can be mitigated.

2.4.2.1 North American gas exporting strategies

The literature review suggests that existing studies on North American LNG export lack the representation of suppliers' reaction to market dynamics. This study aims to apply Gas-GAME to link North American export with market conditions. Instead of using a static representation of high or low supply volumes, this study changes the investment decision criteria of North American suppliers. Such an approach captures how North American exporters evaluate import requests and market prices before making their decisions, and therefore improves the existing modelling efforts.

Two scenarios representing conservative and aggressive North America LNG expansion are simulated. Insights on how these two strategies may affect future global gas trade are provided. Besides, the reactions of other exporting countries to the North American strategies are analysed. The discussion also covers how the strategies influence prices and imports in different gas markets.

2.4.2.2 Uncertain gas demand and China-US LNG tariff

The objective of this study is to analyse the impacts of different demand levels and China-US LNG tariff conditions on global gas import-export relationships.

The number of studies investigating different demand scenarios is limited, and the existing studies commonly assume that gas consumption follows a constant high or low growth rate throughout the simulation horizon. This study simulates a different demand scenario which represents a "disjoint shift" condition. Gas demand levels are higher initially based on current policy pledges, whereas a sudden

shift to lower levels is induced by new climate policies or other factors. How such a condition would affect global gas suppliers and markets is discussed. Gas-GAME-Risk is applied in this analysis to extend the existing literature by explicitly allowing investors to consider demand risks during capacity expansion.

By the time of writing, there is no quantitative simulation of the China-US LNG tariff. Hence, this study aims to address the impacts of this tariff on future global gas trade dynamics. In two demand scenarios, the base case and the "disjoint shift" case, how the tariff will influence market prices is analysed. Furthermore, how North America will change its exports and how other suppliers will respond to the changes are discussed.

2.4.2.3 Asset stranding in natural gas export facilities

This work aims to analyse the magnitude of future investments in gas production and transmission capacities, and more importantly, to what extent stranding may occur to these capacities on a worldwide basis. Firstly, the results show the scale of gas infrastructure stranding under the normal condition. Secondly, the results show the stranding when the markets experience an unexpected demand decrease. In addition, insights on how governments could intervene to avoid stranding and how markets may respond to the issues are discussed.

Existing studies on stranded assets, in order to calculate the maximum potential risk, overlook the following market features: 1) investors use market signals to evaluate the project profitability; and 2) markets can be affected by changes in supply capacity. Gas-GAME-Spot is applied in this study to simulate how contract constraints may affect the utilisation of capacities and how suppliers compete in spot trade. The suppliers are assumed to invest based on prices and market-required volumes, both of which fluctuate based on simulated market conditions. Hence, this study should fill the gap in asset stranding literature.

2.4.2.4 The sensitivity of stranding outcomes to uncertain contract structures and agent behaviours

The objective of this section is to evaluate how the stranding outcomes would be affected by the changes in contract-structure and agent-behaviour related parameters. These uncertain parameters are assumed to stay constant for the future periods. However, these parameters may change based on the actions taken by different stakeholders in the gas industry. This study simulates the scenarios in which these parameters vary from the base assumption and investigates how the outcomes are influenced. The actions which may effectively alleviate regional stranding are discussed. Furthermore, the impacts on gas export capacity development and global gas trade are analysed.

Chapter 3. Methods

This chapter describes the Gas-GAME model first. Then Gas-GAME-Risk, which is developed to account for uncertain demand scenarios, is introduced. Following that, the design of Gas-GAME-Spot, which improves the modelling capability by representing contract-based and spot trade explicitly, is also explained.

3.1 Gas-GAME

Gas-GAME (Gas Global Agent-based Market Expansion) model, is formulated to simulate investment in and operation of international gas trading assets. It takes an agent-based approach, analysing the simultaneous interactions of multiple different agents, each of which behaving according to their own rule set. Two categories of agents are considered; exporting regions as supply agents (set denoted as *S*), and importing markets as demand agents (set denoted as *D*). The world is disaggregated into 9 export regions (each denoted as *i*) and 5 import markets (each denoted as *j*), as listed in Table 3- 1. Further details and justification of this regional disaggregation are presented in Appendix A. Nomenclature of parameters and variables in Gas-GAME is presented in Table N- 1 to Table N- 4.

Table 3- 1: Region segregation

	Region segregation
Export regions ($i \in S$)	Russia; Norway; Middle East; ASEAN; Australia; North America; South America; Africa; Caspian
Import markets ($j \in D$)	East Asia; West Europe; East Europe; China; India

Table N- 1: Sets and notation in Gas-GAME

Symbol	**Description**
i	Supply agent (subscript)
S	Set of supply agents i
j	Demand agent (subscript)
D	Set of demand agents j
t	Time-period (subscript)
PRD	Production (superscript)
PIPE	Pipeline transmission (superscript)
LNG	Liquefied Natural Gas transmission (superscript)
LIQ	Liquefaction (superscript)
REG	Regasification (superscript)

Table N- 2: Parameters in Gas-GAME

Symbol	Description
$C_{i,j,t}^{PIPE}$	Average cost of selling one unit of gas from supply region i to import region j in period t via pipeline, including both production and transmission
$C_{i,j,t}^{LNG}$	Average cost of selling one unit of gas from supply region i to import region j in period t via LNG, including both production and transmission
$MAX_{i,t}^{PRD}$	Production capacity of supply agent i in period t
$MAX_{i,j,t}^{PIPE}$	Pipeline transportation capacity from supply agent i to import agent j in period t
$MAX_{i,t}^{LIQ}$	Liquefaction capacity of export region i in period t
$MAX_{j,t}^{REG}$	Regasification capacity of import market j in period t
$\gamma_{i,j,t}^{PIPE}$	Market power indicator for region i in import market j in period t for pipeline export
$\gamma_{i,j,t}^{LNG}$	Market power indicator for region i in import market j in period t for LNG export
$INT_{j,t}$	The intercept of price-demand relationship in market j in period t
$SLP_{j,t}$	The slope of price-demand relationship in market j in period t

Table N- 3: Market Equilibrium Module variables in Gas-GAME

Symbol	Description
$SALE_{i,j,t}^{PIPE}$	Pipeline export from supply agent *i* to demand agent *j* in time period *t*
$SALE_{i,j,t}^{LNG}$	LNG export from supply agent *i* to demand agent *j* in time period *t*
$\pi_{j,t}$	Gas import price in market *j* in period *t*
$IMP_{j,t}$	Total import volume of market *j* in period *t*
$\zeta_{i,t}^{PRD}$	Dual variable of production capacity constraint for export region *i* in period *t*
$\zeta_{i,t}^{LIQ}$	Dual variable of liquefaction capacity constraint for export region *i* in period *t*
$\zeta_{i,j,t}^{PIPE}$	Dual variable of pipeline capacity constraint between export region *i* and import market *j* in period *t*
$\zeta_{j,t}^{REG}$	Dual variable of regasification capacity constraint in import market *j* in period *t*
$\mu_{i,j,t}^{PIPE}$	Dual variable of positive pipeline sale constraint between export region *i* and import market *j* in period *t*
$\mu_{i,j,t}^{LNG}$	Dual variable of positive LNG sale constraint between export region *i* and import market *j* in period *t*

Table N- 4: Infrastructure Equilibrium Module variables in Gas-GAME

Symbol	Description
$EXP_IMP_{j,t'}$	Demand agent j total "Expected Import Volume" for the future planning period t'
$CT_IMP_{j,t'}$	Already contracted volume by demand agent j at period t' in the Contract Database
$R_IMP_{j,t'}$	Remaining volume to be contracted by demand agent j for future period t'
$\alpha_{i,j,t}^{PIPE}$	Percentage of remaining to-be-contracted volume by which demand agent j would allocate "Contract Request" volume to supply agent i via pipeline method in period t
$\alpha_{i,j,t}^{LNG}$	Percentage of remaining to-be-contracted volume by which demand agent j would allocate "Contract Request" volume to supply agent i via LNG method in period t
$CT_{i,j,t}^{PIPE}$	Contract request volume from demand agent j to supply agent i via pipeline method in period t
$CT_{i,j,t}^{LNG}$	Contract request volume from demand agent j to supply agent i via LNG method in period t
$CT_SALE_{i,j,t'}^{PIPE}$	Total contracted sale volumes from supply agent i to demand agent j at time-period t' through pipeline
$CT_SALE_{i,j,t'}^{LNG}$	Total contracted sale volumes from supply agent i to demand agent j at time-period t' through LNG
$MAX_REQ_{i,t'}^{PRD}$	Maximum required production capacity for supply agent i at time-period t'
$MAX_REQ_{i,j,t'}^{PIPE}$	Maximum required pipeline transmission capacity between supply agent i and demand agent j at time-period t'
$MAX_REQ_{i,t'}^{LIQ}$	Maximum required liquefaction capacity for supply agent i at time-period t'
$MAX_REQ_{j,t'}^{REG}$	Maximum required regasification capacity for demand agent j at time-period t'
$MAX_AVL_{i,t'}^{PRD}$	Available regasification capacity for supply agent i at time-period t'
$MAX_AVL_{i,j,t'}^{PIPE}$	Available pipeline capacity between supply agent i and demand agent j at time-period t'
$MAX_AVL_{i,t'}^{LIQ}$	Available liquefaction capacity for supply agent i at time-period t'
$MAX_AVL_{j,t'}^{REG}$	Available regasification capacity for demand agent j at time-period t'
$MAX_ADD_{i,t}^{PRD}$	Production capacity expansion by supply agent i at time-period t
$MAX_ADD_{i,j,t}^{PIPE}$	Pipeline capacity expansion between supply agent i and demand agent j at time-period t
$MAX_ADD_{i,t}^{LIQ}$	Liquefaction capacity expansion by supply agent i at time-period t
$MAX_ADD_{j,t}^{REG}$	Regasification capacity expansion by demand agent j at time-period t

3.1.1 Model structure

The structure of the overall model is as follows: it has a two-module structure; (1) a single time-period *Market Equilibrium Module* (MEM), and (2) a forward-looking *Infrastructure Expansion Module* (IEM). Both modules are specifically designed and implemented for Gas-GAME, and the general model structure is shown in Fig. 3 - 1. Fig. 3 - 2 presents a more detailed data flow between the two modules.

The MEM is used to determine market prices and gas trade volumes within a simulation period, while the IEM is used to determine the capacity expansion decisions. Starting from the initial (historical) time-period t_0 (the base year), the MEM uses a Mixed Complementarity Problem (MCP) approach to calculate the flow of gas between supply agents and demand agents, with fixed maximum capacities of flow between regions, and known characteristics of supply and demand. This process generates prices in import markets. Following this, the IEM simulates capacity expansion decisions by supply and demand agents driven by the contracting and investment strategies of these two sides, based on the trade flows and prices emanating from the MEM. These expansion decisions then update the infrastructure database, which will influence the inter-region flow capacities for the next time-period. Subsequently, the complete simulation process for the following time-period runs. This continues until the last period in the model time horizon. Both pipeline and LNG transport are included, separately.

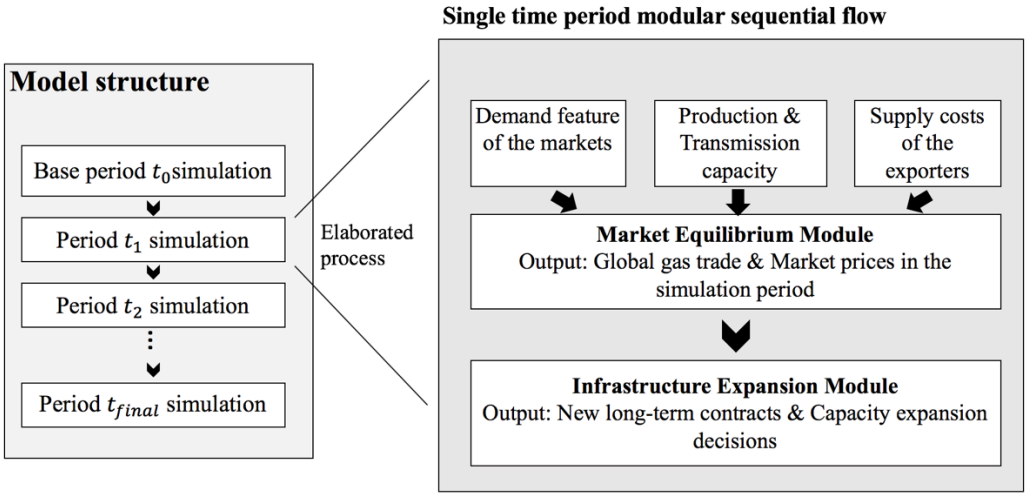


Fig. 3 - 1. Gas-GAME model structure (left) and modular sequential flow (right)

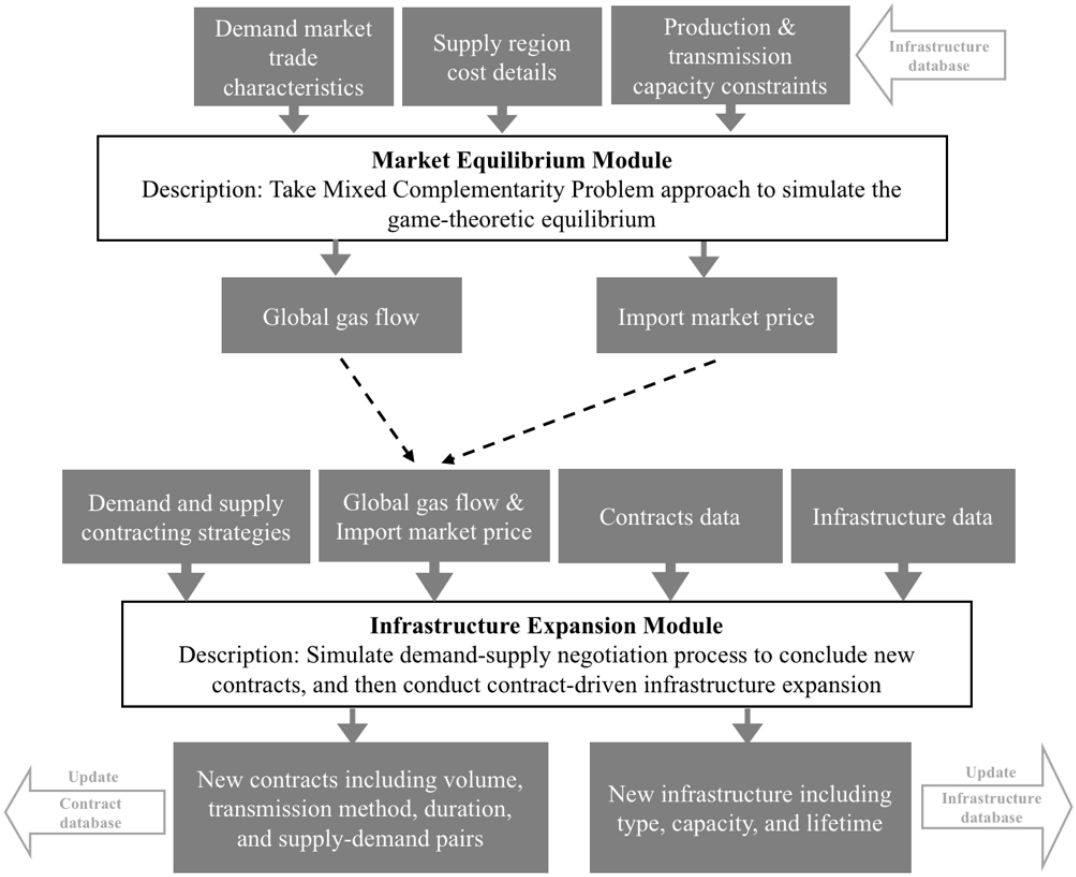


Fig. 3 - 2. Detailed modular structure, input, and output of Gas-GAME

3.1.2 Market equilibrium module (MEM)

This section describes the mathematical formulation of the MEM module. Firstly, the context, assumptions, and general problem description are presented. Then, how the problem is formulated as an MCP is explained.

3.1.2.1 Optimisation problem formulation

This module computes the Nash-Cournot market equilibrium for each single time-period. The core of this module is that each supply agent maximises its gas export profit, knowing the decisions of other exporters. For example, Norway decides on how much gas to export towards Western Europe, considering how the volumes exported to Western Europe from other players (*e.g.* the Middle East and Russia) would impact upon price. The objective function of each supply agent is presented here, and the decision variables include: export volumes via pipeline $SALE_{i,j,t}^{PIPE}$, via LNG $SALE_{i,j,t}^{LNG}$, and market price $\pi_{j,t}$.

Objective function	Every export region $\forall i \in S$	$Max \sum_{j \in D} \left[SALE_{i,j,t}^{PIPE}\left(\pi_{j,t} - C_{i,j,t}^{PIPE}\right) + SALE_{i,j,t}^{LNG}\left(\pi_{j,t} - C_{i,j,t}^{LNG}\right)\right]$	(1)

The profit maximisation is subject to capacity constraints, presented in Table 3- 2. If the available capacity of a certain infrastructure is used to its maximum level, the dual value would be positive, and is commonly viewed as the shadow price for corresponding capacity expansion.

Table 3- 2: Market equilibrium module capacity constraints

Type	Constraint range	Formula		Dual
Production Capacity	Every export region $\forall i \in S$	$\sum_{j \in D}\left(SALE_{i,j,t}^{LNG} + SALE_{i,j,t}^{PIPE}\right) \leq MAX_{i,t}^{PRD}$	(2)	$\zeta_{i,t}^{PRD}$
Pipeline Capacity	Every pipeline route $\forall i \in S, \forall j \in D$	$SALE_{i,j,t}^{PIPE} \leq MAX_{i,j,t}^{PIPE}$	(3)	$\zeta_{i,j,t}^{PIPE}$
Liquefaction Capacity	Every export region $\forall i \in S$	$\sum_{j \in D} SALE_{i,j,t}^{LNG} \leq MAX_{i,t}^{LIQ}$	(4)	$\zeta_{i,t}^{LIQ}$
Regasification Capacity	Every import market $\forall j \in D$	$\sum_{i \in S} SALE_{i,j,t}^{LNG} \leq MAX_{j,t}^{REG}$	(5)	$\zeta_{j,t}^{REG}$

Besides the capacity constraints, additional market relationships, presented in Table 3- 3, are required in the formulation of the supply agents' optimisation problems. The first relationship is the market price-demand relationship, which binds the price to the total market import. The two variables are negatively correlated, and a linear relationship is assumed. The second relationship is the market clearing algorithm, in which the total import by one market equals to the total export to the market from all suppliers. The third one is related to market power. The model assumes that, every exporter is aware of how its export would affect the total import of the corresponding market and uses this to

affect the market price. This assumption represents the Cournot competition feature, and the market power indicators $\gamma_{i,j,t}^{PIPE}$ and $\gamma_{i,j,t}^{LNG}$ are assumed as 1.

Table 3- 3: Market equilibrium module market relationship constraints

Relationship description	Formula	
Import market price-demand relationship	$\pi_{j,t} = INT_{j,t} - SLP_{j,t}IMP_{j,t}$	(6)
Market clearing algorithm	$IMP_{j,t} = \sum_{i \in S}\left(SALE_{i,j,t}^{PIPE} + SALE_{i,j,t}^{LNG}\right)$	(7)
Market power indicator	$\frac{\partial\left(IMP_{j,t}\right)}{\partial\left(SALE_{i,j,t}^{PIPE}\right)} = \gamma_{i,j,t}^{PIPE} = 1$	(8)
	$\frac{\partial\left(IMP_{j,t}\right)}{\partial\left(SALE_{i,j,t}^{LNG}\right)} = \gamma_{i,j,t}^{LNG} = 1$	(9)

Since the price in a market is a function of the exports to this market by all suppliers, for every supply agent, the optimal solution is subject to the results (export volumes) of other suppliers' optimisation problems.

By nature, such a problem can be solved in an iterative manner. The first supplier makes an assumption on the export volumes of other suppliers to all markets and then computes its own optimal solution (*i.e.* export volume to each market). The next supplier would adapt the same assumption with the first supplier's optimal result updated. It then solves its own optimisation problem, the result of which feeds into the third suppliers' optimisation problem. The first round of iteration continues until the last supplier updates all suppliers' solutions in the assumption and have its optimisation problem solved. The second round then starts and the first supplier computes its new optimal solution with the assumption as the optimal results from all suppliers in the last round. The second round continues in the same manner as the first one, followed by the subsequent rounds. The iteration would stop until the optimal export volumes solved by the suppliers are the same as the assumed ones (*i.e.* the optimal results of the last round). At this point, all suppliers are at their optimal condition subject to the equilibrium. However, the above-mentioned computation process is time-consuming, and therefore, the MCP approach is adopted to solve the equilibrium with multiple optimisation problems. As discussed in the Literature review, this approach is commonly used in gas-sector models which assume imperfect market competition.

3.1.2.2 Mixed Complementarity Problem formulation

The first step in the MCP method is to decompose every optimisation problem into its Karush–Kuhn–Tucker (KKT) conditions (*i.e.* first order conditions). The details of KKT conditions are illustrated below.

For a general optimisation problem:

$$\underset{x \in R^n}{\text{Minimise}}\ f(x) \qquad (10)$$

s.t. inequality constraints $g_i(x) \leq 0$ (dual variable v_i), where $i = 1, \dots, m1$

equality constraints $h_j(x) = 0$ (dual variable λ_j), where $j = 1, \dots, m2$

The KKT conditions include:

1) Primal feasibility: $g_i(x) \leq 0, h_j(x) = 0$.

2) Dual feasibility: Lagrangian differentiation equals to zero

$$\nabla f(x) + \sum_{i=1}^{m1_i} v_i \nabla g_i(x) + \sum_{j=1}^{m2_j} \lambda_i \nabla h_j(x) = 0 \qquad (11)$$

And the corresponding dual variable (Lagrangian multiplier) $v_i \geq 0, \lambda_j$ free.

3) Complementarity slackness: $v_i g_i(x) = 0$

These conditions are the necessary and sufficient conditions for the global optimal solution of a problem when a) g_i for all i, h_j for all j are continuously differentiable; b) f and g_i are convex; and c) h_j are affine on R^n. Since the above-mentioned supply agents' problems fulfil these requirements, a result satisfying the KKT conditions of one supplier's problem, shown in Table 3- 4, is the supplier's optimal export volumes. When all suppliers' KKT conditions are satisfied, all suppliers are at their optimal points subject to the result condition, which is the market equilibrium in a single time-period. Simple mathematical re-arrangement changes these KKT conditions into complementarity format as $0 \leq x \perp F(x) \geq 0$, which means the inequality constraints of both sides need to be satisfied and $x \cdot F(x) = 0$. The detailed formulation is presented in Table 3- 5.

Table 3- 4: KKT conditions for a supplier's optimisation problem

Condition type	Formula	
Primal feasibility	$SALE_{i,j,t}^{PIPE} \geq 0$; Dual variable: $\mu_{i,j,t}^{PIPE}$	(12)
	$SALE_{i,j,t}^{LNG} \geq 0$; Dual variable: $\mu_{i,j,t}^{LNG}$	(13)
	$MAX_{i,t}^{PRD} - \sum_{j \in D} \left(SALE_{i,j,t}^{LNG} + SALE_{i,j,t}^{PIPE} \right) \geq 0$	(14)
	$MAX_{i,j,t}^{PIPE} - SALE_{i,j,t}^{PIPE} \geq 0$	(15)
	$MAX_{i,t}^{LIQ} - \sum_{j \in D} SALE_{i,j,t}^{LNG} \geq 0$	(16)
	$MAX_{j,t}^{REG} - \sum_{i \in S} SALE_{i,j,t}^{LNG} \geq 0$	(17)
	$\pi_{j,t} \geq 0$	(18)
Dual feasibility	$\gamma_{i,j,t}^{PIPE} SLP_{j,t} SALE_{i,j,t}^{PIPE} - \pi_{j,t} + C_{i,j,t}^{PIPE} + \zeta_{i,t}^{PRD} + \zeta_{i,j,t}^{PIPE} - \mu_{i,j,t}^{PIPE} = 0$	(19)
	$\mu_{i,j,t}^{PIPE} \geq 0;\ \zeta_{i,t}^{PRD} \geq 0;\ \zeta_{i,j,t}^{PIPE} \geq 0$	

	$\gamma_{i,j,t}^{LNG} SLP_{j,t} SALE_{i,j,t}^{LNG} - \pi_{j,t} + C_{i,j,t}^{LNG} + \zeta_{i,t}^{PRD} + \zeta_{i,t}^{LIQ} + \zeta_{j,t}^{REG} - \mu_{i,j,t}^{LNG} = 0$	(20)
	$\mu_{i,j,t}^{LNG} \geq 0;\ \zeta_{i,t}^{PRD} \geq 0;\ \zeta_{i,t}^{LIQ} \geq 0;\ \zeta_{j,t}^{REG} \geq 0$	
Complementarity slackness	$SALE_{i,j,t}^{PIPE} \mu_{i,j,t}^{PIPE} = 0$	(21)
	$SALE_{i,j,t}^{LNG} \mu_{i,j,t}^{LNG} = 0$	(22)
	$\left[MAX_{i,t}^{PRD} - \sum_{j \in D} \left(SALE_{i,j,t}^{LNG} + SALE_{i,j,t}^{PIPE}\right)\right] \zeta_{i,t}^{PRD} = 0$	(23)
	$\left[MAX_{i,j,t}^{PIPE} - SALE_{i,j,t}^{PIPE}\right] \zeta_{i,j,t}^{PIPE} = 0$	(24)
	$\left[MAX_{i,t}^{LIQ} - \sum_{j \in D} SALE_{i,j,t}^{LNG}\right] \zeta_{i,t}^{LIQ} = 0$	(25)
	$\left[MAX_{j,t}^{REG} - \sum_{i \in S} SALE_{i,j,t}^{LNG}\right] \zeta_{j,t}^{REG} = 0$	(26)

Table 3- 5: Market equilibrium module complementarity constraints

Type	Range	Formula	
Pipeline export	$\forall i \in S$ $\forall j \in D$	$0 \leq SALE_{i,j,t}^{PIPE} \perp \gamma_{i,j,t}^{PIPE} SLP_{j,t} SALE_{i,j,t}^{PIPE} - \pi_{j,t} + C_{i,j,t}^{PIPE} + \zeta_{i,t}^{PRD} + \zeta_{i,j,t}^{PIPE} \geq 0$	(27)
LNG export	$\forall i \in S$ $\forall j \in D$	$0 \leq SALE_{i,j,t}^{LNG} \perp \gamma_{i,j,t}^{LNG} SLP_{j,t} SALE_{i,j,t}^{LNG} - \pi_{j,t} + C_{i,j,t}^{LNG} + \zeta_{i,t}^{PRD} + \zeta_{i,t}^{LIQ} + \zeta_{j,t}^{REG} \geq 0$	(28)
Production capacity	$\forall i \in S$	$0 \leq \zeta_{i,t}^{PRD} \perp MAX_{i,t}^{PRD} - \sum_{j \in D} \left(SALE_{i,j,t}^{LNG} + SALE_{i,j,t}^{PIPE}\right) \geq 0$	(29)
Pipeline capacity	$\forall i \in S$ $\forall j \in D$	$0 \leq \zeta_{i,j,t}^{PIPE} \perp MAX_{i,j,t}^{PIPE} - SALE_{i,j,t}^{PIPE} \geq 0$	(30)
Liq capacity	$\forall i \in S$	$0 \leq \zeta_{i,t}^{LIQ} \perp MAX_{i,t}^{LIQ} - \sum_{j \in D} SALE_{i,j,t}^{LNG} \geq 0$	(31)
Regas capacity	$\forall j \in D$	$0 \leq \zeta_{j,t}^{REG} \perp MAX_{j,t}^{REG} - \sum_{i \in S} SALE_{i,j,t}^{LNG} \geq 0$	(32)
Market price	$\forall j \in D$	$0 \leq \pi_{j,t} \perp \pi_{j,t} - INT_{j,t} + SLP_{j,t} \sum_{i \in S} \left(SALE_{i,j,t}^{LNG} + SALE_{i,j,t}^{PIPE}\right) \geq 0$	(33)

The MCP with constraints in Table 3- 5 can then be solved by a particular optimisation solver, and the global gas exports and prices in the emanated equilibrium would be used in the following module IEM.

3.1.3 Infrastructure expansion module (IEM)

The IEM uses a heuristic algorithm to simulate infrastructure expansion decisions. Typically, take-or-pay contracts are formed to underpin new capacity investment, as infrastructure development in gas industry is always highly capital-intensive [11]. Hence, the module is designed based on an abstraction of the contracting processes observed in the real world. Both supply and demand agents have roles in

this process. The simulation can be split into two parts; (a) demand-supply contracting, and (b) contract-based capacity expansion. Section (a) runs first, followed by section (b). In part (a), the demand agents generate long-term contract requests that are presented to supply agents, including volumes and transmission methods. The supply agents then decide whether to accept or reject these requests based on their own economic evaluation of the contracts. Then in part (b), where new contracts are confirmed, required infrastructure expansion proceeds.

3.1.3.1 Demand-supply contracting

This submodule generates long-term sale-purchase contracts through the interaction between demand and supply agents. There is an initial *Contract Database* which stores the information (including export region, import region, start, duration, end, annual contracted quantity, and transmission type) of the historical long-term contracts. The endogenously generated contracts are updated in the contract database, which will be used to underpin new expansion as well as evaluate future contracting amounts. The contracting processes are illustrated in Fig. 3 - 3, and the details are explained below:

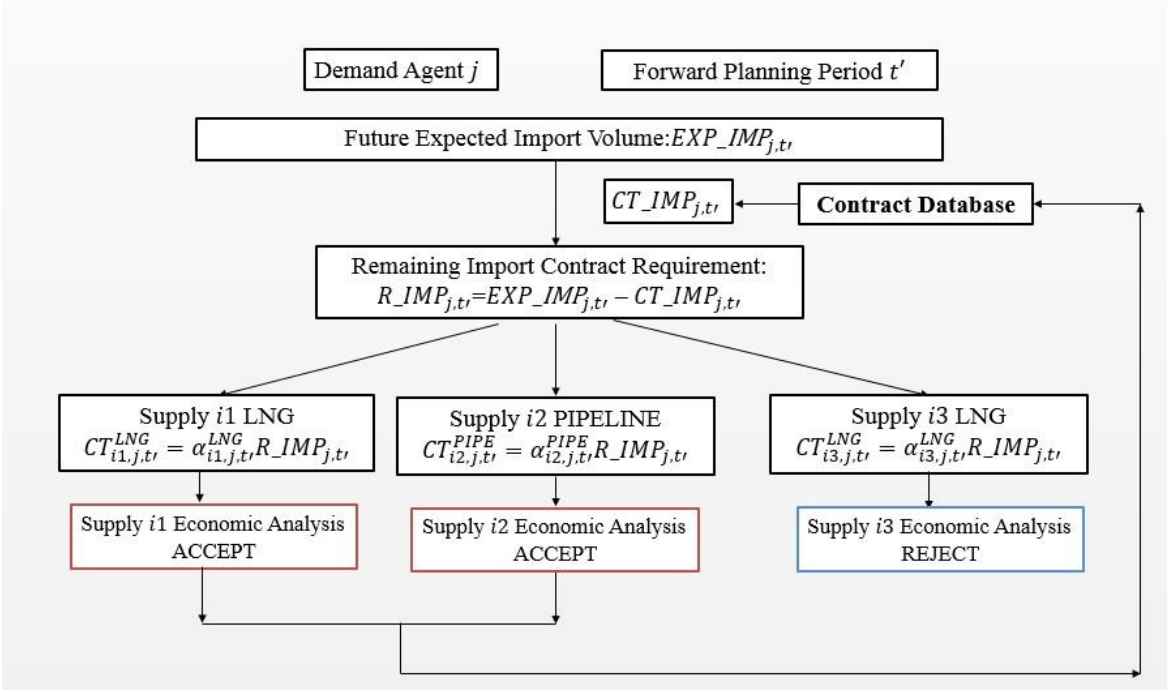


Fig. 3 - 3. Algorithm flow for demand-supply contracting in Gas-GAME IEM

Demand agents act first,

1) Every demand agent j plans ahead and calculates the volumes of import requirements for the future. To represent the several future periods when new contracts would be in force, the midpoint t' of these future periods is used so that annual required volumes can be evaluated. The value agent j calculates is its total "Expected Import Volume" $EXP_IMP_{j,t'}$ at period t'.

2) Agent j then sums up the "Already Contracted Volume" $CT_IMP_{j,t'}$ at period t' based on the information in the contract database.
3) Then it computes the "Remaining Volume" $R_IMP_{j,t'}$ as the difference between the two values above. It is assumed that demand agents targets to contract all its required import. Therefore, this value is the maximum total amount that agent j targets to contract in the running period t for the future planning period t'.

$$R_IMP_{j,t'} = EXP_IMP_{j,t'} - CT_IMP_{j,t'} \quad (34)$$

4) Agent j distributes the remaining volume $R_IMP_{j,t'}$ via *Contract Requests* to all supply agents. The share (in percentage) each supply agent i gets from the total remaining volume, specified as $\alpha_{i,j,t}^{PIPE}$ and $\alpha_{i,j,t}^{LNG}$, are based on the allocation-rule defined by demand agent j. The corresponding contract request volumes in period t are:

$$CT_{i,j,t}^{PIPE} = \alpha_{i,j,t}^{PIPE} R_IMP_{j,t'} \quad (35)$$

$$CT_{i,j,t}^{LNG} = \alpha_{i,j,t}^{LNG} R_IMP_{j,t'} \quad (36)$$

The strategies of demand agents applied in the study of North American export strategy are summarised below, and the flexibilities the model allows are also presented.

(a) Evaluation of future import requirements based on their own method: the demand agents use their next-period price-demand relationships, and interpret the future requirements based on the resultant prices generated from MEM simulation in period t. Since multiple outlooks indicate the phasing out of fossil fuels beyond 2050, the importing markets, from 2035 onwards, fix their future demand requirements at low levels [41, 123]: West Europe 400 BCM/yr; East Asia and China 200 BCM/yr each; East Europe and India 100 BCM/yr each.

Flexibility: Alternatively, they may also use "expected" future prices to project expected future demand volume. The characteristics of the price-demand relationships can also be changed based on the demand agents' outlook of its own energy industry. Moreover, if the demand agent has a known import plan, the values of planned import may be used directly.

(b) Options on contracted volumes: In the model design described above, the demand agents put all their future import volumes into contract requests.

Flexibility: the model structure also allows the demand agents to stop entering long-term contracts, or to set a percentage of the maximum ratio to be contracted. Such flexibility can be used to explore how long-term contracts influence the development of gas industry. It also allows the demand markets to inform the future supply capacities using their contract strategies.

(c) Options on supplier preference: After evaluating the "to-be-contracted" volumes in t', the demand agents have the flexibility to decide which supply agents to send contract requests and

at what volumes. In this thesis, the percentages depend on the shares suppliers take in the total import of the corresponding market in the running-period t MEM result, as shown in Equation (37) and (38). In addition, 10% is used as the starting shares for new potential suppliers (See Appendix A). When a pair of supply and demand agents has contracted over 30 BCM/yr, yet they do not trade in MEM in period t, the demand agent would stop sending contract requests to that supplier in the following period.

$$\alpha_{i,j,t}^{PIPE} = \frac{SALE_{i,j,t}^{PIPE}}{IMP_{j,t}} \quad (37)$$

$$\alpha_{i,j,t}^{LNG} = \frac{SALE_{i,j,t}^{LNG}}{IMP_{j,t}} \quad (38)$$

Flexibility: The demand agents may have preferences in contract allocation based on geopolitical reasons or energy security concerns. For example, Western Europe may decide to diversify its import from Russia and therefore reduce its Russian contract request volumes, even though the market imports a large percentage of Russian gas in the last period. This model allows users to explicitly represent such regional preferences and is capable of investigating how such preferences would affect the global trading dynamics.

Supply agents act after the demand agents. Each supply agent evaluates all the contract requests received, using its own economic criterion. If one contract request meets the criterion, the supply agent ACCEPTs the request, thus creating a *Confirmed Contract*. Whereas if the criterion is not met, the supply agent REJECTs the request (see Fig. 3 - 4). All the confirmed contracts are then updated in the contract database, with details in the same format as the initial contracts in the database, including export region, import region, start, duration, end, annual contracted quantity, and transmission type.

The strategies of supply agents used in the study of North American export strategy are summarised below, together with the flexibilities allowed by the model.

(a) Configurable economic evaluation method and profitability criteria: It is assumed that supply agents examine the Internal Rate of Return (IRR) for every contract request. The IRR is chosen because it is a common measure of capital project profitability and can be used to compare investments regardless of their scale. If the IRR of a contract exceeds a certain level, the contract request will be confirmed.

Flexibility: The model allows the evaluation method and profitability criteria vary from agent to agent. Users can take this model and study how the strategies of different suppliers affect infrastructure development and market dynamics. Furthermore, contracts may be rejected on geopolitical or similar grounds.

(b) Investor perspectives: Supply agents do not have perfect foresight, and therefore may make decisions based on their own perspectives and projections of future quantities such as price. In this study, the market equilibrium prices emanated from the MEM in period t are used by supply agents for their future revenue calculation for project IRR values.

Flexibility: If model users can gather further information from the stakeholders regarding their views on future market prices, they can simulate how these perspectives of investors can affect the future gas trade dynamics.

(c) Configurable profitability criteria subject to market condition: The model also allows supply agents to change their criteria throughout the simulation time horizon, reflecting the fact that gas exporters may change their strategies when facing different market conditions. In this study, the criteria are the same from the beginning to the end of simulation periods.

Flexibility: Other rules can also be applied, based on users' understanding of investment strategies. For instance, when market price is higher than a certain level, supply agents become more aggressive in investment. The rules can also include responses to other agents' investing activities.

3.1.3.2 Contract-based capacity expansion

This section updates the infrastructure database by calculating the infrastructure expansion. Fig. 3 - 4 illustrates the algorithm of this process. The expansion is conducted to ensure that the updated capacity sufficient to deliver the contracted trade in the future period t'. The process starts by each agent evaluating the production and transmission capacity required to satisfy the confirmed contracts, which are recorded in the contract database. Variables $CT_SALE_{i,j,t'}^{PIPE}$ and $CT_SALE_{i,j,t'}^{LNG}$ are the total contracted sales for time-period t', and the formula of required capacities MAX_REQ are shown in Table 3- 6.

Table 3- 6: Capacity requirement in Gas-GAME IEM

Type		Formula	
Production capacity	$\forall i \in S$	$MAX_REQ_{i,t'}^{PRD} = \sum_{j \in D} (CT_SALE_{i,j,t'}^{PIPE} + CT_SALE_{i,j,t'}^{LNG})$	(39)
Pipeline capacity	$\forall i \in S$ $\forall j \in D$	$MAX_REQ_{i,j,t'}^{PIPE} = CT_SALE_{i,j,t'}^{PIPE}$	(40)
Liquefaction capacity	$\forall i \in S$	$MAX_REQ_{i,t'}^{LIQ} = \sum_{j \in D} (CT_SALE_{i,j,t'}^{LNG})$	(41)
Regasification capacity	$\forall j \in D$	$MAX_REQ_{j,t'}^{REG} = \sum_{i \in S} (CT_SALE_{i,j,t'}^{LNG})$	(42)

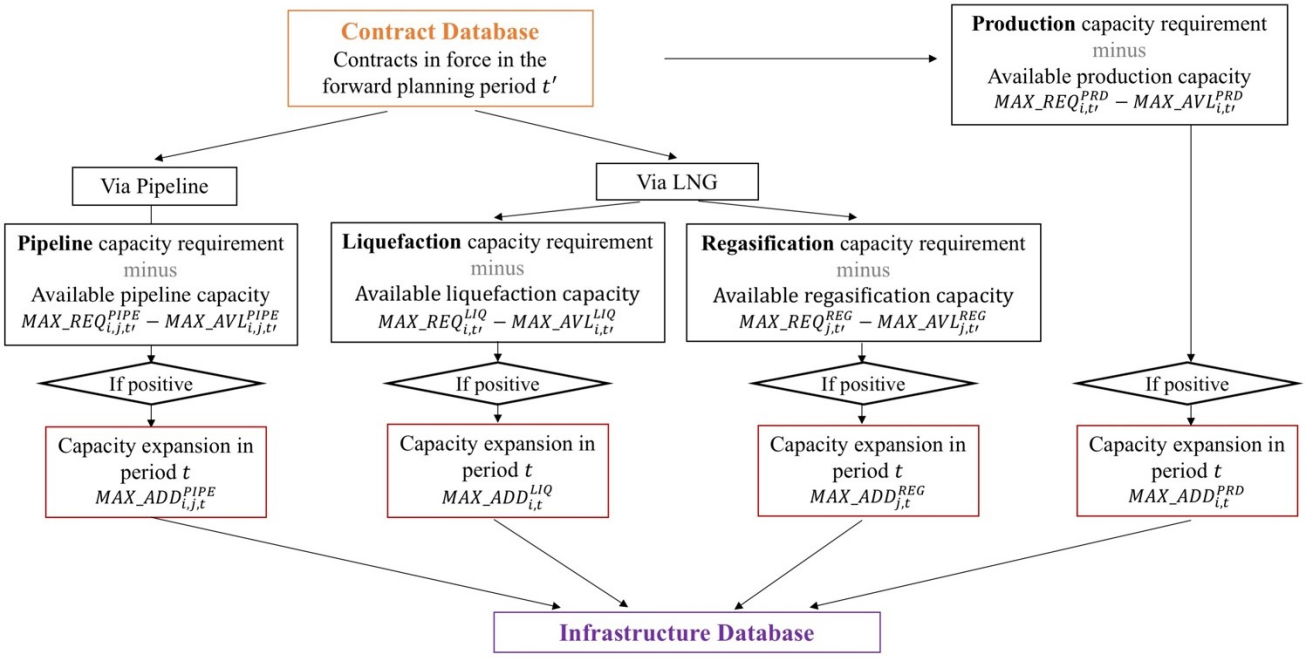


Fig. 3 - 4. Algorithm flow for contract-based capacity expansion in Gas-GAME IEM

The capacity expansion is to allow the total capacity in future period t' larger than or equal to the MAX_REQ values. Supply agents, based on the *Infrastructure database*, evaluate the capacity, specified as MAX_AVL, that will be in place (*i.e.* available capacity) in period t'. If the amount is larger than or equal to the required capacity MAX_REQ values, no expansion or investment would be placed for the corresponding infrastructure. In contrast, if the amount is less than the MAX_REQ values, new infrastructure is constructed to be in place for the next period. The expansion amount MAX_ADD is the difference between MAX_REQ and MAX_AVL.

Table 3- 7: Capacity expansion calculation in Gas-GAME IEM

Type		Formula	
Production capacity	$\forall i \in S$	$MAX_ADD^{PRD}_{i,t} = Max(0, MAX_REQ^{PRD}_{i,t'} - MAX_AVL^{PRD}_{i,t'})$	(43)
Pipeline capacity	$\forall i \in S$ $\forall j \in D$	$MAX_ADD^{PIPE}_{i,j,t} = Max(0, MAX_REQ^{PIPE}_{i,j,t'} - MAX_AVL^{PIPE}_{i,j,t'})$	(44)
Liquefaction capacity	$\forall i \in S$	$MAX_ADD^{LIQ}_{i,t} = Max(0, MAX_REQ^{LIQ}_{i,t'} - MAX_AVL^{LIQ}_{i,t'})$	(45)
Regasification capacity	$\forall j \in D$	$MAX_ADD^{REG}_{j,t} = Max(0, MAX_REQ^{REG}_{j,t'} - MAX_AVL^{REG}_{j,t'})$	(46)

The expanding projects would then be updated in the infrastructure database with information including region, infrastructure type (production, liquefaction, regasification, or pipeline), annual capacity, start, lifetime, and end. When the MEM runs for the next period, it uses the updated infrastructure database to evaluate the production and transmission capacities.

3.1.4 Programming environment and solver

The model is programmed in Python, with the intention that it become open-source in the future. Regarding the MEM MCP problem, Pyomo (Python Optimization Modelling Objects) package [124] is used to interface with the PATH solver [125].

3.2 Gas-GAME-Risk

This model variation has been designed to address the issue of global gas demand uncertainty. It allows investors to incorporate stochastic analysis during their decision making when facing uncertain demand conditions. Firstly, the different demand projections used in this model are explained. Then, the scenario tree representing the realisation of alternative demand scenarios is presented. Finally, this section highlights the methodological difference in the IEM module in Gas-GAME-Risk, as compared to Gas-GAME.

3.2.1 Different gas demand scenarios

For the base period t_0, the price-demand relationships (Equation (6)) are computed using the total consumption data from the BP Statistical Review of World Energy [126], gas import data from IEA gas information [127] and regional prices from International Gas Union (IGU) Whole Sale Gas Price Report [128]. For the future periods, two price-demand relationship trajectories are computed: a base one referred as NPS and a low-demand variant referred as LOW. The two trajectories represent the uncertain range of gas demand. Detailed computation of the relationships is explained in Chapter 4. The following paragraphs focus on the differences between the two trajectories and the relationship changes from period to period, to facilitate the method explanation.

The base relationship trajectory is calibrated using the New Policies Scenario (NPS) in World Energy Outlook (WEO) 2017 [18]. The market import levels in 2040 at their reference prices are presented in

Table 3- *8*. This projection assumes that the gas consumption trend would follow current policy pledges and is the common baseline for natural gas market simulation. The slope SLP values remain constant throughout the simulation, whereas the price intercept INT values adapt towards the 2040 import levels in a linear manner between 2010 and 2040. From 2040 to 2060, the relationships are assumed to be the same as those in 2040.

The LOW relationships are calibrated based on the lowest level simulation results in literature [18, 38, 129-131]. It is worth noticing that these levels are obtained from feasible decarbonisation solutions instead of targets. Regional import volumes in 2040 are compiled in

Table 3- *8*. For Western Europe, Eastern Europe, and Eastern Asia, the values are taken from the Sustainable Development Scenario (SDS) in WEO [18]. For China, the lower import volume in 2030 projected by China National Petroleum Corporation (CNPC) [130] is used with an extrapolation towards the volume in 2040. Indian natural gas import in NPS is at the lowest end of multiple projections [18, 38], and therefore a 20% reduction is assumed for the 2040 demand level in LOW. The price-demand relationships in different markets in 2040 are computed with a modified assumption on demand elasticity (see Appendix C). Regarding the periods between 2010 and 2040, the slope SLP values change gradually at a constant rate. The intercept INT values are then calculated to ensure the import level based on the reference price in each period equals to interpolated import level. From 2040 to 2060, the relationships are assumed to be the same as those in 2040.

Table 3- 8: Different future demand scenarios in Gas-GAME-Risk

	Reference price in 2010 ($/MMBtu)	Import level in 2040 (BCM/yr)	
		Base Scenario (NPS)	Low Demand Scenario (LOW)
West Europe	8.0	463	347
East Europe	4.5	58	44
East Asia	10.5	359	215
China	6.3	278	205
India	4.4	99	79

3.2.2 Scenario tree in Gas-GAME-Risk

If the gas market develops smoothly, the demand level in each region may evolve following either NPS or LOW trajectory after 2020. However, a disjoint shift from the base demand level towards the lower one may happen. In such a scenario, efforts to tackle climate challenge are initially insufficient, but the perception of climate disruption triggers a precipitous transition towards lower emissions, thereby inducing a shift in import market price-demand relationships. One scenario framework, named as "Disjointed Transition Case" in WEO [18], assumes the shift happens between 2030 and 2035. However, it is unclear to the exporting countries whether and when the shift towards lower gas demand may happen. A fast transition may happen as early as 2020 to 2025 if policymakers determine to drive the decarbonisation process mainly by renewable energy. In contrast, it is also possible that the transition does not happen until 2060 due to the lock-in effect of gas power plants and other gas-related infrastructure. The intermittency issue of renewable supplies, which may require natural gas to back up for energy security, can also lead to a slow transition in the coming decades. Therefore, a scenario tree reflecting the potential demand trajectories with disjoint shifts at different periods is constructed.

As shown in Fig. 3 - 5, the demand shift may happen in every time-period after 2020. Once the demand relationship has shifted from the NPS (represented by blue nodes) to the LOW trajectory (represented by green nodes), it follows the LOW trajectory and does not shift back. If the demand relationship keeps following the NPS trajectory, the possibility of shifting increases over time. Such a design assumes that if decarbonisation does not happen early, due to the urgency for climate change mitigation, gas demand is increasingly likely to shift lower in order to meet the climate target.

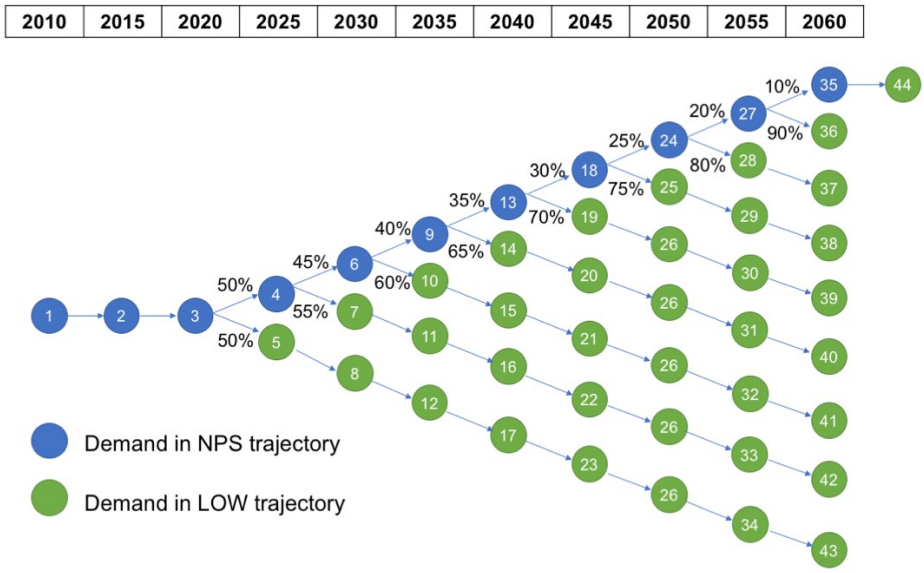


Fig. 3 - 5. Illustration of scenario tree in Gas-GAME-Risk

3.2.3 Investment decision based on stochastic analysis

The two-part structure of the IEM module: (a) demand-supply contracting, and (b) contract-based capacity expansion, is the same as Gas-GAME. Fig. 3 - 6 illustrates the IEM design briefly and highlights the additional feature in Gas-GAME-Risk. The major difference is in the supply agents' economic analysis process in part (a). In Gas-GAME, the supply agents evaluate the project profitability based on the assumption that all the volumes in the contract requests proposed by importers would be sold. In Gas-GAME-Risk, when supply agents evaluate the profitability, they use the expected revenue for all possible realisations of future demand trajectories in the scenario tree, considering the risks of lower demand scenarios.

When the demand relationship at the time-period for decision making is in the NPS trajectory (*i.e.* the market has not yet shifted to the lower-demand scenarios), the supply agents evaluate all the possible routes linked to the current node within the term period of the proposed contracts. It is assumed that, for future NPS nodes, all proposed volume ($CT_{i,j,t}^{LNG}$ or $CT_{i,j,t}^{PIPE}$) will be sold at the market equilibrium price of period t. For future LOW nodes, the current equilibrium prices are still used but the volume those suppliers expect to sell is only a portion of the proposed volume ($\beta_j CT_{i,j,t}^{LNG}$ or $\beta_j CT_{i,j,t}^{PIPE}$).

