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An economic analysis of gas pipeline trade cooperation in the GCC

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ABSTRACT

Natural gas plays an important role in the global energy system. Thus, optimizing trade in natural gas is a key concern for many countries. This study investigates the value of expanding the Gulf Cooperation Council's (GCC) natural gas grid. We consider the documented successes and failures of the regional gas trade in Europe and Asia and weigh them against a GCC case study. The case study uses a partial equilibrium model of energy production, trade and demand calibrated to 2018 conditions to assess regional pipeline gas trade opportunities. The model incorporates parameters that are relevant to energy policy issues, including fuel allocation and energy price reforms. We also incorporate the regional liquified natural gas (LNG) trade strategy of Qatar, a regional and