Table 3- 9 presents the reduced levels for each import market, and the values are obtained by comparing the 2040 imports in LOW to those in NPS. The expected revenues of the proposed contracts are calculated based on the branching probabilities in the scenario tree, and these expected revenues are then used for the computation of the expected IRRs. The supply agents then decide whether to confirm the new contracts based on the expected IRR values. The following capacity expansion process in part (b) is the same as Gas-GAME.

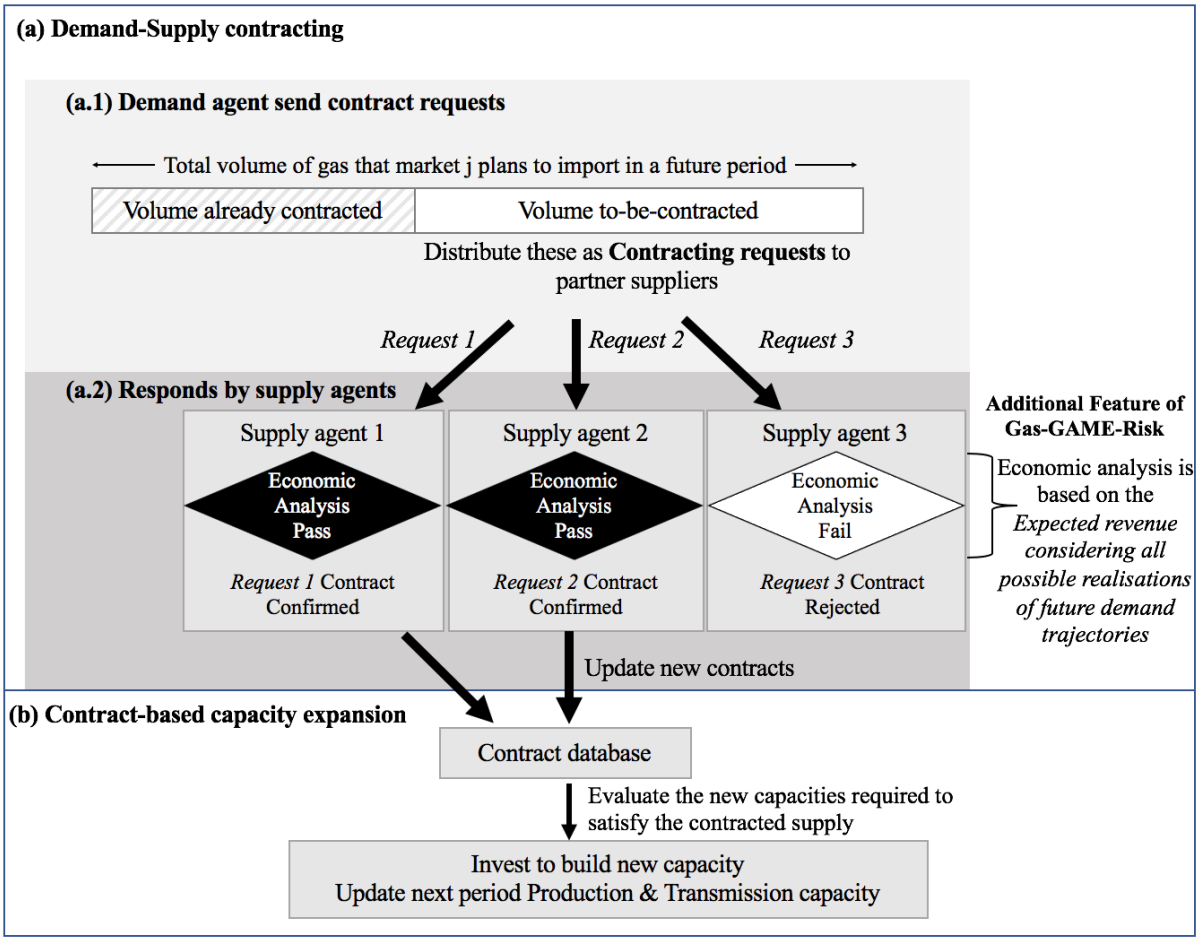


Fig. 3 - 6. Gas-GAME-Risk IEM module method illustration

Table 3- 9: Values of parameter β_j in Gas-GAME-Risk

Region j	West Europe	East Europe	East Asia	China	India
Parameter β_j	75%	76%	60%	74%	80%

3.3 Gas-GAME-Spot

The Gas-GAME-Spot model is developed to examine the potential stranding risks of investment. In order to fully explore the risks, the assumption that suppliers invest without considering demand uncertainties is made. Consequently, Gas-GAME-Spot does not have the risk evaluation feature of Gas-GAME-Risk.

The model, built based on Gas-GAME, has contract commitments and spot trade added to the original method. Besides the MEM and IEM in the original model, the Spot-Contract trade Module (SCM) is added. Fig. 3 - 7 presents the Gas-GAME-Spot model structure, modular sequential flow, and the output of each module. After the MEM finishes simulating the single time-period Nash-Cournot market equilibrium, the SCM simulates how importers and exporters trade to approach the market equilibrium under the contract constraints. The result of SCM includes two parts: 1) contract-based sales; and 2) sales in the spot market. After that, IEM runs to generate new long-term contracts based on SCM results, and the contracts are used to underpin new capacity development.

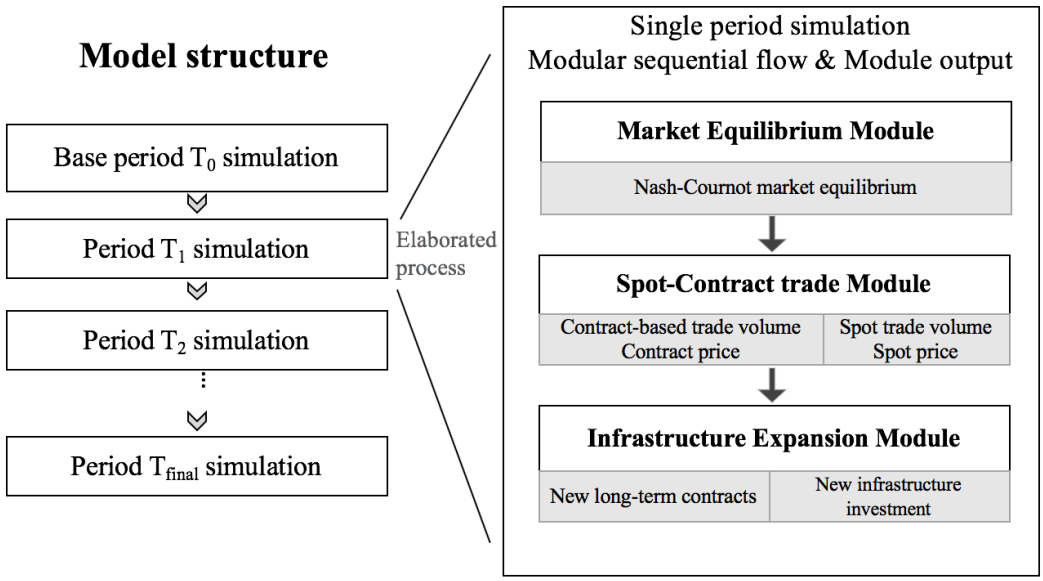


Fig. 3 - 7. Gas-GAME-Spot model structure (left) and Modular sequential flow (right)

Table N- 5: Additional sets and notations in Gas-GAME-Spot

Symbol	Description
D_{Seller}	Set of demand agents j with "Sellers' market" characteristic for spot trading
D_{Buyer}	Set of demand agents j with "Buyers' market" characteristic for spot trading
CT	Contract (superscript)
SP	Spot (superscript)
EQ	Market equilibrium (superscript)

Table N- 6: Additional parameters in Gas-GAME-Spot

Symbol	Description
$PREM_j^{SP}$	The spot price premium in Sellers' market *j*
$PROF_j^{SP}$	The minimum level of profit suppliers require for spot trade in Buyers' market *j*
$\mu_{j,t}^{CT}$	The minimum purchase obligation of a long-term contract with market j in period t

Table N- 7: Modified notations of variables in MEM in Gas-GAME-Spot

Symbol	Description
$SALE_{i,j,t}^{PIPE,EQ}$	Pipeline export from supplier *i* to market *j* in equilibrium in period *t*
$SALE_{i,j,t}^{LNG,EQ}$	LNG export from supplier *i* to market *j* in equilibrium in period *t*
$\pi_{j,t}^{EQ}$	Equilibrium gas import price in market *j* in period *t*

Table N- 8: Variables in the Spot-Contract trade Module of Gas-GAME-Spot

Symbol	Description
$SALE_{i,j,t}^{PIPE,SP}$	Spot sale via pipeline from supplier *i* to market *j* in period *t*
$SALE_{i,j,t}^{LNG,SP}$	Spot sale via LNG from supplier *i* to market *j* in period *t*
$SALE_{i,j,t}^{PIPE,CT}$	In-place contract volume for pipeline export from supplier *i* to market *j* in period *t*
$SALE_{i,j,t}^{LNG,CT}$	In-place contract volume for LNG export from supplier *i* to market *j* in period *t*
$\pi_{j,t}^{CT}$	Term price for gas import in contracts in market *j* in period *t*
$\pi_{j,t}^{SP}$	Equilibrium gas import price in market *j* in period *t*
$\pi_{j,t}^{AVG}$	Weighted average gas import price covering both contract-based and spot import by market *j* in period *t*
$IMP_{j,t}^{CT}$	Total contracted import volume in market *j* in period *t*
$IMP_{j,t}^{SP}$	Total import volume by spot trade in market *j* in period *t*

$SetC_{j,t}^{PIPE}$	The set of short-term costs of spot gas delivery via pipeline to market j in period t
$SetC_{j,t}^{LNG}$	The set of short-term costs of spot gas delivery via LNG to market j in period t
$MAX_{i,t}^{PRD,Seller}$	Production capacity available of supplier i in period t for spot trade in sellers' markets
$MAX_{i,j,t}^{PIPE,Seller}$	Pipeline capacity available from supplier i to market j in period t for spot trade in sellers' markets
$MAX_{i,t}^{LIQ,Seller}$	Liquefaction capacity available of supplier i in period t spot trade in sellers' markets
$MAX_{j,t}^{REG,Seller}$	Regasification capacity available by market j (with sellers' market feature) for its spot import in period t
$MAX_{j,t}^{DMD,Seller}$	Maximum spot import level by market j (with sellers' market feature) in period t
$MAX_{i,t}^{PRD,Buyer}$	Production capacity available of supplier i in period t for spot trade in buyers' markets
$MAX_{i,j,t}^{PIPE,Buyer}$	Pipeline capacity available from supplier i to market j in period t for spot trade in buyers' markets
$MAX_{i,t}^{LIQ,Buyer}$	Liquefaction capacity available of supplier i in period t spot trade in buyers' markets
$MAX_{j,t}^{REG,Buyer}$	Regasification capacity available by market j (with buyers' market feature) for its spot import in period t
$MAX_{j,t}^{DMD,Buyer}$	Maximum spot import level by market j (with buyers' market feature) in period t
$MAX_{j,t}^{DMD,Buyer}$	Maximum spot import level by market j (with buyers' market feature) in period t

3.3.1 Market equilibrium module (MEM)

The design of the MEM is the same as Gas-GAME, and therefore is not explained again in details. However, in Gas-GAME-Spot, the Nash-Cournot market equilibrium emanated from the MEM is interpreted as the theoretical equilibrium instead of the practical trade condition. The equilibrium is then used as the reference condition for the following SCM module.

3.3.2 Spot-contract trade module (SCM)

The SCM module simulates how market participants trade in each time-period, close to the theoretical equilibrium. The process consists of two parts: contract commitment and spot trade, and both are explicitly represented in this module. Three steps, namely 1) market categorisation, 2) contract sale simulation, and 3) spot trade simulation, are involved. The method is illustrated in Fig. 3 - 8, and the nomenclature for SCM is presented in Table N- 8.

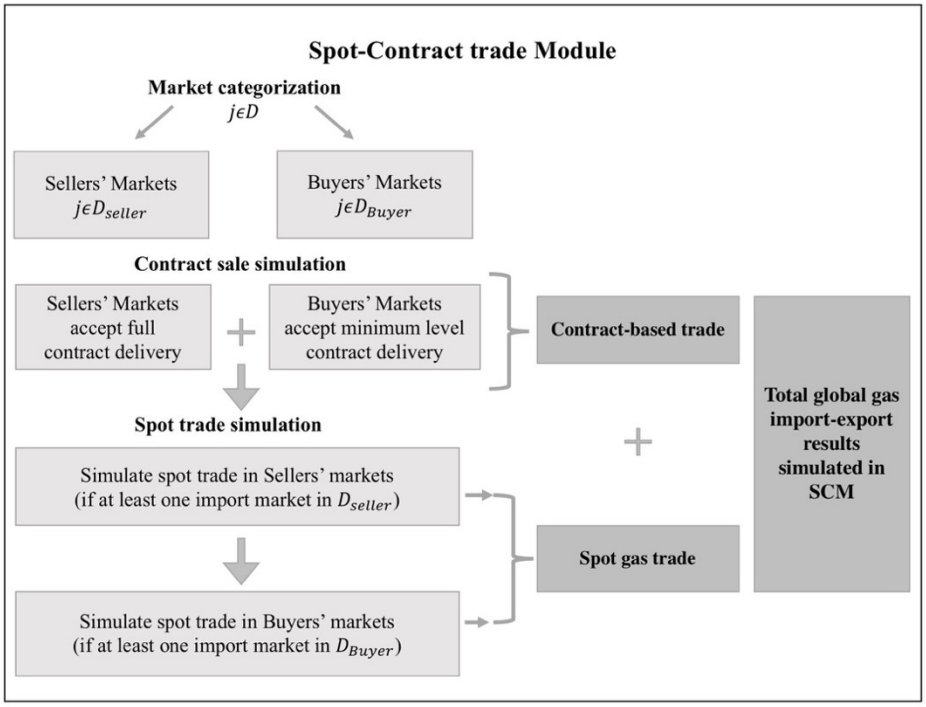


Fig. 3 - 8. Spot-Contract trade module method illustration

3.3.2.1 Market categorisation

In this step, the module evaluates the sales obliged by contracts, and how much they deviate from the Nash-Cournot equilibrium generated by MEM. It then categorises the import markets into two types: "Sellers' market" and "Buyers' market". The criterion for categorisation and the features of the two types of markets are introduced below.

As illustrated in Fig. 3 - 9, a market is categorised as a "Sellers' market" if it has contracted a less-than-equilibrium level of gas import. In this case, the supply secured by in-force contracts is insufficient to satisfy the market demand in equilibrium. Hence, the demand agent seeks to import more gas via spot trade. The supply capacities which can provide spot gas are limited because most capacities have been used to serve the contracted sales. In contrast, the market needs to purchase more to approach the equilibrium demand level. As a result, the pricing power in spot trade falls to the suppliers' side, and the concept of "Sellers' market" is used to describe this market disequilibrium condition [132]. The features of contract-based import and spot trade in a "Sellers' market" are summarised in Table 3- 10.

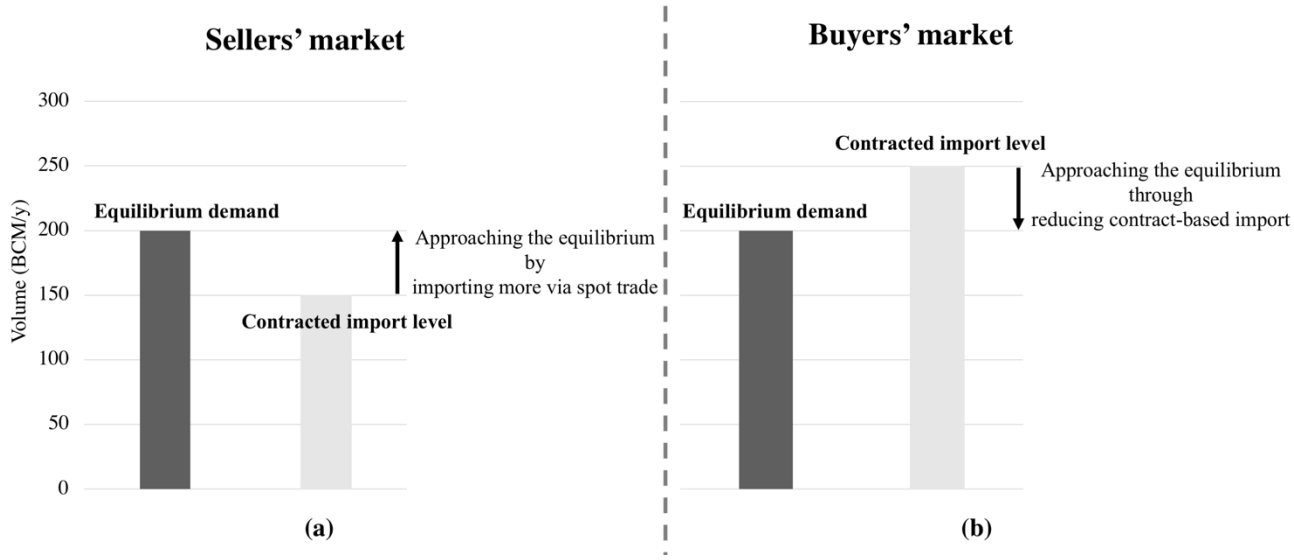


Fig. 3 - 9. Illustration of market categorisation in Gas-GAME-Spot

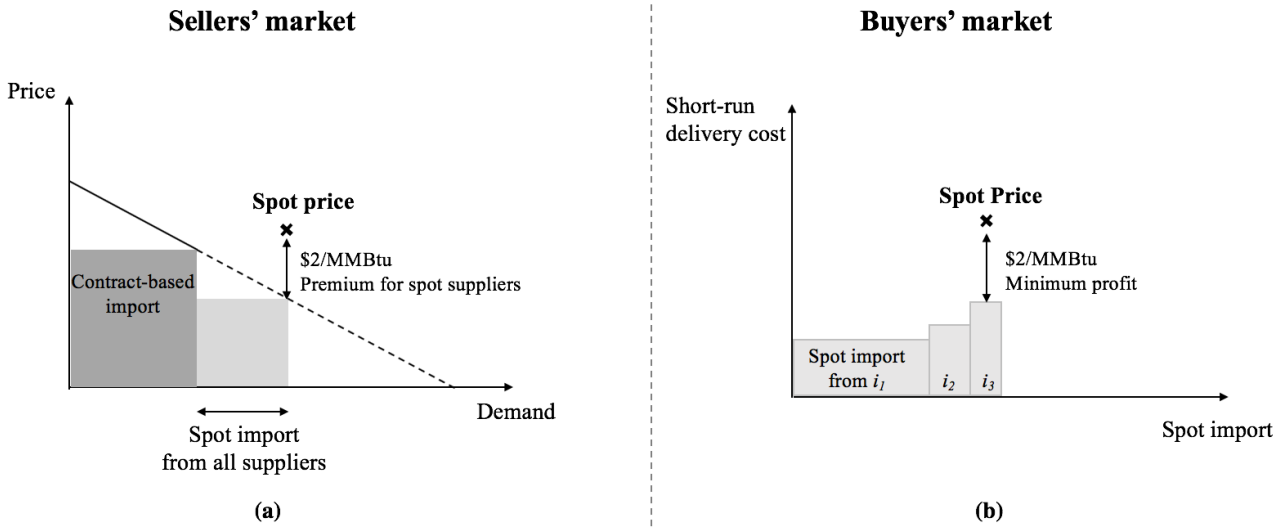


Fig. 3 - 10. Price for spot import in (a) Sellers' market and (b) Buyers' market

A market is categorised as a "Buyers' market" if a higher-than-equilibrium amount of gas supply has been contracted in that market. In this case, in order to approach the equilibrium, the market reduces its contract-based import by leveraging the contract flexibility. The buyers have little incentive to purchase on spot, and hence have power in price negotiation. This type of market has "Buyers' market" characteristics [132]. The algorithm of gas trade in a "Buyers' market" is presented in Table 3- 11.

Table 3- 10: Features of a Sellers' market

Process & Feature	Detailed setting in a Sellers' market	Justification
Purchase from the contracts	All in-place contracts are committed at full annual contract quantity in the time-period being simulated. The demand agent buys all the volumes as agreed on the contracts. The simulated contract-based trade equals $SALE_{i,j,t}^{PIPE,CT}$ and $SALE_{i,j,t}^{LNG,CT}$.	The market demand in equilibrium is higher than the contracted volume. The importer wants its demand satisfied by the secured supply based on contracts as much as possible, so that less gas needs to be sourced via the uncertain spot trades.
Term price of the contracted import $\pi_{j,t}^{CT}$	The term price is calculated based on the price-demand relationship in the market, with the demand equals to the total volume of contracted imports.	The price a demand agent would pay for the contracted volume of import should follow the market price-demand relationship.
Spot price of imports via spot trade $\pi_{j,t}^{SP}$	The spot price, as shown in Fig. 3 - 10a, is the price on the price-demand curve at the total demand level, plus a premium $PREM_j^{SP}$ ($2/MMBtu) paid for spot supplies.	The market price when demand equals to the total import can induce more consumption beyond the contracted level. The additional consumption is satisfied by the imports via spot trade. Therefore, the spot price is set based on this market price. Also, a premium, which is the extra return for the risks exporters hold when investing in additional capacities, needs to be paid for the importer's spot demand. The value of this premium is estimated based on historical data. Details are shown in Appendix A.
Maximum spot demand in a Sellers' market $MAX_{j,t}^{DMD,Seller}$	The difference between the equilibrium demand and the total contracted import	The demand agent imports additional gas via spot trade to reach the equilibrium demand level. The market stops importing if the equilibrium is reached.

Table 3- 11: Features of a Buyers' market

Process & Feature	Detailed setting in a Buyers' market	Justification
Purchase from the contracts	The market only purchases at the minimum level from the contracts. That is, for every contract in place, the contract-based sales are $\mu_{j,t}^{CT} SALE_{i,j,t}^{PIPE,CT}$ and $\mu_{j,t}^{CT} SALE_{i,j,t}^{LNG,CT}$. $\mu_{j,t}^{CT}$ is the minimum percentage of purchase obligation, and $SALE_{i,j,t}^{PIPE,CT}$ and $SALE_{i,j,t}^{LNG,CT}$ represent the trade volumes agreed on the contracts between i and j.	The market has already contracted more-than-enough for its demand in equilibrium. Though it wants to import less to approach the equilibrium, the long-term contracts have Take-or-Pay clauses which oblige the buyers to lift or pay for a minimum amount of gas, regardless of the buyers' demand. These clauses are simulated through the minimum purchase obligation, which is represented as a percentage of the annual contract quantity to address contracts of different sizes.
Term price of the contracted import $\pi_{j,t}^{CT}$	The term price is calculated based on the price-demand relationship in the market, with the demand equals the total volume of contract-based purchase.	The price a demand agent would pay for the contracted volume of import should follow the market price-demand relationship.
Spot price of imports via spot trade $\pi_{j,t}^{SP}$	The spot price in a Buyers' market, shown in Fig. 3 - 10b, consists of the highest short-term cost for spot delivery to this market, and the minimum level of profit $PROF_j^{SP}$ ($2/MMBtu) suppliers require to cover the project capital investment [133].	Since the buyer has the pricing power, the spot import should be priced at the marginal cost of spot gas supply. All suppliers need positive returns, and therefore the highest operational cost of spot sales to one market is chosen as the basis of the spot price there. Besides the operational cost, the suppliers need to have their capital cost covered on every trade they make. This leads to a minimum level of "profit" added to the highest operational cost, and the resulting spot price reflects the lowest level at which suppliers would agree to sell gas. Details on the estimation of the minimum profit are shown in Appendix A.
Maximum spot demand in a Buyers' market $MAX_{j,t}^{DMD,Buyer}$	If the total contract-based import is higher than the equilibrium demand, the market has no spot demand. If the total contract-based import is less than the equilibrium demand, the difference between these two amounts is the maximum spot demand.	The market minimises its purchase from its contract obligations. If the minimised import is still higher than the equilibrium, to best approach the equilibrium, the importer would stop importing spot gas. Otherwise, it imports the remaining amount via spot trade to reach the market equilibrium.

3.3.2.2 Contract sale simulation

As shown in Table 3- 10 and Table 3- 11, markets of different types purchase gas through their contracts in different ways. For a Sellers' market, all secured volumes from the contracts ($SALE_{i,j,t}^{PIPE,CT}$ and $SALE_{i,j,t}^{LNG,CT}$) are imported since the market equilibrium demand is higher than the contracted volume. For a Buyers' market, since it has already contracted more than enough to meet equilibrium demand, it purchases at the minimum level allowed by the contracts. The minimum level is assumed to be a percentage μ of the total contracted volume, and every contracted delivery to this market is minimised ($\mu_{j,t}^{CT} SALE_{i,j,t}^{PIPE,CT}$ and $\mu_{j,t}^{CT} SALE_{i,j,t}^{LNG,CT}$). The term prices of the contract-based imports are determined based on the market demand-price relationships. The justification is presented in Table 3-10 and Table 3- 11, and the detailed price equations are shown in Table 3- 12.

Table 3- 12: Spot-Contract trade Module market price equations

Market type	Price type	Price equation	
Sellers' market $j \epsilon D_{Seller}$	Contract term price	$\pi_{j,t}^{CT} = INT_{j,t} - SLP_{j,t}\left(IMP_{j,t}^{CT}\right)$	(47)
Sellers' market $j \epsilon D_{Seller}$	Spot price	$\pi_{j,t}^{SP} = INT_{j,t} - SLP_{j,t}\left(IMP_{j,t}^{CT} + IMP_{j,t}^{SP}\right) + PREM_{j}^{SP}$	(48)
Buyers' market $j \epsilon D_{Buyer}$	Contract term price	$\pi_{j,t}^{CT} = INT_{j,t} - SLP_{j,t}\left(\mu_{j,t}^{CT} IMP_{j,t}^{CT}\right)$	(49)
Buyers' market $j \epsilon D_{Buyer}$	Spot price	$SetC_{j,t}^{PIPE} = \left\{C_{i,j,t}^{PIPE}\right\};\ \forall SALE_{i,j,t}^{PIPE,SP} > 0$	(50)
		$SetC_{j,t}^{LNG} = \left\{C_{i,j,t}^{LNG}\right\};\ \forall SALE_{i,j,t}^{LNG,SP} > 0$	(51)
		$\pi_{j,t}^{SP} = \max_{j,t}\left(SetC_{j,t}^{PIPE} \cup SetC_{j,t}^{LNG}\right) + PROF_{j}^{SP}$	(52)

3.3.2.3 Spot trade simulation

The suppliers serve the contract-based sales first and calculate the corresponding capacities used for producing and transporting the gas in these sales. They then utilise the remaining capacities for spot export. The schematic chart of supply agents' participation in spot trade is presented in Fig. 3 - 11.

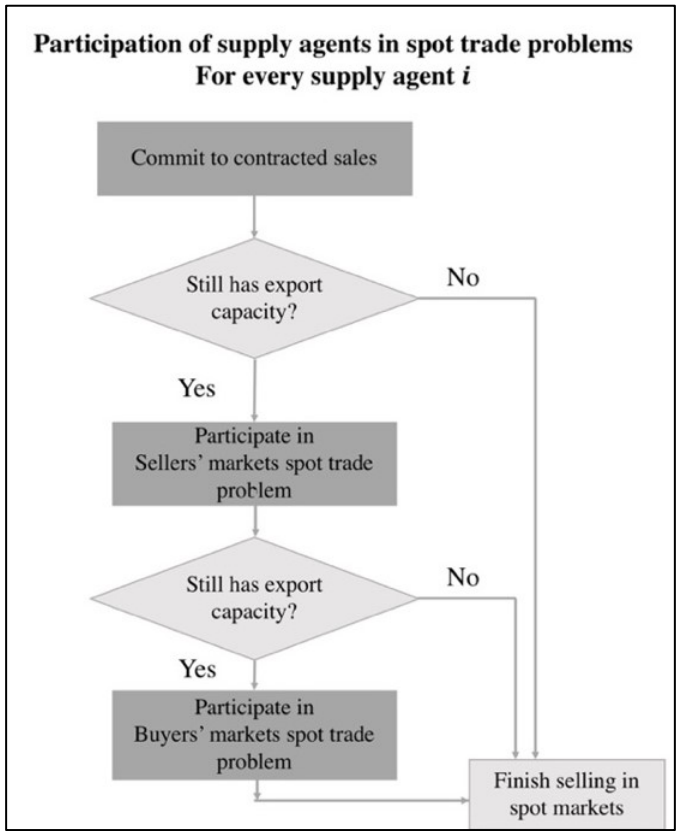


Fig. 3 - 11. Supply agent spot trade schematic chart

The simulation of spot trade starts from the Sellers' markets, because these markets require additional spot gas to reach the equilibrium demand and therefore offer higher prices. All suppliers with spare capacities participate to sell, and all markets categorised as "Sellers' market" participate to buy. The problem, presented in Table 3- 13, is formulated as overall system profit maximisation subject to the constraints on capacity and spot demand. The assumption of perfect competition is made because the remaining supply capacities are limited, and suppliers do not expect to alter spot prices via their sales. The capacity constraints ensure that the remaining production and transmission capacities are sufficient to deliver the spot sales. The maximum spot demand of each market, with the equations presented in Table 3- 14, is the difference between the market equilibrium demand and the total contract-based import. The justification of maximum spot demand is presented in Table 3- 11.

The module then continues to simulate the spot trade in the Buyers' markets. The suppliers who still have extra capacities participate to sell, and all markets categorised as "Buyers' market" participate to buy. In this problem, as presented in Table 3- 15, the suppliers are also assumed as price takers, and they use the term price as the reference price for the overall system profit maximisation. The term price is chosen as the reference price because it represents the ceiling of the spot price in a buyers' market. The demand agents, when over-contracted, will not pay higher-than-term for their spot purchase. Similar to the Sellers' market problem, the available capacity and maximum spot demand,

calculated following the formula in Table 3- 16, limit the volume of spot trade. The difference between the market equilibrium demand and the total contract-based import is calculated. If the value is positive, it is the maximum spot demand of the market. Otherwise, the market does not import via spot.

The spot trades simulated in Sellers's markets and Buyers' markets are then combined with contract-based trades. The combined trades represent the global gas flows in the simulation time-period. In essence, this simulated condition is a pragmatic realisation of the theoretical market equilibrium with the contract obligations fulfilled.

Table 3- 13: Sellers' market problem in Gas-GAME-Spot

Description	Formula	
Objective function	$\text{Max} \sum_{j\in D_{Seller}} \sum_{i\in S} \left[SALE_{i,j,t}^{PIPE,SP}\left(\pi_{j,t}^{SP} - C_{i,j,t}^{PIPE}\right) + SALE_{i,j,t}^{LNG,SP}\left(\pi_{j,t}^{SP} - C_{i,j,t}^{LNG}\right)\right]$	(53)
Production capacity $\forall i \in S$	$\sum_{j\in D_{Seller}} \left(SALE_{i,j,t}^{LNG,SP} + SALE_{i,j,t}^{PIPE,SP}\right) \leq MAX_{i,t}^{PRD,Seller}$	(54)
Pipeline capacity $\forall i \in S;\ \forall j \in D_{Seller}$	$SALE_{i,j,t}^{PIPE,SP} \leq MAX_{i,j,t}^{PIPE,Seller}$	(55)
Liquefaction capacity $\forall i \in S$	$\sum_{j\in D_{Seller}} SALE_{i,j,t}^{LNG,SP} \leq MAX_{i,t}^{LIQ,Seller}$	(56)
Regasification capacity $\forall j \in D_{Seller}$	$\sum_{i\in S} SALE_{i,j,t}^{LNG,SP} \leq MAX_{j,t}^{REG,Seller}$	(57)
Maximum demand $\forall j \in D_{Seller}$	$\sum_{i\in S} \left(SALE_{i,j,t}^{LNG,SP} + SALE_{i,j,t}^{PIPE,SP}\right) \leq MAX_{j,t}^{DMD,Seller}$	(58)

Table 3- 14: Maximum capacity and demand in the Sellers' market problem

Type	Maximum value calculation	
Production capacity $\forall i \in S$	$MAX_{i,t}^{PRD,Seller} = MAX_{i,t}^{PRD} - \sum_{j\in D_{Seller}} \left(SALE_{i,j,t}^{PIPE,CT} + SALE_{i,j,t}^{LNG,CT}\right) - \sum_{j\in D_{Buyer}} \mu_{j,t}^{CT}\left(SALE_{i,j,t}^{PIPE,CT} + SALE_{i,j,t}^{LNG,CT}\right)$	(59)
Pipeline capacity $\forall i \in S;\ \forall j \in D_{Seller}$	$MAX_{i,j,t}^{PIPE,Seller} = MAX_{i,j,t}^{PIPE} - SALE_{i,j,t}^{PIPE,CT}$	(60)
Liquefaction capacity $\forall i \in S$	$MAX_{i,t}^{LIQ,Seller} = MAX_{i,t}^{LIQ} - \sum_{j\in D_{Seller}} SALE_{i,j,t}^{LNG,CT} - \sum_{j\in D_{Buyer}} \mu_{j,t}^{CT} SALE_{i,j,t}^{LNG,CT}$	(61)
Regasification capacity $\forall j \in D_{Seller}$	$MAX_{j,t}^{REG,Seller} = MAX_{j,t}^{REG} - \sum_{i\in S} SALE_{i,j,t}^{LNG,CT}$	(62)
Maximum demand $\forall j \in D_{Seller}$	$MAX_{j,t}^{DMD,Seller} = IMP_{j,t}^{EQ} - IMP_{j,t}^{CT}$	(63)

Table 3- 15: Buyers' market problem in Gas-GAME-Spot

Description	Formula	
Objective function	$\text{Max} \sum_{j\in D_{Buyer}} \sum_{i\in S}\left[SALE_{i,j,t}^{PIPE,SP}\left(\pi_{j,t}^{CT} - C_{i,j,t}^{PIPE}\right) + SALE_{i,j,t}^{LNG,SP}\left(\pi_{j,t}^{CT} - C_{i,j,t}^{LNG}\right)\right]$	(64)
Production capacity $\forall i \in S$	$\sum_{j\in D_{Buyer}} \left(SALE_{i,j,t}^{LNG,SP} + SALE_{i,j,t}^{PIPE,SP}\right) \le MAX_{i,t}^{PRD,Buyer}$	(65)
Pipeline capacity $\forall i \in S;\ \forall j \in D_{Buyer}$	$SALE_{i,j,t}^{PIPE,SP} \le MAX_{i,j,t}^{PIPE,Buyer}$	(66)
Liquefaction capacity $\forall i \in S$	$\sum_{j\in D_{Buyer}} SALE_{i,j,t}^{LNG,SP} \le MAX_{i,t}^{LIQ,Buyer}$	(67)
Regasification capacity $\forall j \in D_{Buyer}$	$\sum_{i\in S} SALE_{i,j,t}^{LNG,SP} \le MAX_{j,t}^{REG,Buyer}$	(68)
Maximum demand $\forall j \in D_{Buyer}$	$\sum_{i\in S}\left(SALE_{i,j,t}^{LNG,SP} + SALE_{i,j,t}^{PIPE,SP}\right) \le MAX_{j,t}^{DMD,Buyer}$	(69)

Table 3- 16: Maximum capacity and demand in the Buyers' market problem

Type	Maximum value calculation	
Production capacity $\forall i \in S$	$MAX_{i,t}^{PRD,Buyer} = MAX_{i,t}^{PRD,Seller} - \sum_{j\in D_{Seller}} \left(SALE_{i,j,t}^{PIPE,SP} + SALE_{i,j,t}^{LNG,SP}\right)$	(70)
Pipeline capacity $\forall i \in S;\ \forall j \in D_{Buyer}$	$MAX_{i,j,t}^{PIPE,Buyer} = MAX_{i,j,t}^{PIPE} - \mu_{j,t}^{CT} SALE_{i,j,t}^{PIPE,CT}$	(71)
Liquefaction capacity $\forall i \in S$	$MAX_{i,t}^{LIQ,Buyer} = MAX_{i,t}^{LIQ,Seller} - \sum_{j\in D_{Seller}} SALE_{i,j,t}^{LNG,SP}$	(72)
Regasification capacity $\forall j \in D_{Buyer}$	$MAX_{j,t}^{REG,Buyer} = MAX_{j,t}^{REG} - \sum_{i\in S} \mu_{j,t}^{CT} SALE_{i,j,t}^{LNG,CT}$	(73)
Maximum demand $\forall j \in D_{Buyer}$	$MAX_{j,t}^{DMD,Buyer} = Max(0, IMP_{j,t}^{EQ} - \mu_{j,t}^{CT} IMP_{j,t}^{CT})$	(74)

3.3.3 Infrastructure expansion module (IEM)

This module is designed in the same way as the original Gas-GAME, except that it takes the results from the SCM, instead of the MEM, to inform the simulation. Three aspects are affected by this change.

Firstly, demand agents' evaluation of the total import request $EXP_IMP_{j,t'}$ in a future period t' is affected. A demand agent uses a reference price and the market price-demand relationship in period t' to determine $EXP_IMP_{j,t'}$. In Gas-GAME-Spot, the weighted average price $\pi_{j,t}^{AVG}$ (see Table 3- 17) of a market considering both contract-based and spot import, emanated from the SCM in the running period t, is used as the reference price. The equilibrium price $\pi_{j,t}^{EQ}$ emanated from the MEM is not used.

Table 3- 17: Weighted average market price in Gas-GAME-Spot

Market type	Formula	
Sellers' market	$\pi_{j,t}^{AVG} = \frac{\left(\pi_{j,t}^{CT} IMP_{j,t}^{CT} + \pi_{j,t}^{SP} IMP_{j,t}^{SP}\right)}{IMP_{j,t}^{CT} + IMP_{j,t}^{SP}}$	(75)
Buyers' market	$\pi_{j,t}^{AVG} = \frac{\left(\pi_{j,t}^{CT} \mu_{j,t}^{CT} IMP_{j,t}^{CT} + \pi_{j,t}^{SP} IMP_{j,t}^{SP}\right)}{\mu_{j,t}^{CT} IMP_{j,t}^{CT} + IMP_{j,t}^{SP}}$	(76)

Secondly, how demand agents distribute the contract requests to each supply partner is affected. The share $\alpha_{i,j,t}^{PIPE}$ and $\alpha_{i,j,t}^{LNG}$ each supply agent i gets from the remaining to-be-contracted volume in market j is based on the sum of contracted and spot sale in period t. Detailed equations are listed in Table 3- 18.

Table 3- 18: Contract request percentage in Gas-GAME-Spot

	Market as a Sellers' market		Market as a Buyers' market	
Pipeline	$\alpha_{i,j,t}^{PIPE} = \frac{\left(SALE_{i,j,t}^{PIPE,SP} + SALE_{i,j,t}^{PIPE,CT}\right)}{IMP_{j,t}^{SP} + IMP_{j,t}^{CT}}$	(77)	$\alpha_{i,j,t}^{PIPE} = \frac{\left(SALE_{i,j,t}^{PIPE,SP} + \mu_{j,t}^{CT} SALE_{i,j,t}^{PIPE,CT}\right)}{IMP_{j,t}^{SP} + \mu_{j,t}^{CT} IMP_{j,t}^{CT}}$	(78)
LNG	$\alpha_{i,j,t}^{LNG} = \frac{\left(SALE_{i,j,t}^{LNG,SP} + SALE_{i,j,t}^{LNG,CT}\right)}{IMP_{j,t}^{SP} + IMP_{j,t}^{CT}}$	(79)	$\alpha_{i,j,t}^{LNG} = \frac{\left(SALE_{i,j,t}^{LNG,SP} + \mu_{j,t}^{CT} SALE_{i,j,t}^{LNG,CT}\right)}{IMP_{j,t}^{SP} + \mu_{j,t}^{CT} IMP_{j,t}^{CT}}$	(80)

Thirdly, when supply agents evaluate the profitability (IRR) of their received contract requests, they use the weighted average market price $\pi_{j,t}^{AVG}$ from the SCM in running period t, instead of the equilibrium prices $\pi_{j,t}^{EQ}$ generated from MEM, for expected revenue calculation.

Besides the changes caused by taking the SCM results as input, the IEM in Gas-GAME-Spot is also modified in the "contract-based expansion" part. The expansion targets to make total capacity in the next period, instead of the future period t', capable of supplying contracted gas export. This

modification is to mimic the gradual development of gas suppliers' infrastructure. If the infrastructure in place MAX_AVL in the next period t_{next} is smaller than the required capacity MAX_REQ, the difference between the two values is the corresponding expansion capacity. Otherwise, no expansion is conducted.

3.3.4 Programming environment and solver

Similar to Gas-GAME and Gas-GAME-Risk, the Pyomo (Python Optimization Modelling Objects) package [134] is used to interface with the solvers. Besides the PATH solver [125], which is used for the MEM MCP problem, IPOPT solver [135] is also used for SCM linear and nonlinear optimisation problems.

Chapter 4. The impacts of North American export strategies on global gas trade

This chapter presents the study based on Gas-GAME to examine the outcomes of North American alternative exporting strategies. The input data of the base case and the general assumptions on agent strategies are firstly introduced. The framework of two alternative scenarios is also presented. In section 4.2, the model is validated by comparing the base case results with other projections from the literature. Why the modelling method of Gas-GAME leads to different gas market projections is also discussed. Following this, the base case results, focusing on how gas imports and prices in three major markets change with respect to time, are presented. In section 4.3, the two alternative scenarios, which respectively simulate conservative and aggressive North American export strategies, are discussed. The impacts of the uncertain strategies are examined based on scenario analysis.

4.1 Model input data and assumptions

The base year is set as 2010, and the model runs until 2060 using 5-year time-periods. This section summarises the parameters and assumptions used in the study. The base case is described first, followed by the scenario framework, which explains how alternative scenarios differ from the base one.

4.1.1 MEM main parameters

The market price-demand relationships in the base period are derived using consumption data from the BP Statistical Review of World Energy [126], import data from IEA Natural Gas Information [136], and regional prices from the IGU Whole Sale Gas Price Report [128]. The elasticity values range from -0.25 to -0.75 [8]. Table 4- 1 presents the reference values of each market, and the calculation of INT and SLP for each market is based on the equations (see Table 4- 2) derived from the definition of elasticity.

Table 4- 1: Base-period import market price-demand relationship parameters

Import market	**Total demand volume [126] (BCM/y)**	**Import volume [137] (BCM/y)**	**Base price [128] (US $/MMBtu)**	**Elasticity [8]**
Symbol	D	D'	P	ε
East Asia	224	155	10.5	-0.25
West Europe	529	354	8.0	-0.7
East Europe	94	77	5.0	-0.6
India	61	12	4.4	-0.5
China	115	14	6.3	-0.5

Table 4- 2: Calculation of price-demand relationships

Parameter	Equation	
Definition of elasticity	$\varepsilon = \frac{\Delta Q}{Q} / \frac{\Delta P}{P}$	(81)
Price-demand slope	$SLP = \frac{\Delta Q}{\Delta P} = \frac{P}{\varepsilon D}$	(82)
Price-demand intersection	$INT = P - \frac{D'}{\varepsilon} * \frac{P}{D}$	(83)

To derive short-run unit gas delivery cost $C_{i,j,t}^{PIPE}$ and $C_{i,j,t}^{LNG}$ for each trade route in the base period, the production and transmission operational costs, with the data sources presented in Table 4- 3, are summed up to derive the literature-based values. However, as real-world gas trades are subject to many other considerations from both sides, such as supply security and geopolitical issues, calibration has been applied to $C_{i,j,t}^{PIPE}$ and $C_{i,j,t}^{LNG}$ to ensure the MEM generates the same global gas flows as the actual conditions in the base year, as per the IEA Natural Gas Information [136]. The calibrated values are then compared with the literature-based values. According to the deviation level between the two values, non-cost factors at \$0/MMBtu, \$3/MMBtu, or \$6/MMBtu are assigned to different routes, reflecting all other drivers or barriers for inter-regional gas trade. Therefore, the short-run unit gas trade costs used in the MEM are the literature-based costs plus the corresponding calibrated non-cost factors. Details of the $C_{i,j,t}^{PIPE}$ and $C_{i,j,t}^{LNG}$ values for all trade routes are presented in Appendix B.

Table 4- 3: Parameters and assumptions in MEM in Gas-GAME

Parameter	Value, description, and reference
Production operational costs	The field-level OPEX median in each region from Wood Mackenzie Upstream Database [138]
Pipeline operational costs	From \$10M/BCM to \$30M/BCM per year, depending on the pipeline distance and onshore/offshore property This is adopted in many studies such as [7, 8, 106].
LNG transmission operational costs	Liquefaction processes: \$40M/BCM per year [106] Regasification processes: \$8M/BCM per year [106] Shipping costs : \$2M/BCM/day [139]; Shipping speed is assumed to be 19 knots. Route distances are approximated from www.distances.com.
Production capacity in the base period	Natural gas production from BP energy statistics [126] This study assumes the base-period export production capacity as the total production volume in each region initially, for the following reasons: 1) The regional production capacity targeting gas export business is not definite, as fields may supply both domestic and international demand.

	2) The total regional production volumes are higher than the export volumes, allowing the capacity limit not met. This reflects the condition in the base period [8]. 3) After the initial period, the simulation of capacity expansion will narrow the deviation of this assumption.
Pipeline capacity in the base period	For the gas pipelines to Europe, the European Natural Gas Network map published by ENTSOG is used [140]. For the remaining inter-regional pipelines, the IEA Oil and Gas Emergency Policy assessment report [141] is used.
Liquefaction capacity in the base period	Based on the country-wise data published in the IGU World LNG report [139].
Regasification capacities in the base period	Based on the country-wise data published in the IGU World LNG report [139].

The calculation of base-period production, liquefaction, regasification, and pipeline capacity is also presented in Table 4- 3. To construct the initial *Infrastructure Database*, the decommissioning of base-period capacities is assumed to be over a period of 25 years at a constant rate, starting from 2015.

The simulation does not account for the inflation rate, and all the costs and prices are represented in the base year real values. For the simulation of future periods, the market price-demand relationships are adjusted from the base-period values to the projection presented in WEO [41]. It is assumed that the SLP values remain constant, whereas the INT values, between 2010 and 2040, adapts gradually towards the WEO New Policies Scenario 2040 gas market import levels in a linear manner [41]. From 2040 till 2060, demand agents are assumed to keep using the 2040 relationships. The detailed values of INT and SLP for each market in all simulated periods are presented in Appendix B. The values of short-run delivery costs $C_{i,j,t}^{PIPE}$ and $C_{i,j,t}^{LNG}$ are kept constant throughout the simulation horizon. The production and transmission capacities are updated endogenously through the IEM simulation.

4.1.2 IEM main parameters and agent strategy assumptions

To construct the initial *Contract Database*, contracts concluded by 2014 are obtained from a literature survey of long-term contracts compiled by DIW Berlin [142]. The LNG contracts concluded after 2014 until 2016 are compiled from the GIIGNL annual reports [131]. The pipeline contracts, which are limited in number, are individually gathered based on the announced projects. It is assumed that future contracts are 30-years in length, and this corresponds to the lifetime of the supply capacities underpinned by these contracts [29].

The demand agents' contracting strategies have been explained briefly in Chapter 3. Further details and justifications are presented here. For the IEM running in period t, the demand agents conduct forward planning using t', which is 15 years ahead of the next period (20 years ahead of t).

This period t' is chosen to represent the average import and contracting requests (with annual contract quantity) over the future periods when new contracts would be in force. Therefore, the period t' is assumed as the midpoint of the 30 years from the next period onwards. The feasible contracting partners of each market are presented in Appendix A. These are summarised based on historical trade condition and geographical trade feasibility. From 2010 to 2035, each demand agent uses its market price, generated from running period MEM, and the next-period demand curve to estimate future import requirements. The next-period demand curve is used because the demand agents lack future market information and therefore calculate based on the latest available information they have. From 2035 onwards, it is assumed that importing countries consider the limitation of fossil fuels beyond 2050 due to climate policies, and therefore fix their future import requirements at low levels [41, 123]: West Europe 400 BCM/yr; East Asia and China 200 BCM/yr each; East Europe and India 100 BCM/yr each.

The maximum contract ratios are 100%, and the contract request allocation to suppliers is based on the last-period MEM market shares. For the new potential suppliers (See Appendix B), 10% is used as the starting shares. Since the 10% is not included in the last-period market share, the total $\alpha_{i,j,t}^{PIPE}$ and $\alpha_{i,j,t}^{LNG}$ for a market which has new suppliers would be more than 100%. However, the influence of such extra allocation is limited for two reasons. Firstly, not all contracts would be agreed, and the total volume of confirmed contracts is always smaller than the total required contract volume. Secondly, the extra allocation to new suppliers only happens once for each market. Once a contract is confirmed between a new pair and gas trade is simulated between the two regions, the new suppliers become normal suppliers and receive contract request allocation based on the market share in period t. When a pair of supply and demand agents have contracted over 30 BCM/yr, yet fail to trade in MEM during the last period, the demand agent will stop sending contract requests to that supplier in the following period. This additional assumption is to avoid the condition, in which an exporter keeps contracting with one importer (a new trade partner) to develop capacities, which are then used for gas sales to other importers.

The supply agents' economic evaluation method for contract agreement is also explained briefly in Chapter 3. IRR is used as the metric of decision making, and supply agents accept contracts with IRR higher than 12% [143]. Regarding the computation of IRR, both production and transmission projects at contract-requested volumes are considered. Supply agents evaluate the pipeline contracts considering production and pipeline capital investment, and the LNG contracts considering production and liquefaction capital investment. The capital costs are calculated based on references presented in Table 4- 4. For annual revenue estimation, the market prices in period t are multiplied by the requested

volumes. For annual profit calculation, the literature-based short-run trade costs are subtracted from the annual revenues. Regarding the cashflow for IRR calculation, project capital investments are deducted at the beginning and supply agents assume a 5-year lead time. Supply agents assume that they would earn annual profits for 30 years of operation. There is no change in the evaluation criteria throughout the simulation time horizon.

Table 4- 4: Capital cost input parameter references in IEM in Gas-GAME

Capital cost type	Reference description
Production plant capital cost	The total capital cost CAPEX is assumed to be proportional to total expected production volume of the production project. The unit capital cost for each region is the median value based on the field-level data from the Wood Mackenzie Upstream Database [138].
Pipeline capital cost	The cost depends on the transmission pipeline length [144] and the unit construction cost [145].
Liquefaction capital cost	The cost is based on IGU World LNG Report [146] and it varies by export regions.

After the contracts are confirmed, they are updated in the contract database, and capacity expansion is conducted. For the newly expanded infrastructure, the expected lifetime is 30-year for production, liquefaction, regasification, and pipeline [1, 104, 147].

4.1.3 Scenario framework

Besides the base case, two alternative scenarios – ConNA (conservative North America investment) and AggNA (aggressive North America investment) – have been simulated. By comparing the two scenarios with the base case, the impacts of North American LNG investment strategy on future global gas trade are examined.

In the ConNA scenario, North America sets the IRR benchmark for accepting contract requests at 20%, representing investors' expectation of high uncertainties in future LNG prices and hence only expand capacities for high returns. Note that this modification only affects the future contracts generated endogenously in IEM. Regarding those contracts already concluded by 2016, this scenario assumes that the related investment would happen. Other supply agents continue using 12% IRR as their contracting criteria.

The AggNA scenario describes the condition when North America sets its contracting criterion as IRR over 5% and further decreases its non-cost component in $C_{i,j,t}^{LNG}$ to zero gradually from 2010 to 2040. Here, North American investors expand at lower return rates, in an attempt to obtain a dominant LNG supplier position and benefit through high-volume trades. In essence, it represents a scenario where North America intends to realise the value of its gas resources as soon as possible.

4.2 Model validation

Model validation is achieved by comparing the base case result to the World Energy Outlook (WEO) [41]. The results are also compared with WGM [8], which is the best documented mixed complementarity problem global gas model, and BP energy outlook [148], which is another widely known projection in the energy industry. Following the comparison, the reasons why the modelling method presented herein leads to differences in projection results are explained.

4.2.1 Result comparison with other projections

The results in the base year are calibrated with the real world trade data in 2010 [136]. All parameters are sourced from reliable literature and databases. The assumptions, which are justified in the above sections, are carefully chosen to best reflect gas market characteristics. To further validate this model, the base case results are compared with other models. However, it needs to be understood that the comparisons are limited to some constraints. Firstly, some models, for example the BIWGM reviewed in Chapter 2, were published long ago with some assumptions no longer realistic to gas markets at the time of writing [34]. Hence, the differences between the results, instead of challenging the validity of this model, reflect more on changes in this industry. Secondly, most models only publish a small part of their results, which are related to their discussion. Therefore, the results that can be used for cross-model comparison are limited. Subject to these two constraints, the following validation compares the base case with the most relevant results from several well-known industry outlooks and the best documented global gas model. It also needs to be understood that modelling result differences also contribute to further discussion on how alternative gas markets may evolve. This is key to identifying the uncertainties in the energy transition phase.

The base case of Gas-GAME simulation shows a steady increase in global gas trade, from 612 BCM/yr in 2010 to 1100 BCM/yr in 2060. Since the regional segregation is different between the models, the comparison focuses on a general aspect – the global trade growth relative to the level in 2010. In addition, since other models only publish projections until 2040, the comparison is only conducted until then. Detailed figures are shown in Table 4- 5. The base case result of 89% global trade growth in 2040 relative to 2010 is within the range of 72% to 142% suggested by other models.

Table 4- 5: International gas trade growth relative to 2010 projected by different models

	Gas-GAME	**IEA WEO*** **[41]**	**BP Energy outlook [148]**	**World Gas Model [8]**
2020	30%	14%	N.A.	32%
2030	47%	47%	N.A.	55%
2040	89%	72%	142%	N.A.

* This uses the "New policies scenario" from World Energy Outlook

Meanwhile, the share of inter-regional LNG transmission also grows gradually from 40% in 2010 to 60% in 2040, then remains at this level. This is similar to what is projected in industry (see the comparison shown in Fig. 4 - 1).

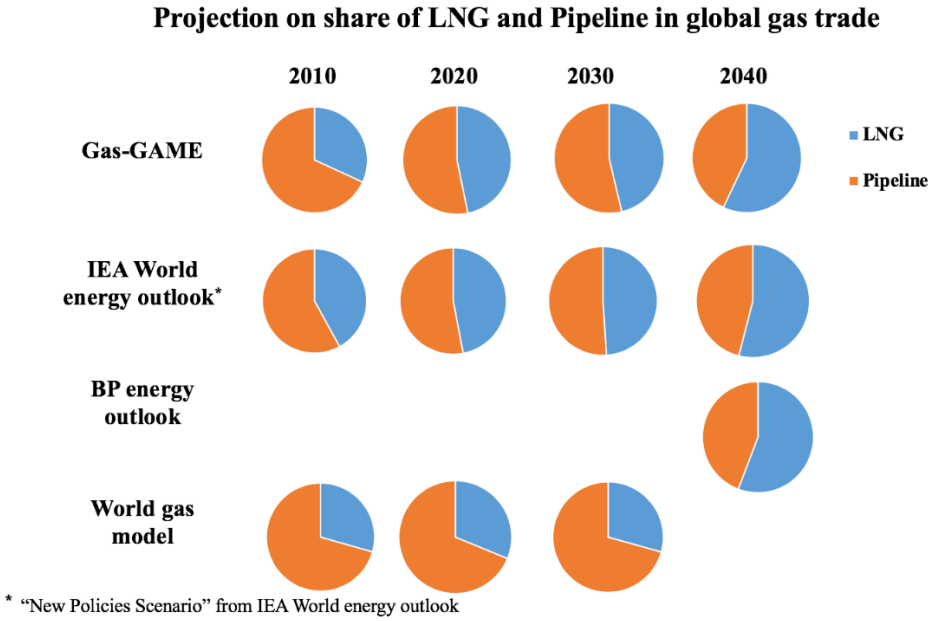


Fig. 4 - 1. Comparison of global LNG and Pipeline trade proportion between Gas-GAME base case and other outlooks

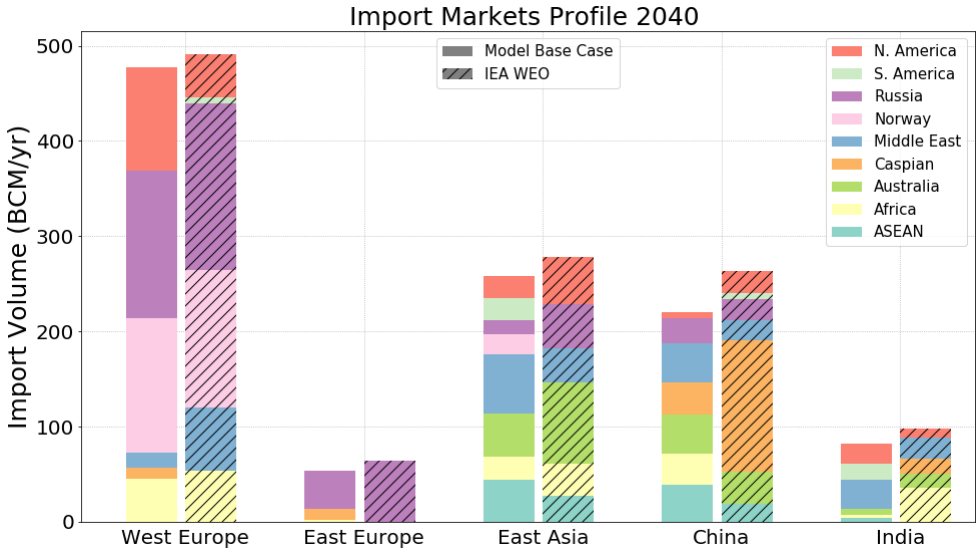


Fig. 4 - 2. Comparison of gas import in 2040 between Gas-GAME base case and WEO New Policies Scenario

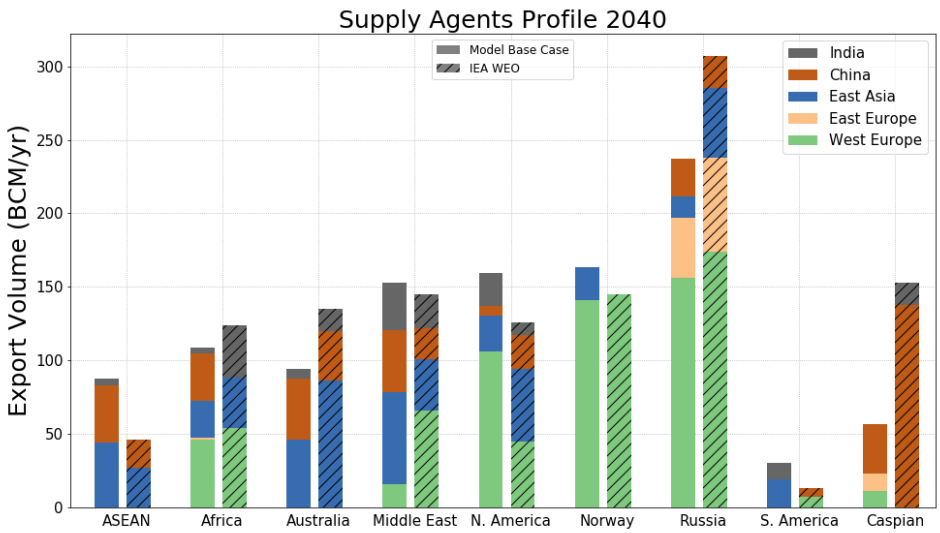


Fig. 4 - 3. Comparison of gas export in 2040 between Gas-GAME base case and WEO New Policies Scenario

Since the IEA WEO New Policies Scenario projection is the only one with global trade details in 2040, it is compared with the Gas-GAME base case to illustrate the validity of this model [41]. Fig. 4 - 2 and Fig. 4 - 3 show that both demand and supply sides have broad similarities. In East Asia, Australia sells less at 46 BCM/yr in Gas-GAME as compared to 88 BCM/yr in WEO. In contrast, higher market shares are gained by the Middle East (24%) and ASEAN (17%) in this simulation. The Chinese gas market grows substantially in both projections to around 250 BCM annual import in 2040. However, unlike WEO which projects that Caspian supplies to dominate the Chinese market by taking 57%, Gas-GAME indicates the Caspian share as only 15%, with the Middle East, Australia and ASEAN each taking around one fifth. The supplies from Russia and Africa also play important roles in the Chinese market. Results are rather similar for Western Europe, with Gas-GAME showing slightly lower imports from the traditional main suppliers like Russia and Norway. The emerging exporters like North America and Caspian achieve more trades.

Generally speaking, most demand agents import slightly less in Gas-GAME base case as compared to WEO. In addition, the volumes flowing into one market are more evenly distributed among the suppliers. The reasons lie in the algorithms of both MEM and IEM: 1) the Nash-Cournot equilibrium computed by MEM tend to have large suppliers with market power strategically selling less for higher profit margins, opening the opportunity for fringe players to grab more market shares; 2) more supplies from one fringe player enable it to receive more contracts for the following period, as the demand agents allocate contract requests in IEM based on last period trades. This correspondingly promotes the regional production and transmission infrastructure development. Hence, new suppliers are allowed with more competitive positions in markets via the Gas-GAME model design.

As WEO does not explicitly model the infrastructure development, the WGM 2030 projection [8] is used for LNG capacity comparison, as shown in Fig. 4 - 4. In WGM, the infrastructure operators invest based on perfect foresight over the whole projection horizon. Hence, major players like the Middle East, ASEAN, and Africa expand their exportation capacities aggressively to secure large volume profitable sales. New entrants in LNG trade, namely North America and Australia, have lower expansion levels as compared to the Gas-GAME base case. This is because the capacity expansion algorithm of Gas-GAME combines demand-side import requests and supply-side economic analysis, both of which are based on current period market prices. When the prices become high, the exporters, similarly with WGM, tend to invest aggressively. However, the importers would see gas less attractive and therefore assign contract requests with lower volumes. In this way, the economic incentives of both sides are balanced, leading to more moderate expansions by major players. New entrants in a market initially receive 10% of the total requests to start their infrastructure development. Once they begin selling in the markets, demand agents continue to assign contract requests and thus their market shares can increase further. Consequently, Gas-GAME IEM allows new entrants to take the market shares from major players gradually as long as they can deliver gas competitively.

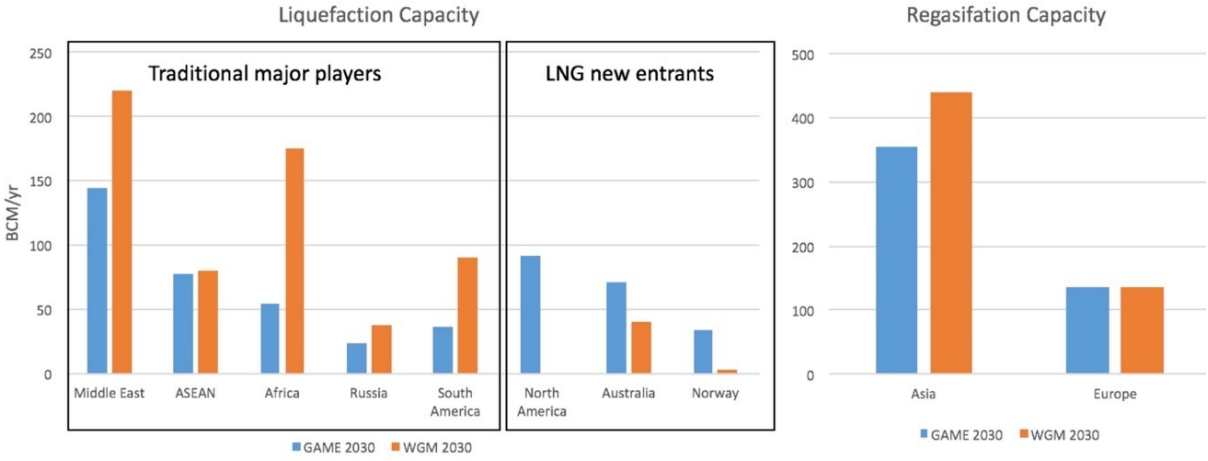


Fig. 4 - 4. Projections on liquefaction and regasification capacity

To conclude, the comparisons and discussions above show that Gas-GAME results align well with industry projections and other models. The variations in global gas trade in 2040 (Gas-GAME versus IEA WEO) and LNG development in 2030 (Gas-GAME versus WGM), are explained through an examination of the modelling methods. Since the base-period result has been calibrated against real world data, and all parameters and assumptions are supported by literature, the alternative scenarios generated from Gas-GAME do explore the possible gas market futures that were traditionally overlooked by other models.

4.2.2 Further discussion on the base case results

Fig. 4 - 5 shows how import volumes of the three major markets change with respect to time, together with the corresponding infrastructure capacities. Western Europe, as the major gas importing region, continues to depend heavily on pipeline supply. Alongside this, LNG trades there stay steady at around 100 BCM/yr, with the regasification capacity decreasing from 160 BCM/yr to 130 BCM/yr during the first half of the projection. The reason is that while the original assets decommission, Western Europe lacks the underpinning long-term LNG contracts to invest in. However, from 2035, its regasification capacity gradually expands back due to the increasing market price and finally reaches 230 BCM/yr in 2060. East Asian demand increases to approximately 250 BCM/yr by 2060, relying solely on LNG. Initially, the regasification plants there are significantly over-capacity. After 2030, the capacity gradually adapts to the real import level. The East Asian market which was dominated by the Middle East and ASEAN countries in 2010, becomes rather different by 2060 because of global LNG developments. Australia takes an 18% share, and others such as Africa (11%) and North America (9%) become more important. Gas import in China grows rapidly, from 14 BCM/yr in 2010 to 230 BCM/yr in 2060. The regasification capacity experiences two rounds of mass investment (in the 2010s to 60 BCM/yr and in the 2030s to 150 BCM/yr) and is usually fully utilised. Regarding the pipelines into China, a major expansion is expected to happen between 2020 to 2040, driven by the contracts with Russia and Caspian countries.

Liquefaction capacities over time, with regional disaggregation, are illustrated in Fig. 4 - 6. The total volume almost doubles from 2010 (400 BCM/yr) to 2060 (930 BCM/yr), with contributions mainly from the Middle East, North America, and Australia. North America invests heavily in the first half of the projection period, reaching its highest export capacity (185 BCM/yr) in 2040. When global LNG supply becomes abundant from 2040, North America slows down the investment, stabilising at 130 BCM/yr level till 2050. Afterwards, the global supplies become tight, leading to higher Asian gas prices, as indicated in Fig. 4 - 7. This then drives the second round of North America liquefaction expansion. A similar trend can be observed for Australian LNG development.

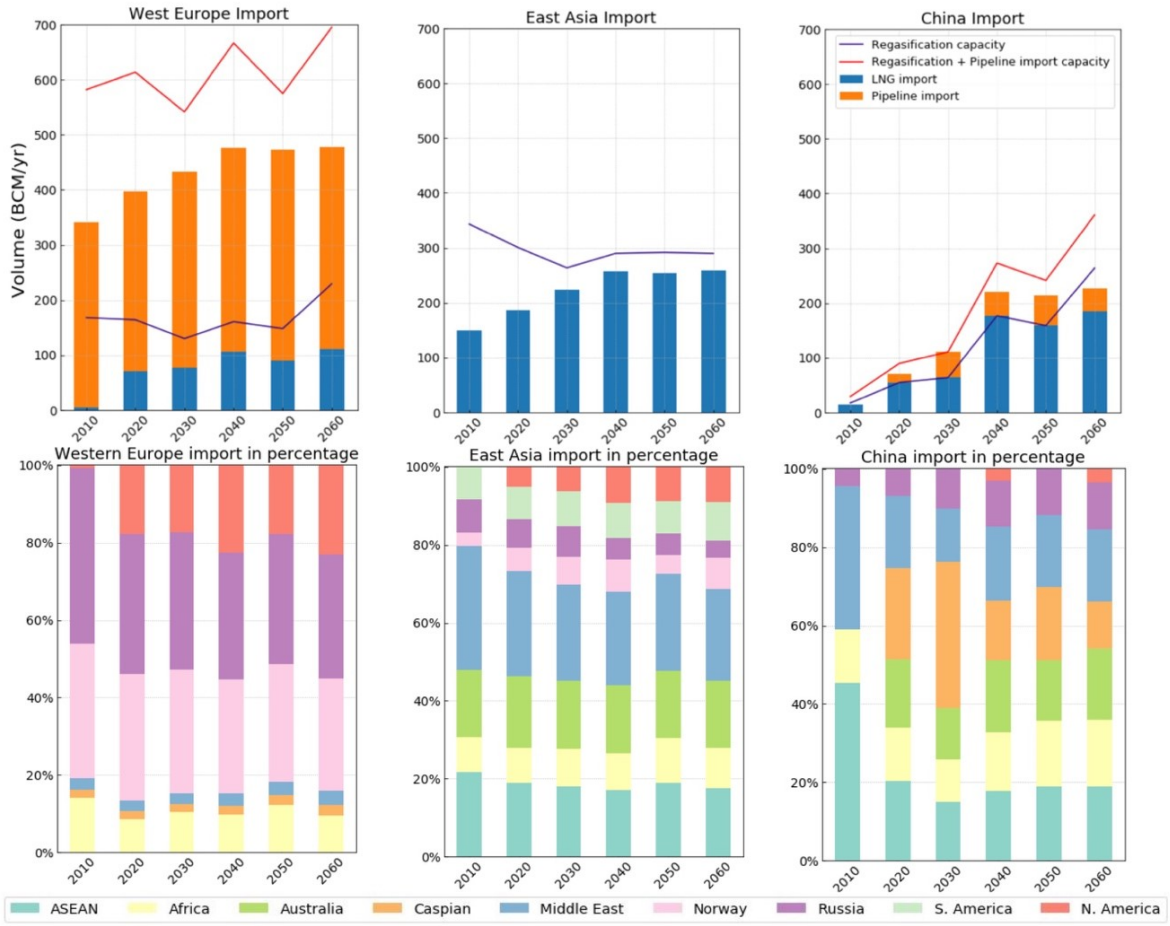


Fig. 4 - 5. Major import market trade and capacity details in Gas-GAME base case

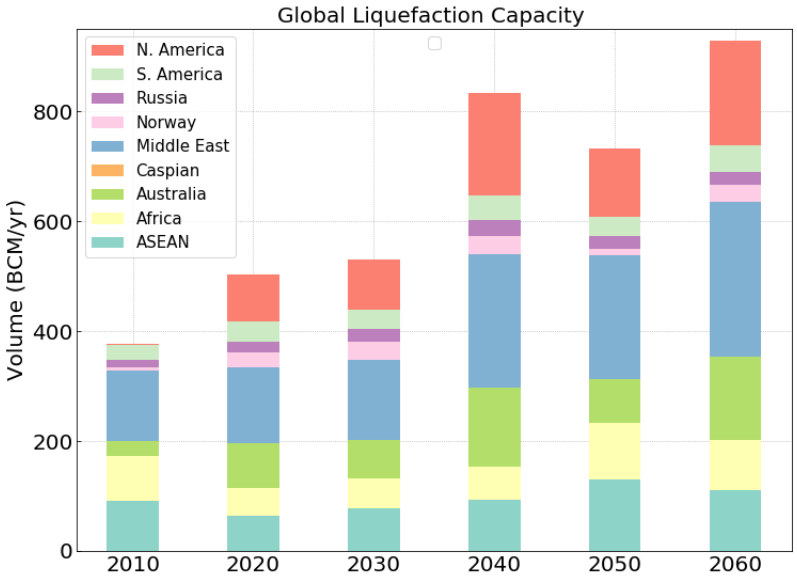


Fig. 4 - 6. Global liquefaction capacity in Gas-GAME base case

Fig. 4 - 7 shows the base case market prices. The fluctuating pattern of regional prices highlights the advantage and novelty of this modelling method. This fluctuation mimics the investment cycle.

Investors expand supply capacities heavily during the high-price period, holding the expectation that future prices will also be high. As a result, supplies become abundant, and market prices decrease. Then the investors face the low-price condition and stop further investment in capacities. This leads to a tight market when the previously expanded infrastructures are decommissioned. The prices then rise again because of the limited supply capacity. Such a price fluctuation is commonly observed in the real markets [149], as shown in Fig. 4 - 8. However, this feature has seldom been captured by other gas models, whose price results usually follow a smoothly increasing or decreasing trend. Fig. 4 - 9 shows an example of the simulated prices in WGM [8].

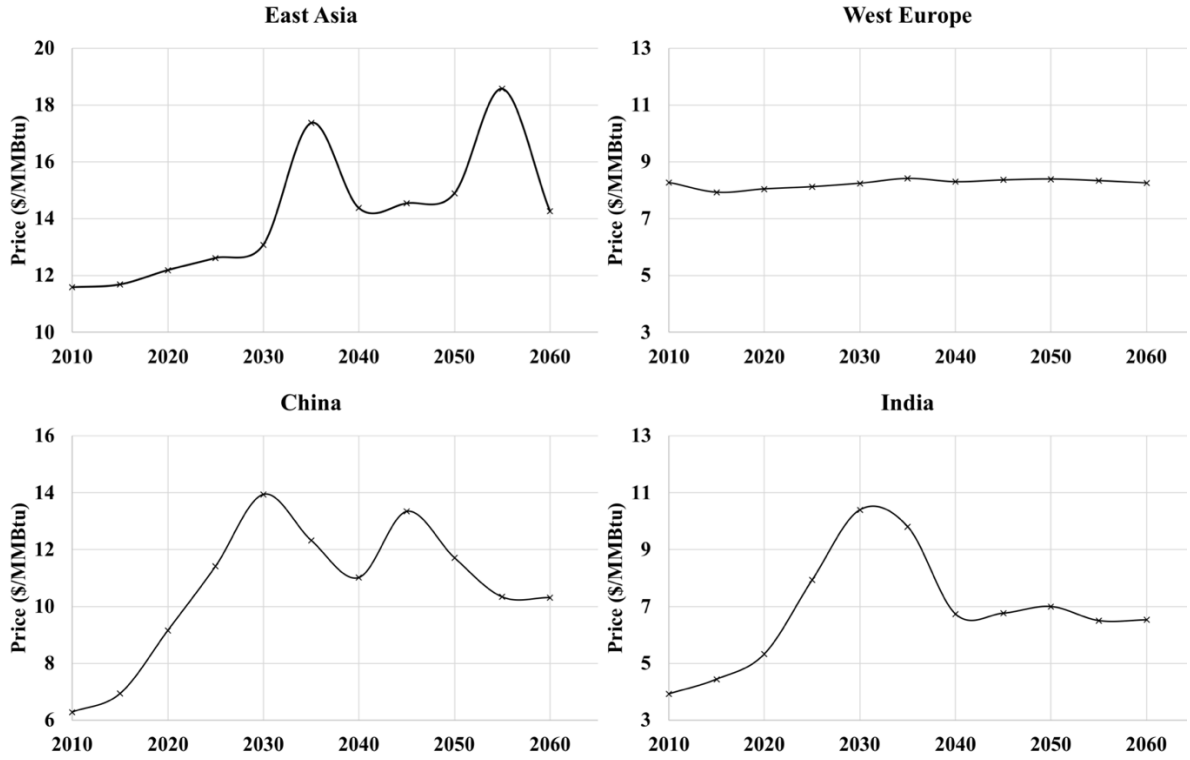


Fig. 4 - 7. Major market prices between 2010 to 2060 simulated in Gas-GAME base case

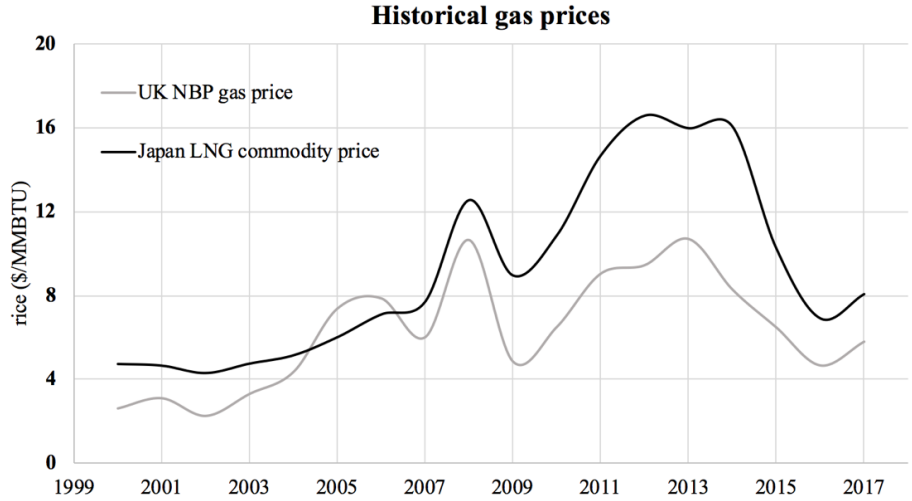


Fig. 4 - 8. Historical gas price (nominal) fluctuation in Europe and Japan

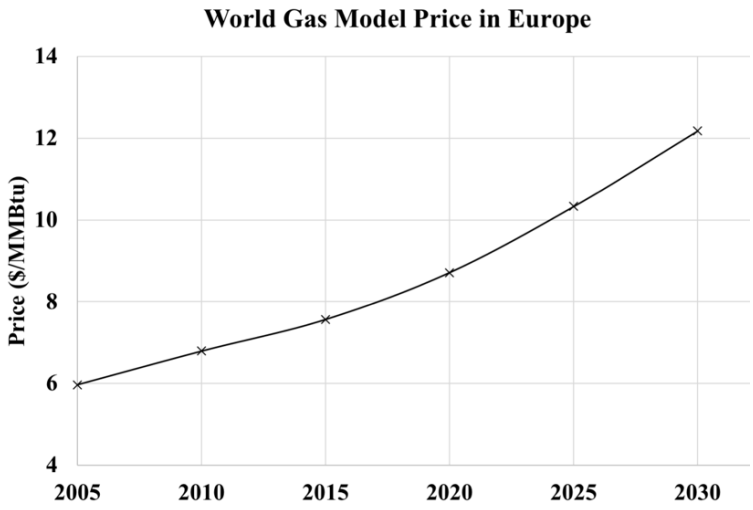


Fig. 4 - 9. European gas prices simulated by World Gas Model [8]

4.2.3 Result sensitivity subject to pipeline lifetime

This study assumes a 30-year lifetime of gas transmission pipelines. This assumption aligns the economic lifetimes of pipelines to the duration of supply contracts which are used to underpin new pipeline projects. Table 4- 6 presents some examples of these contracts and their correlated pipelines. However, the technical lifetime of these pipelines can be longer than 30 years. Table 4- 7 summarises the gas pipeline technical lifetime suggested by different literatures. For international transmission pipelines, which have larger diameters and operate under higher pressures, in comparison to domestic transmission or distribution pipelines, the design lifetime ranges from 30 to 50 years. Though the operation licenses may affect the decommissioning of these pipelines, it is possible for suppliers to continue using the infrastructure after the initial contracts expire. Hence, a sensitivity test is conducted to evaluate how the longer pipeline technical lifetime would affect the result.

Table 4- 6: Pipeline projects and the contracts

Project	Supply	Contract length	Source
Yamal-Europe pipeline	Russia	20 years with Germany	Gazprom [150]
Trans-Balkan pipeline	Russia	25 years with Turkey	Gazprom [150]
Nord Stream pipeline	Russia	20 years with Denmark 25 years with France 25 years with Germany	Gazprom [150]
Power of Siberia	Russia	30 years with China	Gazprom [150]
Power of Siberia 2	Russia	30 years with China	Gazprom [150]
Sino-Myanmar pipeline	Myanmar	30 years with China	IEA [151]

Table 4- 7: Natural gas pipeline technical lifetime

Pipeline type/project	Technical lifetime	Source
General transmission	30 – 50 years	IEA [29]
Europipe I (international transmission)	50 years	Norwegian Ministry of Petroleum and Energy [152]
Europipe II (international transmission)	50 years License valid for 20 years	Norwegian Ministry of Petroleum and Energy [152]
Franpipe (international transmission)	50 years License valid for 20 years	Norwegian Ministry of Petroleum and Energy [152]
Grane Gas Pipeline (international transmission)	30 years	Norwegian Ministry of Petroleum and Energy [152]
Nord stream (international transmission)	50 years	Gazprom [150]
Long distance transmission pipelines within the UK	Average 60 years Range 30 – 100 years Regulatory life 45 years	Ofgem [153]
Distribution pipelines & Inter-state transmission pipelines in the US	Over 50 years	Argonne National Laboratory [154]

It is assumed that the pipeline lifetime is 40, 50, and 70 years in the alternative cases. This lifetime parameter affects two aspects of the simulation. Firstly, the existing pipelines (in base period 2010) will decommission at different rates as compared to the base case. Details are presented in Table 4- 8. Secondly, when updating the infrastructure database with newly confirmed pipeline projects, the corresponding lifetime is based on the alternative assumptions.

The model design assumes that supply agents always consider the capital cost of new infrastructure construction during the contract evaluation process, without examining whether there exists available infrastructure or not. Therefore, assuming a longer pipeline lifetime will not affect the contract negotiation. Practically, if pipelines can operate for over 30 years, it is possible that new supply contracts are agreed based on the existing pipelines, and the capital investment would be lower. As a result, more pipeline contracts may be agreed. However, in the base case, over 90% of pipeline contract requests are accepted. Therefore, neglecting the impact of longer technical lifetime on contract negotiation has a limited influence on the simulation.

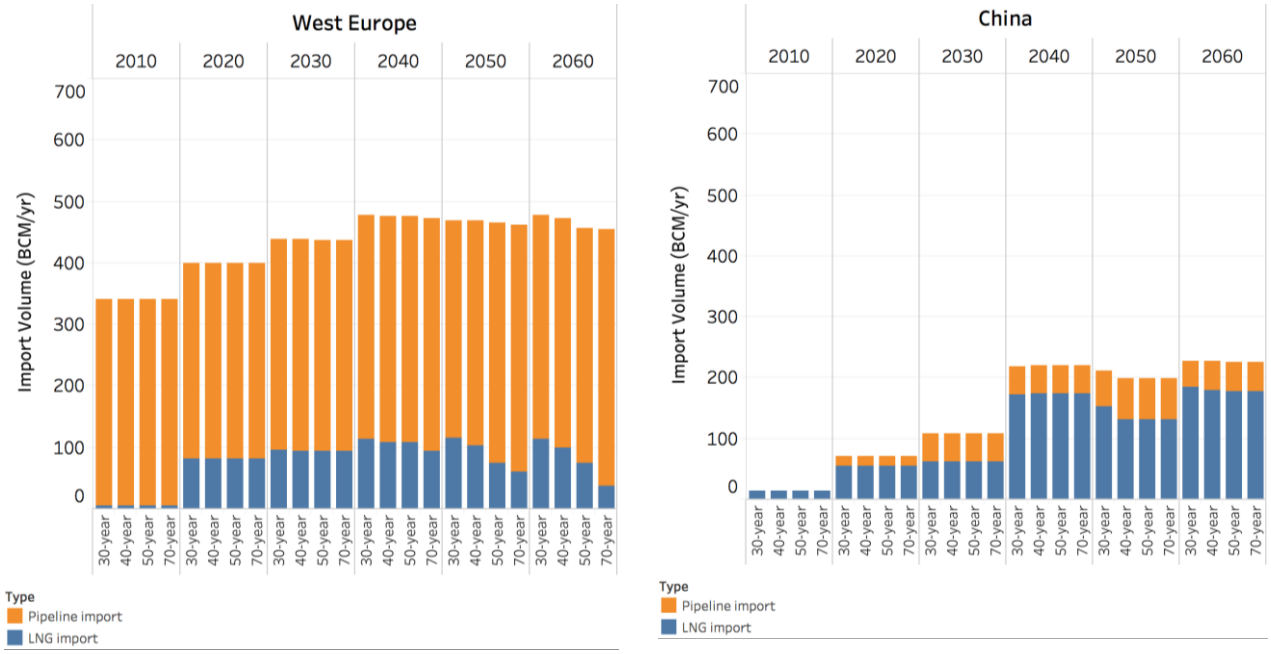
Table 4- 8: Scenario design with different pipeline lifetime assumptions

Pipeline lifetime assumption	30 years	40 years	50 years	70 years
Decommission period of base-period existing pipelines	2015 - 2040	2015 - 2050	2015 - 2060	2015 - 2080
Base-period pipeline capacity decommissioned in each period	20%	14%	11%	8%

Fig. 4 - 10 shows the import conditions in the two major markets which depends heavily on pipeline transmission, namely Western Europe and China. Generally speaking, the impacts of the lifetime assumption on the total import volumes of the two markets are negligible. However, in Western Europe, a longer pipeline lifetime leads to more imports via pipeline compared to LNG, especially after 2040. The pipeline import of 365 BCM/yr in 2060 under the 30-year lifetime assumption increases to 382 BCM/yr under the 50-year assumption, and 418 BCM/yr under the 70-year assumption. This is because the pipeline imports in Western Europe are constrained by the capacities. With a longer lifetime, more capacity is available to transmit gas while the contract-driven expansion projects remain similar. In contrast, the LNG import there in 2060 decreases from 113 BCM/yr in the base case to 75 BCM/yr in the 50-year case, and to 37 BCM/yr in the 70-year case. Fig. 4 - 11 shows the how different supply agents contribute to the two markets. While the increasing pipeline imports in Western Europe are evenly shared by several pipeline suppliers, including Russia, Norway, and Africa, it is mainly North American LNG that decreases with longer pipeline lifetime assumptions.

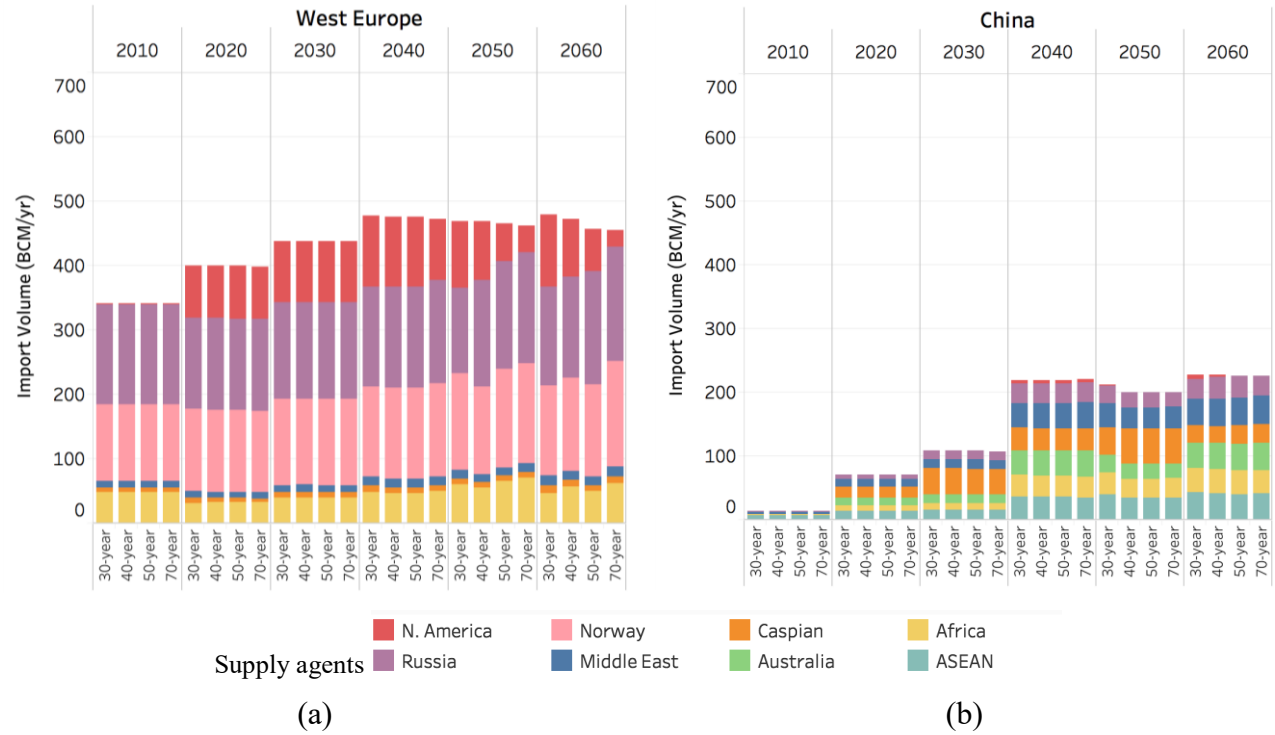
The sensitivity result has some implications on the gas import strategy in Western Europe. Though the technical lifetime of inter-regional pipelines may be longer than 30 years, import countries should be cautious when issuing licenses for the operation beyond contract periods. If Western Europe customers continuously import through the developed pipelines, they may rely more heavily on the pipeline sources and become reluctant to import via LNG. The market will then miss the chance to diversify its gas supply and improve its energy security condition.

For the Chinese market, changing the pipeline lifetime assumption does not affect the import condition. The major pipelines connected to China start operating after 2020 and would decommission only after 2050 under the 30-year lifetime assumption. A longer lifetime of 40 to 70 years therefore has a limited impact over the simulation horizon to 2060.



(a) (b)

Fig. 4 - 10. Pipeline and LNG import in (a) West Europe and (b) China under different pipeline lifetime assumptions



(a) (b)

Fig. 4 - 11. Import from different suppliers in (a) West Europe and (b) China under different pipeline lifetime assumptions

4.3 Discussion on alternative North American export strategies

Two alternative scenarios – ConNA (conservative North America investment) and AggNA (aggressive North America investment) – have been simulated. Each represents a condition where North America sets a different export strategy relative to the base case. The scenario framework has been introduced in section 4.1.1.2. This section begins by discussing the results of ConNA, with its changes compared to the base case clearly illustrated. Then the section focuses on the AggNA case.

4.3.1 Conservative North America investment scenario (ConNA)

Fig. 4 - 12 presents North American LNG export conditions for all scenarios. In ConNA, the capacities only expand in the initial period, driven by the contracts already concluded before 2016. The capacity level, between 2015 and 2040, stabilises at around 80 BCM/yr. When these capacities decommission, after 2040, gas export from North America plunges to less than 10 BCM/yr level, creating a tight global LNG supply.

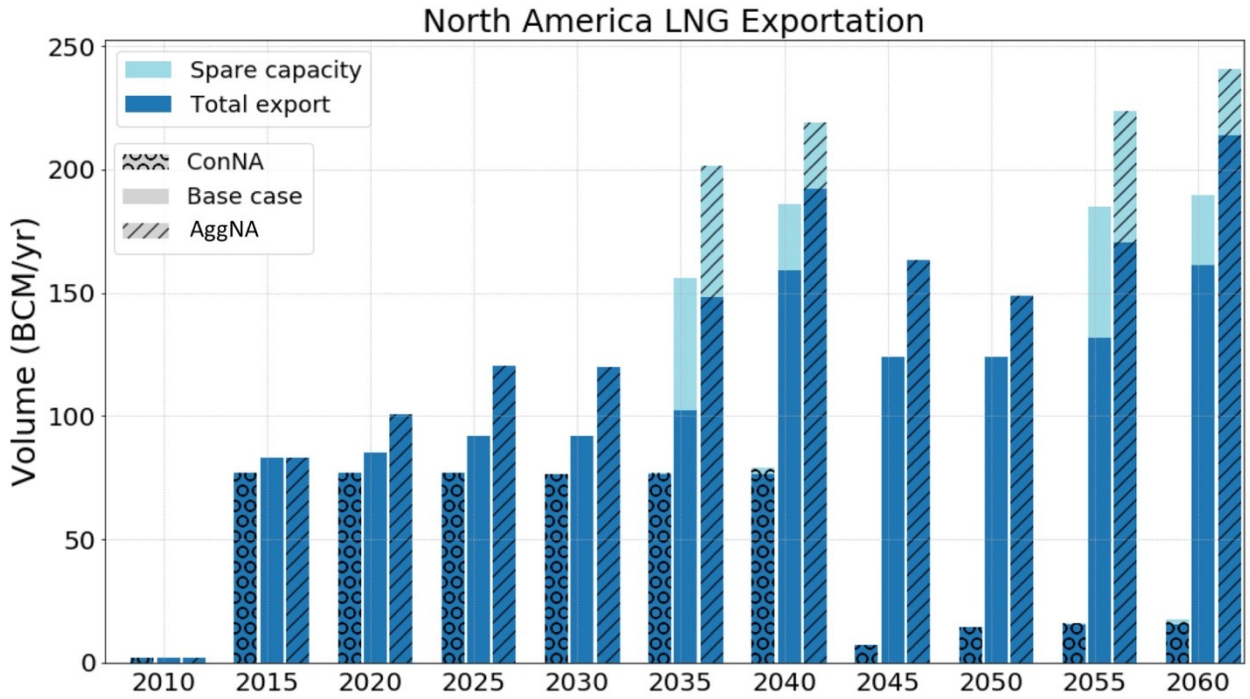


Fig. 4 - 12. North America LNG export in the base, ConNA, and AggNA cases simulated by Gas-GAME

Fig. 4 - 13 illustrates the changes in global gas trade and the impacts on major markets due to North American conservative exportation. North American LNG mainly targets the Western European market in the initial projection periods. Afterwards, facing its capacity decommissioning, North America chooses to serve East Asia demand first for the high profitability there, leaving nearly zero supply to Western Europe. Hence, other European gas suppliers, mainly Russia, Norway, and Africa take up the slack with sales increased. Fig. 4 - 14 shows the regional total revenue results simulated in

the three scenarios. It is observed that Russia earns an additional revenue of US$ 300 Billion in this scenario during the whole projection horizon, benefiting the most from the conservative North American expansion strategy. Russia takes nearly 40% of Western Europe imports and thus further secures its dominant position.

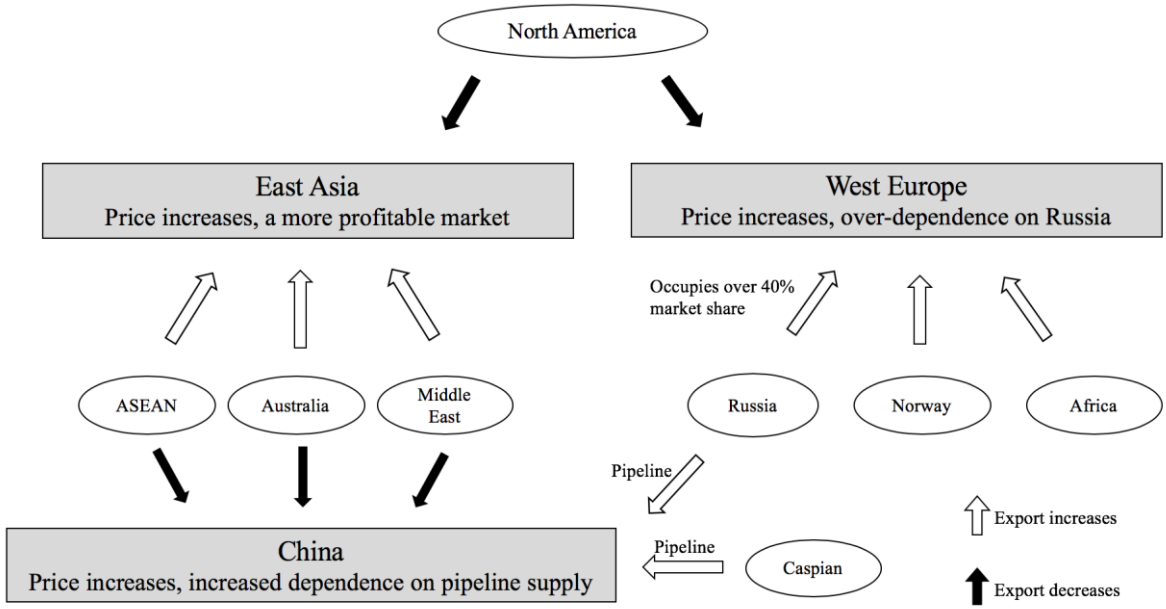


Fig. 4 - 13. Illustration of gas flow changes in ConNA scenario

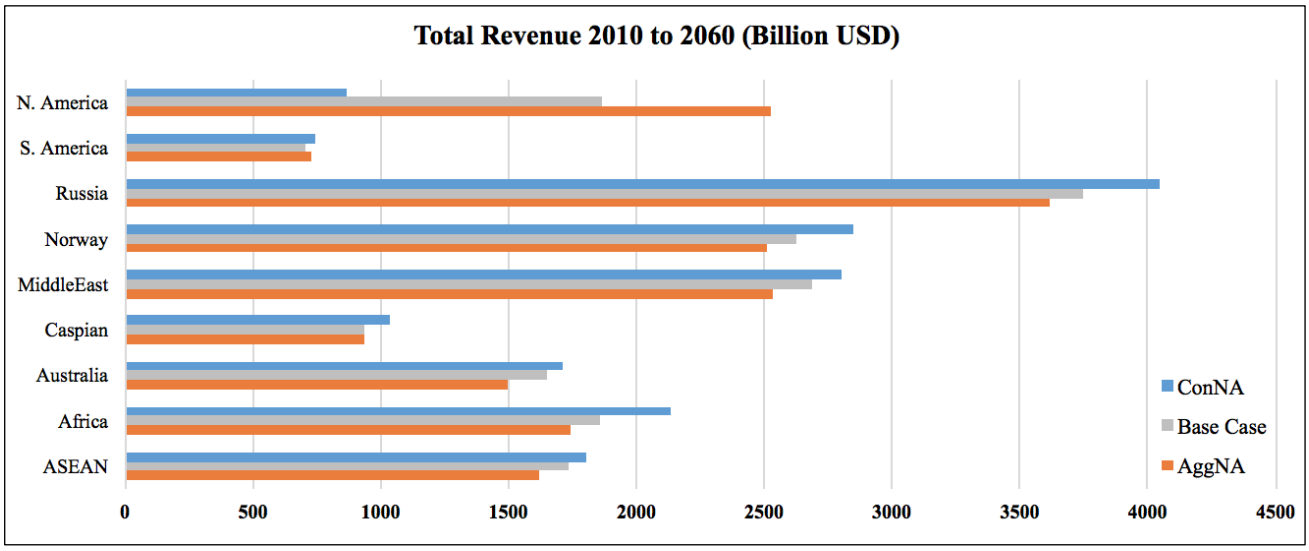


Fig. 4 - 14. Total undiscounted revenue (real) earned by supply agents over the simulation horizon

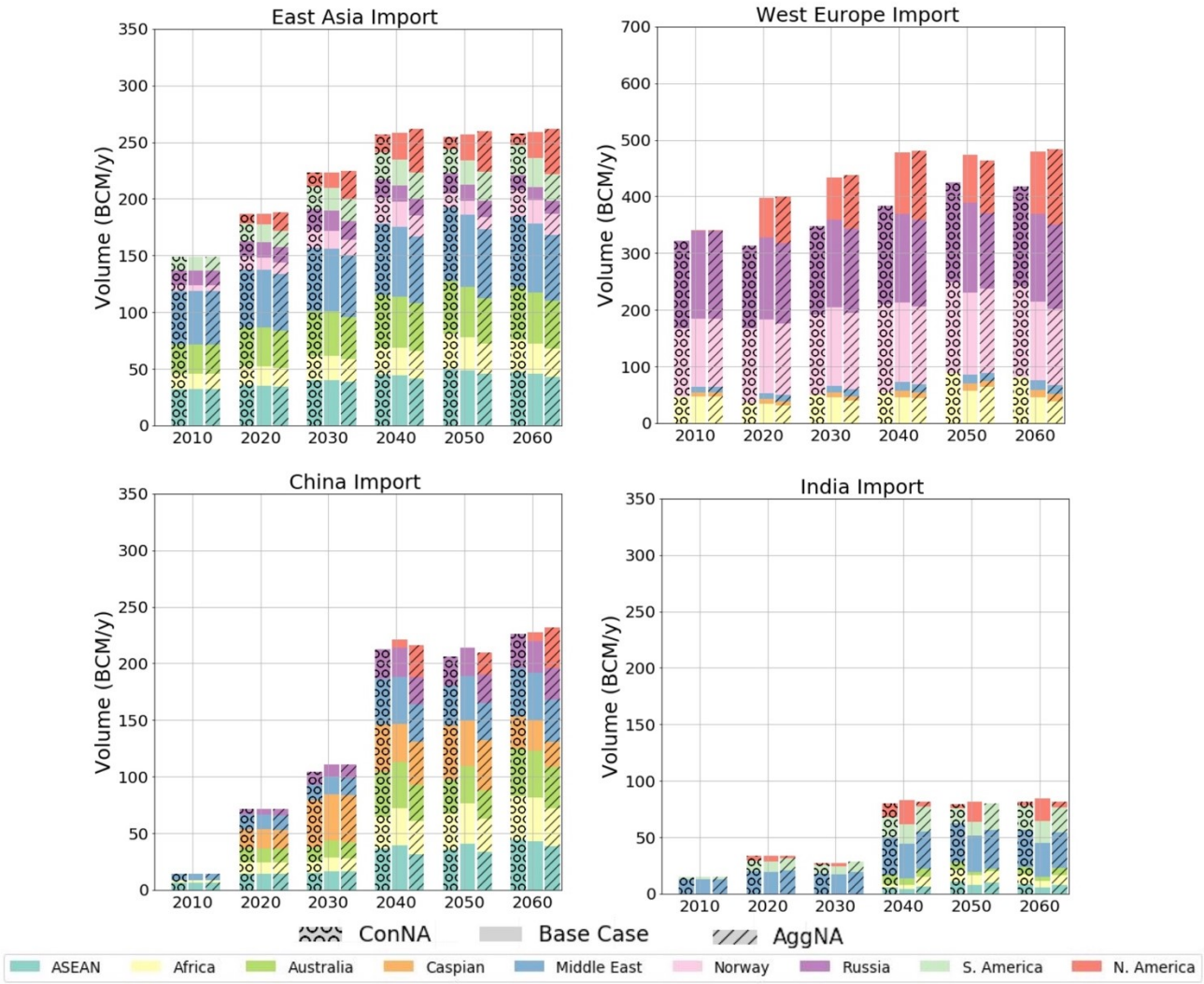


Fig. 4 - 15. Major market import between 2010 and 2060

The prices in the two alternative cases, when compared to the base case, are presented in Fig. 4 - 16. East Asia becomes more profitable (*i.e.* market price increases) for LNG export in ConNA as compared to the base case because of the decreased supply from North America. Hence, ASEAN countries, Australia, and the Middle East increase their sales to East Asia, earning considerably higher revenues (see Fig. 4 - 15). Since these regions are also the major LNG suppliers to the Chinese market, their increasing supplies to East Asia leads to a supply reduction in China. As a result, the Chinese gas prices increase in ConNA scenario. From the other side, this allows the Caspian region to expand more pipeline capacities and gain higher market shares in China, increasing its total revenue by US$ 100 Billion.

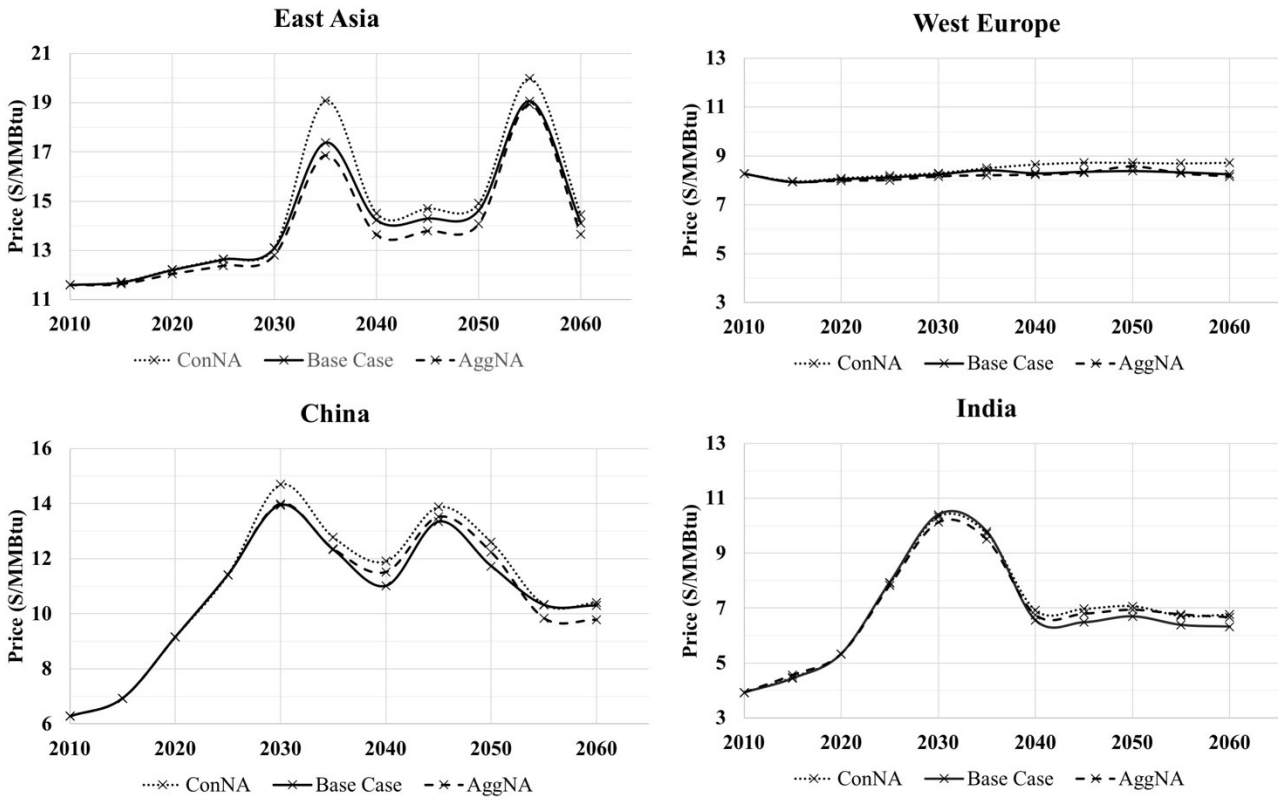


Fig. 4 - 16. Market import prices between 2010 and 2060 in the base, ConNA and AggNA cases simulated by Gas-GAME

4.3.2 Aggressive North America investment scenario (AggNA)

By conducting an aggressive expansion, North American export capacity exceeds 200 BCM/yr by 2035 and 240 BCM/yr by 2060. The values are approximately 30% larger than the base case, and the additional expansion is mainly driven by two factors. Firstly, more contracts, which have lower return rates, are agreed with Western Europe. Secondly, the Chinese contract requests received by North America have higher volumes. As shown in Fig. 4 - 15, sales by North America in Eastern Asia, Western Europe, and China all increase considerably compared to base case. Consequently, its total revenue throughout the projection period is 35% higher. These additional earnings are more than adequate for the extra capital investment required, which is around US$ 80 Billion. Hence, there exists a high possibility that North America will take an aggressive expansion strategy, as simulated in this scenario, under the current assumptions.

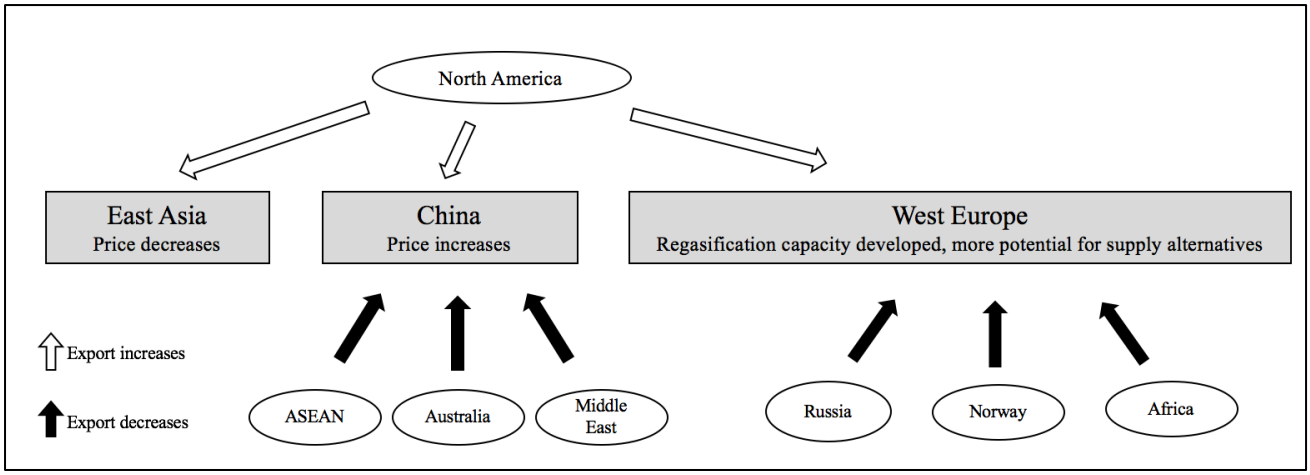


Fig. 4 - 17. Illustration of gas flow changes in AggNA scenario

Fig. 4 - 17 illustrates the changes in global gas trade in AggNA scenario as compared to the base case. On the market side, East Asian gas prices are lower in this scenario (See Fig. 4 - 16) because of the considerable additional supply from North America. In contrast, China imports gas more expensively, and the total import volume decreases. Though more North American LNG flows to China, mainly after 2035, other LNG exporters, including ASEAN countries, Africa, Australia, and the Middle East, decrease their supplies to China to maintain the market price level. The penetration of North American LNG into the Chinese market creates pressure on other gas suppliers there. Although a similar supply reduction by other exporters is also observed in the East Asian market, due to the high profitability there, other suppliers' total reduced amount is relatively lower. Therefore, the total export to East Asia still increases when North America exports LNG aggressively.

Regarding other gas exporters, Russia, with its cost advantages in production and pipeline transmission, still plays the dominant role in the West European gas market. Although this is similar to the base case, more contracts are concluded between Western Europe and North America in this scenario, resulting in fast development in European regasification plants. By 2035, Western Europe achieves a 200 BCM/yr LNG import capacity, and the capacity reaches 300 BCM/yr by 2060. The utilisation rate of the regasification capacity stays at around 60% throughout the projection periods, which indicates that the aggressive expansion strategy by North America allows Western Europe to have a higher potential for supply alternatives.

The Middle East and Australia are influenced by North American aggressive export substantially, both suffering total revenue reduction by US$ 150 Billion. The major reason is their sales reduction to the Chinese market. ASEAN countries, Africa, Russia, and Norway also lose over US$110 Billion in their revenue, respectively. The result suggests that these exporters may take actions when they see North America expanding its LNG export in an aggressive way. Russia and the Middle East, which have relatively low capital costs for gas production development, may consider similarly aggressive

export strategies to directly compete with North American gas supplies. However, the other exporters who do not have a cost advantage, may take other approaches like offering contracts with more favourable terms to buyers.

4.4 Concluding remarks

This section illustrates the simulation capability of Gas-GAME, presents the model validity, and examines the impacts of alternative North American export strategies to global gas trade.

In order to illustrate the model's functionality, a base case has been simulated. The general consistency between the Gas-GAME base case results and other well-known gas market projections, including IEA World energy outlook [30], BP Energy outlook [31], and the World gas model [24] is shown to validate this new modelling method.

Besides the base case, two scenarios representing conservative and aggressive North American LNG expansion strategies are presented. When North America remains conservative in its strategy, its exportation is constrained to 80 BCM/yr level before 2040 and 10 BCM/yr afterwards, creating a global LNG supply tightness. Meanwhile, other gas exporters take advantage of this by supplying more in West European and East Asian markets. Among these exporters, Russia is the biggest winner. Its total gas trade revenue increases by US$ 300 Billion. Moreover, by taking over 40% market share, Russia reinforces its dominant position in the West European gas market.

When North America sets its strategy to be aggressive, it manages to expand its LNG exportation capacity to 240 BCM/yr by 2060 and increases its revenue by 35%. East Asia and China import considerably more from North America under this assumption. In addition, Western Europe becomes more accessible to global LNG supplies, and thus has more bargaining power in price negotiation with Russia.

Overall, this chapter illustrates how Gas-GAME can be applied to investigate supply-side strategies. Besides North America, the export strategies of Russia and the Middle East will also affect the global trade scenario significantly. Further studies are required to investigate the combined impacts of these exporters' strategies.

Chapter 5. The impacts of demand uncertainties and China-US natural gas tariff on global gas trade

Gas-GAME-Risk is applied to investigate how uncertainties in gas demand are captured by suppliers, and what the resulting future gas trade scenario will be like. The impacts of the China-US gas tariff are also studied in this chapter by explicit scenario analysis.

This section starts with the model input data, and presents how the dataset is revised and updated as compared to the study in Chapter 4. In addition, the scenario framework is explained. The base simulation covers two scenarios with different gas demand projections. Section 5.2 discusses the differences in the import-export relationship between the two scenarios. Additional analysis is also presented regarding how the results, due to updated input data and changed methodology, differ from the results of the base case in Chapter 4. The study also simulates another two scenarios considering a 25% China-US LNG trade tariff. Section 5.3 focuses on the results of those two scenarios and discusses how such a tariff would affect gas trade conditions in both a short- and a long-term future.

5.1 Model input data and scenario framework

The data used for this simulation is presented in this section. This section also explains how the four cases representing different realisations of future demand conditions and Chinese LNG tariff are simulated.

5.1.1 Input data update

While most of the data and assumptions are the same as in Chapter 4, some changes, presented in Table 5- 1, are made. Essentially, some assumed calculation processes are changed in a more sophisticated version to enhance the representation of reality.

Table 5- 1: Updates in Gas-GAME-Risk model input data and assumption compared to Chapter 4

Updated aspect	**Chapter 4: North American alternative export strategy**	**Chapter 5: Demand uncertainties and China-US LNG trading tariff**	**Justification & Explanation**
Type of uncertainty	Supply strategy uncertainty	Market demand uncertainty Trade relationship uncertainty	
Models applied	Gas-GAME	Gas-GAME-Risk	
Price-demand relationships in future periods (in MEM)	After the base period, the relationship in each region adapts to the WEO New Policies Scenario projection gradually until 2040. After 2040, the relationships are assumed to be the same as the 2040 relationship for each region.	The demand-price relationships in the NPS trajectory is the same as in the Gas-GAME base case. The assumption that parameter SLP stays constant is held. The LOW demand relationships are calibrated with the low-level demand outlooks in 2040 (see Table 3- 8). The elasticities and therefore the SLP values change as well. For the markets including East Asia, China, and India, the elasticities in 2040 are adjusted to more negative values (see Appendix C). Based on the elasticities and demand levels, the corresponding SLP values in 2040 are then calculated. For the periods between 2010 and 2040, the SLP values change in a linear manner. The INT values are then calculated in the same way as Gas-GAME base. The detailed SLP, INT, and elasticity values are presented in Appendix C.	The reason why elasticities are adjusted in LOW is that consumption is assumed to be less price sensitive, due to the imposed climate policies and the penetration of renewables. Asian gas markets with lower demand will be more liberalised, and hence the elasticities are approaching the European level.

Regasification capacity (in MEM and IEM)	Limited capacity based on [131]	The regasification capacities are assumed as a large number to ensure that regasification does not limit LNG import in all markets.	The capital cost of building regasification plants decreased considerably. In addition, the development of FSRU makes importing terminals no longer fixed to certain places [6]. It is assumed that, facing demand uncertainties, markets build sufficient import capacity to be prepared for all conditions. This section focuses on the potential limitation or under-utilisation of supply capacities.
Projection on future required import volume $EXP_IMP_{j,t}$, by demand agents (in IEM demand agent contract request generation)	Before 2035, the running period MEM price in the corresponding market is used to calculate the future required import, based on the next-period price-demand relationship. After 2035, a fixed import request is assumed for each region.	For all simulation periods, the running period MEM price in the corresponding market is used to calculate the future required import, based on the next-period price-demand relationship. This study does not fix the import request level after 2035.	To capture the demand market uncertainties, it is inappropriate to represent the import demand requests as fixed values. Hence, the "fixed request" method for post-2035 periods in Chapter 4 is replaced by the application of the price-demand relationships. The relationships are different for different demand scenarios, and therefore can capture how demand changes affect the import requests.

Production capital cost (in IEM supply agent contract economic evaluation)	Fixed capital cost per unit production capacity for each supply region based on [138] regional median level.	A production capex curve (see Appendix C), which reflects how many reserves can be developed at what capital cost, with gas discoveries until 2010 is computed for each supplier based on [138]. The initial production capacity expansion in each supply region develops the cheapest reserve there. Once the cheaper reserves are developed, the capital cost of gas production projects in the next period increases to the level at which the cheapest remaining reserves can be developed.	This change is to enhance the representation of practical production development. Such curves are commonly adopted in evaluation on the potential development of different projects [28, 155]
Calculation of IRR: initial capital cost allocation (IEM supply agent contract economic evaluation)	Capital costs are deducted at the beginning of the project lifetime altogether, and a 5 years' lead time exists for each project.	The initial capital costs are evenly allocated to every year in the initial 5 years. After the initial 5 years, the project starts earning expected revenues.	This change is to enhance the representation of the investment process. During the years of plant construction, capital costs are invested at different times for different purposes instead of altogether [156]. Hence, this section revised the assumption of capital cost allocation.

5.1.2 Scenario framework

The demand trajectories in the scenario tree, as shown in Fig. 5 - 1 (also presented in Chapter 3 as Fig. 3 - 5 for model design illustration) reflect a variety of possible developments of gas import markets. The demand relationship in each market may shift at a different time-period and therefore has nine potential routes. At which period the shift may happen depends not only on the international climate policy implementation, but also on the regional efforts and strategies to achieve the decarbonisation goal.

Among the nine potential routes, two major realisations, namely Shift2030 and NPS2060, are simulated. The pathways of these two realisations are shown in Table 5- 2, and it is assumed that the demand condition (*i.e.* NPS or LOW) applies to all markets. The Shift2030 takes the same scenario framework as WEO 2017 for its analysis on natural gas asset stranding risks [18], while NPS2060 assumes that the development would follow current policy pledges and is the common baseline of many gas market studies. Though only two realisations are examined, the supply agents, prior to the demand change, still consider all possibilities and evaluate the potential return of their contracts based on expected revenues. How the expected revenues are calculated has been explained in Chapter 4.

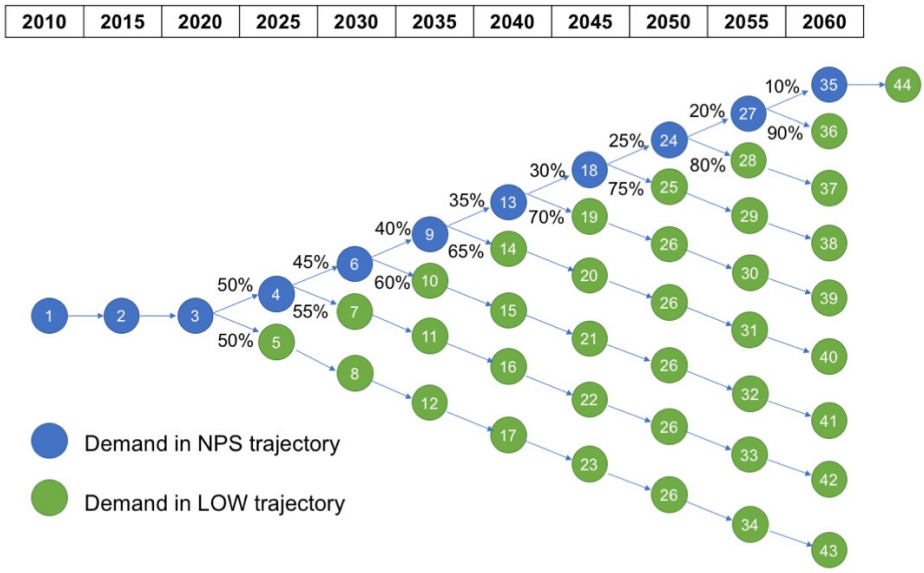


Fig. 5 - 1. Scenario tree of uncertain gas demand

Table 5- 2: Realisations of the changing import market demand relationships

Scenario	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
	Node number										
Shift2030	1	2	3	4	7	11	16	22	26	33	42
NPS2060	1	2	3	4	6	9	13	18	24	27	35

Another research objective of this chapter is to examine how the LNG trade tariff between China and the US would affect the future natural gas market on a global scale. For both Shift2030 and NPS2060, the scenarios with (Shift2030T and NPS2060T) and without (Shift2030B and NPS2060B) the tariff are simulated. Table 5- 3 summarises the framework of the four scenarios.

Table 5- 3: Scenario framework for Chapter 5

	Future market price-demand relationship	**Tariff condition**
NPS2060B	Future market demand changes based on NPS until 2060	No tariff between China and North America LNG trade
Shift2030B	Future market demand changes based on NPS until period 2025 From 2030, market demand trend follows LOW	No tariff between China and North America LNG trade
NPS2060T	Future market demand changes based on NPS until 2060	Tariff exists between China and North America LNG trade
Shift2030T	Future market demand changes based on NPS until period 2025 From 2030, market demand trend follows LOW	Tariff exists between China and North America LNG trade

The tariff assumed in this study is 25%. This is based on the announcement by the Chinese government regarding the tariff they intend to charge on the US LNG [19]. Though the level has changed several times in 2018 and 2019 due to the negotiation process between the two countries, this study assumes a 25% tariff, which is the highest proposed value, because this allows the study to simulate and explore the largest possible impact. There are two aspects in which the tariff scenarios differ from the without-tariff ones. Firstly, in the MEM market equilibrium simulation, the revenue North American supplier receives for a unit of LNG sold to China is $0.75\pi_{China,t}$, rather than $\pi_{China,t}$. This affects the profit maximisation objective function of the North American supplier. Secondly, in the IEM, when North America evaluates the contract requests proposed by China, the annual revenue expectation, which equals to the product of the equilibrium price and the expected annual contract-trade volume, is reduced by 25% as well.

5.2 Future gas market scenarios based on two demand projections

In this section, how gas markets evolve following different demand trajectories (NPS2060B and Shift2030B) is firstly discussed. Among the five importing regions, East Asia and China show considerable changes when their demands shift to lower levels. This section also contains a comparison between the NPS2060B scenario simulated with Gas-GAME-Risk and the base scenario presented in

Chapter 4. What leads to the differences between the projected future gas import-export relationship is also explained.

5.2.1 Gas trades in two demand scenarios

Fig. 5 - 2 shows the import conditions of three major import markets in the two base scenarios. The import by East Asia gradually increases from 150 BCM/yr in 2010 to 280 BCM/yr in 2030. In scenario NPS2060B, the level rises further to 340 BCM/yr in 2040 and then stabilises there. In contrast, the Shift2030B scenario shows a declined East Asian demand to 210 BCM/yr after 2030. Such a difference in the demand level is mainly attributed to the different price-demand relationships in the two scenarios. While exporters see East Asian prices at around US$ 13/MMBtu in NPS2060B, the same amount of export (*i.e.* total 340 BCM/yr LNG) can only be sold at a negative price in Shift2030B. Hence, to maintain their profitability, exporters choose to reduce their sales in East Asia considerably, leading to a decreasing East Asian LNG import. Notable changes are observed not only in the total import volume, but also in the market shares of different exporters. When the demand trend follows current policy pledges (NPS2060B), North America penetrates the East Asian market gradually. The share is around 14% in 2020, and it increases to a considerable 42% in 2040. Eventually in 2060, North America becomes a dominant supplier in East Asia, taking over 65% market share. The reasoning behind this is the low capital requirement in the US for the production of natural gas reserves since the shale boom, which is supported by the supply curve from Wood Mackenzie upstream data [138]. East Asia stays as the most profitable market for North American LNG, and as more North American gas is exported to East Asia, more contracts are signed between these two trade partners. Consequently, more North American LNG projects targeting East Asian clients are developed. This gradually leads to the dominance of North America in this market. Such dominance is not observed in the Shift2030B scenario. Because of the changed price-demand relationship since 2030, East Asian prices in Shift2030 are lower by US$ 2 – 4/MMBtu as compared to NPS2060B (see Fig. 5 - 3). This market becomes much less profitable for North American exporters, especially because of the high LNG shipping cost. As a result, North America stops exporting to East Asia. The Middle East, instead, becomes the major supplier, increasing its supply to East Asia from 50 BCM/yr in 2020 to 80 BCM/yr in 2040 and 100 BCM/yr in 2060. Its market share there also increases from the initial 30% to 50% in 2060. This is led by the cost advantage of the Middle East exporters. Their production cost is within the lowest range. Moreover, their shipping cost to East Asia is much less than other competitors in this market. Hence, even when the price is weaker, the Middle East exporters can still push their sales in East Asia while making profit.

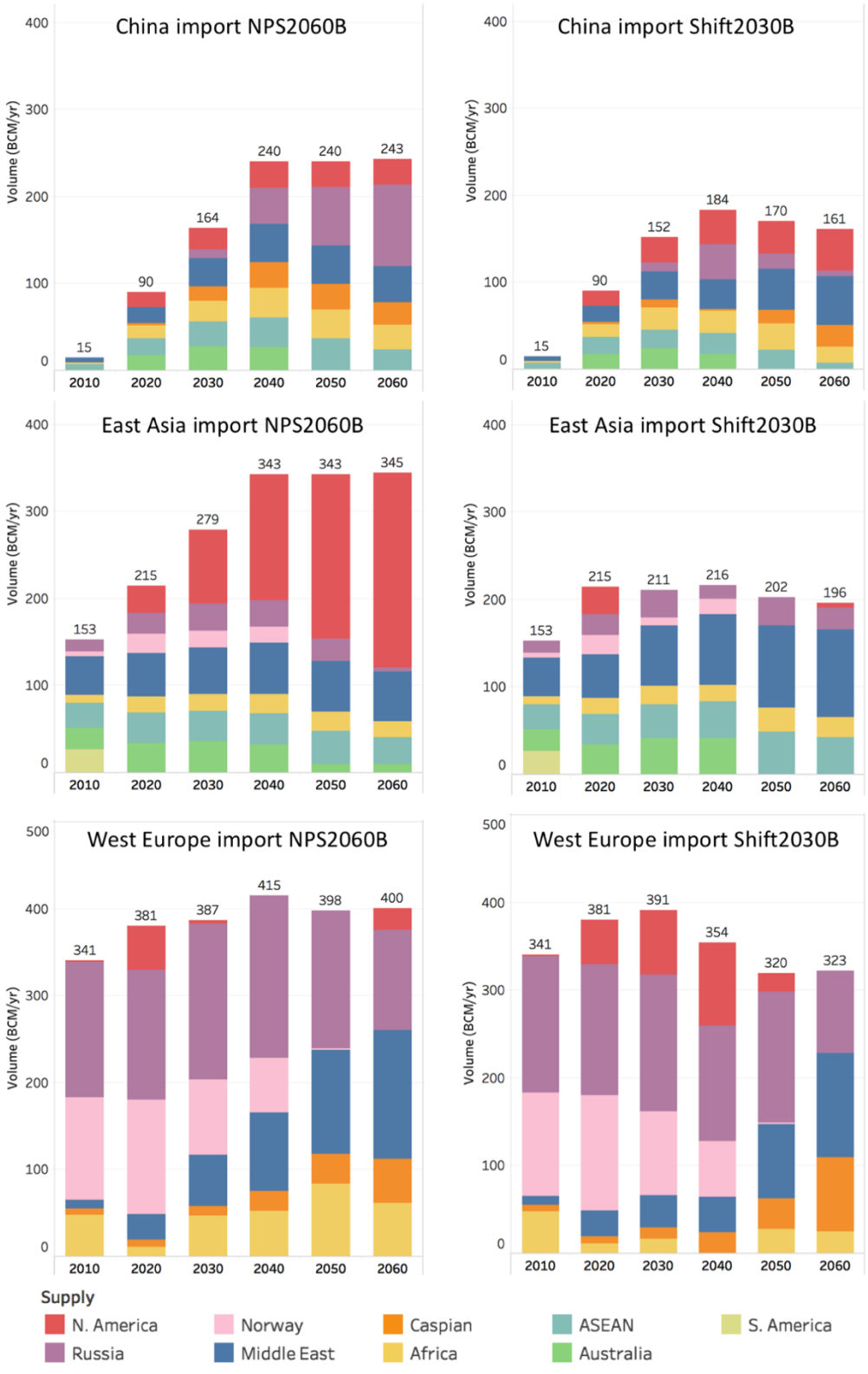


Fig. 5 - 2. Major market import sources and volumes in NPS2060B (left) and Shift2030B (right)

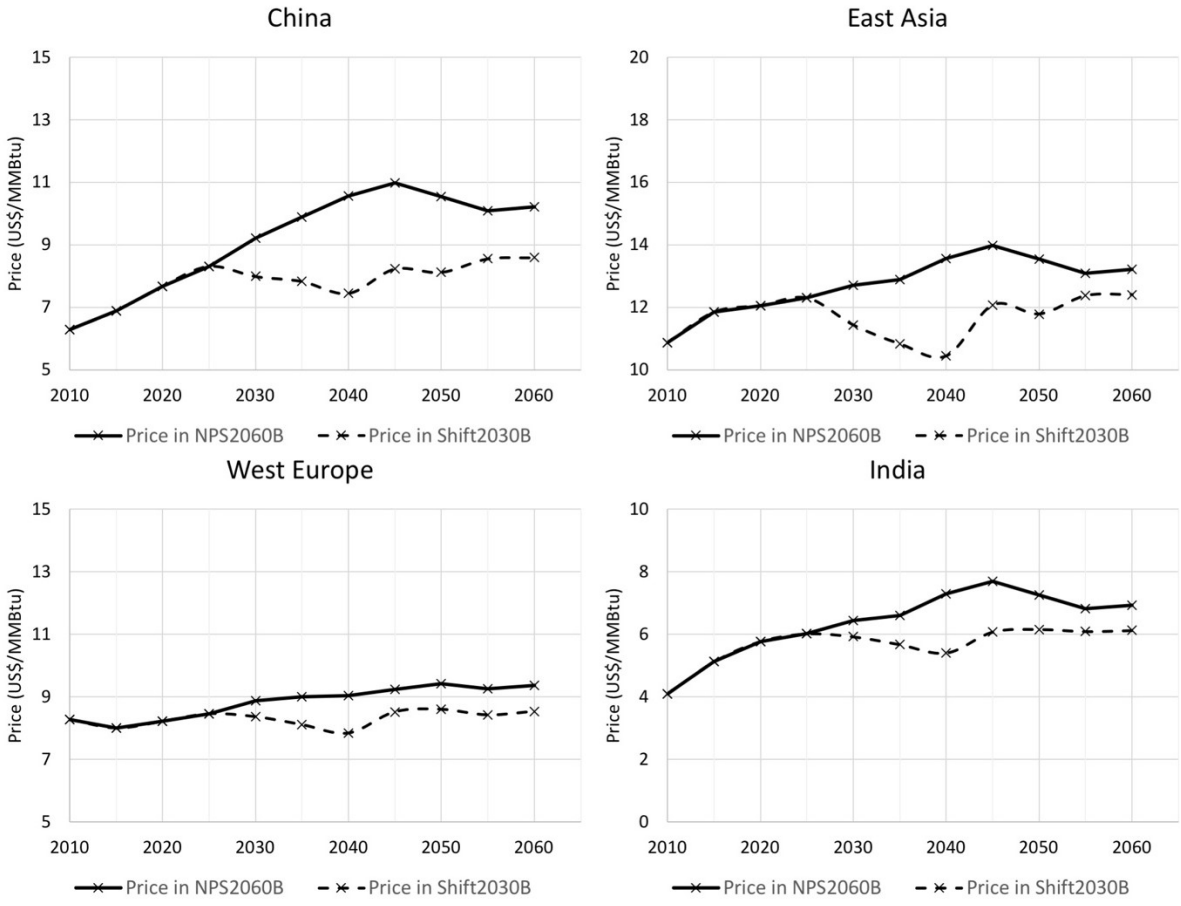


Fig. 5 - 3. Major market price for NPS2060B and Shift2030B

China is a fast-growing gas market, and its import amounts to 240 BCM/yr in 2040 in the NPS2060B scenario. Whereas in Shift2030B, the import reaches a plateau of 180 BCM/yr in 2040 and then drops slightly to around 160 BCM/yr afterwards. Similar to East Asia, the demand change in China is because of the shifted price-demand relationship. The same import volume of 240 BCM/yr in NPS2060B (priced at over US$ 10/MMBtu) would only be priced at US$ 4.5/MMBtu in Shift2030B. Hence, exporters reduce their sales to keep the price at a profitable level. One of the major differences between these two scenarios is the supply from Russia. In NPS2060B, Russia takes up the Chinese gas demand gradually. Its market share increases to 17% in 2040, and to as high as 40% in 2060, leaving the other exporters (*i.e.* ASEAN, Africa, Caspian, Middle East, and North America) splitting the remaining amount. The broad diversification of gas supplies grants China the bargaining power for its gas import deals, though the dominance by Russia can be an issue worthy of concern. However, China imports considerably less from Russia in Shift2030B. Russian market share is at around 20% in 2040, and it decreases to 5% in 2060. Such a decrease is attributed to 1) relative higher profitability for Russian export to East Asia (US$ 8.9/MMBtu between 2025 and 2060) as compared to China (US$ 5.8/MMBtu); 2) an increasing competition in China, as imports from the Middle East and North

America increases. While the Middle East benefits from its cheaper delivery cost, North America sells more to China to compensate for its decreased sales in East Asia. By 2060, they occupy a majority of the Chinese market (North America 30% and the Middle East 35%). Notably, North America plays a more important role in China after the demand decreases in the Shift2030B scenario. Between 2030 and 2060, the LNG trade between North America and China increases by an average of 30% relative to NPS2060B. The total additional volume amounts to nearly 400 BCM. Regarding the gas price, China sees a reduction by around US$ 3/MMBtu, and this brings the Chinese market price closer to the European price level.

The impact of the demand shift in Western Europe is relatively less significant compared to China and Eastern Asia. This is related to 1) the relative reference 2040 demand level in LOW as compared to NPS (see Table 3- 8); 2) the low SLP value in Western Europe price-demand relationship due to the high price elasticity there. With the demand reduction, Russian supply decreases by 10 - 20% from 2030. The gas imports from Africa also shrink by a large extent between 2030 to 2040, mainly because the LNG supply from North America starts flowing into this market. The amount of North American LNG supply is around 100 BCM/yr in 2040, but decreases to around 20 BCM/yr in 2050. By 2060, there are no longer imports from North America in the West European market. While the rising North American supply in Western Europe is due to its decreased export to East Asia, the decrease after 2050 is related to the lack of liquefaction capacity development. The reduction of North American supply is then compensated by the increasing import from the Caspian region. The share of Caspian pipeline supply reaches 26% in Shift2030B, doubling the 13% in NPS2060B. It is not only the short-run cost advantage that allows Caspian exporters to grab more shares in Western Europe. Also, the relatively low capital cost of the pipeline projects between the two regions, as compared to liquefaction projects, secures further development in transmission capacity. The demand change also leads to reduced gas prices in Western Europe, and the relative difference is around US$ 1/MMBtu (see Fig. 5 - 3).

Fig. 5 - 4 shows the total revenue of natural gas trade by different exporters between 2010 and 2060. Among the major exporters, North America faces a substantial revenue reduction by 60% (from US$ 3.9 trillion in NPS2060B to US$ 1.6 trillion in Shift2030B). The revenue loss by Russia is also considerable, which amounts to US$ 1.0 trillion throughout the simulation horizon. For the medium-sized exporters, Africa has its revenue reduced by nearly 40% when facing the global gas demand shift. In contrast, the impacts on ASEAN countries are relatively minor because their supplies remain to be cost-competitive in China and Eastern Asia.

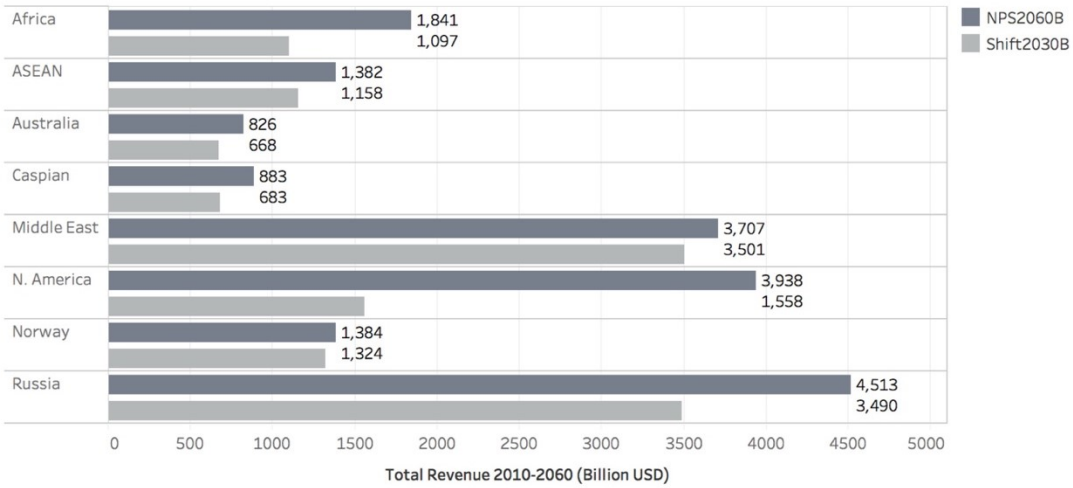


Fig. 5 - 4. Supply agents total revenue comparison

5.2.2 Comparison with the Gas-GAME base result

The NPS2060B scenario shows some differences as compared to the base case presented in Chapter 4. This is related to the changes in 1) the simulation method of Gas-GAME-Risk; and 2) the updated parameters and assumptions.

Fig. 5 - 5 presents the comparison of total production capacity in the two studies. Note that this capacity excludes the domestic production, and covers only the export represented in this thesis. The NPS2060B case shows 10% less production capacity, which is around 80 BCM/yr, relative to the Gas-GAME base case between 2040 and 2050. Between 2050 and 2060, the development trends of the two scenarios diverge. While an increase of around 200 BCM/yr is observed in Gas-GAME base, the total production capacity declines gradually in NPS2060B. The additional risk evaluation process by supply agents in Gas-GAME-Risk is one of the reasons which drives the relative less production development. In Gas-GAME-Risk, the suppliers take the potential low-demand scenario into account when evaluating the contract profitability. As a result, their expansion decisions are more conservative than the Gas-GAME case where suppliers assume all their contracted gas will be sold.

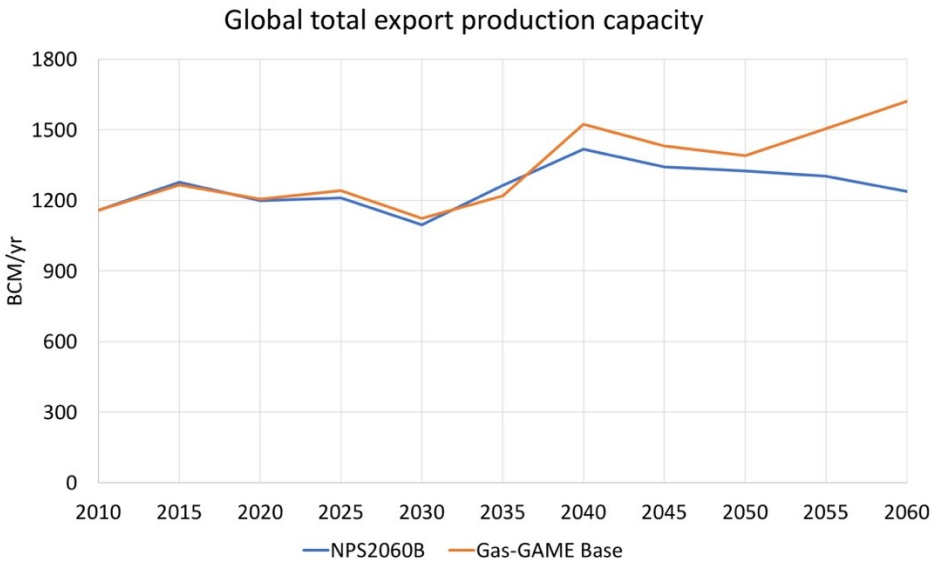


Fig. 5 - 5. Comparison of global gas production capacity in NPS2060B (Gas-GAME-Risk) and Gas-GAME base case

However, not all regions develop less capacity in NPS2060B. Fig. 5 - 6 shows the export production capacity in the Middle East and North America. These two exporters see their capacities higher in the NPS2060B as compared to the Gas-GAME base. While in the base case, the Middle East production capacity stays at around 200 – 250 BCM/yr after 2040, the value is over 350 BCM/yr in the NPS2060B scenario. For North America, the initial relative increase in NPS2060B is around 20 BCM/yr between 2015 and 2030, and the value reaches over 100 BCM/yr after 2045. By 2060, the production capacity developed in North America in NPS2060B is around twice the amount in Gas-GAME base. Such an increase in capacity development is attributed to the parameter update of production CAPEX for project investment, which then affects profitability evaluation. In Gas-GAME base, the unit production CAPEX is the regional field-level median whereas the more detailed CAPEX-Reserve supply curves are used in NPS2060B. For the Middle East and North America, a considerable amount of gas reserves (over 13000 BCM in North America, over 11500 BCM in the Middle East) can be developed at lower-than-median capital costs. The unit CAPEX values from the supply curves are so low that even when risk evaluation is conducted, the expected revenues considering lower demand scenarios can still make the project profitable. Hence, more projects are agreed by these two exporters. Other regions, like ASEAN and Australia as shown in Fig. 5 - 7, develop less capacity due to the risk evaluation and higher unit CAPEX values. Consequently, these regions export less to markets, thereby increasing shares of contract requests which are allocated to the Middle East and North America. Such an impact accelerates the capacity expansion by the Middle East and North America in NPS2060B.

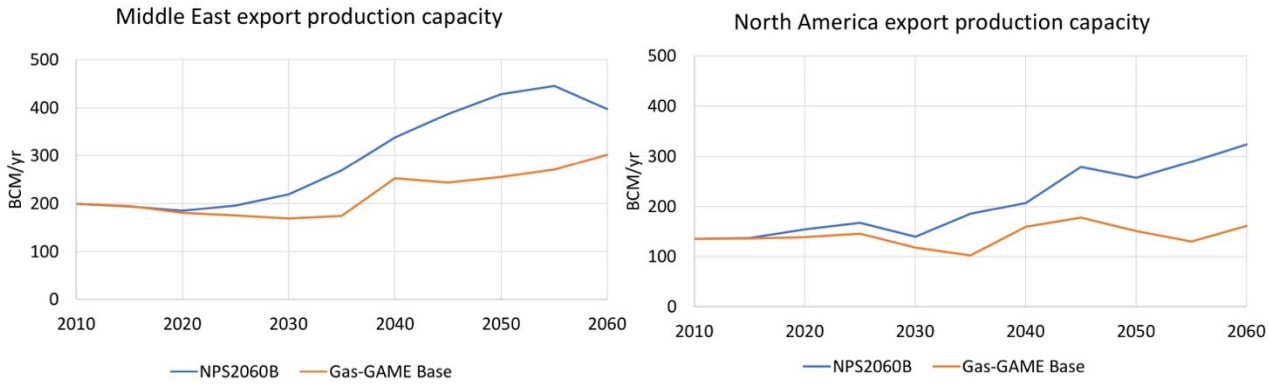


Fig. 5 - 6. Comparison of regional gas production capacity in NPS2060B (Gas-GAME-Risk) and Gas-GAME base case: Middle East & North America



Fig. 5 - 7. Comparison of regional gas production capacity in NPS2060B (Gas-GAME-Risk) and Gas-GAME base case: ASEAN & Australia

Another change made in this chapter in exporters' contract evaluation process is on how capital is spent in the project cashflow. It is assumed in Chapter 5 that the total investment is made in the initial 5 years evenly, rather than altogether in the very first year. This change leads to higher IRR values for all contract requests, and therefore has an opposing impact relative to the risk evaluation process. However, among the 300 contract requests simulated in NPS2060B, most hold the same AGREE/REJECT decisions with both investment allocation methods. Only 10% of the requests receive AGREE rather than REJECT when capital investment is split into 5 years. Table 5- 4 summarises the difference in agreed contract volumes attributed to this method change. The difference is only observed after 2030, and becomes more notable gradually to 30% of the total contracted volume in 2040. The increasing difference is related to the use of production CAPEX curve, making the capital costs for production development to increase with more reserves developed. In 2055, all contracts agreed in NPS2060B have IRR values smaller than 13%, and therefore will be rejected if the investment is allocated to the first year. These contracts all target the East Asian market, and the major supplier is North America, which accounts for 53 BCM/yr contracted volume.

Table 5- 4: Comparison of agreed contract requests in NPS2060B (Gas-GAME-Risk) and Gas-GAME base case

	Total volume of agreed contract requests in NPS2060B (BCM/yr)	Volume of contract requests which will be rejected if all investment is spent in the first year (BCM/yr)	Percentage of change due to the method change of capital investment
2030	369	38	10%
2035	185	37	20%
2040	244	84	35%
2045	158	55	35%
2050	198	61	31%
2055	75	75	100%

Besides the supply side, changes are also observed in the demand side market prices. The major difference is in the Asian markets. Fig. 5 - 8 presents the comparison of the prices in the two scenarios for both China and East Asia. In these two markets, the price fluctuation is much smoother in NPS2060B compared to Gas-GAME base.

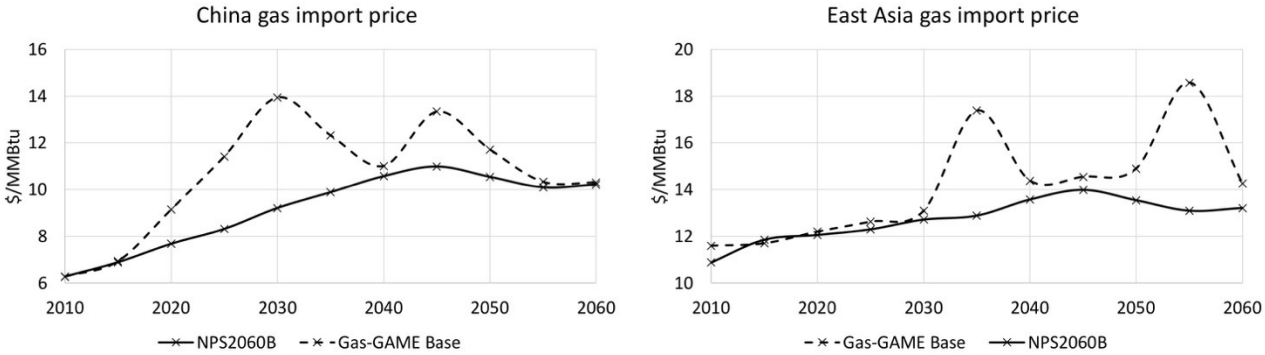


Fig. 5 - 8. Comparison of regional gas prices in NPS2060B (Gas-GAME-Risk) and Gas-GAME base case: China & East Asia

Regarding the Chinese market, the higher prices around 2030 and 2045 in Gas-GAME base are attributed to the limited regasification and pipeline facilities. However, as the capacity constraint of regasification plant is relaxed in NPS2060B, two LNG exporters including the Middle East and North America both expand their supplies there, leading to relatively lower Chinese prices. The comparison is illustrated in Fig. 5 - 9. In addition, the supply from Russia also sees a considerable increase and contributes to the price reduction. In the Gas-GAME base case, Russia and other suppliers share the Chinese import demand relatively evenly, each occupying 10 – 20%. Whereas in NPS2060B, Russia becomes the dominant supplier, taking nearly 40% in 2060 via both LNG and pipeline trade. This change in Russian supply is related to the application of production CAPEX supply curves. In addition, the relatively lower contract agreement level between China and other suppliers, which is attributed to the risk evaluation process, provides Russia with more contracting opportunities.

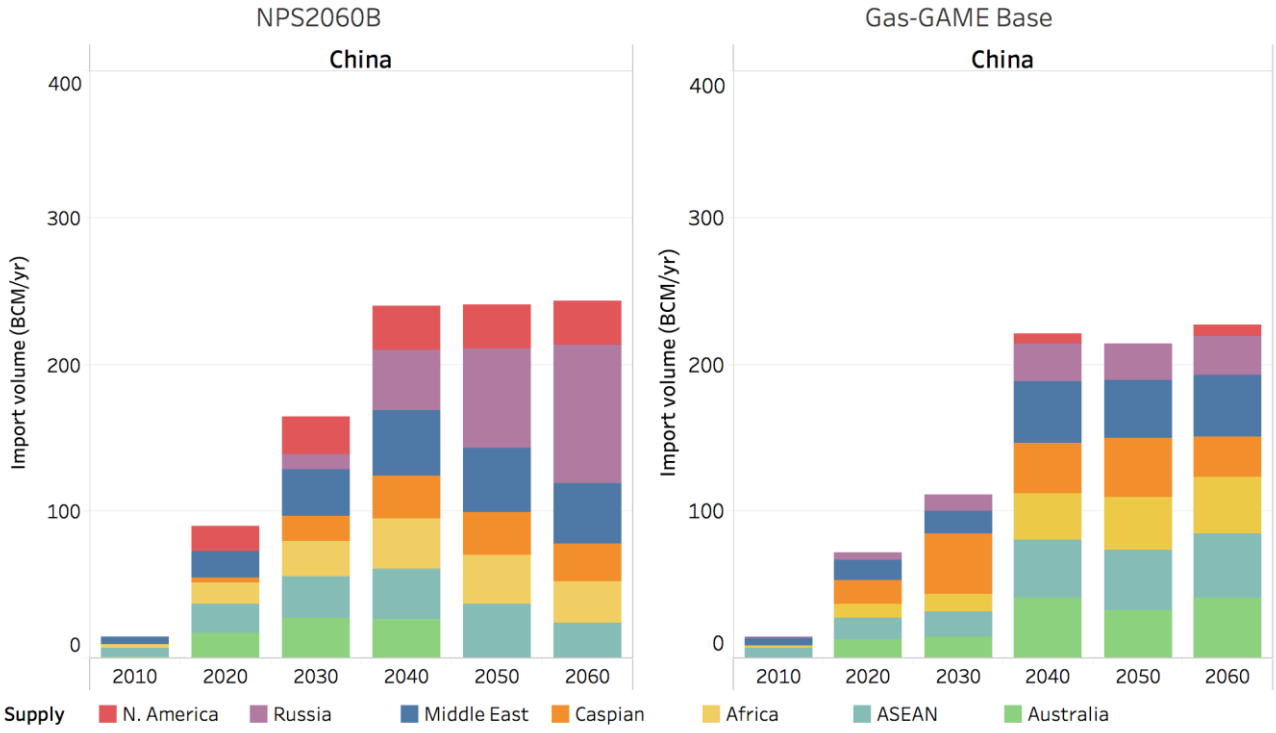


Fig. 5 - 9. Comparison of Chinese gas import in NPS2060B (Gas-GAME-Risk) and Gas-GAME base

Regarding the East Asia market, the higher prices in 2035 and 2055 in the Gas-GAME base case are also attributed to the limited regasification capacity. The dual value of this capacity constraint is as high as US$ 4/MMBtu in the two periods. As the constraint is relaxed in NPS2060B, the substantial price increase (see Fig. 5 - 8) is no longer observed. A notable difference in the East Asian market, as shown in Fig. 5 - 10, is the continuous expansion of North American supply. In NPS2060B, North America takes the dominant position in East Asia, and this is attributed to the lower production CAPEX when using the corresponding supply curve. Other exporters, including ASEAN, Africa, Australia,

and Norway, reduce their supply to this market in NPS2060B. These exporters have relatively higher CAPEX for project development, and the low-demand risk, which is 60% as compared to the base, significantly affects the contracting process.

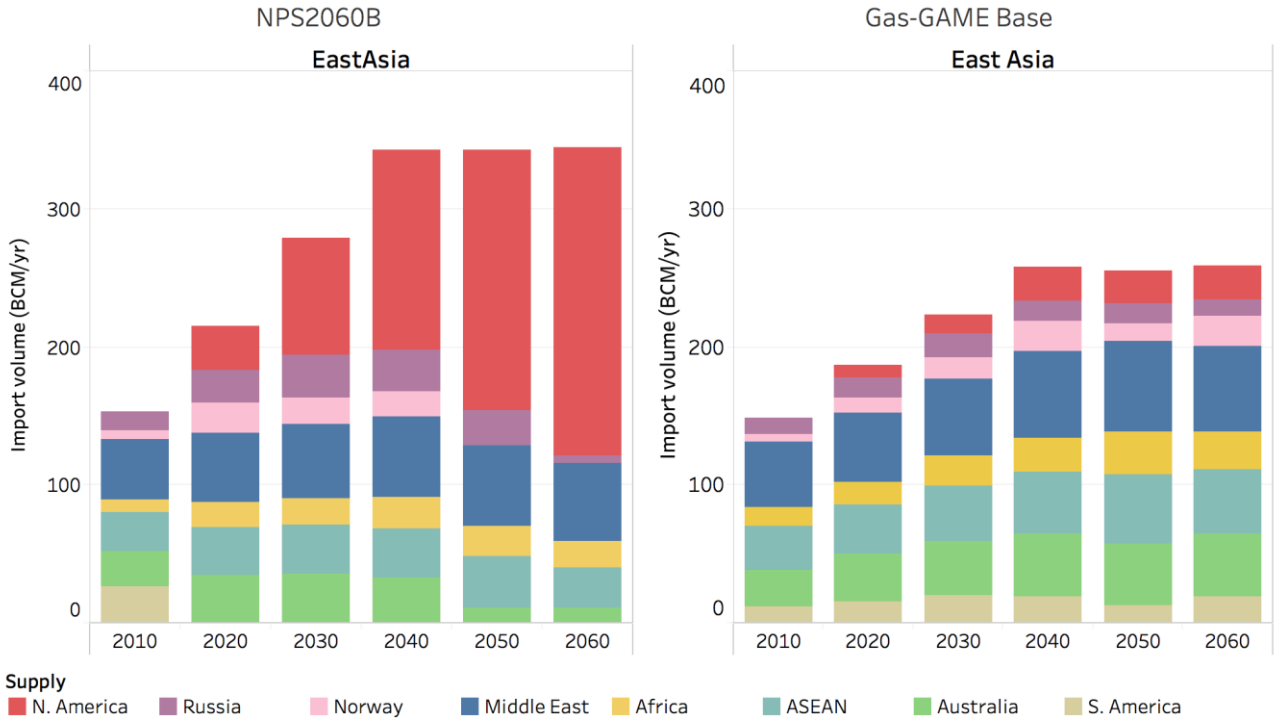


Fig. 5 - 10. Comparison of East Asia gas import in NPS2060B (Gas-GAME-Risk) and Gas-GAME base

Regarding Western Europe, the price relationship between the two scenarios is different from the Asian markets. The price in Gas-GAME base, as shown in Fig. 5 - 11, is relatively lower as compared to the NPS2060B case. The difference reaches around US$ 0.5/MMBtu in 2030, and increases to around US$ 1.0/MMBtu in 2060. Fig. 5 - 12 presents the comparison of import between the two scenarios. The gas supply from Norway gradually decreases in NPS2060B due to the lack of production capacity development. There are limited reserves in Norway that can be developed at low production CAPEX. Hence when NPS2060B uses the CAPEX supply curve in contract evaluation and the lower demand risk in Europe is considered, fewer Norwegian gas supply contracts are agreed. North America also exports to Europe less in NPS2060B as compared to the Gas-GAME base. However, the reason is not the CAPEX parameter. In NPS2060B, though most contracts with all markets are agreed by North American exporters, they gradually focus on the East Asian market, driven by the higher profitability there in short-term trade. Whereas in the Gas-GAME base case, North America focuses on Western Europe because it does not have a significant cost advantage over other exporters in East Asia. Another difference between the two scenarios is the supply from the Middle East. The export level is less than 20 BCM/yr in Gas-GAME base case, whereas in NPS2060B, the

Middle East exports nearly 90 BCM/yr in 2040 and 150 BCM/yr in 2060. Similar to other increasing supplies observed in NPS2060B, this difference is to a large extent attributed to the production CAPEX supply curve.

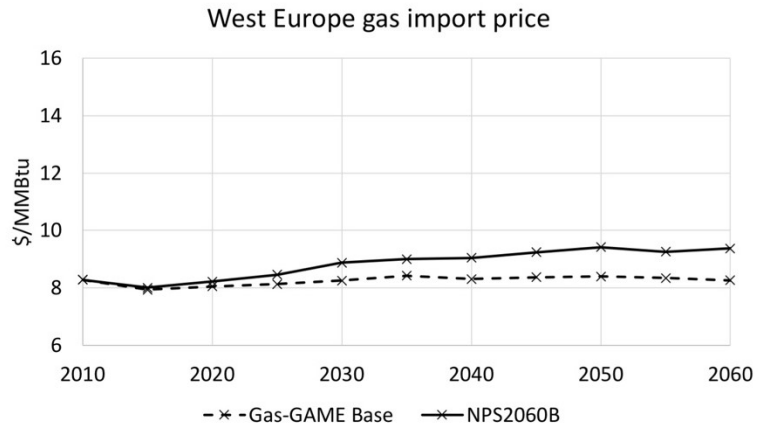


Fig. 5 - 11. Comparison of regional gas prices in NPS2060B (Gas-GAME-Risk) and Gas-GAME base case: West Europe

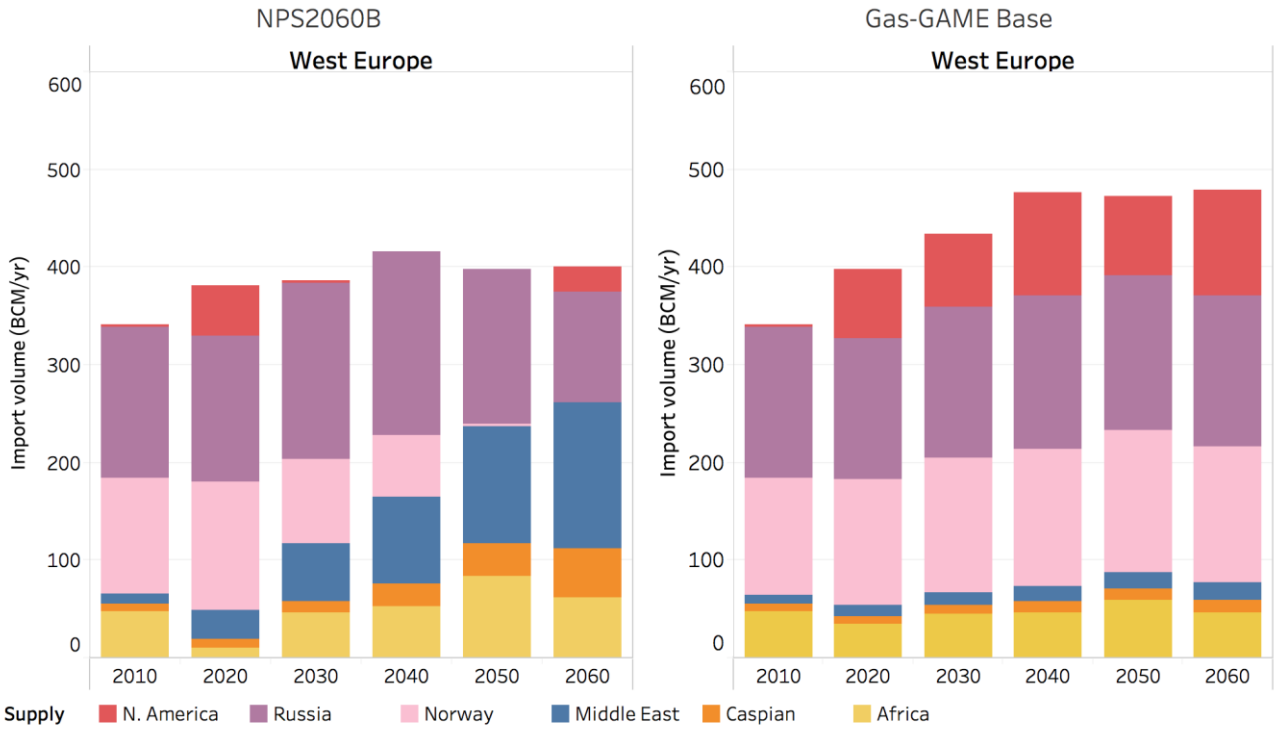


Fig. 5 - 12. Comparison of West Europe import in NPS2060B (Gas-GAME-Risk) and Gas-GAME base

5.3 The impact of China-US natural gas tariff

Section 5.2.1 illustrates how different global import-export relationships could evolve under the two demand trajectories. In this section, how the global gas trade would be affected by the Chinese tariff on North American LNG export is discussed for the two demand scenarios separately. The base case refers to NPS2060B in section 5.3.1 and to Shift2030B in section 5.3.2. The impacts are examined not only focusing on the markets, but also covering exporters, including both North America and its competitors.

5.3.1 With gas demand relationships based on current policies

The market prices in the two scenarios, namely NPS2060B and NPS2060T, are presented in Fig. 5 - 13. With the tariff imposed, China needs to import natural gas at slightly higher prices (by around US$ 0.3/MMBtu) in the near future (2020 to 2030). Such influence becomes more noticeable in the longer term, as the Chinese gas price increases by US$ 0.5 to US$ 1.0/MMBtu after 2045. This change in price is caused by the change in import volume. As shown in Fig. 5 - 14 and Table 5- 5, China imports much less from North America because of the tariff. The annual amount drops significantly from 20 – 30 BCM to less than 10 BCM, which can increase the Chinese gas price by US$ 2/MMBtu. The reason why Chinese gas price is only influenced mildly between 2020 and 2030 is that the reduced North American LNG supplies are replaced by the additional gas from the Middle East, Russia, Caspian, Australia, and ASEAN countries. These exporters each contribute to part of the demand (around 3 BCM/yr), and these additional supplies together allow the Chinese market to remain in equilibrium without much LNG import from North America. However, after 2045, a considerable amount of currently existing and upcoming production and export infrastructure will decommission. These infrastructures include the major pipelines between China and Russia, and the liquefaction plants in ASEAN countries. The LNG supply capacity in Australia also drops to nearly zero due to the lack of further investment. Although the Middle East and Caspian can compensate the reduced North American supply by each increasing their exports to China by around 5 BCM/yr export to China, other gas exporters lack the spare capacity to sell additional volumes to China. As a result, the total Chinese import after 2045 is 4 – 10 BCM/yr less in the tariff scenario relative to NPS2060B. As such, with the tariff imposed, China would see its price increase between 2045 and 2060 by a relatively higher amount than between 2020 and 2030.

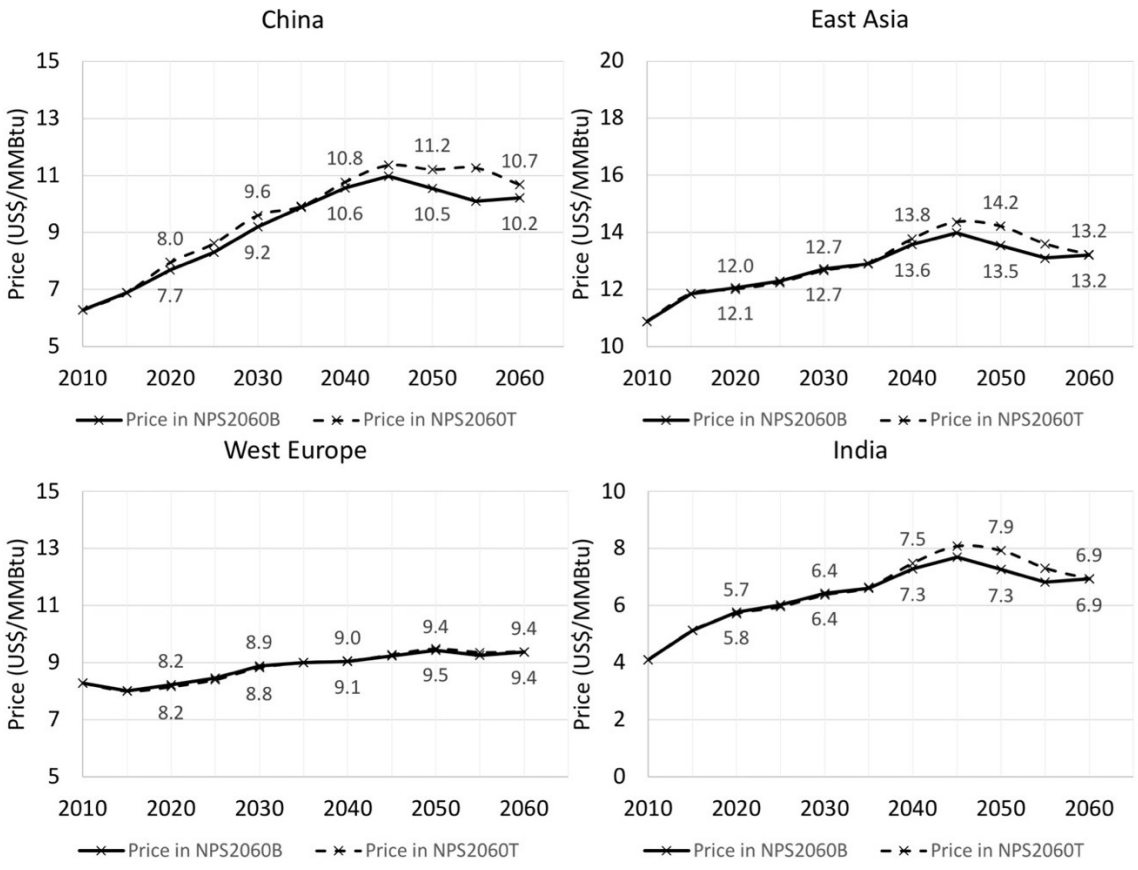
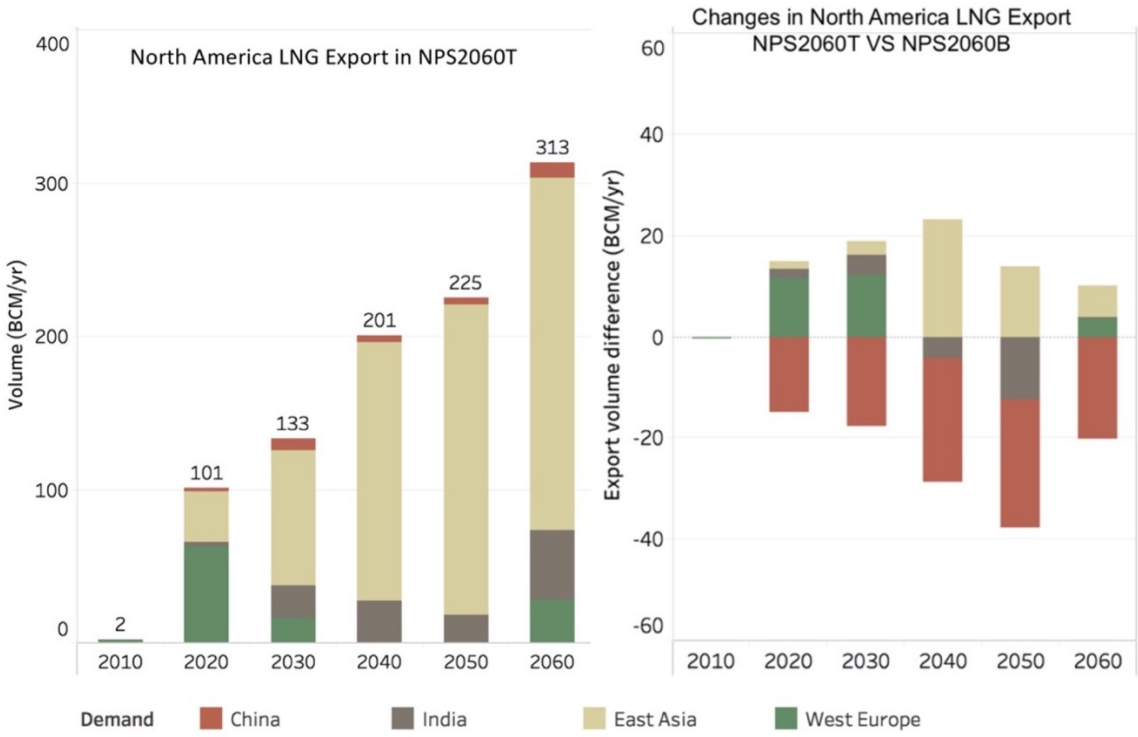


Fig. 5 - 13. Price in major markets for NPS2060 scenarios



Note: The bar chart on the right illustrates how North American LNG export in NPS2060T differs from NPS2060B. The value on the negative axis means that North America decreases the export to the market when the China-US tariff is imposed. The positive values indicate an increasing export from North America to the market.

Fig. 5 - 14. Gas export by North America in NPS2060T and changes as compared to NPS2060B

Table 5- 5: Changes in the import volumes in NPS2060T as compared to NPS2060B

	Changes in the Chinese market import (BCM/yr)					Changes in the East Asia market import (BCM/yr)				
Origin	2020	2030	2040	2050	2060	2020	2030	2040	2050	2060
N. America	-15	-18	-24	-25	-20	2	3	23	14	6
Russia	0	-1	17	3	1	0	0	-26	-23	-5
Caspian	3	4	2	6	4	0	0	0	0	0
Middle East	3	4	2	6	4	0	0	1	4	0
Australia	3	2	0	0	0	0	-1	0	0	0
ASEAN	3	2	1	0	2	0	-1	0	0	-1
Africa	3	4	1	4	4	0	0	1	2	0
Norway	0	0	0	0	0	0	0	0	0	0
Total Change	-3	-4	-2	-6	-4	0	0	-1	-4	0

Due to the 25% tariff, no long-term LNG contract between North America and China is confirmed endogenously after 2020. This leads to a lower LNG export capacity in North America relative to the base case. In the base case, around 50 BCM/yr North American LNG capacities are underpinned by the Chinese contracts. However, this amount is zero in NPS2060T. Although the contracts with Eastern Asia and Western Europe have relatively higher volumes, they are not sufficient to compensate for the impact of the Chinese tariff. As a result, North America develops less LNG capacities, exacerbating the tightness in global gas supply between 2040 and 2050. Such supply tightness not only influences the Chinese market, but also leads to an increase in East Asian and Indian gas prices. Both markets see their prices US$ 0.5/MMBtu higher than the base scenario. This shows how the reduced investment in North American LNG capacities can affect gas markets globally.

Table 5- 6: Total revenue of North America and Russia in NPS2060 scenarios

	Total revenue between 2010 and 2060 (Billion USD)	
	North America	**Russia**
NPS2060B	3,940	4,510
NPS2060T	3,960	4,340
Difference in revenue	20	-170

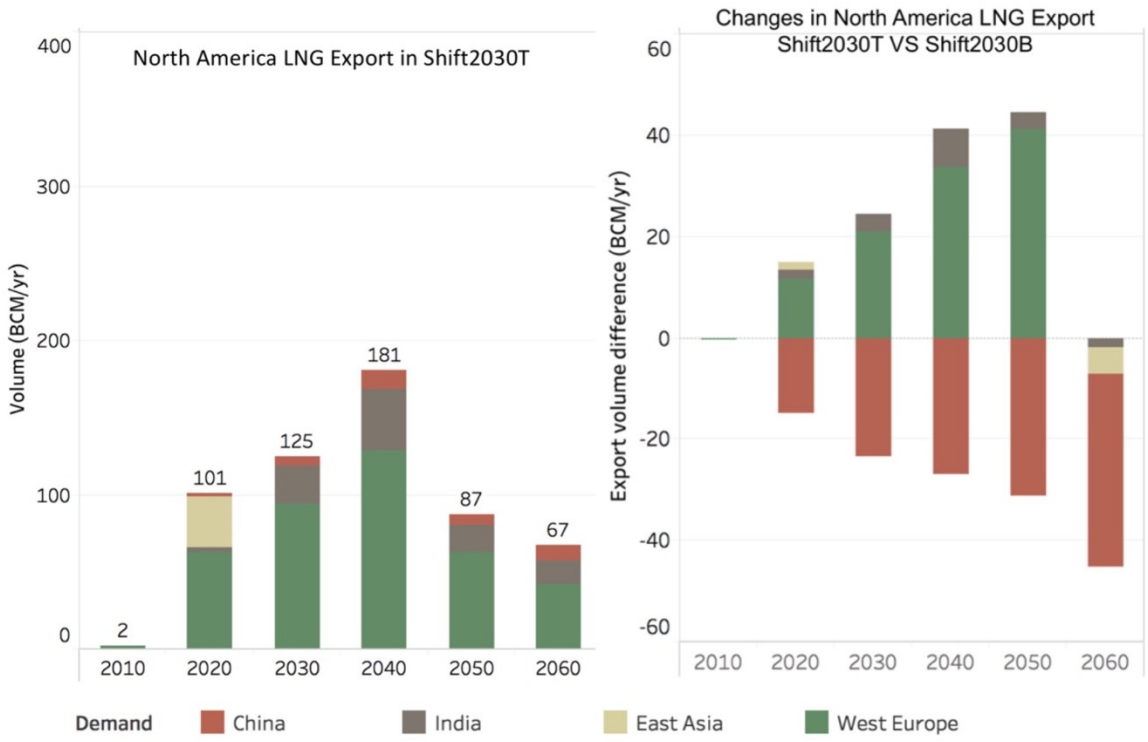
Fig. 5 - 14 describes the destination and volume of North American LNG export in NPS2060T, and how it differs from the corresponding base case. The comparison of the total revenue of North American gas export is illustrated in Table 5- 6. Between 2020 and 2030, the reduced export to China is redirected to Western Europe. Since Western Europe is a relatively large market, the additional amount of LNG import from North America (10 – 15 BCM/yr) does not significantly influence the market shares of other major suppliers. These suppliers, including Russia, Africa, and the Middle East, only have their exports reduced by 2 – 5 BCM/yr. After 2035, East Asia becomes the destination on

which North American LNG focuses. The gas that is sold to China in NPS2060B is redirected to East Asia in NPS2060T. Such a supply shift strengthens the dominance of North American LNG in East Asia, and the market share increases from 42% (NPS2060B) to 50% (NPS2060T) in 2040 and from 55% to 60% in 2050. The total revenue of North America in the tariff case is approximately the same as that in the base one. This indicates that North America would only be influenced marginally by the tariff proposed by China, if the demand trajectory follows current policy pledges.

In contrast, the Russian LNG export faces a serious challenge in this tariff scenario. Around two-thirds of the Russian supply to Eastern Asia in NPS2060B (20 – 30 BCM/yr) can no longer be sold because of the increasing North American supply to the market. Though Russia has the spare capacity to export more LNG to East Asia, the trade would be less profitable as the increasing volume would weaken the market price. Hence, during the short period between 2030 and 2040, Russia redirects its LNG to China. Afterwards, no more LNG projects are developed in Russia, and a revenue reduction of US$ 170 billion, as shown in Table 5- 6, is observed. The result suggests that, if China imposes the tariff to North American LNG, Russia should consider investing more conservatively in their LNG projects targeting the East Asian market. Instead, the pipeline projects targeting China may play a more important role in the Russian gas export portfolio.

5.3.2 Facing gas demand change

Here, the discussion focuses on the scenarios when global gas demand shifts to a lower level in 2030 (*i.e.* Shfit2030B and Shift2030T). Table 5- 7 shows the revenue comparison between the two scenarios for both North America and Russia. No reduction in the total revenue of North America is observed when the Chinese trade tariff is imposed. In fact, the revenue increases slightly from the US$ 1.56 trillion (in Shift2030B) to US$ 1.60 trillion (in Shift2030T). Between 2030 and 2050, North America exports more LNG in Shift2030T than in Shift2030B. The LNG which would have been shipped to China is redirected to Western Europe. As shown in Fig. 5 - 15, North American export to Western Europe increases by 30 BCM/yr in 2040 and by 40 BCM/yr in 2050. Consequently, the long-term contracts between this pair are assigned with higher volumes, and these contracts then underpin more LNG capacities in North America. On average, North America has 15 BCM/yr additional export capacity between 2030 and 2050 in Shift2030T. Because of the increased capacity, the total export volume from North America sees an increase relative to the base case, though the trade between North America and China shrinks considerably. Similar to the NPS2060 cases, the results of the Shift2030 cases also indicate that the impact of the Chinese tariff on North American LNG business is limited. The cost advantage allows North America to increase its export to other markets to compensate for the loss in the Chinese market.



Note: The bar chart on the right illustrates how North American LNG export in Shift2030T differs from Shift2030B. The value on the negative axis means that North America decreases the export to the market when the China-US tariff is imposed. The positive values indicate an increasing export from North America to the market.

Fig. 5 - 15. Gas export by North America in Shift2030T and changes as compared to Shift2030B

Table 5- 7: Total revenue of North America and Russia in Shift2030 scenarios

	Total revenue between 2010 and 2060 in Shift2030 scenarios (Billion USD)	
	North America	**Russia**
Shift2030B	1,560	3,490
Shift2030T	1,600	3,350
Difference in revenue	40	-140

The result also suggests that the tariff only imposes a mild impact on the Chinese market. The changes in the Chinese import in Shift2030T are presented in Table 5- 8. The gas price in China, as shown in Fig. 5 - 16, differs by a maximum of US$ 0.4/MMBtu in Shift2030T as compared to Shift2030B. Though the Chinese import from North America decreases from over 100 BCM/yr (in Shift2030B) to less than 10 BCM/yr (in Shift2030T), additional gas can be sourced from other major suppliers. These suppliers, including the Caspian region, the Middle East, Australia, ASEAN countries, Africa, and Russia, all have spare capacities to deliver additional gas since all markets have decreased demand after 2030. Because of this, China can still import a similar level of gas (95% – 98% relative to the amount in Shift2030B) to retain the market equilibrium even if it loses the North American supply. In addition, the Chinese market demand becomes more elastic, and therefore a minor change in the import volume only has a low impact on the price.

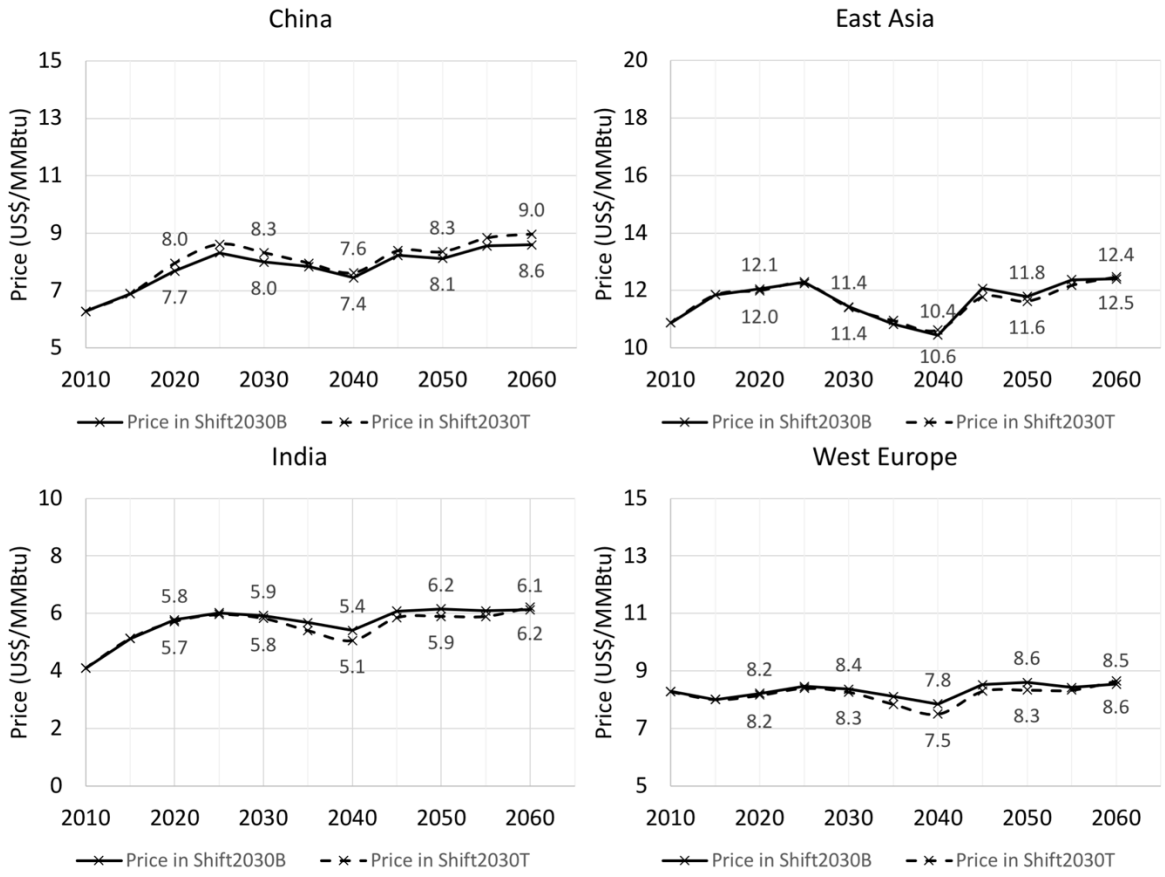


Fig. 5 - 16. Price in major markets for Shift2030 scenarios

Table 5- 8: Changes in the import volumes in Shift2030T as compared to Shift2030B

	Changes in the Chinese market (BCM/yr)					Changes in the West Europe market (BCM/yr)				
Origin	2020	2030	2040	2050	2060	2020	2030	2040	2050	2060
N. America	-15	-23	-27	-31	-38	12	21	34	41	0
Russia	0	-1	7	-3	-2	-3	-5	-16	-2	-2
Caspian	3	5	3	5	7	0	0	-1	-3	-32
Middle East	3	5	3	5	7	-3	-4	-1	-18	-1
Australia	3	2	0	0	0	0	0	0	0	0
ASEAN	3	5	5	7	-4	0	0	0	0	0
Africa	3	4	5	14	22	-3	-5	0	-12	-13
Norway	0	0	0	0	0	0	-3	0	0	0
Total Change	-3	-5	-3	-5	-7	3	5	16	6	-48

The other market which is influenced by the tariff is Western Europe. Since North America increases its export there, other suppliers including Russia, Africa, and the Middle East have their exports reduced to keep the market price at a profitable level. Among these suppliers, Russia is the dominant one in the base case, and its export is influenced to a great extent. For example, in 2040, over 15 BCM/yr Russian pipeline supply to Western Europe is replaced by North American LNG. As a result, the dominance of Russian gas in this market is alleviated. In Shift2030B, Russia supplies over 50% of Western Europe gas import in 2045. This percentage declines to 45% in Shift2030T, and remains below 40% for most of the periods. This suggests that Western Europe benefits to further diversify its gas supply under the Chinese tariff scenario. On the other hand, Russia has a revenue reduction of US$ 140 billion. Such a result indicates a threat to the Russian gas business from North America when the tariff is imposed.

5.4 Concluding remarks

This section presents the future global gas trade scenarios with market demand and trade relationship uncertainties represented. The analysis is based on Gas-GAME-Risk, which allows investors to consider the market demand uncertainties during the contracting process. Two alternative future gas demand trajectories are simulated. Under the New Policies Scenario demand assumption (NPS2060B), North American LNG supply would gradually dominate East Asia, taking a market share of more than 65% by 2060. However, in the disjoint shift condition (Shift2030B), export to East Asia becomes less profitable for North America, and the Middle East becomes the major supplier there with its export volume doubling from 2020 to 2060. A decrease in East Asian and Chinese gas prices by US$ 2 – 4/MMBtu is observed. Both North America and Russia, subject to the disjoint demand shift, may suffer significant revenue loss on global gas trade.

The impacts of potential China-US LNG trade tariff are also examined. When the potential 25% China-US LNG tariff is imposed, under the NPS demand assumption, the Chinese market is affected only mildly in the near future, thanks to the additional supplies from other exporters. After 2045, China sees a higher price relative to the without-tariff case because of supply infrastructure decommissioning and lower North American capacity development. The global LNG supply condition becomes tight, which also leads to higher prices in East Asia and India. With its export to China reduced significantly, North America further dominates the East Asian market, and as a result, Russian LNG faces serious challenges with a 66% supply reduction. The results suggest that Russia should invest more in the Chinese pipeline projects rather than in LNG projects if such a tariff is imposed.

When the tariff is imposed under the Shift2030 assumptions, the Chinese market is only mildly affected. Additionally, no reduction is observed in North American total gas export revenue. North

America shifts its emphasis to the Western Europe market, and this leads to a further expansion of North American LNG capacities. Russia has its market share in Western Europe reduced, and the competition in the Chinese market allows Russia little space to increase its export there. As a result, Russia is negatively affected by such a tariff, with its total revenue reduced by US$140 Billion between 2020 to 2060.

This chapter also includes a base case result comparison between the one simulated by Gas-GAME-Risk and the one presented in Chapter 4. How the result changes are related to the changes in parameters, constraints, and simulation methods is discussed. Two typical demand scenarios, among the infinite number of possible ones, are examined in this study, shedding light on how one potential demand change would affect gas market development. Further simulations, which represent the full spectrum of demand uncertainties with variations in different markets, are required to provide a comprehensive picture of future global gas trade. Similarly, only one trade relationship (geopolitical) uncertainty is simulated in this study. More research required to firstly identify and quantify these geopolitical uncertainties, and then examine the corresponding impacts.

Chapter 6. Asset stranding in natural gas export facilities

This section focuses on analysing the possibility and scale of asset stranding in natural gas export facilities, which include production plants, liquefaction plants, and pipelines. The model Gas-GAME-Spot is applied, and it examines not only the base scenario in which gas demand follows current policy pledges, but also two alternative scenarios in which gas demand changes.

6.1 Model input data and scenario framework

In this section, the simulation is updated to have the base year as 2015 so that the latest changes in global gas trade can be captured. The model runs until 2060 with 5-year time-periods, and a total three scenarios are simulated to investigate the potential stranding of gas infrastructures. The input parameters of the base case, and how the update has been done as compared to Chapter 4 Gas-GAME simulation, is presented first. The setting of the two alternative scenarios are then described.

6.1.1 Base case datasets

The base period is set as 2015 for this analysis, and many parameters are updated. Table 6- 1 summarises the updated parameters for price-demand relationship calculation, and Table 6- 2 summarises the updated capacity parameters. Similar to the previous two analysis, all existing capacities gradually decommission over a period of 25 years at a constant rate, and this constructs the initial infrastructure database. The contract database is also updated to include those concluded by 2018.

Table 6- 1. Import market parameters in Gas-GAME-Spot base-period 2015

Import market	Import volume [127] (BCM/y)	Base price [157] (US$/MMBtu)	Base price (Million US$/BCM)	Elasticity [8]
East Asia	167	10.4	371	-0.25
West Europe	343	7.1	253	-0.7
East Europe	42	8.0	285	-0.6
India	17	8.0	284	-0.5
China	56	9.7	346	-0.5

Table 6- 2. Updated capacity parameters in Gas-GAME-Spot base period 2015

Capacity type	References and updates
Production capacity	The production capacity of each supply region in 2015 is assumed to be 20% over the supplier's total export obtained from IEA [127]. This assumption is made because: 1) there is no detailed data suggesting the part of production capacity that is related to export; 2) the global liquefaction capacity, which is often directly connected to export production plants, is observed to have 20% surplus in 2015 [146].

Liquefaction capacity	The liquefaction capacity of each region in 2015 is summed up from the country-wise data published in the IGU World LNG report [146].
Regasification capacity	The regasification capacities are assumed as a large number to ensure that regasification does not limit LNG import in all markets.
Pipeline capacity	Besides the capacities in the European Natural Gas Network map [140] and IEA Oil and Gas Emergency Policy assessment report [141], the newly constructed projects, including TANAP and Sino-Myanmar, are also included.

While the literature-based short-run costs of gas exports are the same as presented in Chapter 4 and 5, the additional factors which represent the non-cost components are re-calibrated against 2015 real global gas trade data. By adding these factors to the literature-based costs, the simulated global gas trade in base-period MEM and SCM shows a good consistency with the historical data. The comparison is shown in Fig. 6 - 1 and Fig. 6 - 2. These calibrated factors are presented in Appendix D. One difference in the calibration, as compared to the process applied in Chapter 4 and 5, is that the additional factors are not restricted to the three values (0, 3, or 6). Instead, they can be any integer values between 0 and 7, so that smaller deviation in geopolitical and energy security aspects can be captured.

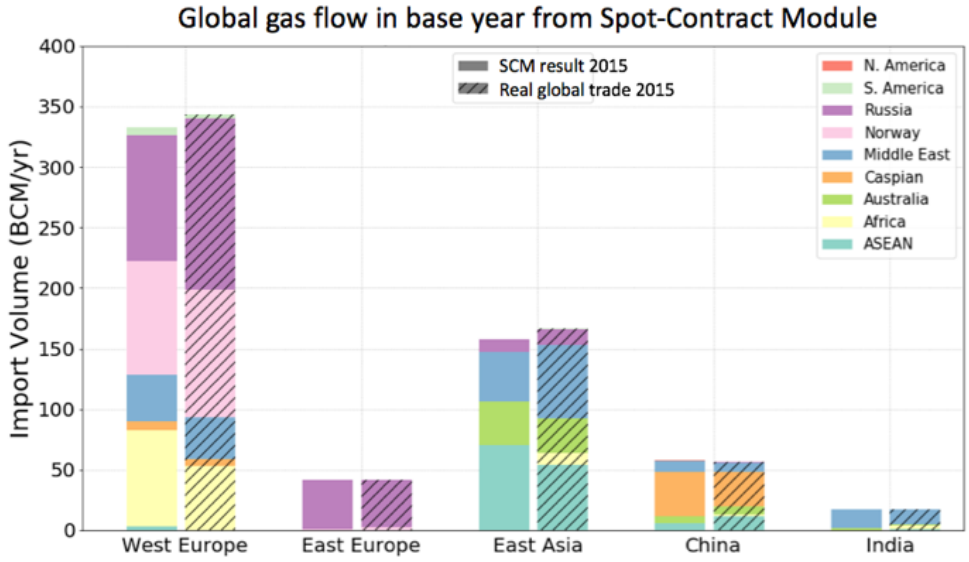


Fig. 6 - 1. Comparison of gas imports in base year 2015 between Gas-GAME-Spot SCM and real data

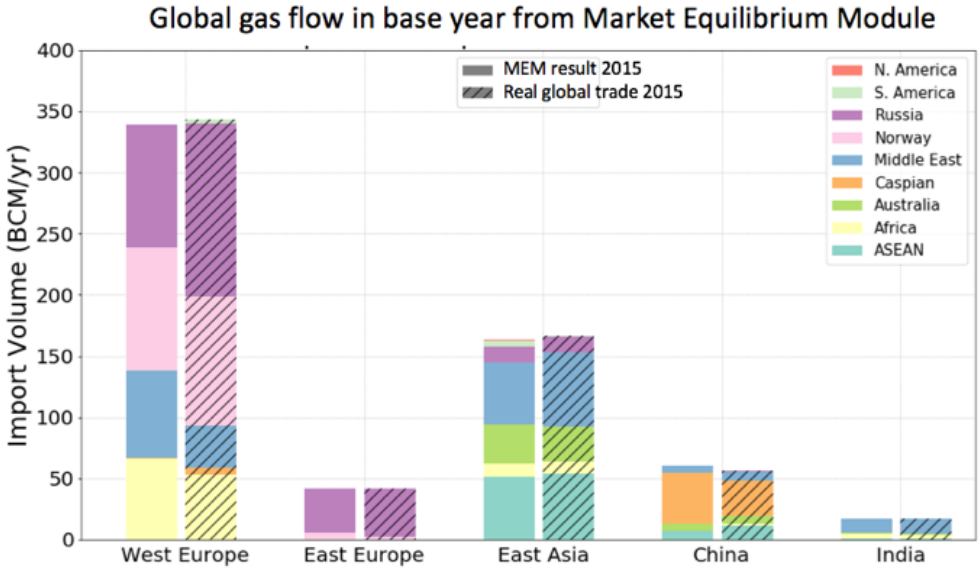


Fig. 6 - 2. Comparison of gas imports in base year 2015 between Gas-GAME-Spot MEM result and real data

The way in which the parameters in the future periods change relative to the base period follows the same method as in Chapter 4. For example, the future price-demand relationship in each region changes to adapt to the WEO New Policies Scenario until 2040, with the SLP values staying constant and INT values changing gradually. After 2040, the relationships are assumed to be the same as the 2040 relationship for each region. The short-run costs and the calibrated non-cost factors are assumed not to change in future periods, and the capacities are updated endogenously.

The additional parameters, which are specific to Gas-GAME-Spot in the SCM, have been explained in Chapter 3. In the base case, the minimum market purchase obligation $\mu_{j,t}^{CT}$ is assumed as 70% for the whole simulation horizon. This assumption is based on three sources of flexibilities in current long-term contracts: (1) downward quantity adjustment [4]; (2) provision of rescheduling to future periods [158]; and (3) flexible destination clauses and options for reselling [158]. This parameter $\mu_{j,t}^{CT}$ is highlighted here as it would be changed in other scenarios.

Regarding the simulation in IEM, the differences in agents' strategies and assumptions, as compared to Chapter 4, are summarised in Table 6- 3.

Table 6- 3: Updates of IEM agent strategies in Chapter 6

	Chapter 4: North American alternative export strategy	**Chapter 6: Asset stranding in natural gas export facilities**
Type of uncertainty	Supply strategy uncertainty	Market demand uncertainty
Model applied	Gas-GAME	Gas-GAME-Spot
Projection on future required import volume by demand agents *(IEM demand agent contract request generation)*	Before 2035, the running period MEM price in the corresponding market is used to calculate the future required import volumes, based on the next-period price-demand relationship. After 2035, a fixed import request is assumed for each region.	The running period SCM weighted average (considering both spot and contract-based trade) price in the corresponding market is used to calculate the future required import volumes, based on the assumed future price-demand relationship. For the periods before 2045, the assumed future relationships are the 15-year-later (mid-point of 30-year long-term contract) demand curve following the same trend as the running period. If the running period is beyond 2045, the future relationships are those representing the market condition in 2060.
Production capital cost *(IEM supply agent contract economic evaluation)*	Fixed capital cost per unit production capacity for each supply region based on [138] regional median level.	A production unit capex curve with gas discoveries until 2018 is computed for each supplier based on [138]. Compared to the capex curves in Chapter 5, the curves used in this analysis are updated with the latest gas reserve discoveries, assessment, and development. Each curve shows the unit production capital cost, in ascending order, and the corresponding amount of gas reserves can be developed. The capacity development in each region starts from the cheapest reserves, and the capital cost then increases according to the amount of reserves developed.
IRR initial cost allocation *(IEM supply agent contract economic evaluation)*	Capital costs are deducted at the beginning of project lifetime altogether, and there is a 5-year lead time for each project.	The initial capital costs are evenly allocated to every year in the initial 5 years. After the initial 5 years, the project starts earning expected revenues.

6.1.2 Alternative scenarios

Besides the base case, alternative scenarios are simulated to study how changes in market demand can potentially lead to asset stranding. The two alternative scenarios represent demand trajectories in which international efforts are initially insufficient to tackle the climate challenge, but the perception of climate disruption by mid-2020s would trigger a precipitous transition towards lower emissions. Table 6- 4 presents the different references based on which future demand trends are characterised. The design of alternative scenarios is shown in Table 6- 5.

Table 6- 4: Different future demand scenarios in Chapter 6 Asset stranding analysis

	Import level in 2040 (BCM/yr)		
	WEO New Policies Scenario (NPS)	WEO Sustainable Development Scenario (SDS)	Very Low Demand Scenario (VLOW)
West Europe	463	347	213
East Europe	58	44	27
East Asia	359	215	215
China	278	306	205
India	99	129	79

Table 6- 5: Scenario framework for Chapter 6 Asset stranding analysis

	Period	**Base scenario**	**Shift-SDS scenario**	**Shift-VLOW scenario**
Market demand relationship	2015-2030	NPS	NPS	NPS
	2035-2060	NPS	SDS	VLOW
Projection basis markets use to plan 15 years ahead	2015-2025	NPS	NPS	NPS
	2030-2060	NPS	SDS	VLOW

For the initial period from 2015 to 2030, the simulation for the two alternative scenarios, namely Shift-SDS and Shift-VLOW, is the same as the base scenario, which follows the NPS demand projection. After that, the alternative scenarios simulate a disjoint shift to low-level demands in import markets, and the price-demand relationships align with two different demand projections. This scenario framework is similar to WEO 2017 analysis on stranded natural gas assets [18] and also to the Shift2030 scenarios described in Chapter 5, except that the two alternative demand trajectories to which the base demand relationship shifts are different from Shift2030.

For Shift-SDS, the low-level demands are based on the projection from WEO Sustainable Development Scenario (SDS) [18]. In SDS, as shown in Table 6- 4, the traditional major gas markets

like Europe and East Asia have lower gas demand levels. In contrast, China and India, in order to reach their sustainable development goals, consume more gas to replace coal.

The Shift-SDS scenario is not sufficient to study the extreme condition in which all the markets have low gas demand. Hence, an alternative demand scenario named as VLOW is simulated, and Shift-VLOW represents the condition when demand relationships change to the VLOW scenario. Similar to the LOW scenario in Chapter 5, the lowest level of demand in each market is estimated based on the lowest value compiled from multiple projections in the literature [38, 129-131, 159-161]. The difference of the VLOW scenario as compared to the LOW, shown in Table 6- 6, is that the two European markets have lower demand levels. The lower European demand in VLOW is based on a climate *target* scenario "energy [r]evolution" [161]. Unlike other *simulation* scenarios, based on which LOW scenario is compiled, this target scenario makes an ambitious assumption on renewable development and on energy efficiency increase. The future gas demand is estimated based on the emission target, and is much lower than other simulation results. Even though such a demand level is unlikely to be achieved, it is used in this study to examine the extreme condition from which the stranding risks can be fully explored.

Table 6- 6: Comparison of LOW and VLOW demand projection in Europe

	Very low Demand Scenario (VLOW) BCM/yr	**Low Demand Scenario (LOW) applied in Chapter 5 BCM/yr**
West Europe	213	347
East Europe	27	44

The detailed price-demand relationships for all three scenarios are shown in Appendix D. With the changes in the relationships (i.e. *INT* and *SLP* parameters), the MEM market equilibrium simulation is affected. Additionally, the evaluation of future required imports by demand agents in IEM is also affected. As shown in Table 6- 5, at the tipping point of the demand change, which is 5 years before the demand relationship shifting period, the market starts making projections based on the new relationships instead of the original ones. This mimics the adaptation of markets to their new demand levels and simulates the condition when those markets send signals to reflect the changes. Another minor adjustment on the scenario design as compared to Shift2030 is that the period when demand relationships change to the lower level is delayed to 2035. This adjustment is to allow the base NPS projection to inform investment decisions for the following decade, and the analysis can therefore avoid an over-conservative estimation on stranding risks.

The 70% contract commitment level ($\mu_{j,t}^{CT}$) assumed in the base scenario changes in Shift-SDS and Shift-VLOW. The percentage decreases by 5% for every period after 2030. In 2060, only 40% of the

contracts are obliged to be committed. The decreasing commitment is assumed because contract renegotiation can be triggered by lower gas demand. Since the commitment level ensures the utilisation of capacities, its value is assumed to be lower in the two alternative scenarios for the stranding risks to be better explored. The decrease is assumed to happen gradually because positive trade partnerships need to be maintained.

6.2 Results and discussion

Results on gas infrastructure development from the base simulation are presented, followed by a detailed analysis on the stranding condition of these capacities. In addition, the potential asset stranding when markets face sudden demand changes is also discussed to provide a more comprehensive analysis on how asset stranding may happen in the future.

6.2.1 Global gas infrastructure expansion and stranding

Overall investment in gas production and transmission (pipeline and LNG liquefaction) infrastructure, which is related to inter-regional trade, sums up to US$3.2 trillion from 2015 to 2060. Around one third of the investment is made during the initial 20 years, and the average annual investment between 2015 and 2030 is US$51.5 billion. This value fits in the range estimated by multiple Integrated Assessment Models [162]. Fig. 6 – 3 shows the accumulated investment in different regions. Russia and the Middle East are the two major investors, each spending over US$800 billion in export capacity. The amount of capital invested by North America (US$375 billion) and Australia (US$315 billion), the two new entrants to the LNG market, is also considerable. Around 80% of the total investment is in the production sector. The remaining is in transmission, with 88% (US$590 billion) relating to LNG facilities and 12% (US$80 billion) to pipelines.

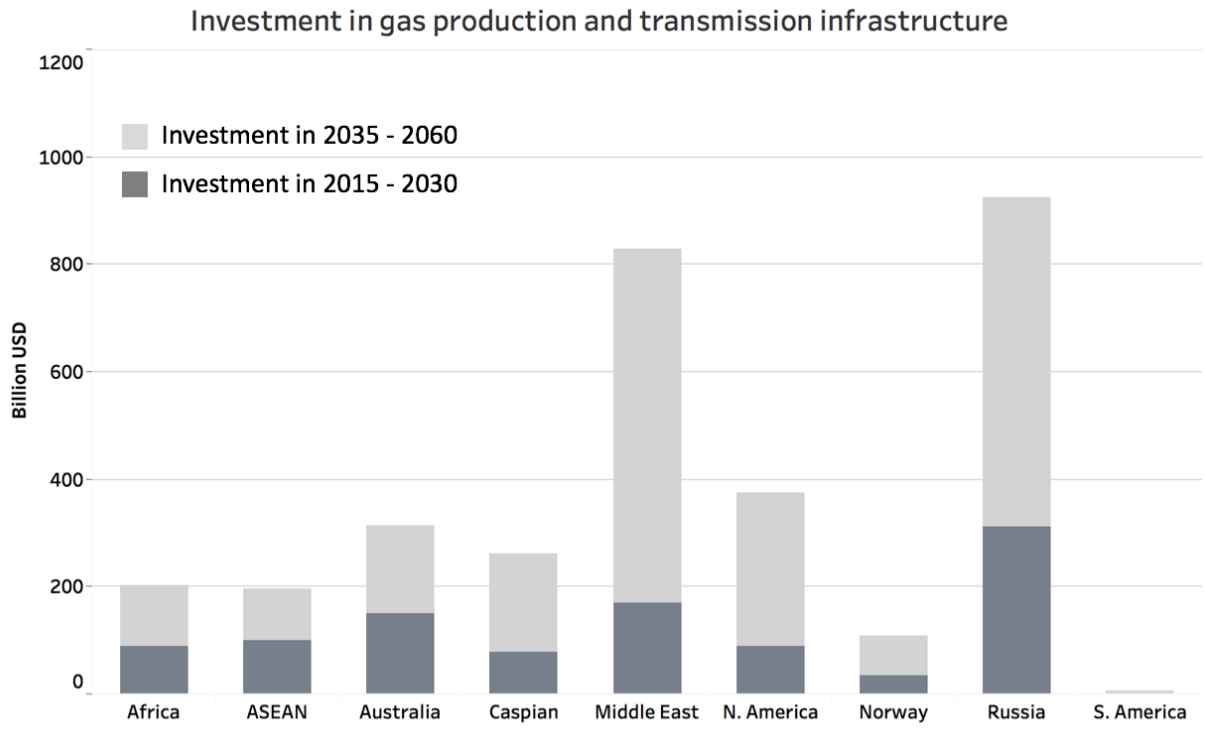


Fig. 6 – 3. Regional investment in gas infrastructure simulated in Gas-GAME-Spot base case

The export capacity discussed in this section is the capacity that each exporter is capable to both produce and transport to markets. Fig. 6 – 4 illustrates the export capacity development and the shares of supply agents. Global gas export capacities nearly double from 860 BCM/yr in 2015 to around 1770 BCM/yr in 2040 and 2045. After 2045, total capacities see a decrease, which is caused by the decommissioning of facilities developed by 2020, and then stay stable at 1200 BCM/yr. By 2060, the two major exporters are Russia and the Middle East, together contributing to two thirds of the total export capacity globally. While the Middle East targets the clients in Eastern Asia, Russia dominates the Western European and Chinese markets. North America gradually expands its infrastructure and can export nearly 200 BCM/yr by the end of the projection period.

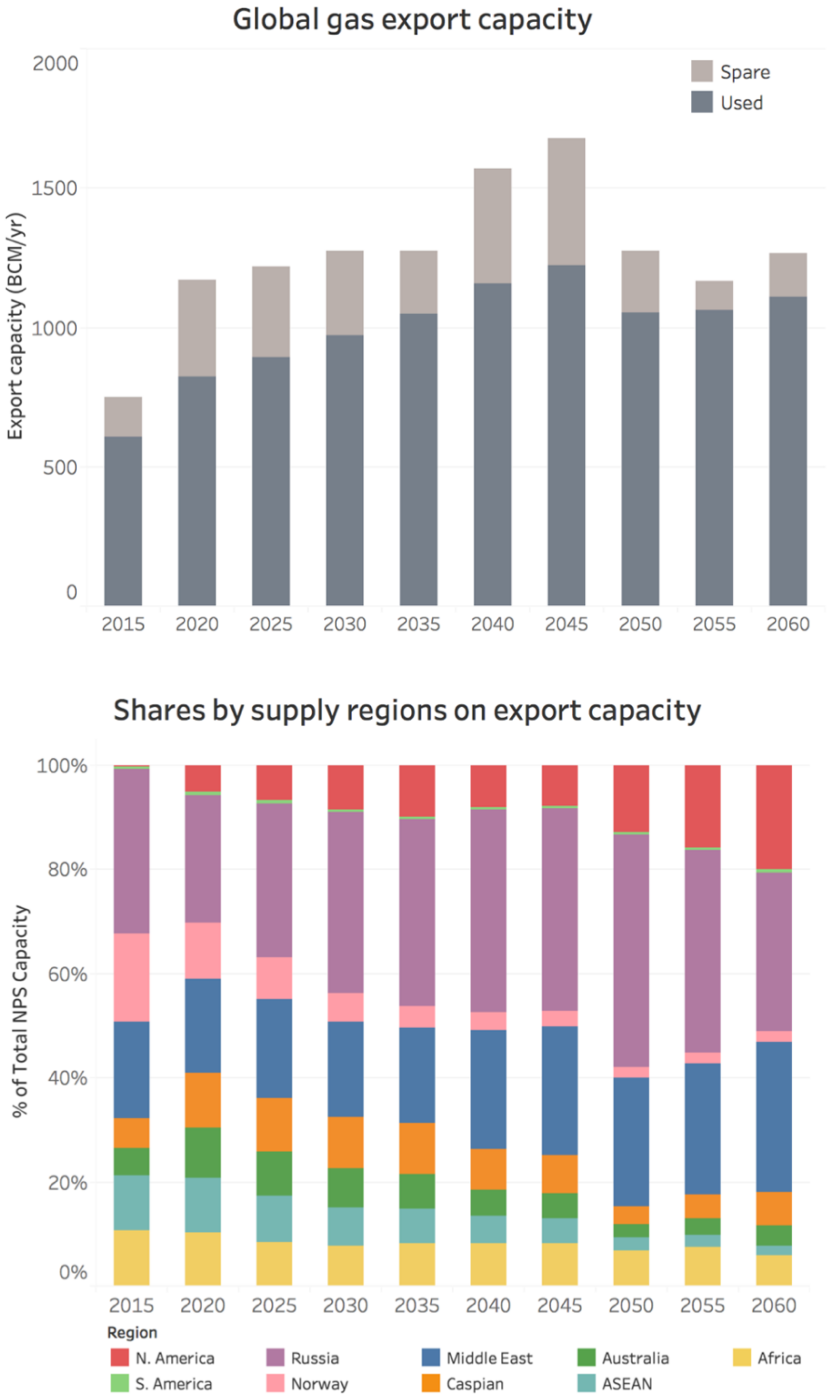


Fig. 6 – 4. Global gas export capacity simulated in Gas-GAME-Spot base case

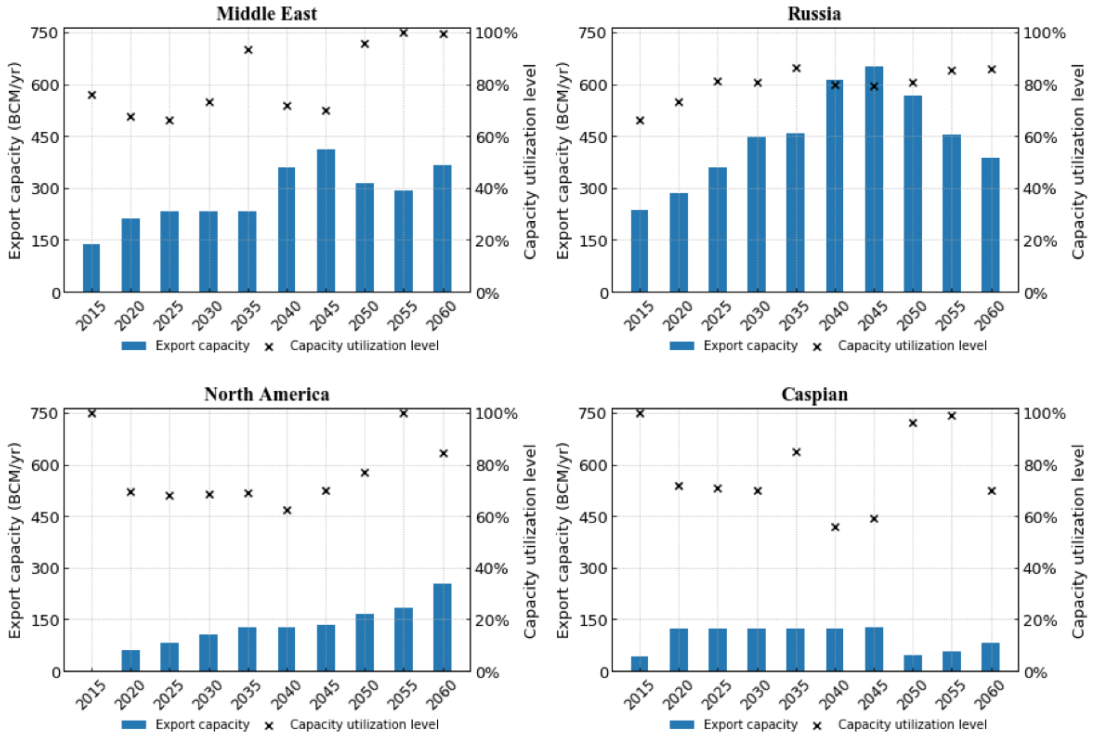


Fig. 6 – 5. Regional export capacity development and utilisation level in Gas-GAME-Spot base case: the Middle East, Russia, North America, Caspian

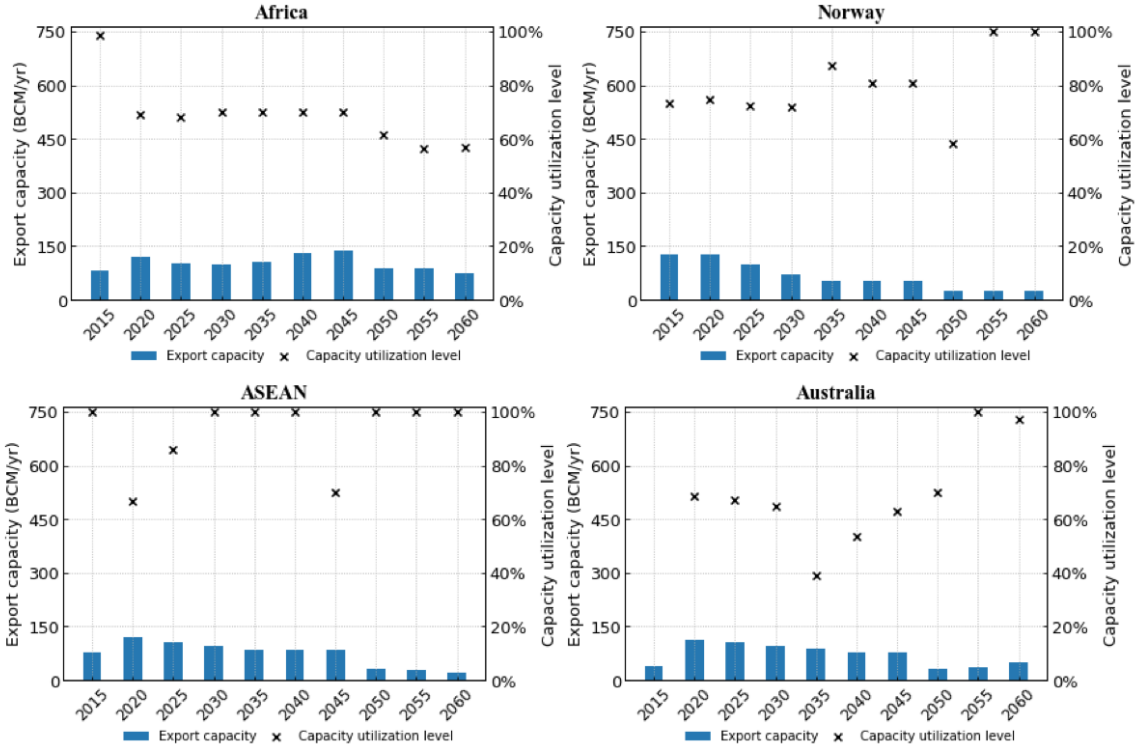


Fig. 6 – 6. Regional export capacity development and utilisation level in Gas-GAME-Spot base case: Africa, Norway, ASEAN, Australia

The results indicate limited stranding for global gas export infrastructure. When the gas demand trend follows current policy pledges, as simulated in this base case, the average infrastructure utilisation from 2015 to 2060 is 80% globally. The highest level of total spare capacity is around 460 BCM/yr in 2045, and even in this condition, there is still 73% of the total export capacity utilised. In the following 5 years, export capacity decreases by a considerable amount (400 BCM/yr). This leads to a spare capacity of only 100-200 BCM/yr and an average utilisation of 88% after 2050. In the main supply regions like the Middle East, Russia, and North America, as shown in Fig. 6 – 5, the utilisation level is between 70% and 100% throughout the projection periods. This utilisation is reasonable and will not lead to significant stranding as exporters do need a small amount of spare capacity to address uncertain demand, infrastructure maintenance, and trade flexibility.

Australia has relatively low utilisation from 2035 to 2045 as most of its contracts signed by the time of writing will end 10 years before the related infrastructure decommissions. Without the export secured by contracts, the market share of Australia in Eastern Asia is challenged by increasing supplies from the Middle East. Though the capacity utilisation in Africa and Caspian countries are also relatively low (around 60%) in certain periods, the amount of spare capacity is not significant.

The reason for limited asset stranding is related to the slowing down of further capacity development by medium-sized suppliers like Africa, ASEAN countries, Australia, and Norway, as shown in Fig. 6 – 6. The capital required to develop gas reserves in these regions keeps increasing, whereas the market prices (weighted average prices of contract-based and spot trade) cannot guarantee high profits to underpin new contracts and expansion projects. As a result, these medium-sized suppliers reject most of the contract requests, as shown in Fig. 6 – 7, and less new capacity is developed. The total new production capacity developed between 2015 and 2030 by these four regions can provide up to 8 TCM (Trillion Cubic Meter) gas supplies. However, only 4 TCM gas reserves get developed for production after 2030.

While medium-sized suppliers develop their new capacities slowly after 2030, their old capacities decommission gradually. As a result, a supply shortage from these suppliers is observed. In contrast, Russia, the Middle East, and North America keep confirming new contracts as they require lower capital investment to develop their gas reserves. Hence, they continue to expand and their newly developed infrastructure can be utilised at higher levels to compensate for the supply shortage caused by the other exporters.

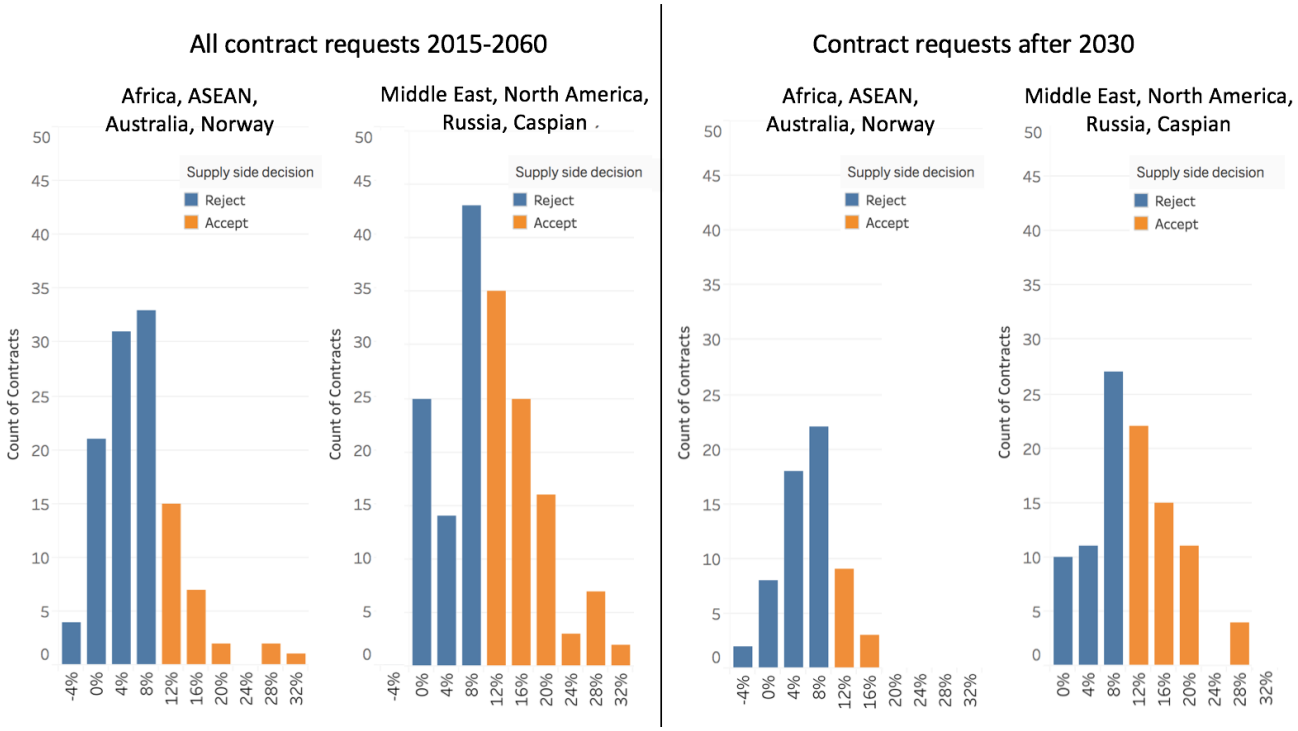


Fig. 6 – 7. Histogram for contract request IRR values in Gas-GAME-Spot base case

Similar findings are presented in the IEA WEO [18] analysis. However, its conclusion of unlikely widespread stranding is based on the argument that the decrease in gas demand after 2030 is much smaller than the decline in producing fields and the decommissioning of existing assets. The IEA study overlooks the question of how the assets that will be developed, especially in the next 20 years, may be used in future. Hence, this work broadens the current literature with a more comprehensive analysis considering both existing infrastructures and the upcoming expansion of gas export capacities.

6.2.2 Facing lower demand

The issue of stranding may bring more risks for gas industry investors when the future gas demands decrease unexpectedly. The decrease can be triggered by a rapid unanticipated switch in policy direction or intensity to reach decarbonisation targets. Here, we present the results of the two alternative scenarios, Shift-SDS and Shift-VLOW, which simulate a sudden change in the demand trajectory from 2030 to 2035.

6.2.2.1 Two phases after the demand change

From the global perspective, as shown in Fig. 6 – 8, the stranding condition is still moderate even when the markets shift to lower demand levels. Two phases, showing different levels of stranding risks, are identified in the time-periods after the change in market demand.

The first one, named as the “Transition Phase”, is from 2035 to 2045. Facing a sudden change in demand, most markets find themselves over-contracted and therefore minimise their purchase from

contracts to approach the equilibrium. As the export infrastructures underpinned by these contracts are still in place, a risk of stranding is observed. Globally, around 200 BCM/yr capacity will be stranded in 2035 if the demand shifts to the Sustainable Development Scenario (shown in Fig. 6 – 8a in Shift-SDS). The stranded capacity is over 350 BCM/yr if demand decreases to the extremely low scenario (shown in Fig. 6 – 8b in Shift-VLOW). However, the risk is moderate as it is bounded by the limited flexibility of the long-term contracts. The importers are obliged to buy minimally 65% - 55% from the contracts during this phase, and this ensures the utilisation of these infrastructures. On average, the export capacity is utilised at 79% globally in Shift-SDS and at 66% in Shift-VLOW during this phase.

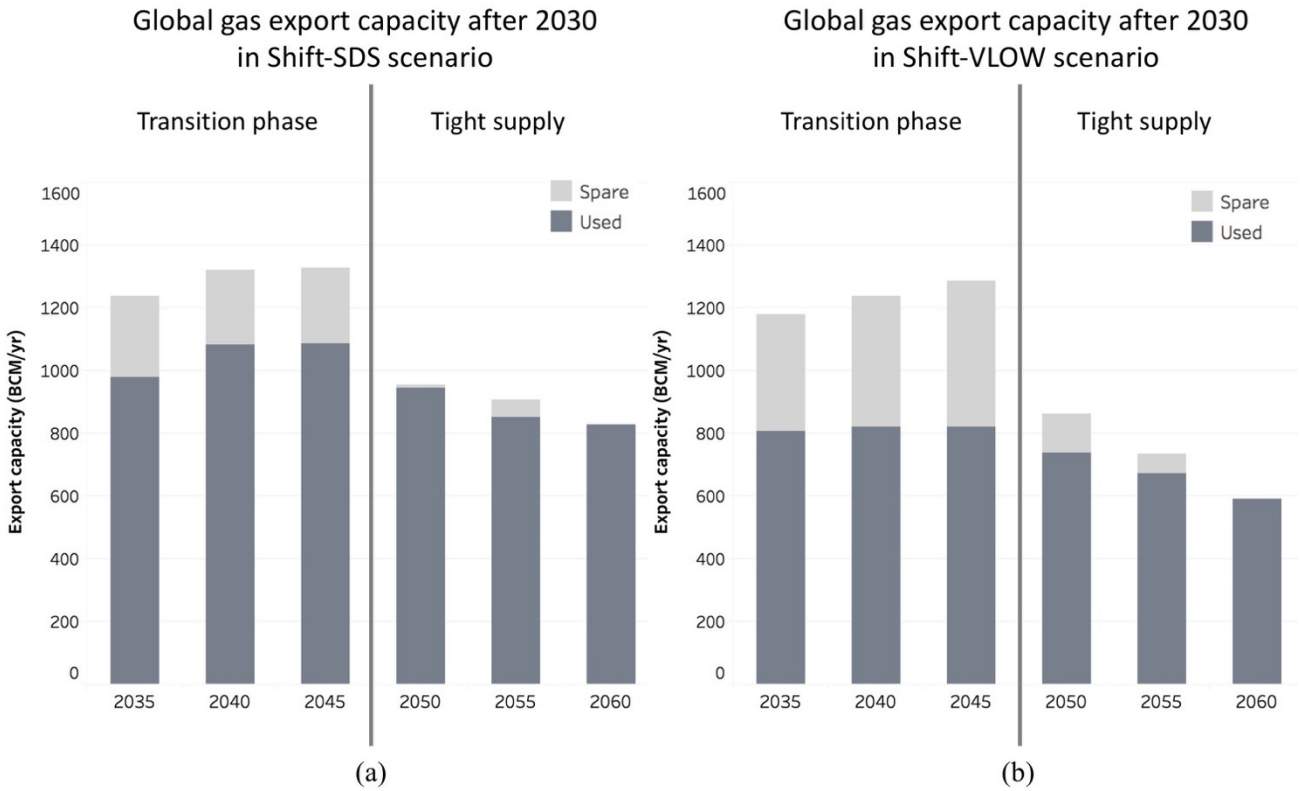


Fig. 6 – 8. Global gas export capacity in Gas-GAME-Spot alternative scenarios

The second phase, between 2050 and 2060, is characterised by "tight supply". During this phase, the result indicates a very low risk of stranding and the capacity utilisation is high – an average of 98% in Shift-SDS and 92% in Shift-VLOW. The reason behind this is that global gas export capacity declines by around one third from 2050, with two factors contributing to this decline. The first one is the decommissioning of the infrastructures developed in 2020, which amount to an export capacity of 550 BCM/yr (nearly 40% of the total capacity in 2045). The second one is the slowing down of further expansion from 2030. Table 6- 7 lists the volumes of contract requests and the confirmed contracts from 2030 to 2060 in the three scenarios. During this period, the total contract requests proposed by suppliers are nearly 3000 BCM/yr in the base scenario. In contrast, the amount is considerably lower at around 2600 BCM/yr and 2200 BCM/yr in Shift-SDS and Shift-VLOW respectively. The import

markets adapt to the new demand patterns and therefore generate lower import contract requests. This simulates the condition that markets, when facing changes in their demand levels, send signals to the suppliers to slow down investment. The suppliers also confirm fewer contracts because they expect lower market prices. As a result, the export capacities do not expand much. The two factors together lead to a tight supply globally and therefore the risk of stranding is low.

Table 6- 7: Contracting volume comparison between Gas-GAME-Spot base and alternative cases

	Total contract request volume (BCM/yr)			**Confirmed contracts volume (BCM/yr)**		
	Base	**Shift-SDS**	**Shift-VLOW**	**Base**	**Shift-SDS**	**Shift-VLOW**
2030	209	148	27	119	76	13
2035	609	474	415	444	203	157
2040	350	456	389	142	30	66
2045	531	657	535	33	184	87
2050	438	413	452	137	131	106
2055	738	539	389	324	139	73
Total	**2876**	**2686**	**2207**	**1198**	**762**	**502**

Total investment reductions after 2030, compared to the base scenario, are US$1 trillion in Shift-SDS and US$1.4 trillion in Shift-VLOW. As shown in Fig. 6 – 9, over 60% of the reduction is contributed by the Middle East and Russia. In the base case, they continue expanding after 2030 because of their low capital requirements for reserve development. Although their capital requirement is still low in Shift-SDS and Shift-VLOW, their investment is constrained by the low volume of contract requests sent by importers. This again highlights how the markets, by signalling their reduced demands, can help adjust the expansion of supply capacity. If the markets continue sending high-level import requests, suppliers will continue to confirm new contracts and invest in new infrastructure which may face the risk of stranding.

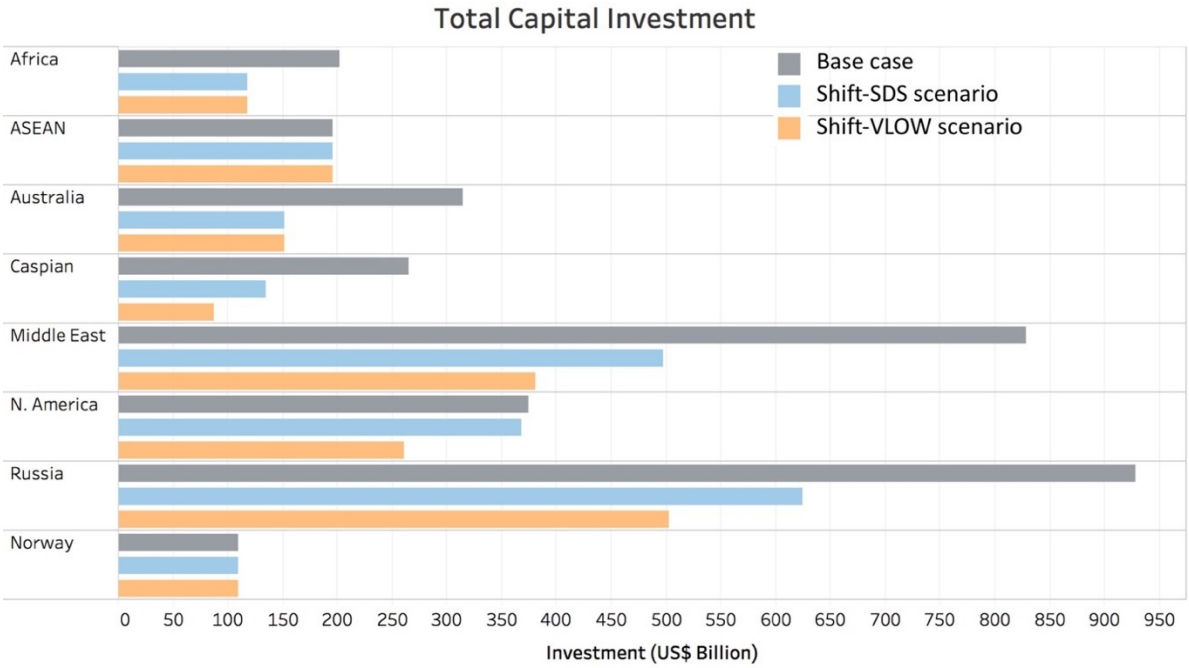


Fig. 6 – 9. Capital investment by different supply agents in Gas-GAME-Spot base and alternative cases

6.2.2.2 Regional stranding during the Transition phase

Although the stranding condition during the Transition phase (2035 to 2045) is limited from a global perspective, certain regions are exposed to higher stranding risks than others. Export capacities in the key regions and their utilisation conditions in the two alternative scenarios are presented in Fig. 6 – 10. In Shift-SDS, Australian and North American export infrastructures face high stranding risks that may affect their investors to a considerable extent. In Australia, around 50 BCM/yr production and liquefaction capacities could be stranded in 2035, which is 10 -15 years ahead of the end of their lifetime. These are mainly the capacities built from 2015 to 2020, underpinned by the contracts with the East Asia market. For North America, the capacities with stranding risks amount to around 40 BCM/yr. These capacities are also built in the early 2020s, and the target clients are in Eastern Asia and Western Europe.

The reason why the stranding issue is more noticeable in Australia and North America is examined. Additional capacities are developed following ill-conceived import expectations, which are sent by the markets before their demand relationships change. When the demand levels decline unexpectedly, gas buyers in the two major markets – Western Europe and Eastern Asia – find themselves over-contracted. In order to achieve the equilibrium, they minimise their purchase from contracts and instead opt for the cheaper spot trade. As a result, a portion of contracted North American and Australian supplies to the two markets are taken by spot sales from the Middle East, Russia, and ASEAN countries. These regions have two reasons to win the spot sales. On one hand, they have extra capacities for spot supply

as their contracts also become relaxed. On the other hand, they have cost advantages for short-term delivery. Hence, their capacities are utilised at higher rates and therefore face lower risks of stranding in Shift-SDS, as shown in Fig. 6 – 10a.

In Shift-VLOW, North America and Australia face similar stranding risks as in Shift-SDS, primarily because of the same level of contract purchase obligations. However, higher stranding risks are observed for infrastructures in the Middle East and Russia. Around 80 BCM/yr capacities would be stranded in the Middle East after 2040. These are the facilities built for the LNG projects targeting East Asian and Chinese markets. In Russia, around 100 BCM/yr capacities, mainly the pipeline projects to Western Europe and China, would be stranded after 2035. The reason for stranding in the Middle East and Russia is that, the market spot demand is much lower in Shift-VLOW as compared to the base case and Shift-SDS. The demand level simulated in this scenario leaves little space for markets to import after they purchase based on the contracts. For example, the average spot demand in Western Europe during the Transition phase is only 18 BCM/yr in Shift-VLOW, whereas in Shift-SDS, the spot demand is 105 BCM/yr. The comparison for the Chinese market is 51 BCM/yr in Shift-VLOW versus 104 BCM/yr in Shift-SDS. With small amounts of gas sold via spot trade and contracted supplies minimised, the Middle East and Russia have around 30% of their capacities left stranded. The results suggest that, in the extremely low demand scenario, these two major suppliers may face a moderate-level of stranding risk.

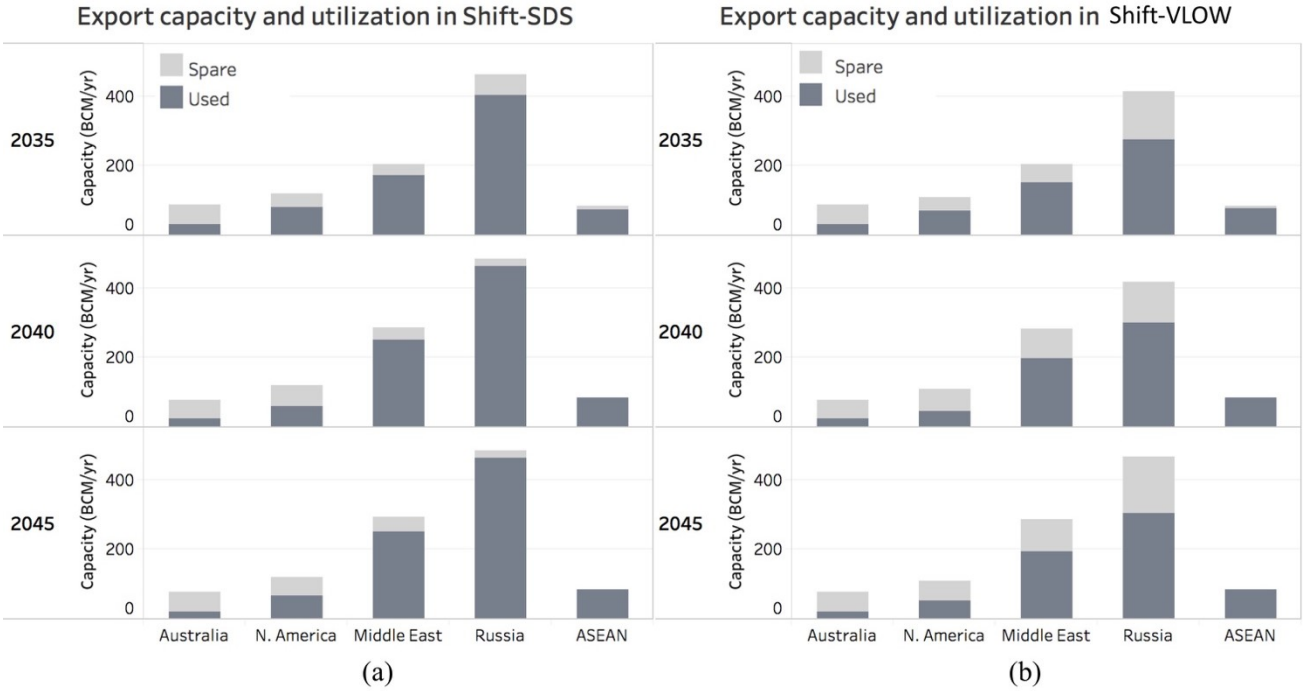


Fig. 6 – 10. Regional export capacity and utilisation between 2035 and 2045 in Gas-GAME-Spot alternative scenarios

6.3 Policy implications

The simulation result illustrates how markets, by signalling to investors via both prices and contracting volumes, can effectively alleviate the risk of asset stranding in gas production and transmission. However, moderate stranding on a regional level can still be observed when gas demand decreases precipitously. Based on the above analysis, some policy implications on how gas asset stranding can be minimised are presented in this section. This illustrates the capability of the model to provide insights for policymakers.

6.3.1 Implications for import markets

One crucial aspect to minimise the potential stranding is that import countries should have a clear long-term expectation on their gas demand, and thus avoid over-contracting. The role of natural gas in each country's energy mix during the energy transition and in the future low-carbon economy should be clarified and communicated to all stakeholders in the market.

In this study, it is assumed that contract renegotiations would allow importers to purchase much less than the agreed volumes when their demand becomes lower. However, two aspects of risks are associated with this renegotiation process. Firstly, importers may fail to reach an agreement with the exporters. In this circumstance, following the take-or-pay terms, importers are still obliged to pay for the minimum volume as agreed originally while only taking gas at their lower demand levels. The importers therefore would spend much more on long-term contracts and have little chance to purchase from cheaper spot sources. Secondly, such a contract renegotiation may lead to tensions in international relationships. Some exporting countries have their economies heavily relying on hydrocarbon businesses, and their natural gas projects are handled by state-owned companies (*e.g.* Gazprom in Russia). Thus, the renegotiation is likely to involve the governments of both sides, and could potentially affect the general trade relationships between two countries.

Besides the above-mentioned risks which may reveal shortly after the demand decrease, importers may see long-term gas supply issues resulting from contract renegotiation. Essentially, the gas export business model wouls be challenged since the project revenues can no longer be guaranteed by contracts. Without a fully liquid spot market, new supply projects may face significant difficulties to secure investment. The tight supply condition after 2050, which has been simulated in this study, may become worse. Importing markets will then face high gas prices and energy security issues.

Another way for importing markets to avoid over-contracting is to conduct deep decarbonisation as early as possible. Stronger environmental policy signals are required in import countries to avoid a disjointed shift in gas demand after 2030. This would also benefit domestic gas consumption industries to reduce wasted investment in infrastructure.

6.3.2 Implications for exporting countries

Governments in exporting countries should scrutinise the details of new long-term contracts and highlight the potential risks to the investors. It is observed that recent natural gas contracts have higher volumes and destination flexibilities [133, 163]. Although this may lead to a more liquid global gas market, the continuation of this trend would increase the stranding risk of the highly capital intensive gas production and transmission assets.

This study suggests that, if there is a sharp decline in gas demand, the contract purchase obligation is crucial to prevent infrastructure from large-scale stranding in the 10 to 15 years period after the decline. If the volume and destination flexibility becomes higher, importers will leverage the flexibility when their demand changes. Consequently, the exporters, especially those with higher short-run delivery costs, will compete in a highly volatile spot market, and their supply infrastructures are more vulnerable to stranding. The exporters prefer fixed volume and destination clauses in the current highly uncertain gas market. However, since they are competing to develop and monetise their reserves, it is likely that they add more flexibility in the contract clauses in order to secure long-term buyers. The governments, therefore, should highlight the stranding risks to companies and investors. Regulations should require companies to conduct a more stringent risk analysis and a revision on contract structure for each of their development projects. In addition, collaboration between exporters and importing markets should be promoted. For example, exporting countries should welcome importers to invest in their gas supply projects. In this way, exporters could mitigate their stranding risks and importers could also benefit from having better control over their gas supply.

6.4 Concluding remarks

The strict carbon budgets required for climate change mitigation have resulted in concerns on asset stranding in fossil fuel industry. This section analyses the magnitude and speed of gas export infrastructure development and whether the infrastructure may face the risk of stranding. Gas-GAME-Spot is applied for this study, broadening the existing stranded asset analysis by including two more factors: 1) investors' decision making based on market signals; 2) fluctuation in market price subject to supply capacity. The main conclusions can be summarised as follows:

- In the baseline scenario, between 2015 to 2060, US$ 3.2 trillion is invested in global gas production and transmission capacities for inter-regional trade. These capacities double the initial 2015 level, and reach around 1700 BCM/yr in 2040. The total capacity decreases to 1200 BCM/yr after 2050 due to the decommissioning of initial facilities.
- If the gas market demand trend follows current outlooks, the stranding level is likely to be very limited. The major exporters all have their utilisation levels between 70% and 100%, and the

global average utilisation is 88% after 2050. The major reason for this is weakening investment and capacity decommissioning by the medium-sized exporters (*i.e.* Australia, ASEAN countries, and Norway).

- If gas demand decreases unexpectedly after 2030, for example triggered by policy changes for decarbonisation, the stranding risks increase, but are still moderate due to the constraints of long term take-or-pay contracts. The risks are mainly observed in the transition phase between 2035 to 2045. After 2050, there is a tight gas supply globally because the markets adapt to the lower demand and less contracts are formed.
- During the transition phase, Australia and North America face higher stranding risks because their relatively high short-run delivery costs make them uncompetitive for selling spot gas. Russia and the Middle East may see 30% stranding if all markets change to extremely low-level demands and have limited imports via spot. The over-expansion by suppliers is attributed to ill-conceived import expectations by demand markets prior to unforeseen demand shifts.

Policy insights on stranding risk mitigation are provided, for both import markets and exporting countries. The long-term expectation on gas demand should be clarified by importers to avoid over-contracting, and strong policy signals are required to drive deep decarbonisation the earliest possible. Exporting countries should scrutinise the contract details of new supply projects, requiring more stringent risk evaluation before approving final investment decisions.

While this study suggests that markets will signal the demand decrease via prices and contracting volumes, thereby alleviate stranding risks, further studies are required to examine how different contract strategies and supply- or demand-side actions may result in alternative conditions.

Chapter 7. The sensitivity analysis of stranding results to uncertain contract structures and agent behaviours

Chapter 6 discusses how stranding in gas export infrastructure may occur in the long-term future. Besides the demand uncertainties in different regions, other factors like contract terms, market import strategies, and supplier export strategies impact on the future stranding condition. Therefore, this chapter explores how sensitive the stranding outcomes are subject to these factors.

Shift-VLOW presented in Chapter 6 is chosen as the reference for comparison in this chapter. This scenario explores the maximum stranding risk when gas demands in all regional markets decrease abruptly in 2035. The other scenarios simulated in this chapter follow the demand changes in Shift-VLOW and explore how different contract structures or agent strategies can affect the stranding outcomes. The analysis is based on Gas-GAME-Spot, and insights on what measures may alleviate or increase the stranding risks are provided.

7.1 Contract structure

As concluded in Chapter 6, long-term contracts play an important role in sustaining the trade between importers and exporters. When the market demand decreases, the contracts oblige importers to purchase a minimum amount from partner suppliers. In this way, the stranding risks of these suppliers are bounded. However, two parameters in the contract simulation may affect this mechanism; They are 1) the minimum market purchase obligation ($\mu_{j,t}^{CT}$) and 2) contract length. These are uncertain parameters, and the study makes assumptions on how these parameters may change in the future. In this section, sensitivity of results to these two parameters is evaluated.

7.1.1 The minimum market purchase obligation

The minimum market purchase obligation ($\mu_{j,t}^{CT}$) reflects the flexibility of long-term contracts. In Shift-VLOW, the value is 70% from 2015 to 2030, and a 5% decrease per time-period after 2030 is assumed to account for the potential contract renegotiation triggered by lower demand. Different settings for parameter $\mu_{j,t}^{CT}$ in the scenarios are reported in Table 7- 1. The two alternative scenarios, namely "10% decrease" and "15% decrease" represent the cases when importers achieve more favourable terms in renegotiation. The decreasing rates of contract purchase obligation are 10% and 15% per time-period respectively, and importers have higher flexibility to purchase via spot trade. The "Zero obligation" scenario assumes that the market demand decrease leads to a disruptive effect in long-term contracts and importers have the flexibility to not buy any gas from the contracts from 2035. Though this

scenario is less likely to happen as the trade relationships between importers and exporters need to be maintained, it explores how global gas trade may evolve without the binding of long-term contracts.

Table 7- 1: Case description for sensitivity on the minimum market purchase obligation

	Reference	**10% decrease**	**15% decrease**	**Zero obligation**
	Minimum market purchase obligation $\mu_{j,t}^{CT}$			
2015 – 2030	70%	70%	70%	70%
2035	65%	60%	55%	0%
2040	60%	50%	40%	0%
2045	55%	40%	25%	0%
2050	50%	30%	10%	0%
2055	45%	20%	0%	0%
2060	40%	10%	0%	0%

On a global scale, the risk of stranding does not show a significant increase, even if the contract obligations are relaxed. The general stranding risk in the alternative scenarios is similar to the reference case. Fig. 7 – 1 shows the spare export capacities in the four scenarios. During the transition phase between 2035 and 2045, 350 – 550 BCM/yr of global export capacities would remain idle no matter what contract obligation assumption is held. After that, the stranding risk becomes very low as the less capital is invested for capacity expansion.

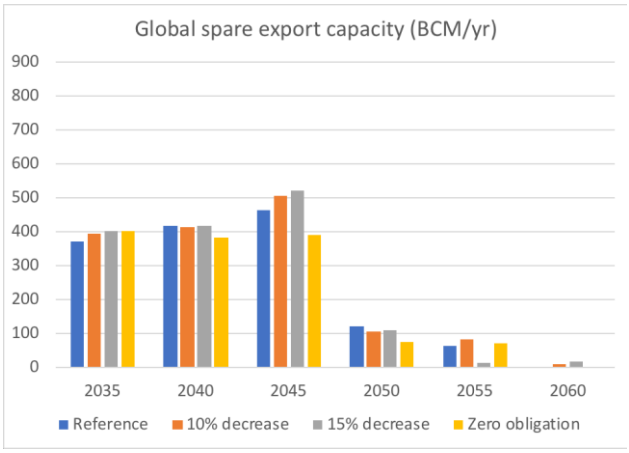


Fig. 7 – 1. Global spare capacity in contract purchase obligation cases

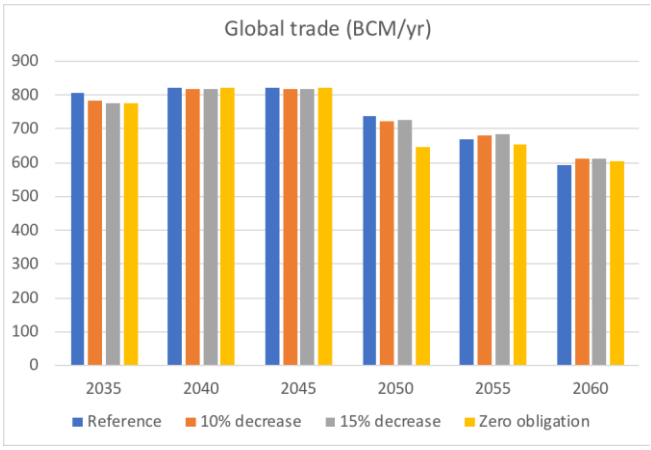


Fig. 7 – 2. Global trade in contract purchase obligation cases

When the contract obligation level decreases at a rate of 10% or 15% per period, a minor increase in the spare capacities, as compared to the reference case, is observed. However, such increase is much smaller than the amount of further-relaxed contract-based imports. Total gas trade and consumption globally, as shown in Fig. 7 – 2, is not very sensitive to the contract obligation level. Even with the assumption of "Zero obligation", there is no large-scale stranding from a global perspective. However, the result suggests a clear shift from contract-based to spot trade when the purchase obligation is relaxed; Increases in global spot trade levels (see Fig. 7 – 3) and decreases in global contract-based trade (see Fig. 7 – 4) are observed in the low-obligation scenarios. Between 2035 and 2045, the

additional amount of spot trade in the "10% decrease" and "15% decrease" cases, as compared to the reference case, is similar to the amount of decreasing contract-based trade. The markets still have remaining demand after minimising their purchase from contracts, and therefore choose to import more from the cheaper spot option. Such a change in trade method becomes more significant when the contract obligation is fully relaxed. As shown in the case of "Zero obligation" in Fig. 7 – 3 and Fig. 7 – 4, over 90% of trade in the transition phase is in the spot market.

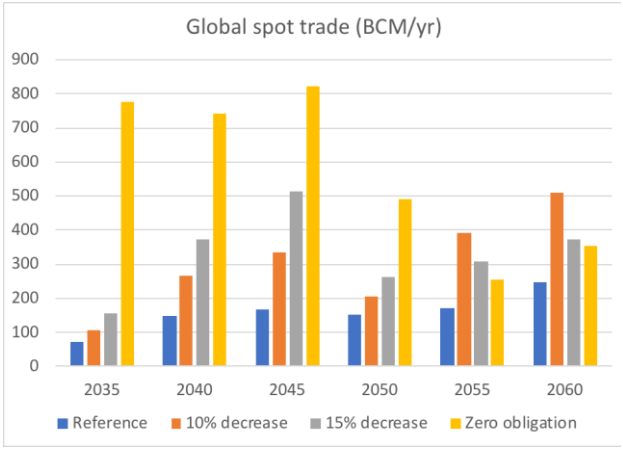


Fig. 7 – 3. Global spot trade in contract purchase obligation cases

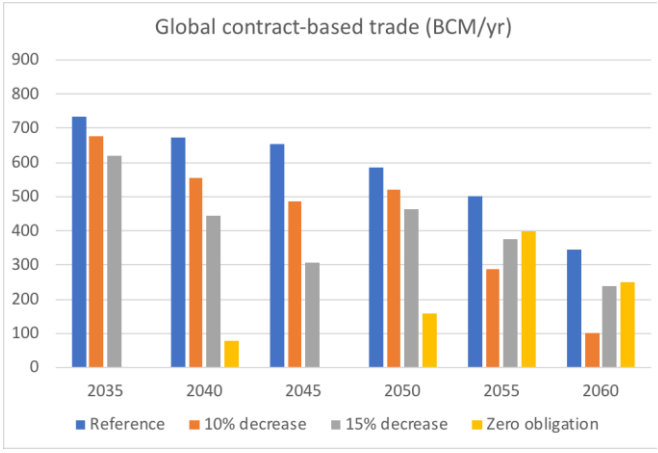


Fig. 7 – 4. Global contract-based trade in contract purchase obligation cases

The increasing spot trade due to the relax of purchase obligation also influences the regional exports. Africa, Australia, and North America export less because of the fall in contract-based trade. This leads to lower utilisation of their infrastructure during the transition phase (2035 to 2045), as shown in Fig. 7 – 5a to Fig. 7 – 5c, and the stranding risks in these regions therefore increase. For example, Africa has its export capacity used at 60% - 50% in the transition phase in "10% decrease" case, and the utilisation drops to 55% - 25% in "15% decrease" case. Such utilisation, as compared to the 65% - 55% in the reference case, is directly affected by the parameter setting of $\mu_{j,t}^{CT}$ as Africa sells zero via spot. In contrast, Russia and the Middle East face lower risks when the obligation is relaxed. The utilisation of export capacities in Russia increases in the lower obligation cases, as seen in Fig. 7 – 5. Though contract-based export decreases, Russia sells more with its increasing spot trade. The reason why Russia manages to grab more shares in the spot market, when competing with Africa, Australia, and North America, is that it has a cost advantage in short-term delivery. Similarly, the Middle East is not negatively affected by the relaxation of purchase obligation. Its utilisation stays at around 70% in the "10% decrease" and "15% decrease" cases, and increases to around 90% in the "Zero obligation" case.

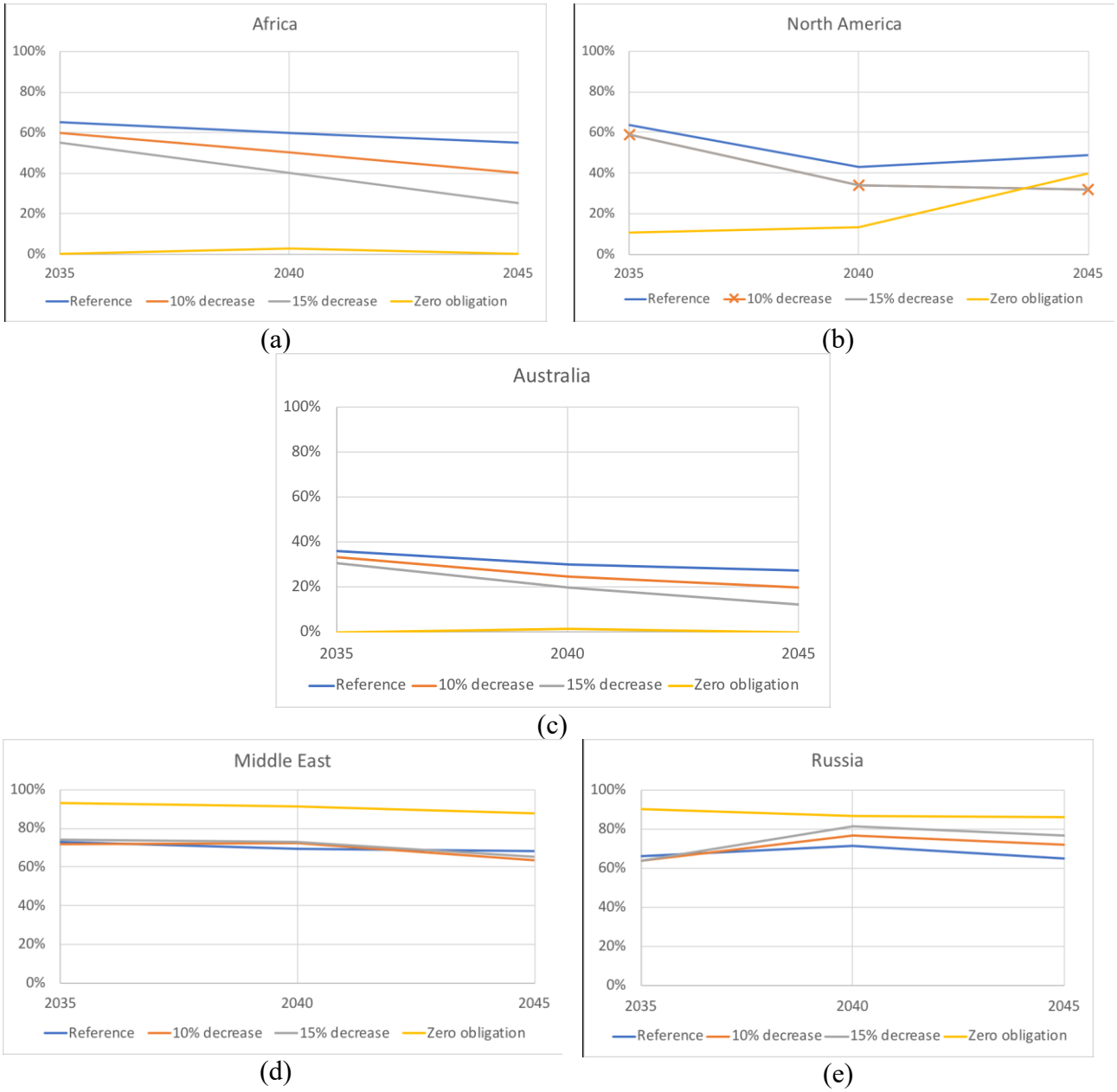


Fig. 7 – 5. Utilisation of export infrastructure in contract purchase obligation cases for different regions

This simulation does not consider how the suppliers may change their contracting strategies subject to the renegotiation on contract flexibility after the market demand decrease. However, as the number of contracts agreed after 2030 is very low, this assumption has negligible impacts on further capacity expansion and potential stranding.

To conclude, the changes in the minimum purchase obligation of long-term contracts does not affect the general trend of stranding risks in the two different phases. On a global scale, the total gas trade is relatively insensitive to different obligation levels. However, the proportions of contract-based trade and spot trade are affected significantly. As a result, the export capacities in the regions with

higher short-term delivery costs, like Africa, Australia, and North America, have decreased utilisation. These exporters face higher stranding risks if the markets manage to reduce their obligation by a larger amount through contract renegotiation. In contrast, exporters with lower short-term delivery costs, like Russia and the Middle East, have better opportunities to sell through spot markets if the obligation is relaxed.

7.1.2 Contract length

Another important parameter in the contract structure is the length (i.e. duration) of the contract. In reality, the length of each long-term contract ranges from 10 to 40 years [131] depending on the related project. In the base simulation, the contract length is assumed as 30 years to retain a strong connection with infrastructure's lifetime. However, it is controversial whether the contract length will reduce in future periods if the market becomes more liquid. In this section, four alternative scenarios besides the reference one are simulated, and their assumptions on the standard contract length are presented in Table 7- 2. Three aspects are affected by the parameter of contract length. Firstly, the duration of all endogenously generated contracts depends on the parameter. Secondly, when the exporters evaluate the profitability of proposed contract requests, they expect the revenue for the number of years as specified by this parameter. Thirdly, when the importers evaluate their future expected import volumes, they use their expected demand curves of y years ahead, where y is around half of the contract length.

Table 7- 2: Case description for sensitivity on contract length

	Reference	**25-year case**	**20-year case**	**15-year case**	**10-year case**
Contract length	30 years	25 years	20 years	15 years	10 years
How many years ahead do importers plan ahead $y = t' - t_{next}$	15 years	15 years	10 years	10 years	5 years

Fig. 7 – 6 illustrates the global export capacity in the reference case, and Fig. 7 – 7 shows the relative capacity levels in other scenarios as compared to the reference. When the contracts are 25-year long, the expansion is similar to the reference case. However, when the contracts are 20-year or 15-year long, the results show a reduction in total export capacity by around 20%. With a lower contract length, the exporters expect fewer years of revenues in the project cash flow. As a result, the contracts require higher revenues per year to be agreed by investors, and the expansion is relatively slower. This effect is more significant when the contract length is reduced to 10-year. Between 2040 and 2050, the export capacity globally is only 40% as compared to the reference 30-year case.

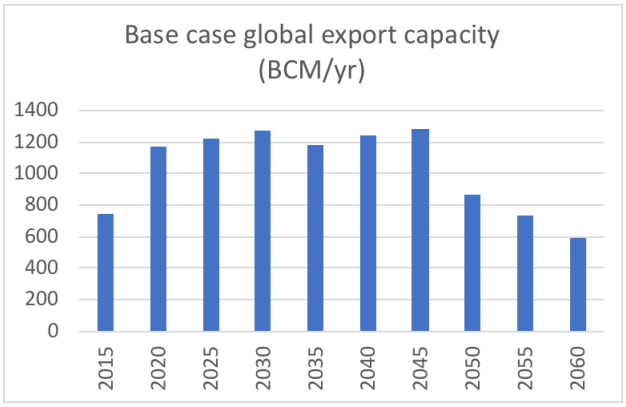


Fig. 7 – 6. Global export capacity in the reference case

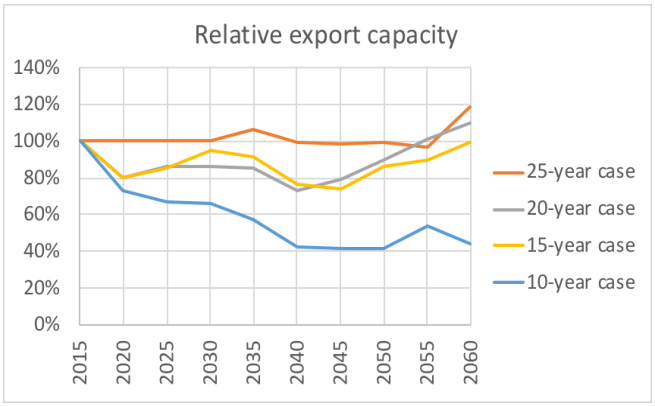


Fig. 7 – 7. Relative export capacity as compared to the reference in contract length cases

Fig. 7 – 8 shows the global spare capacity levels in all five scenarios. The scenarios with contract length between 15 and 25 years show the similar "two phase" feature as in the reference case. During the transition phase, the spare capacities in the "20-year" and "15-year" cases are around half of those in the "25-year" and reference cases. The spare percentages in total export capacities, as shown in Fig. 7 – 9, are also significantly lower in the "20-year" and "15-year" cases. This result suggests that, contracting for shorter terms with a duration between 20 and 15 years would alleviate the risk of stranding and the scale of spare assets can decrease by around 50%. During the tight supply phase between 2050 and 2060, the results are robust to different contract lengths. Limited number of contracts are confirmed in the reference case, and this condition is not affected when contract length is reduced. All scenarios show little spare capacity and the stranding risk is minute.

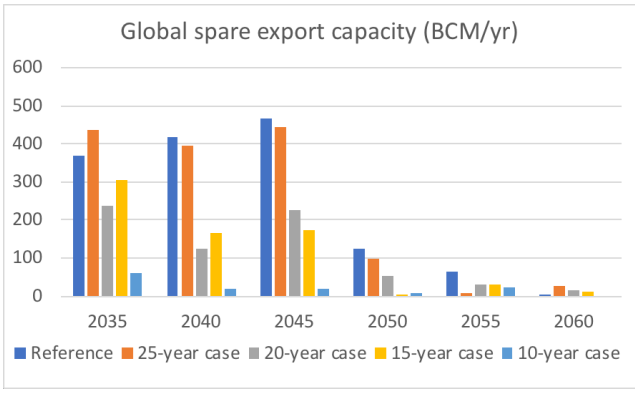


Fig. 7 – 8. Global spare export capacity in contract length cases

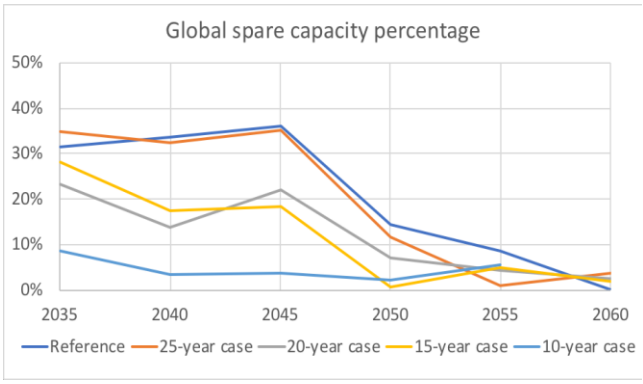
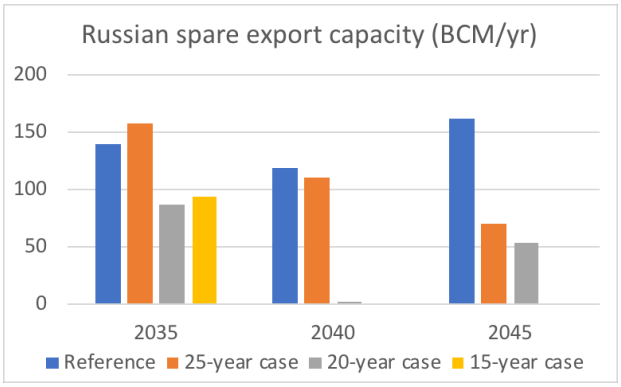


Fig. 7 – 9. Global spare export capacity percentage in contract length cases

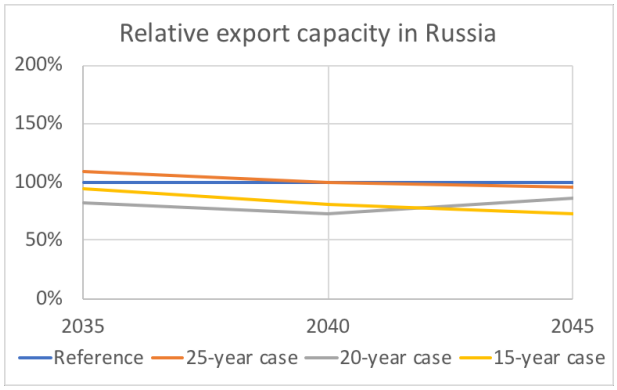
A different stranding outcome is observed in the "10-year" case. Only a negligible amount of capacity becomes spare from 2035 to 2055, as shown in Fig. 7 – 8. This is attributed to the slow expansion, as most contracting requests cannot meet the economic criteria with revenue for 10 years. Though the negligible spare capacities guarantee a low stranding risk, a spare percentage below 10%, as shown in Fig. 7 – 9, means that little room remains for capacity maintenance and trade flexibility.

In 2060, the result suggests an infeasible Nash-Cournot market equilibrium as there is not enough available export capacity. This indicates that, though shorter-term contracts can prevent wasting capitals in assets that may be stranded, the contract length should be at least 15 years to facilitate a stable natural gas market. The following discussion does not further discuss the "10-year" case.

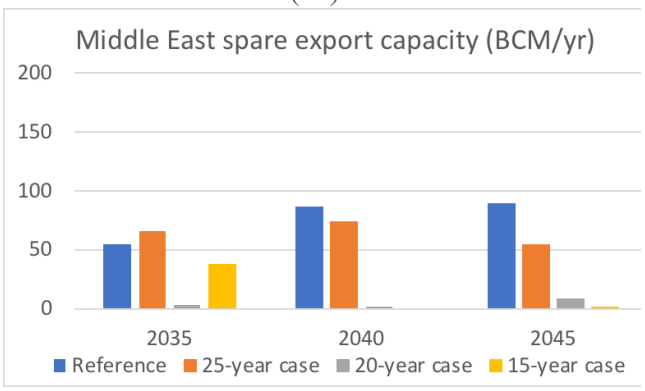
In terms of the regional stranding issue, Russia, the Middle East, Africa, and North America are exposed to lower risks in the transition phase in the "20-year" and "15-year" cases. However, the reason why less stranding may happen for each region is partly different. For Russia and the Middle East, the spare capacities reduce to less than half of the reference case level, as shown in Fig. 7 – 10a1 and Fig. 7 – 10b1. Since the export from these two regions remains nearly the same as the reference case, the alleviation of the stranding risk is mainly attributed to the reduced investment in capacity (see Fig. 7 – 10a2 and Fig. 7 – 10b2.). For Africa, the shorter contract duration reduces the spare capacity by 40% in 2035 and over 60% by 2045, as shown in Fig. 7 – 10c1. While such a reduction is also related to the decreasing capacity investment, African total export drop by around 50% as well (see in Fig. 7 – 10c2). With a higher short-term delivery cost, Africa has little advantage in the spot market, and therefore cannot secure the same amount of gas trade as in the reference case when its contract-based export decreases. For North America, the reduced stranding (see Fig. 7 – 10d1) is not because of less capacity expansion. The total export capacity in North America is similar for all cases. However, the gas export (see Fig. 7 – 10d2) increases considerably relative to the reference case when the contract length is shortened. The increasing export is mainly directed to the Eastern Asia market, where the supply from ASEAN countries decreases as a result of reduced investment in capacity.



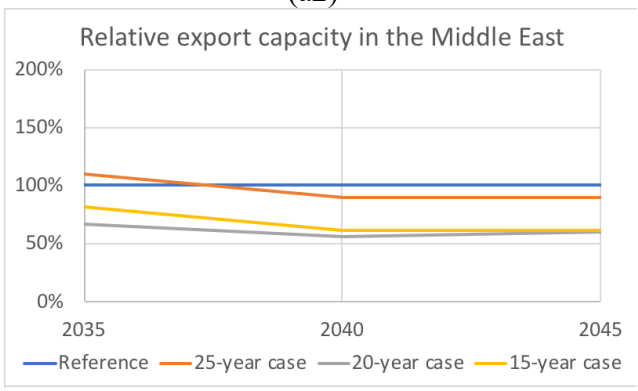
(a1)



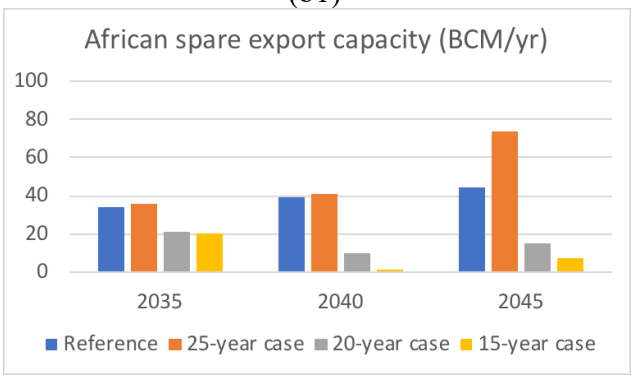
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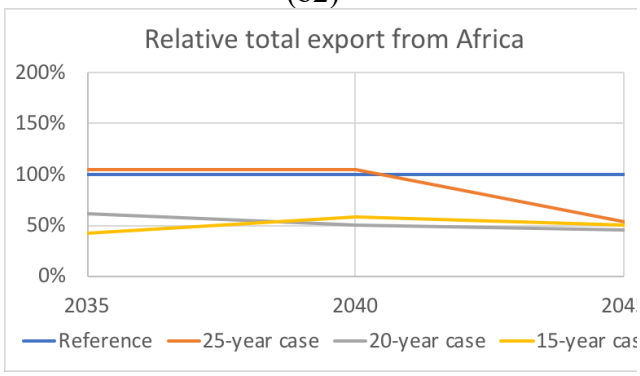
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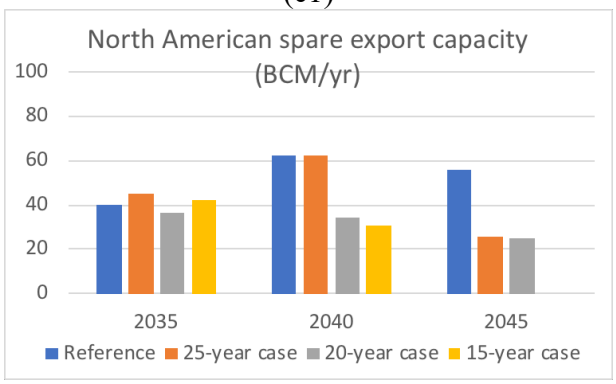
(b2)



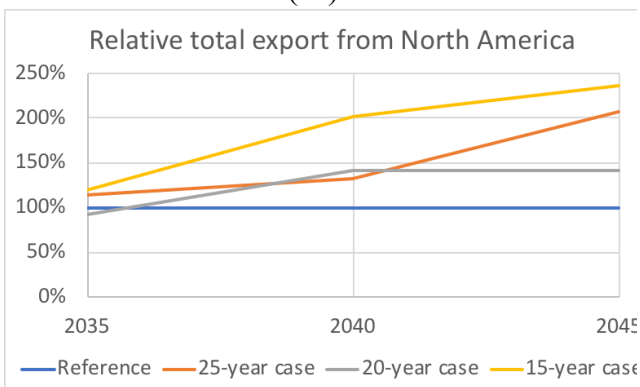
(c1)



(c2)



(d1)



(d2)

Fig. 7 – 10. Spare export capacity (left) and Relative export capacity (right) in contract length cases for different regions

However, the stranding risk in Australia is not mitigated by the shorter contract length. Fig. 7 – 11 shows the spare capacities in Australia, and the results in “25-year”, “20-year”, and “15-year” cases

are similar to the reference. The reason why future contract length has little impact in Australia is that the number of endogenously generated contracts there is limited. Since the capacity expansion in Australia is mainly underpinned by the contracts that have been concluded before 2018, the change of this contract length parameter cannot further lower the expansion.

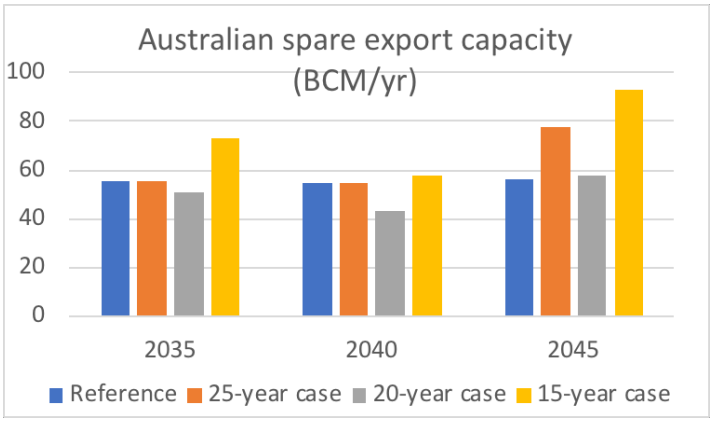


Fig. 7 – 11. Australian spare export capacity in contract length cases

In summary, the measure of lowering contract lengths can help alleviate the stranding risk on a global scale. By changing the contract duration from 30 years to the level between 15 and 20 years, the scale of spare capacities globally can reduce by 50% in the transition periods. Russia, the Middle East, Africa, and North America all see their risks reduced with the reduction in the contract length, whereas Australia has the similar stranding level for all scenarios. However, the reduction of contract length has a lower limit. A contract length of 10 years would significantly affect gas export capacity expansion and may lead to market instability.

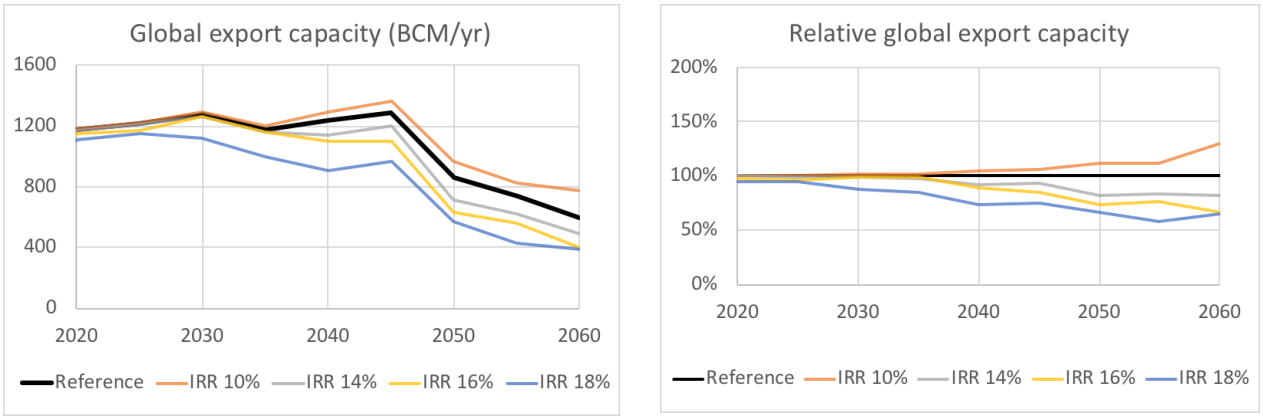
7.2 Supplier side contracting strategy

The parameters discussed above, related to contract structure, depend on the negotiation between the supply and demand side. There are also some parameters solely affected by the strategies of the supply side. It is assumed in the model that suppliers use “IRR over 12%” as the criterion to agree on contracting requests. Here, further analysis on how the IRR criterion affects the stranding outcome is presented. Table 7- 3 shows the parameter settings in different scenarios. There is one alternative case which assumes a more aggressive contracting strategy than the reference. The minimum IRR value for accepting a contract request is reduced to 10%. This scenario, named as “IRR 10%”, is designed to examine to what extent stranding may happen more severely if all suppliers are slightly more aggressive in capacity expansion. The other scenarios, including “IRR 14%”, “IRR 16%”, and “IRR 18%” explore how conservative strategies by exporters, when facing uncertain demand, may affect the stranding outcomes.

Table 7- 3: Case description for sensitivity on supplier contracting criteria

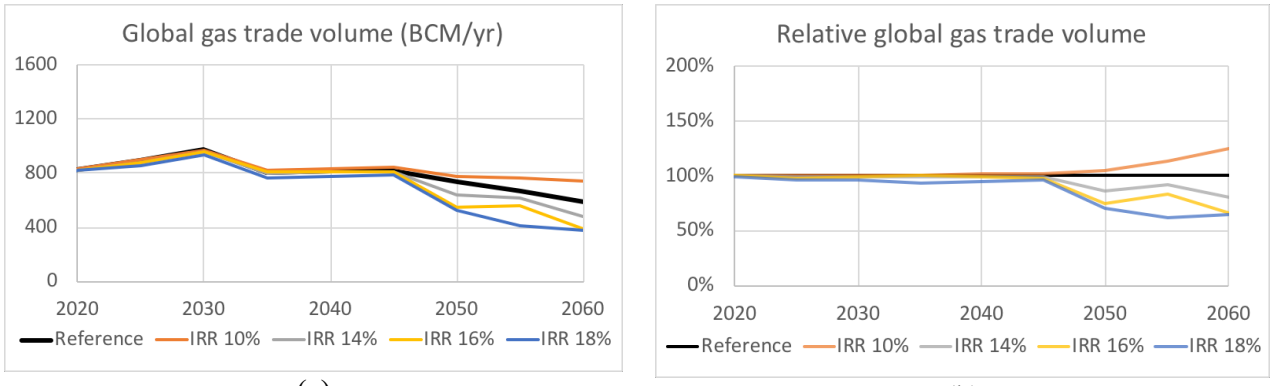
	Reference	IRR 10%	IRR 14%	IRR 16%	IRR 18%
IRR level for suppliers to agree on contracting requests	12%	10%	14%	16%	18%

The direct impact of different IRR criterion is on capacity development. Fig. 7 – 12a shows the global export capacity levels in different scenarios, and Fig. 7 – 12b shows the relative levels as compared to the reference. From 2015 to 2035, the capacity levels are similar in the scenarios with the IRR criterion ranging from 10% to 16%. After 2035, a decrease in the IRR criterion to 10% leads to an increase in total capacity by 10-30%. In contrast, an increasing IRR criterion to 14% leads to a decrease in total export capacities by 10-20%. A very high IRR criterion of 18% results in lower capacities from as early as 2020. The relative difference as compared to the reference case reaches 20% by 2035 and 40% by 2060. Fig. 7 – 13 compares the total global trade volumes in different cases with absolute and relative values respectively. It is observed that, the changes in capacities have little influence on the total trade before 2050. After 2050, the trade is limited by the reduced export capacities.



(a) (b)

Fig. 7 – 12. Global export capacity (a: Absolute values; b: Relative values) in contracting criterion cases



(a) (b)

Fig. 7 – 13. Global gas trade (a: Absolute values; b: Relative values) in contracting criterion cases

With more aggressive or more conservative contracting strategies, global spare capacities and stranding risks are also affected. As shown in Fig. 7 – 14a, the major difference is observed in the transition phase between 2035 and 2045. After 2050, the spare capacities in all scenarios are insignificant. Fig. 7 – 14b shows the relative spare levels in all scenarios as compared to the reference case during the transition phase. The more aggressive strategy with "IRR 10%" leads to an increase in global spare capacities by 5% to 15% when compared to the reference. In contrast, the more conservative strategies simulated in "IRR 14%" and "IRR 16%" reduce the capacity sparseness by 20% and 40% by 2045 respectively. Such a reduction suggests an effective mitigation in stranding risks on a global scale. When the suppliers lift the criterion to IRR over 18%, global spare capacities are reduced by around 50% during the transition phase, and the stranding risk of over 200 BCM/yr export capacities can be mitigated. Yet the spare percentage in the "IRR 18%" case is less than 20%, which may be insufficient to support trade flexibility and facility maintenance.

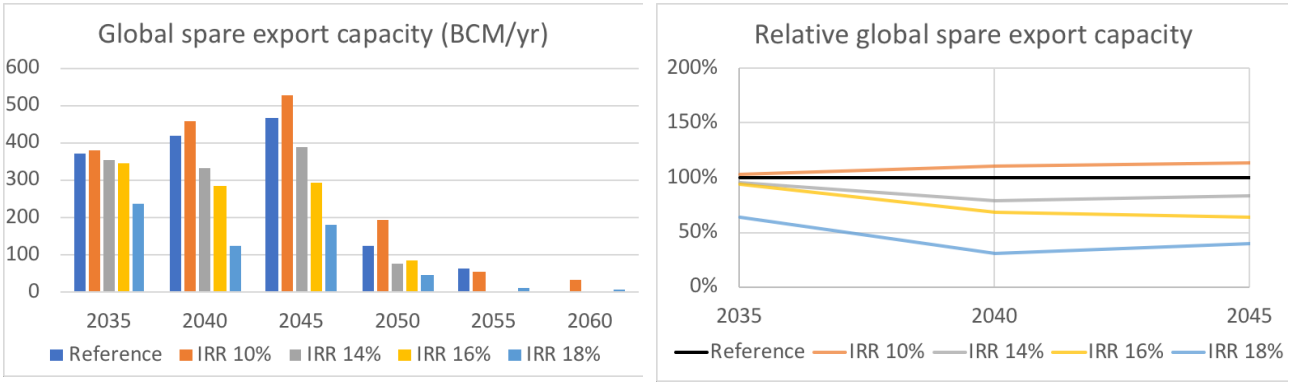


Fig. 7 – 14. Global spare export capacity (a: Absolute values; b: Relative values) in contracting criterion cases

The sensitivity response to the IRR criterion varies by different exporting regions. While the Middle East, North America, and Russia will develop less capacities (by 25%, 20%, and 10% respectively) at 14% IRR criterion as compared to the reference 12%, Africa and Australia only see reduction in expansion when the IRR criterion is raised to 16%. The stranding outcomes for these regions are presented in Fig. 7 – 15. In general, 16% IRR is the criterion which can effectively alleviate the stranding risks during the transition phase in most regions. At this level, the export capacities in the Middle East are utilised at over 90%, which is considerably higher than in other regions. One reason for this is that the export capacities in the Middle East see a decrease by 30% in the "IRR 16%" scenario. Another reason is that the export volume from the Middle East is the same as the reference, due to the increasing spot trades there. More contracts are agreed by the Middle East with the Chinese and the West European market, whereas fewer are agreed with East Asia. However, when the demand decreases and markets minimise their purchase, the Middle East manages to export around 40 BCM/yr spot LNG to the East Asian market and therefore can make full use of its export capacities. Unlike the

reference case where all markets import little from spot after 2030, East Asia still has some spot demand in the "IRR 16%" case because it secures fewer contracts due to the more conservative strategies by all exporters. This 16% IRR criterion also reduces the spare capacities in Russia, North America, and Africa by around 15% - 25% during the transition phase. For Australia, the stranding risk is relatively hard to mitigate by tightening future contract strategies, since most expansions are underpinned by already-concluded contracts. Regarding the "IRR 10%" scenario, the difference in stranding outcomes as compared to the reference is negligible for most regions, while Australia sees a minor increase by 6% in its spare capacities.

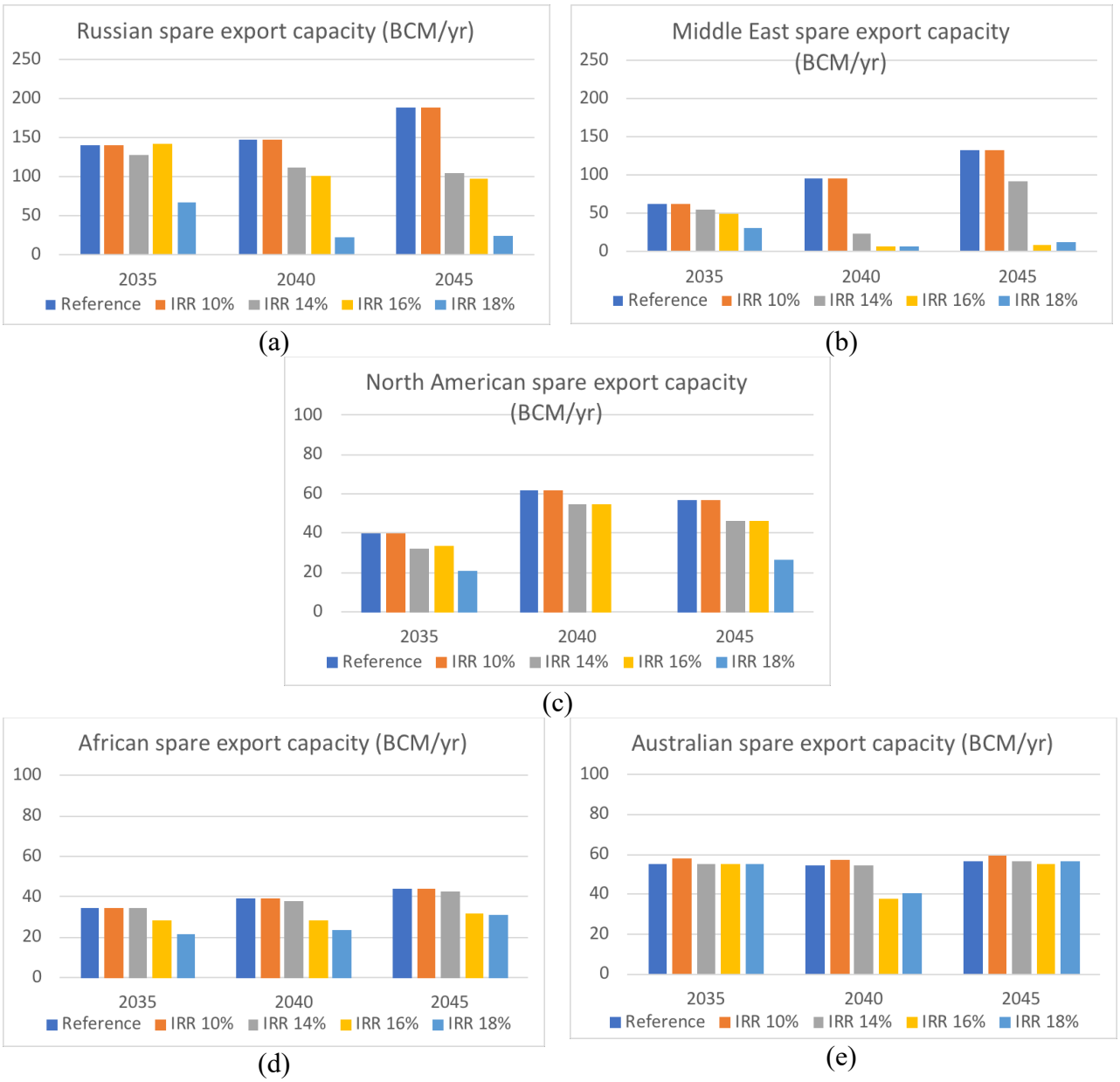


Fig. 7 – 15. Spare export capacity in contracting criterion cases for different regions

To sum up, a decrease in the supplier's economic criterion from IRR 12% to 10% has insignificant impacts on the stranding outcome. In contrast, if the IRR criterion increases to 14% - 16%, the reduced

capacities will effectively reduce the global spare level. For most exporting regions, the IRR criterion of 16% can effectively alleviate the stranding risks by at least 15%. In this scenario, the Middle East has nearly zero spare capacity after 2030, whereas the spare capacity in Australia does not change much as compared to the reference.

7.3 Demand side contracting strategy and speed of deep decarbonisation

The importers also have an important role in gas capacity investment. Since the contracting process starts from the requests sent from the markets to suppliers, how the markets choose to allocate their future import into long-term contracts will have an impact on the capacity development and stranding outcomes. It is uncertain how the markets, when facing potential decrease in future demand, will adjust the way they send out contracting requests. The first part in this section focuses on this point, and tests how importers can help mitigate stranding via reducing the contract requests. In addition, it is also uncertain when the markets will shift into the VLOW demand level. The shift may happen as soon as 2020, but it is also possible that governments and other stakeholders delay their actions, leading to an abrupt decrease in 2040. Hence, the second part in this section presents the alternative "demand shift" scenarios and discusses how early actions to deep decarbonise will change the stranding outcome.

7.3.1 Reduced contract requests

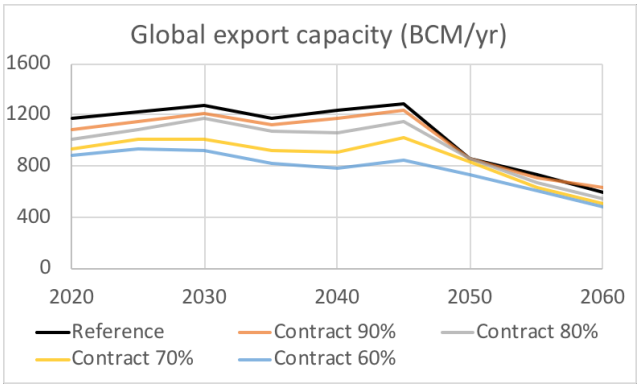
The ill-conceived import and contract requests proposed by markets contribute to stranding to a large extent. Here, alternative scenarios which assume that importers choose to reduce the maximum contract ratio are investigated. Table 7- 4 presents the parameter settings of different scenarios. Importers evaluate their total expected import volume $EXP_IMP_{j,t'}$ at period t' (15-year ahead of the next period). All scenarios have this process the same as the reference case. However, when evaluating the remaining volume to be contracted $R_IMP_{j,t}$, the importers set the maximum contract ratio $\theta_{j,t}$ as 90% to 60% instead of 100% as in the reference. The detailed equation is presented below.

$$R_IMP_{j,t} = \theta_{j,t} EXP_IMP_{j,t'} - CT_IMP_{j,t'} \quad (84)$$

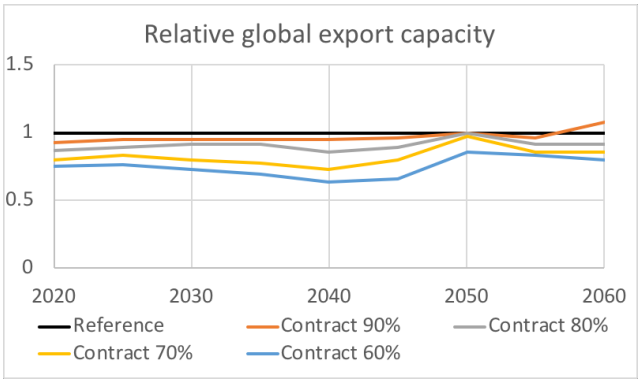
Table 7- 4: Case description for sensitivity on importer contract requests

	Reference	**Contract 90%**	**Contract 80%**	**Contract 70%**	**Contract 60%**
Maximum contract request ratio $\theta_{j,t}$	100%	90%	80%	70%	60%

Fig. 7 – 16 show the global export capacities in all scenarios in both absolute and relative terms. For all alternative scenarios which reduce the maximum contract ratio, decreases in total export capacity are observed. The most significant decrease is around 35% for the "Contract 60%" case. Other cases with 90%, 80%, and 70% contracting limits see the decrease at 5%, 10%, and 20% respectively. The changes in export capacity development are slightly lower as compared to the changes in contract ratios. Because of the increasing market prices, contracts are agreed at higher percentages relative to the reference. Though the export capacities become lower globally, the total amount of gas trade, as shown in Fig. 7 – 17, is only affected mildly by less than 10% in most periods.

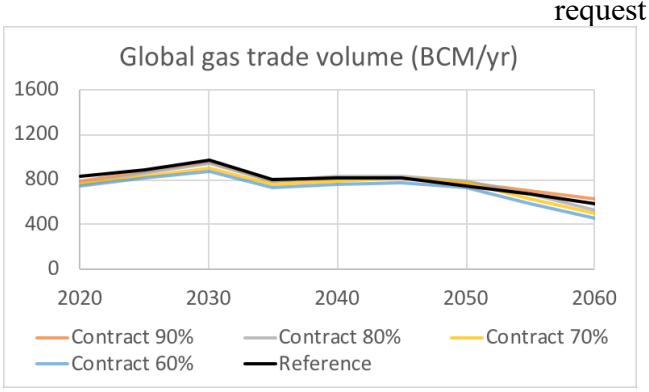


(a)

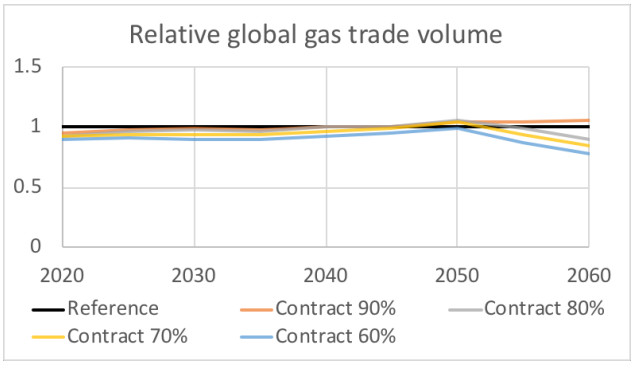


(b)

Fig. 7 – 16. Global export capacity (a: Absolute values; b: Relative values) in reduced contract request cases



(a)



(b)

Fig. 7 – 17. Global gas trade (a: Absolute values; b: Relative values) in reduced contract request cases

Fig. 7 – 18 shows the total spare capacity globally after 2030 in all scenarios. The "two-phase" feature is not affected by the changes in the maximum contract ratio. During the transition phase, a ratio between 90% and 80% reduces the spare level by 10% - 30% on average. The percentages of sparseness (see Fig. 7 – 19) in these scenarios, are around 25% to 35%, suggesting a sufficient buffer for trade and maintenance flexibility. In these two scenarios, around 50 BCM/yr and 80 BCM/yr of export capacities would avoid being stranded. When the maximum contract ratio is reduced to 70% and 60%, the spare capacities see a considerable decrease by over 60%, indicating a stranded asset mitigation of around 200 BCM/yr export capacity. However, the spare percentage in this scenario is below 20%, which suggests a potential risk of tight and unstable gas supply.

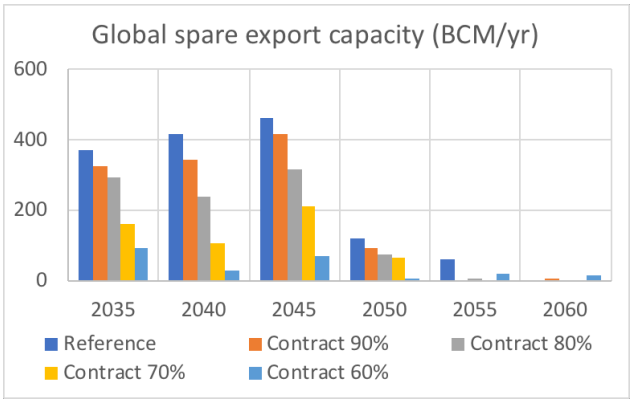


Fig. 7 – 18. Global spare export capacity in reduced contract request cases

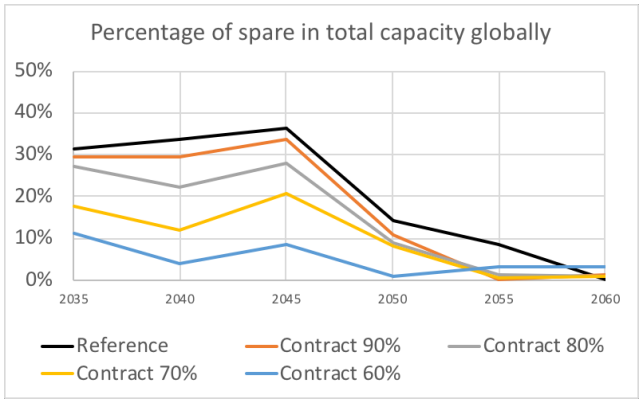


Fig. 7 – 19. Global spare percentage in reduced contract request cases

From the regional stranding perspective, Russia and the Middle East are considerably influenced by importers' strategy of reducing contract ratio. Fig. 7 – 20 and Fig. 7 – 22 shows the spare capacities in all scenarios for these two exporters during the transition phase. The average decrease of Russian spare capacity, as compared to the reference, during the transition phase is between 25% and 50% in the "Contract 90%" and "Contract 80%" cases. Mitigation of stranding risks of around 40 BCM/yr and 60 BCM/yr export capacity can be achieved in the two cases, respectively. When the maximum contract ratio is reduced to 70% and 60%, there is little Russian export capacity left spare. As the relative changes in Russian export are insignificant, which is within 10%, the reduction in the spare capacity is mainly attributed to the decreasing capacity development, as shown in Fig. 7 – 21. For the Middle East, the stranding risk of around 60 BCM/yr capacity during the transition phase is alleviated in the "Contract 80%" case. This correlates to an average reduction of 25% export capacity during that period (see Fig. 7 – 23). A lower contract ratio of 70% or 60% removes all spare capacities in the Middle East, which is attributed to a capacity reduction by 40% and 55% respectively. However, the capacity reduction in these two cases also limits the total export from the Middle East, and therefore a decrease in trade by 15% and 40% respectively is observed.

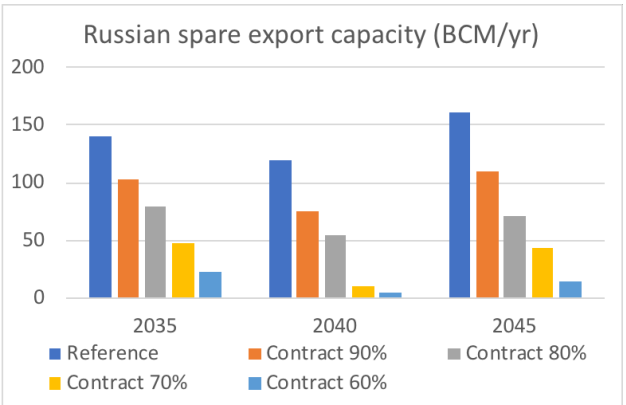


Fig. 7 – 20. Russian spare export capacity in reduced contract request cases

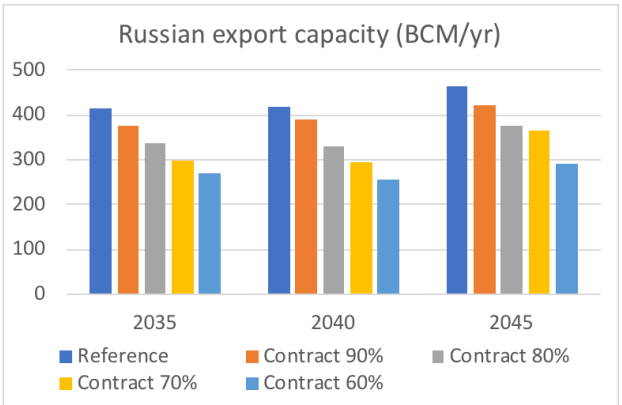


Fig. 7 – 21. Russian total export capacity in reduced contract request cases

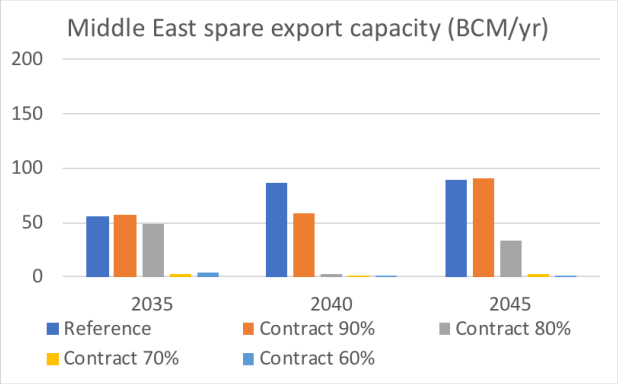


Fig. 7 – 22. Middle East spare export capacity in reduced contract request cases

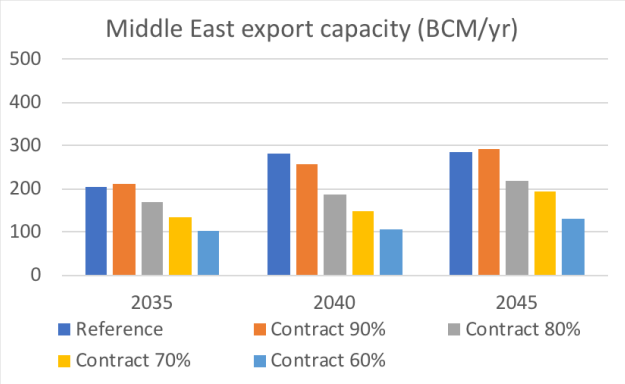


Fig. 7 – 23. Middle East total export capacity in reduced contract request cases

For medium-sized exporters, the spare capacities in Africa (see Fig. 7 – 24a) during the transition phase is reduced considerably when the maximum contract ratio is 70%. This mitigates the stranding risk of 20 BCM/yr export capacity and is attributed to a reduction by around 60% in both capacity and export. The 70% contract ratio also allows North America to reduce its spare capacities significantly by around 60%, as shown in Fig. 7 – 24b. While the North American total export capacity in this case is only 10% less relative to the reference, the reduction in spare capacity is mainly attributed to the 35% increase in export volumes. The increasing exports are the spot trades directed to China and India, both of which become “Sellers’ market” when the contract ratio is reduced. For Australia, the 70% contract ratio has a notable impact only in 2040 during the transition phase. As shown in Fig. 7 – 24c, a reduction of spare capacities by 55% is observed. Whereas in periods 2035 and 2050, the spare capacity remains nearly the same as the reference.

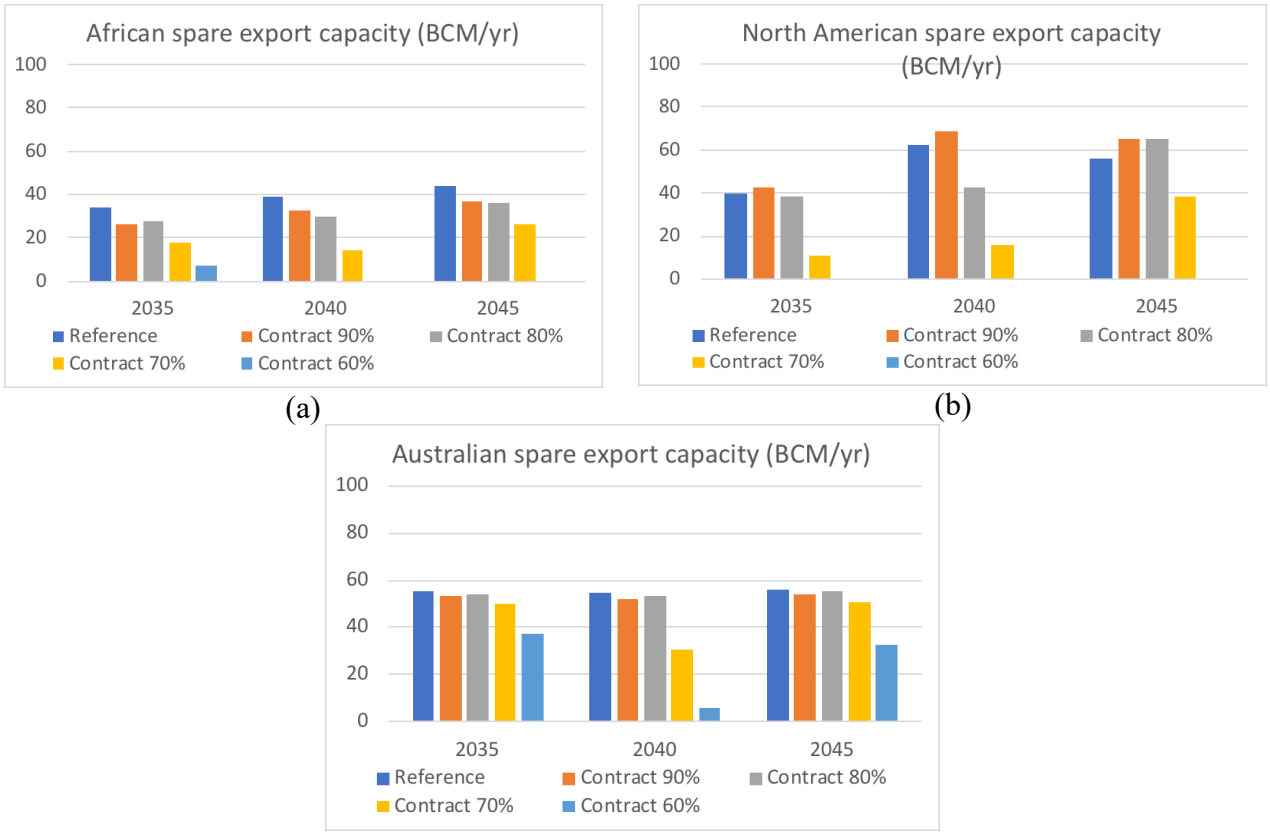


Fig. 7 – 24. Spare export capacity in reduced contract request cases for medium-sized exporters

In brief, if the importers reduce the maximum contract ratio to 90% - 80%, there will be a decrease of 50 – 80 BCM/yr in global stranded capacity between 2035 and 2045. However, further reduction of the ratio may lead to an unstable and tight supply of natural gas. Russia sees a considerable decrease in its spare level, mainly because of the changes in capacity development. While the spare level in the Middle East also decreases significantly in the "Contract 70%" and "Contract 60%" cases, the total export there reduces by the over 15% due to the lower capacity expansion. The scenarios in this section assume that all markets use the same maximum contract ratio. This setting is to test the general sensitivity of results subject to this parameter. Further studies can assume that each importing market chooses the ratio based on its own demand uncertainties, and therefore can investigate the impact of this contract ratio parameter in each market.

7.3.2 Demand decrease in alternative time periods

Another major reason that leads to the stranding issue is that importing markets do not take deep decarbonisation actions at early stages. The time period when global gas demand experiences a disjoint shift from the "New Policies Scenario" to the "Very Low demand scenario" is 2035 in the reference case. In this section, other scenarios make alternative assumptions on when the demand decrease may happen due to more aggressive or conservative deep decarbonisation actions taken by the gas

consuming countries. Table 7- 5 illustrates the transition period assumed for different scenarios. Two scenarios, namely "Decrease2025" and "Decrease2030", assume that the disjoint shift in gas demand happens earlier than the reference. This can be triggered by larger political efforts to push deep decarbonisation and faster deployment of renewables. The other two scenarios, namely "Decrease2040" and "Decrease2045", reflect the possibility that the low-emission transition cannot be triggered in 2030 due to the delayed actions by governments or slow pace in technology developments. The disjoint transition therefore is assumed to happen later in the period of 2040 and 2045 respectively.

Table 7- 5: Case description for sensitivity on when demand decrease happens

	Reference	**Decrease 2025**	**Decrease 2030**	**Decrease 2040**	**Decrease 2045**
Time-period when gas demand decrease happens	2035	2025	2030	2040	2045
Time-period when importers projection on future demand changes	2030	2020	2025	2035	2040

The global gas trade (also demand) volumes in all scenarios are shown in Fig. 7 – 25. As illustrated, the demand shift towards the lower level is smoother in the two cases with earlier transitions. Both cases also see reduced capacities by 15% in 2030 as compared to the reference (see Fig. 7 – 26). In contrast, delayed transitions lead to abrupt changes in global trade. The capacity level in Decrease2040 is very similar to the reference. Regarding the Decrease2045 case, the capacity level after 2030 is constantly higher than the reference, and the increase on average is over 20%. This is due to a notably large expansion between 2035 and 2040. Such expansion is attributed to the new contracts of over 400 BCM/yr global trade agreed in 2035, and the expansion scale is large due to the future decommissioning of the capacities constructed between 2015 and 2020. For all the cases which assume the transition earlier than 2045, the global trade levels after the disjoint shift are approximately the same. However, when the transition is delayed to 2045, the global trade after 2050 becomes around 15% higher than the reference case. The further expanded capacities alleviate the tight supply condition, which is observed after 2050 in the reference and other scenarios.

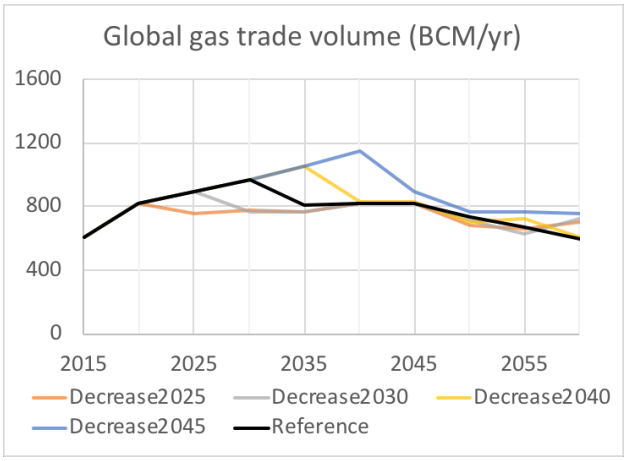


Fig. 7 – 25. Global gas trade volume in demand decrease period cases

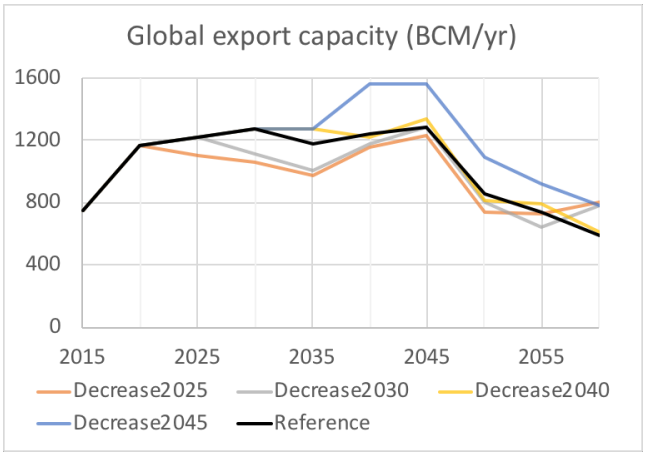


Fig. 7 – 26. Global export capacity in demand decrease period cases

Regarding the stranding risks, Fig. 7 – 27 shows the level of global spare capacities after 2020, and Fig. 7 – 28 shows the spare percentages of total capacity. For the early transition cases (*i.e.* Decrease2025 and Decrease2030), only minor increases by less than 10% in spare capacity level relative to the reference are observed in 2025 and 2030. This is due to reduced global export in the two alternative scenarios as the demand reduction happens earlier. In 2035, both cases see considerably lower spare levels by 130 – 160 BCM/yr relative to the reference, and the spare percentages are around 25%. The potential stranding in these two cases is therefore relatively lower. For the late transition cases (*i.e.* Decrease2040 and Decrease2045), lower sparseness is also observed before the transition period. For example, the spare percentage in 2035 in Decrease2045 is only 18% as compared to 31% in the reference. This is because Decrease2045 has higher trade levels in 2035 since the demand change does not happen then. However, after the demand decrease, Decrease2045 sees a much higher stranding risk related to nearly 300 BCM/yr export capacities globally. In contrast, the stranding and spare levels in Shift2035 are similar to the reference. This suggests that a 5-year delay in the low-demand transition may not lead to significant extra stranding, whereas the stranding risk would increase notably if the transition happens after 2040.

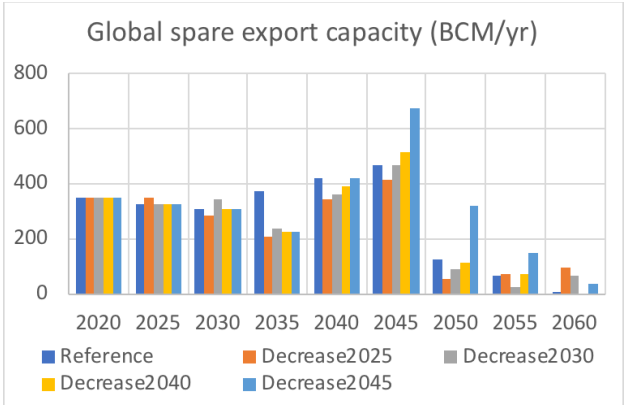


Fig. 7 – 27. Global spare export capacity in demand decrease period cases

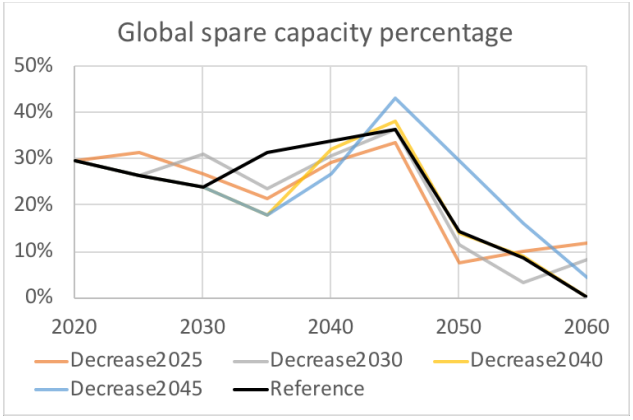
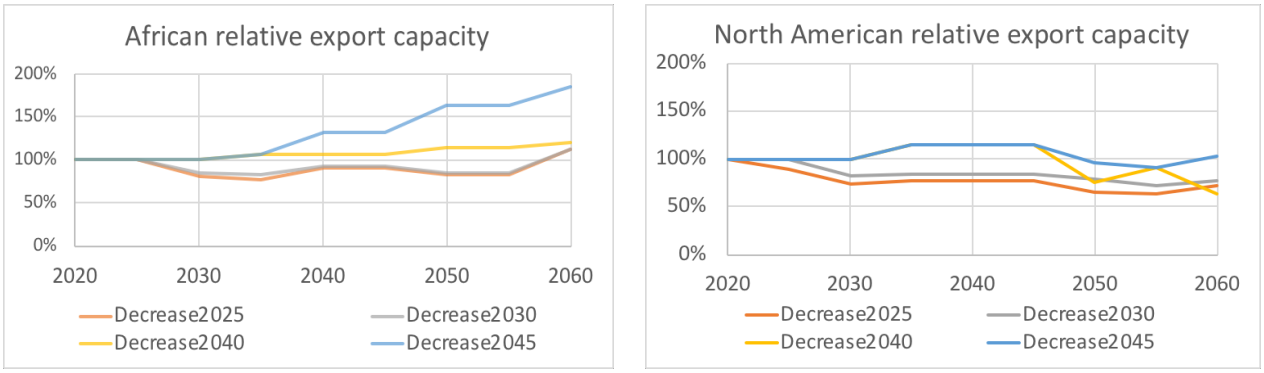


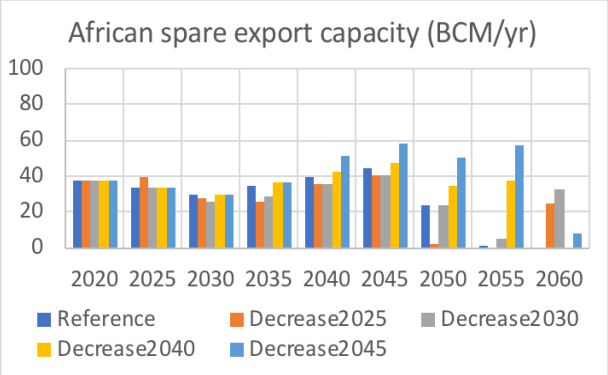
Fig. 7 – 28. Global spare capacity percentage in demand decrease period cases

The impacts of an early or delayed transition are different for different exporting regions. For Africa, as shown in Fig. 7 – 29a, an earlier demand reduction decreases the export capacity after 2030 by 10% - 20%. If the decrease happens in 2040, an increase in African export capacity by nearly 10% is observed. The impact is more significant if the demand change is further delayed to 2045, in which case the capacity increase relative to the reference reaches over 30% in 2040 and over 60% in 2050. As a result, the stranding risk is considerably higher in Decrease2045 as Africa has over 50 BCM/yr of its capacity stay spare for 15 years from 2040 to 2055 (see Fig. 7 – 30a). For North America (see Fig. 7 – 29b and Fig. 7 – 30b), the export capacities in Decrease2025 and Decrease2030 after the demand reduction are 25% and 20% less than the reference level respectively. This effectively alleviates the stranding risk and contributes to around 20% reduction in spare capacity between 2035 and 2045. Among the two delayed shift cases, Decrease2040 shows a considerable increase in the spare level during the transition phase because of two factors. The first one is the relative increase in total export capacity by 15%. The second one is the decreasing contract-based trade with China and East Asia. Regarding the Decrease2045 case, the result shows an extension of the transition phase to 2050, and the spare level is similar to the reference case. For Australia, only a little change is observed for all alternative scenarios relative to the reference. The results are insensitive to the timing of demand shift because of the limited endogenously generated capacity expansion.

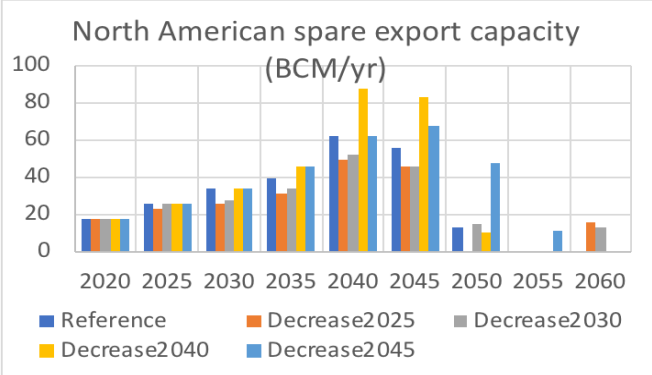


(a) (b)

Fig. 7 – 29. Relative export capacity in demand decrease period cases for (a) Africa and (b) North America



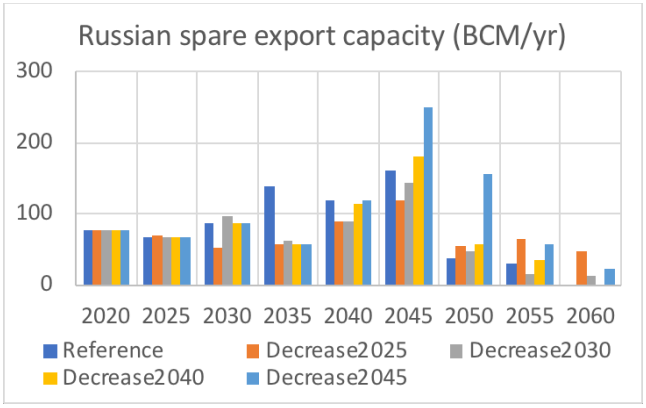
(a)



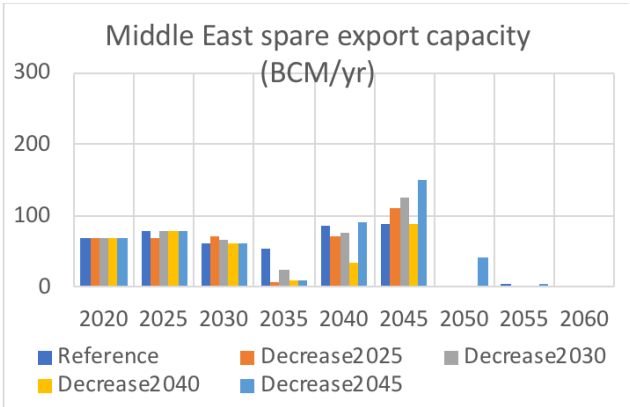
(b)

Fig. 7 – 30. Spare capacity percentage in demand decrease period cases for (a) Africa and (b) North America

For the two major exporters, Russia and the Middle East, the of export and spare capacities are shown in Fig. 7 – 31 and Fig. 7 – 33. An early demand change in 2025 allows Russia to reduce its spare capacity by over 50% in 2035, whereas a delayed change in 2045 will increase its post-change spare level by over 50%. The changes in Russian spare capacities subject to different demand shifting periods are attributed to the changed capacity development. As shown in Fig. 7 – 32a, the total export capacity in Russia in Decrease2025 is approximately 70% of the reference level. In contrast, the maximum Russian export capacity in Decrease2045 is 30% higher than the reference, reaching 600 BCM/yr in 2045. After the abrupt demand decrease, over 40% of these export capacities are left spare, leading to a high-level of stranding risk between 2045 and 2050. The Middle East is influenced by the timing of demand reduction in a similar way as Russia. In the Decrease2045 scenario, the Middle East has its export capacities 15% - 20% higher than the reference (see Fig. 7 – 33b). This leads to a 70% increase in the spare capacities in 2045, which exacerbates the stranding issue after the demand reduction.

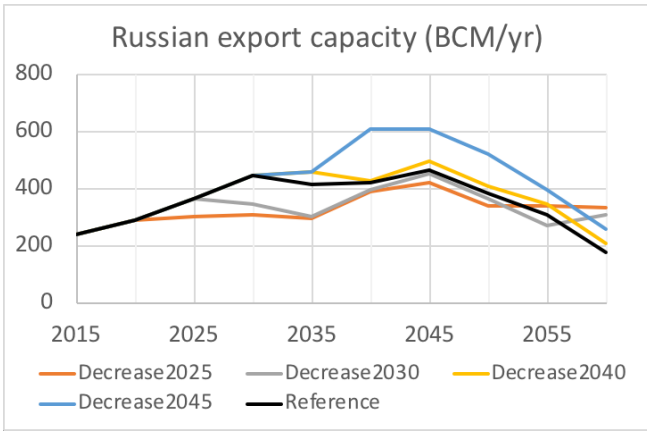


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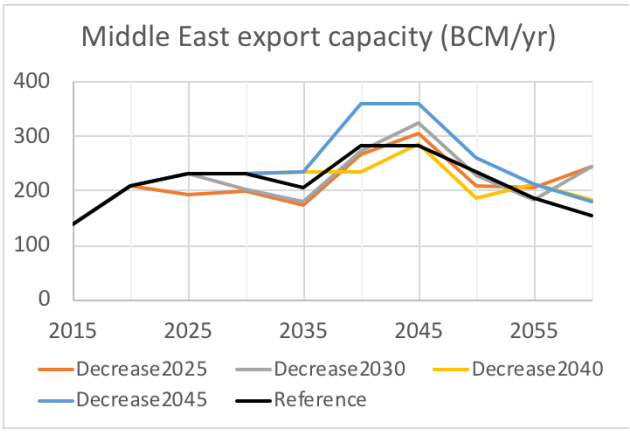


(b)

Fig. 7 – 31. Spare capacity in demand decrease period cases in (a) Russia and (b) the Middle East

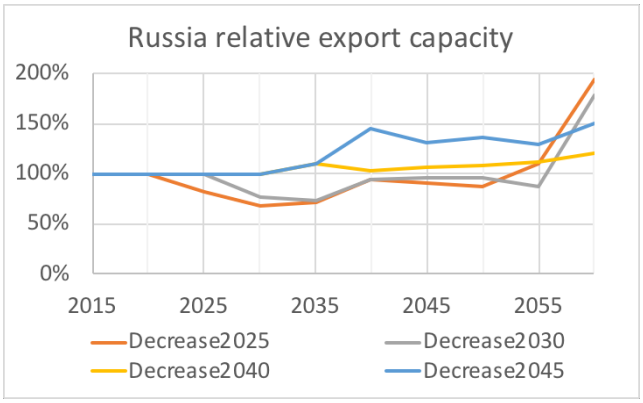


(a)

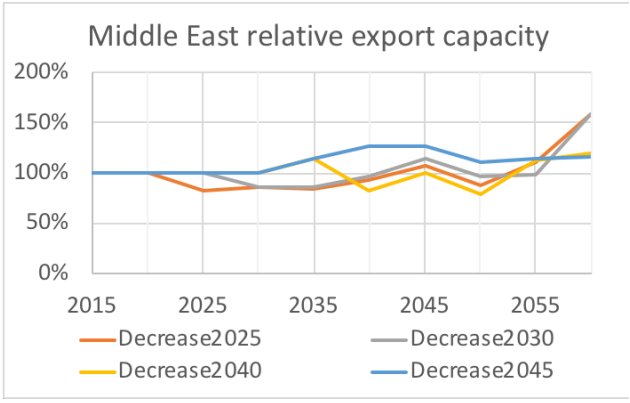


(b)

Fig. 7 – 32. Export capacity in demand decrease period cases in (a) Russia and (b) the Middle East



(a)



(b)

Fig. 7 – 33. Relative export capacity in demand decrease period cases in (a) Russia and (b) the Middle East

In conclusion, earlier demand decrease can effectively reduce the spare level and therefore mitigate the stranding risks on a global scale and in most exporting regions. The change in total demand and trade is smoother when the transition is earlier in 2025 and 2030. In addition, the export capacities developed in the early transition cases are 15% lower in 2035 as compared to the reference, and this results in a considerable decrease in spare capacities. For the delayed transition cases, Decrease2045 has a more significant impact which increases the total export capacity by 20%. A higher stranding risk of 300 BCM/yr capacities globally is observed after the demand decrease in this scenario.

7.4 Concluding remarks

In this section, the effect of the uncertain parameters related to contracts and agents' strategies on the stranding result is presented. The reference case is taken as the Shift-VLOW case in Chapter 6 so that the most extreme stranding condition can be tested. Both global and regional impacts are discussed, and the reasons for changes in the stranding result are also explained.

For contract related parameters, the first one studied is the minimum market purchase obligation $\mu_{j,t}^{CT}$. The result suggests that, the relaxation of this parameter to a lower level will not increase the stranding risk on a global scale. However, exporting regions with high short-run delivery costs will face more stranding after the demand shift because global gas trade becomes more spot-based. The second parameter discussed is the contract length. The development of global export capacity is reduced when the contract length is shortened to 15 – 20 years, and this leads to an effective mitigation of global stranding risks. Most regions have less capacity spare during the transition phase. While Africa is one of these regions, its total exports also decrease due to the lack of capacity expansion related to the shortened contract length.

The alternative suppliers' strategic parameter simulated in this chapter is the contract agreement criterion. With the criterion lifted to IRR over 16% from the reference 12%, global spare capacity during the transition phase reduces by 40%. The reduction in spare level is attributed to more conservative capacity expansion. Though less contracts are agreed between importers and exporters due to the stricter criterion, an increasing spot demand allows the total export globally to be affected only marginally during the transition phase. If the suppliers are more aggressive than what the reference case assumes and hold the criterion as IRR over 10%, the relative increase in capacity and stranding is 5% – 15% throughout the simulation periods.

For the demand side strategic parameters, the maximum contract ratio is tested, and the result suggests that with the ratio reduced to 90% – 80%, the stranding of 50 – 80 BCM/yr export capacities globally can be avoided. A further reduction of contract ratio to 70% may trigger a supply security issue as the global spare level could fall below 20%. Another demand-side uncertain parameter examined is the time period when the demand decrease will happen. If the importing markets conduct deep decarbonisation more actively and bring the gas demand decrease to the periods before 2035, global export capacity will see a 15% reduction as compared to the reference, and the related stranding is limited. In contrast, a delayed demand change in period 2045 will significantly increase the potential stranding to 300 BCM/yr level globally.

Among the five tested strategic parameters which may affect the stranding, contract length, suppliers' contracting criterion, and market maximum contractible ratio affect the stranding risk and capacity spare level mainly by influencing the capacity expansion process. While the stranding mitigation measures related to the first two parameters favour more economically profitable projects, those related to the third parameter reduce the expansion scale of all exporters regardless of relative profitability. However, when the agents alter these parameters, it is crucial to keep these parameters

within a certain range. Otherwise, global gas supply may become tight and unstable due to lack of capacity expansion.

Overall, this section discusses the alternative outcomes of global gas export capacity, trade, and stranding subject to different contract structures and agent strategies. This provides insights on how mitigation of the stranding risk can be achieved by certain actions of the agents. The corresponding impacts on trade in different regions are also examined. However, this analysis assumes that all players hold the same strategy, since this is the preliminary examination of the general impact of each strategic parameter. Further studies can be conducted with the agent-based modelling framework to test the impact of each player's alternative strategy to discuss the best strategy combination to alleviate the potential stranding risks.

Chapter 8. Conclusions and future work

This section provides the conclusion of this thesis. How this work contributes to existing modelling methods is presented first. The major innovations of Gas-GAME and the further improvements of Gas-GAME-Risk and Gas-GAME-Spot are summarised. Then, the key insights on future global gas trade from the model applications are provided. This section continues with the main conclusions regarding the gas export asset stranding issue. Finally, the limitations of this work and future research directions are discussed.

8.1 Contributions in modelling methods

This work develops a new gas-sector model which simulates global gas trade scenarios in the medium to long-term future. The model, Gas-GAME, uses an agent-based framework. Two types of agents, namely supply agents (*i.e.* export regions) and demand agents (*i.e.* import markets), are represented. Each agent has the flexibility to exercise its own strategy while making decisions, and such a design allows users to explore how the gas market may be affected by individual players.

Gas-GAME has a two-module structure, including (1) a Market Equilibrium Module (MEM) which simulates the short-term Nash-Cournot equilibrium in gas markets using a Mixed Complementarity Problem (MCP) approach, and (2) an Infrastructure Expansion Module (IEM) mimicking the contract-driven investment process for capacity expansion. Two modules run sequentially in each simulation time-period, and the model runs period by period to 2060.

The main innovation of Gas-GAME is its explicit representation of the bilateral contracting process in the IEM. It is the first model which generates future long-term gas contracts endogenously. The real-world contract negotiation is abstracted, and the simulation involves both supply and demand agents. Demand agents evaluate their required future imports, and send contract requests to the supply agents. Supply agents then conduct profitability analysis on their received requests, and decide which contract requests to accept based on their defined strategies. Another unique feature of Gas-GAME is that it uses the confirmed contracts to inform capacity expansion, which affects the maximum trade capability in future periods.

One key assumption in Gas-GAME is that the agents have limited information about the future while making decisions. Such an assumption is in contrast with the perfect foresight assumption held by most other gas models. In this study, the market prices emulated from the running-period MEM are used by demand and supply agents during the contracting process as an indication of the future market condition. This represents a more realistic investment process, and the sub-optimal expansion results can better reveal the risks in capacity development. Agents can also hold different perspectives on the

future market, and this modelling design allows users to investigate how the investors' perspectives would affect gas trade expansion.

Another key feature of Gas-GAME is the imperfect competition assumption on global gas trade. The MEM module simulates the game-theoretical Nash-Cournot equilibrium. Each supplier maximises its profit subject to the equilibrium, knowing how much their sales would affect prices. Sales by other suppliers' are also anticipated. Such a representation of short-term gas trade reflects the market power observed in historical and current markets. This feature contrasts the assumption that the whole system behaves collectively, but aligns with the agent-based modelling principle, which allows each player to look after their own interests.

Gas-GAME is the first-of-its-kind model capable of analysing future global gas trade scenarios subject to the incentive, strategy, and perspective of each market player. It can be applied to a wide range of market and technology research questions, and is a useful tool for a variety of energy system stakeholders.

Besides the innovation in Gas-GAME, improvements have been made to enhance the range of issues that the model is capable of analysing. Gas-GAME-Risk is developed to better address the market demand uncertainty issue. It extends Gas-GAME by adding a stochastic analysis process in supply agents' contract request evaluation. A scenario tree reflecting different future demand levels is constructed. In IEM, supply agents consider all possible outcomes in the scenario tree and make a hedged contracting decision. Such a process better mimics the risk-evaluation behaviour of real-world investors when they face uncertain market demand. The advantage of an agent-based framework is also highlighted through this modelling exercise, as the agents have the flexibility to change the way they interpret the future market.

This thesis also contributes to the modelling methodology by developing Gas-GAME-Spot. It further advances Gas-GAME by explicitly simulating the two trading mechanisms in gas market, namely contract-based trade and spot trade. In Gas-GAME-Spot, the Nash-Cournot market equilibrium is not assumed as the short-term scenario of global gas trade, but as the ideal condition which suppliers try to achieve with their contract obligations and flexible spot trades. The original two-modular structure in Gas-GAME is extended to a three-modular structure, with a Spot-Contract trade Module (SCM) added between MEM and IEM. In SCM, the two types of trades are simulated depending on the comparison between market contract condition and the equilibrium. An over-contracted market, categorised as a "Buyers' market", minimises its contract-based purchase and has little spot demand. Whereas an under-contracted market, categorised as a "Sellers' market", imports all gas secured by contracts and sources the remaining demand via spot. Supply agents deliver all contract-obliged sales first, and then compete in the spot markets using their remaining production and

transmission capacities. This model design combines the theoretical market equilibrium with real-world market mechanisms to simulate the dynamics of global gas trade in a novel way.

8.2 Contributions in global gas market analysis

The developed models have been applied to examine the key uncertainties identified in global gas supply, demand, and trade relationships. The impacts of each uncertain condition on market prices, export capacity development, and global gas trade are summarised.

8.2.1 The impacts of North American export strategies

It is uncertain how the US would continue to expand its LNG business. In Chapter 4, Gas-GAME is applied to examine how different North American export strategies may affect future global gas market dynamics. Three aspects of impacts are analysed: 1) the exports and revenues of North America, 2) the exports and revenues of other suppliers, 3) the prices and imports of markets. Through this study, the model capability to address the impacts of uncertain supply-side strategies is illustrated.

If North America stays conservative in LNG expansion, setting a higher economic criterion for confirming contracts, its export will be constrained to 80 BCM/yr before 2040 and will decrease to 10 BCM/yr after 2040. Such a reduction in North American LNG export creates a tight supply condition globally, and all major markets, including Western Europe, Eastern Asia, and China, see their prices increase relative to the base condition. Russia will benefit significantly in this scenario, as its market share in Western Europe will exceed 40%. The result indicates a potential energy security issue for the European governments.

If North America expands LNG business aggressively, setting its contracting criterion lower, it will export over 200 BCM/yr in 2060. The increased sales are mainly directed to East Asia and China. While the East Asian price decreases because of the additional North American supply, the Chinese price increases due to the supply reduction from the Middle East, Australia, and ASEAN countries. Western Europe develops more regasification capacity in this scenario, allowing them more options to source their gas supply.

8.2.2 The impacts of demand uncertainties and China-US natural gas tariff

The uncertainties in gas demand levels may lead to significant changes in global gas trade. In addition, the tariff on the US LNG imposed by the Chinese government may also affect the future gas trade scenario considerably. In Chapter 5, Gas-GAME-Risk is applied to examine the impacts of these two uncertain aspects. This study illustrates the model capability to address the issues related to uncertain market demand and trade relationships.

Under the base demand assumption, North American LNG will be sold mainly in East Asia, contributing to over 65% of the market share in 2060. China will also import 20 - 30 BCM of gas from North America annually from 2030 to 2060. If a tariff of 25% is imposed, little North American LNG will be sold to China. However, the impact on the Chinese gas price before 2040 is mild due to the contribution of other suppliers. In the long term, the tariff hinders the capacity development in North America, and when global supply is tightened by decommissioning, gas prices in not only China, but also East Asia and India, will see a notable increase. Facing the tariff, North America will redirect more gas to East Asia where it will further secure the dominant position. This leads to a significant reduction in Russian LNG export, and the result suggests that Russia should focus more on China pipeline projects.

When gas demand decreases abruptly in 2030, the East Asian market will be dominated by the Middle East. North America sells considerably less there, and increases its export to Western Europe and China. If the tariff is imposed, North America will sell the majority of its gas to Western Europe. Such a shift in export focus even promotes the North American capacity development. The Chinese market is only marginally affected because many other exporters have spare supplies in the low-demand scenario. Notably, the Russian export business suffers a total revenue reduction of US$ 140 billion between 2020 and 2060 because of the tariff. This is attributed to its loss of market share in Western Europe.

8.3 Insights on gas export asset stranding

Besides the market analysis, the model has also been applied to examine issues related to gas industry investments. The potential stranding of global gas export capacities is studied by Gas-GAME-Spot. This research broadens the existing stranded asset analysis by including two aspects which have been commonly overlooked: market fluctuation subject to the changing export capacities and the impacts of market signals on investor decision making.

If gas demand follows current policy pledges, the average infrastructure utilisation from 2015 to 2060 is 80% globally. The stranding risk is limited, mainly because the medium-sized exporters (*e.g.* Africa, ASEAN countries, Australia, and Norway) slow down their capacity development after 2030. Russia, the Middle East, and North America keep expanding their new capacities, and these capacities are utilised at high levels to compensate for the supply shortage caused by the other exporters.

If gas demand decreases unexpectedly after 2030, the stranding risk increases but is still moderate on a global scale. The result suggests two phases with different levels of stranding risks. The period between 2035 and 2045 is identified as the "transition phase", when most markets are over-contracted facing the decreased demand. The importers leverage the flexibilities in their long-term contracts and opt more gas through spot trade. Exporting regions with high short-run delivery costs, especially North America and Australia, have higher risks of asset stranding as they are arguably less competitive in spot sales. The period after 2050 features a global "tight supply", and there is little stranding risk. Since the markets adapt to the lower demand, fewer new contracts are confirmed, and limited new export capacity is developed.

A sensitivity analysis of the stranding outcome is conducted, and five key parameters related to contract structures and agent strategies are examined. Further relaxation of the contract purchase obligation leads to increasing spot trades, and the stranding risks faced by Africa, Australia, and North America would also increase. If the long-term contract length is reduced to 15 – 20 years, in contrast to the base 30-year assumption, stranding during the transition phase can be effectively alleviated. On the supply side, a more conservative contracting criterion of 16% IRR can reduce the spare capacity by 40% globally. On the demand side, if importers leave some of their import requests to spot supply and set their maximum contract ratio as 80 – 90%, the stranding of 50 – 80 BCM/yr export capacities globally can be avoided. Besides, an early deep decarbonisation by importing countries will reduce global export capacity by 15% in 2035, mitigating the stranding problem significantly. In contrast, if deep decarbonisation is delayed to 2045, there will be an additional 300 BCM/yr capacity stranded due to the continued expansion in the meantime.

8.4 Limitations and future work

This work focuses on global import-export relationships, and therefore does not consider how the domestic market would affect the future trade scenarios. It is assumed that the domestic suppliers in exporting regions would not affect the global trade there. Users should not compare the capacity and trade results in this thesis with other studies which cover both domestic and export business. However, as the production capacities developed by exporters can also supply the domestic markets, future work should incorporate the domestic demand and supply into the model. A different trading mechanism needs to be developed to mimic the interaction between exporters and domestic consumers. How the domestic market affects the export capacity expansion also requires detailed investigation before being represented in the model.

Some existing gas-sector models represent regions in more detail than Gas-GAME. The five import markets and nine export regions are segregated in this thesis to effectively represent the key features in global gas trade. But there are limitations in this regional segregation. For example, Japan and Korea are two major gas import countries, and are simulated together in the East Asia market. Though they share some similar market features, their gas supply sources and future market development may differ. A more granular regional representation can enhance the model capability to address country-specific issues.

Another challenge regarding the region segregation is the participation of International Oil Companies (IOCs) in global gas trade. These companies (*e.g.* Shell, BP, ExxonMobil) have gas production capacities and reserves throughout the world, and are flexible to sell from their portfolio for certain contracts. Each company operates to maximise its profitability beyond the regional boundary. This is not simulated in Gas-GAME. Future research can include IOCs in the supply agents and discuss the impacts of their operation. Detailed data on company-level reserve, capacity, contract, and trade is required to represent the IOCs appropriately.

The thesis addresses the uncertain issues in supply, demand, and trade relationship mainly through scenario analysis. It needs to be understood that, the simulated scenarios do not represent all possible outcomes, but show the storylines of certain possible futures. A wider range of future scenarios can be explored through more a systematic simulation of all uncertain aspects. The uncertainties in not only parameters but also agent behaviour characterisation require a detailed assessment before being incorporated into the model. For example, this thesis assumes that supply agents use the running period equilibrium prices to evaluate the future profitability of their contracts. The actual stakeholders may hold different perspectives, and expert elicitation is required to represent these perspectives more appropriately. Regarding the methods to address uncertainties, Monte-Carlo Analysis (MCA) and

Modelling to Generate Alternatives (MGA) can be applied. Gas-GAME-Risk simulates the stochastic analysis by investors subject to uncertain demand. Future work can refine the representation of the stochastic analysis, so that demand uncertainties affect not only the sale volumes of contracts, but also future market prices. The analysis can also simulate suppliers' recourse actions when different future demand scenarios are reviewed.

In the study which examines the North American export strategies (Chapter 4), it is assumed that other suppliers do not change their strategies throughout the simulation horizon. This assumption facilitates a proper examination on the impacts of North America, but future studies can allow other suppliers, especially Russia and the Middle East, execute alternative strategies subject to different market conditions. When investigating the impacts of uncertain demand (Chapter 5), all markets are assumed to see demand change in the same period. As each import country may have a unique energy transition pathway, the potential demand changes can be represented more specifically for each market. A variety of future demand scenarios in each market, projected by different outlooks, can be explicitly simulated and compared to identify the risks in gas export business. Regarding the trade relationship between China and the US (Chapter 5), this study simulates a 25% LNG tariff for all future periods, and the result suggests a negative impact on Russian gas export. While Russia, at the time of writing, is still the largest gas exporter globally, it may anticipate the consequences and take actions to secure its sales. Its trade relationships with Europe and China can be further investigated to reveal the plausible actions Russia may take responding to the tariff.

The stranding outcomes presented in this thesis are based on the assumption that markets signal their demand changes mainly through contract requests. The stranding mitigation insights provided from the sensitivity analysis also focus on contract structures and strategies. It is noticed that, some import countries, like Japan and China, have realised the issue of their demand uncertainties and invested in upstream production assets in export countries. They would then have better control over their gas supplies, and can opt to sell their contracted volumes to other markets if their demands decrease unexpectedly. This evolving mechanism may change the existing contract framework, and how this would affect the capacity development and stranding should be further studied.

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Appendices

Appendix A: Chapter 3 - Methods

Table A- 1: Import market region representation

Import Market	Countries
East Asia	Japan, Korea, Chinese Taipei, Afghanistan, Bangladesh, Bhutan, Cook Islands, DPR of Korea, East Timor, Fiji, French Polynesia, Kiribati, Macau, Maldives, Mongolia, Nepal, New Caledonia, Pakistan, Papua New Guinea, Samoa, Solomon Islands, Sri Lanka, Tonga, Vanuatu
West Europe	Austria, Belgium, Czech Republic, France, Germany, Greece, Hungary, Ireland, Italy, Luxembourg, Netherlands, Poland, Portugal, Slovak Republic, Slovenia, Spain, Turkey, United Kingdom, Estonia, Denmark, Iceland, Sweden, Switzerland
East Europe	Bulgaria, Croatia, Cyprus, Latvia, Lithuania, Malta, Romania, Finland, Albania, Belarus, Bosnia and Herzegovina, FYR of Macedonia, Gibraltar, Montenegro, Republic of Kosovo, Republic of Moldova, Serbia, Ukraine
India	India
China	People's republic of China, Hong Kong

Table A- 2: Export region representation

Export Region	Countries
ASEAN	Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, Viet Nam, Brunei Darussalam, Cambodia
Middle East	Qatar, Oman, Bahrain, Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Saudi Arabia, Syria, United Arab Emirates, Yemen
Caspian	Azerbaijan, Kazakhstan, Turkmenistan, Uzbekistan, Armenia, Georgia, Kyrgyzstan, Tajikistan
Africa	All countries on the continent of Africa
Australia	Australia
North America	America, Canada, Mexico
Norway	Norway
Russia	Russia
South America	Caribbean and South American countries

Due to the focus of this study, the five import markets are selected based on historical gas import volumes and high demand expectation in the future. Though each country has different market dynamics and pricing schemes, aggregation is done for those who share the same import source profile and price levels within the same range. Export regions are chosen to reflect the competitive relationship to serve the import requirement. For example, Russia, Norway, Middle East, and Africa are all supplying the European gas market with different objectives. While Caspian region is also developing pipeline projects to grab some share from there.

Table A- 3: Import-export pairs allowed to form contracts [16, 164]

Import market	Export region	Transmission method
East Europe	Africa	Pipeline
	Middle East	Pipeline, LNG
	Russia	Pipeline
	Caspian	Pipeline
West Europe	Africa	Pipeline, LNG
	Middle East	Pipeline, LNG
	Norway	Pipeline
	Russia	Pipeline, LNG
	Caspian	Pipeline
	North America	LNG
	South America	LNG
China	Russia	Pipeline, LNG
	Caspian	Pipeline
	ASEAN	LNG
	Africa	LNG
	Australia	LNG
	Middle East	LNG
	North America	LNG
East Asia	ASEAN	LNG
	Africa	LNG
	Australia	LNG
	Middle East	LNG
	North America	LNG
	Russia	LNG
India	ASEAN	LNG
	Africa	LNG
	Australia	LNG
	Middle East	LNG
	North America	LNG
	South America	LNG

Table A- 4**:** Justification for key parameters in SCM

Parameters	**Values**	**Data-source and justification**
Sellers' market		
Premium over market price-demand curve $PREM_j^{SP}$	$2/MMBtu	The value of this premium is estimated based on historical data. The case when Japan requires additional spot gas after the Fukushima accident is studied. The wholesale price of Japanese gas import [165] between 2012 and 2014 is around $16.5/MMBtu. Whereas the LNG spot price in Japan during the same period is around $18.5/MMBtu for the peak seasons [166]. The difference between the two prices indicates a premium of $2/MMBtu for spot sales in Sellers' market, and this value is therefore used as the model parameter.
Buyers' market		
Minimum commitment level $\mu_{j,t}^{CT}$	NPS scenario: 70% SDS & LOW scenario: 70% 2015 to 2030; The value decreases by 5% each period after 2030	The minimum market purchase obligation is 70% in 2015. This assumption is based on three sources of flexibilities in current long-term contracts: (1) downward quantity adjustment [4]; (2) provision of rescheduling to future periods [158]; and (3) flexible destination clauses and options for reselling [158]. In the NPS scenario, as the demand follows the current policy trend, this 70% minimum purchase is assumed the same until the end of the simulation horizon. In the SDS and LOW scenarios, market demand experiences unexpected decline after 2030, and this can induce a renegotiation on contract flexibilities. The obligation is assumed to decrease from 2030 because the buyers want to minimize their purchase. The percentage decreases by 5% for every period as a positive trade partnership needs to be maintained. In 2060, only 40% of the contracts are obliged to be committed. Since the commitment level ensures the utilization of capacities, its value is assumed lower to allow the stranding risks better explored.
Minimum level of profit as the adjustment factor added to the cost-based price	$2/MMBtu	The historical spot prices of gas at NBP (UK) and TTF (Dutch) are examined [167]. In late 2009, a global gas supply surplus is observed due to depressed demand, boom in US shale gas, and surging LNG capacity. The European spot gas price decreases to around $5/MMBtu. This value is compared to the highest short-term delivery cost to the European market at around $3/MMBtu, and the minimum profit is therefore estimated at $2/MMBtu level.

Appendix B: Chapter 4 - The impacts of North American export strategies on global gas trade

Table B- 1: MEM short-run delivery costs in the base period

Export region	Import market	Transmission method	Calibrated short-run delivery cost ($/MMBtu)	Literature-based short-run delivery cost [7, 139, 168, 169] ($/MMBtu)	Non-cost term ($/MMBtu)
Middle East	East Asia	LNG	2.55	2.69	0
Middle East	India	LNG	2.86	2.12	0
Middle East	China	LNG	6.13	2.69	3
Middle East	West Europe	LNG	7.24	2.69	6
North America	East Asia	LNG	10.31	3.73	6
South America	East Asia	LNG	10.21	3.29	6
South America	India	LNG	4.28	3.58	0
South America	West Europe	LNG	7.89	3.01	6
Australia	East Asia	LNG	6.56	2.75	3
Australia	China	LNG	5.90	2.75	3
Russia	East Asia	LNG	8.10	2.84	6
Russia	China	LNG	6.27	2.84	3
Africa	East Asia	LNG	9.03	3.06	6
Africa	India	LNG	4.29	2.49	3
Africa	China	LNG	6.30	3.06	3
Africa	West Europe	LNG	7.16	2.21	6
Norway	East Asia	LNG	10.46	4.15	6
Norway	West Europe	LNG	7.93	3.02	6
ASEAN	China	LNG	5.86	2.55	3
Middle East	West Europe	PIPE	7.83	1.08	6
Russia	West Europe	PIPE	5.48	1.93	3
Africa	East Europe	PIPE	4.97	1.31	3
Africa	West Europe	PIPE	7.04	1.31	6
Caspian	China	PIPE	5.93	1.33	6
Caspian	West Europe	PIPE	7.90	1.47	6
Norway	West Europe	PIPE	5.89	2.26	3

Table B- 2: MEM short-run delivery costs in future periods for new trade routes

Export region	Import market	Transmission method	Estimate Short-run delivery cost from calibration ($/MMBtu)	Literature-based short-run delivery cost [7, 139, 168, 169] ($/MMBtu)	Non-cost term ($/MMBtu)
North America	West Europe	LNG	5.00	2.88	3
North America	China	LNG	8.00	3.44	6
North America	India	LNG	4.50	3.44	0
Australia	India	LNG	4.50	2.75	3
ASEAN	East Asia	LNG	7.00*	2.55	3
ASEAN	India	LNG	6.00	2.55	3
Caspian	East Europe	PIPE	4.50	1.33	3
Middle East	East Europe	LNG	7.00	2.69	3
Russia	East Europe	PIPE	2.00*	1.79	0
Russia	China	PIPE	4.00	2.07	0

*: value adjusted from the calibrated result, because the base period calibration leads to a negative cost. Adjustment uses estimation from trades with similar characteristics.

Table B- 3: Demand market relationships in Gas-GAME base case

		West Europe	East Europe	East Asia	China	India
2010	***INT (Million US$/BCM)***	558	424	1412	281	217
	SLP (Million US$/BCM^2)	1	3	7	4	5
2015	***INT***	573	411	1640	455	290
	SLP	1	3	7	4	5
2020	***INT***	587	397	1868	628	364
	SLP	1	3	7	4	5
2025	***INT***	601	384	2096	801	438
	SLP	1	3	7	4	5
2030	***INT***	615	371	2324	974	512
	SLP	1	3	7	4	5
2035	***INT***	629	358	2552	1147	585
	SLP	1	3	7	4	5
2040-2060	***INT***	643	345	2780	1320	659
	SLP	1	3	7	4	5

Appendix C: Chapter 5 - The impacts of demand uncertainties and China-US natural gas tariff on global gas trade

Table C- 1: Market elasticity in 2040 in LOW demand trajectory

Import market	Elasticity
East Asia	-0.5
West Europe	-0.7
East Europe	-0.6
India	-0.6
China	-0.6

Table C- 2: Demand market relationships in under NPS trajectory

		West Europe	East Europe	East Asia	China	India
2010	***INT (Million US$/BCM)***	558	424	1412	281	217
	SLP (Million US$/BCM^2)	1	3	7	4	5
2015	***INT***	573	411	1640	455	290
	SLP	1	3	7	4	5
2020	***INT***	587	397	1868	628	364
	SLP	1	3	7	4	5
2025	***INT***	601	384	2096	801	438
	SLP	1	3	7	4	5
2030	***INT***	615	371	2324	974	512
	SLP	1	3	7	4	5
2035	***INT***	629	358	2552	1147	585
	SLP	1	3	7	4	5
2040-2060	***INT***	643	345	2780	1320	659
	SLP	1	3	7	4	5

Table C- 3: Demand market relationships in under LOW trajectory

		West Europe	East Europe	East Asia	China	India
2025	***INT (Million US$/BCM)***	623	379	1493	687	450
	SLP (Million US$/BCM^2)	1	3	7	3	5
2030	***INT***	573	411	1368	669	290
	SLP	1	3	5	3	4
2035	***INT***	587	397	1246	640	364
	SLP	1	3	4	2	4
2040-2060	***INT***	601	384	1124	602	439
	SLP	1	3	4	1	5

Table C- 4: Unit production CAPEX values

Supply region	**Median unit production CAPEX**	**Unit production CAPEX supply curve**
	$/MMBtu	**x in BCM, CAPEX in $/MMBtu**
Africa	0.94	$CAPEX = 0.1 + 0.0003x$
ASEAN	0.97	$CAPEX = 0.3 + 0.0005x$
Australia	1.76	$x \leq 1500, CAPEX = 0.45;$ $x > 1500, CAPEX = 0.0008x + 0.161$
Caspian	0.97	$x \leq 4200, CAPEX = 0.0002x + 0.3;$ $x > 4200, CAPEX = 0.0006x - 1.35$
North America	1.54	$x \leq 13000, CAPEX = 0.00008x + 0.3;$ $x > 13000, CAPEX = 0.0008x - 9$
Norway	1.00	$x \leq 750, CAPEX = 0.0005x + 0.2;$ $x > 750, CAPEX = 0.0063x - 3.28$
Middle East	0.59	$x \leq 10000, CAPEX = 0.25;$ $x > 10000, CAPEX = 0.0002x - 1.72$
Russia	0.38	$CAPEX = 0.2 + 0.0001x$
South America	1.21	$CAPEX = 0.5 + 0.0011x$

Appendix D: Chapter 6 – Asset stranding in natural gas export facilities

Table D- 1: Delivery cost parameters in Gas-GAME-Spot base case

Export region	Import market	Transmission method	Literature-based short-run delivery cost* [7, 138, 139, 169] (US$/MMBtu)	Non-cost term 2015 (US$/MMBtu)	Non-cost term 2010** (US$/MMBtu)
Middle East	East Asia	LNG	2.69	0	0
Middle East	India	LNG	2.12	2	0
Middle East	China	LNG	2.69	3	3
Middle East	West Europe	LNG	2.69	6	6
North America	East Asia	LNG	3.73	3	6
North America	India	LNG	3.44	3	0
North America	China	LNG	3.44	3	6
North America	West Europe	LNG	2.88	3	3
South America	East Asia	LNG	3.29	7	6
South America	India	LNG	3.58	4	0
South America	China	LNG	3.58	6	6
South America	West Europe	LNG	3.01	4	6
Australia	East Asia	LNG	2.75	3	3
Australia	India	LNG	2.75	5	3
Australia	China	LNG	2.75	6	3
Russia	East Asia	LNG	2.84	7	6
Russia	China	LNG	2.84	6	3
Russia	West Europe	LNG	3.40	4	6
Africa	East Asia	LNG	3.06	6	6
Africa	India	LNG	2.49	4	3
Africa	China	LNG	3.06	6	3
Africa	West Europe	LNG	2.21	4	6
Norway	East Asia	LNG	4.15	6	6
Norway	India	LNG	4.15	4	-
Norway	China	LNG	4.15	6	-
Norway	West Europe	LNG	3.02	6	6
ASEAN	East Asia	LNG	2.55	0	3
ASEAN	India	LNG	2.55	5	3
ASEAN	China	LNG	2.55	6	3
Middle East	West Europe	PIPE	1.08	6	6
Middle East	India	PIPE	1.50	3	-
Russia	West Europe	PIPE	2.00[1]	3	3
Russia	East Europe	PIPE	1.79	0	0
Russia	China	PIPE	2.07	3	0
Africa	East Europe	PIPE	1.31	3	3
Africa	West Europe	PIPE	1.31	5	6
Caspian	China	PIPE	1.33	3	6
Caspian	West Europe	PIPE	1.47	5	6
Caspian	East Europe	PIPE	1.33	6	3
Norway	West Europe	PIPE	2.00[2]	3	3
Norway	East Europe	PIPE	3.07	5	-

Table D- 1 explanation:
*Literature-based costs are based on the same references as in Chapter 4.
Note 1: Minor change compared to $1.93/MMBtu in Chapter 4
Note 2: Minor change compared to $2.26/MMBtu in Chapter 4
The changes make pipeline gas supply from Norway and Russia to West Europe similarly competitive (both at $2/MMBtu) in spot trade.
** These are the values used in Chapter 4, which are calibrated based on 2010 global gas flows. Here, the values are presented to show a transparent comparison with the values calibrated against 2015 historical gas flows.

Table D- 2: Demand market relationships in Base scenario in Chapter 6 Gas-GAME-Spot [18]

		West Europe	East Europe	East Asia	China	India
2015	***INT (Million US$/BCM)***	519	543	1350	549	479
	SLP (Million US$/BCM^2)	1	6	6	4	11
2020	***INT***	538	564	1574	709	663
	SLP	1	6	6	4	11
2025	***INT***	556	584	1798	869	847
	SLP	1	6	6	4	11
2030	***INT***	575	605	2022	1030	1032
	SLP	1	6	6	4	11
2035	***INT***	593	625	2246	1190	1216
	SLP	1	6	6	4	11
2040-2060	***INT***	629	646	2470	1350	1400
	SLP	1	6	6	4	11

Table D- 3: Demand market relationships in Shift-SDS scenario

		West Europe	East Europe	East Asia	China	India
2035	***INT*** ***(Million US$/BCM)***	540	599	1081	747	721
	SLP ***(Million US$/BCM^2)***	1	6	6	4	11
2040-2060	***INT***	522	558	913	612	542
	SLP	1	6	3	1	2

*The SDS demand levels in 2040 are from WEO 2017 [18]. These demand levels together with the elasticity values in Table C-1 and gas price as 2015 are used to construct the demand market relationships in 2040. It is assumed that under normal SDS condition, the relationship shifts gradually from 2015 until 2040. In this study, we simulate a sudden shift from 2030, and hence, the relationships only changes to the SDS condition after 2030.

Table D- 4: Demand market relationships in Shift-VLOW scenario

		West Europe	East Europe	East Asia	China	India
2035	***INT*** ***(Million US$/BCM)***	438	471	1026	654	609
	SLP ***(Million US$/BCM^2)***	1	6	3	2	5
2040-2060	***INT***	418	453	914	611	541
	SLP	1	6	3	1	3

*The VLOW demand levels in 2040 are based on literatures: [38, 129-131, 159, 160, 170].
The demands levels in 2040 together with the elasticity values in Table C-1 and the same price as 2015 are used to construct the demand market relationships in 2040. It is assumed that under normal VLOW condition, the relationship shifts gradually from 2015 until 2040. In this study, we simulate a sudden shift from 2030, and hence, the relationships only changes to the VLOW condition after 2030.

Appendix E: Abbreviation

Abbreviation	Definition
AGGM	ArrowHead Global Gas Model
ALO	Ant Lion Optimiser
ANFIS	Adaptive Network based Fuzzy Inference System
ANN	Artificial Neural Networks
APGM	Asia-Pacific Gas Model
ARIMA	Auto-Regressive Integrated Moving Average
BCM	Billion Cubic Meter
BECCS	Bio-Energy with Carbon Capture and Storage
BIWGM	Baker Institute World Gas Model
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storag
CES	Constant Elasticity of Substitution
CET	Constant Elasticity of Transformation
CGE	Computable General Equilibrium
CIS	the Commonwealth of Independent States
CNPC	China National Petroleum Corporation
CPF	Carbon Price Floor
DOE	The U.S. Department of Energy
EFOM	Energy Flow Optimisation Model
EIA	Energy Information Administration
EMM	Electricity Market Module in NEMS
ENTSOG	European Network of Transmission System Operators for Gas
EPA	the US Environmental Protection Agency
FID	Final Investment Decision
FSRU	Floating Storage and Regasification Units
GASTALE	Gas mArket System for Trade Analysis in a Liberalising Europe
GCAM	Global Change Assessment Model
GECF	Gas Exporting Countries Forum
GIIGNL	International Group of Liquefied Natural Gas Importers
GSAM	Gas Systems Analysis Model
GSM	Gas Supply Model in PRIMES
IAM	Integrated Assessment Model
IEA	International Energy Agency
IEEJ	The Institute of Energy Economics, Japan
IEM	Infrastructure Expansion Module
IGU	International Gas Union
IIASA	International Institute for Applied Systems Analysis
INGM	The International Natural Gas Model
IPCC	The Intergovernmental Panel on Climate Chang

IPOPT	Interior Point OPTimizer
IRENA	The International Renewable Energy Agency
IRR	Internal Rate of Return
KKT	Karush–Kuhn–Tucker
LMDI	Logarithmic Mean Divisia Index
LNG	Liquefied Natural Gas
LOW	Low Demand Scenario
MAGICC	Model for Greenhouse gas Induced Climate Change
MCA	Monte Carlo Analysis
MCP	Mixed Complementarity Problem
MEM	Market Equilibrium Module
METI	Japan Ministry of Economy, Trade and Industry
MGA	Modelling to Generate Alternatives
MMBtu	Million British thermal unit
MNL	Multinomial Logit function
NEMS	National Energy Modelling System
NGTDM	Natural Gas Transmission and Distribution Module
NLME	Nonlinear mixed effects model
NPS	New Policies Scenario
NPV	Net Present Value
OIES	Oxford Institute for Energy Studies
OPEX	Operating Expenditure
PM	Particulate Matter
PNIP	Principle of New Information Priority
PRIMES	Price-Induced Market Equilibrium System
Pyomo	Python Optimization Modelling Objects package
S-GGM	Stochastic Global Gas Model
S-NGEM	Stochastic-Natural Gas Equilibrium Model
SCM	Spot-Contract trade Module
SDS	Sustainable Development Scenario
SLP	Successive Linear Programming
SPA	Sale and Purchase Agreement
TCM	Trillion Cubic Meter
TIAM	TIMES Integrated Assessment Model
TIMER	the Targets IMage Energy Regional model
TIMES	The Integrated MARKAL-EFOM System
UNFCCC	United Nations Framework Convention on Climate Change
USEA	The United States Energy Association
VaR	Value at Risk
VLOW	Very low Demand Scenario
WEO	World Energy Outlook by International Energy Agency
WEPS+	World Energy Projection System Plus
WGM	World Gas Model

SLP	Successive Linear Programming
SPA	Sale and Purchase Agreement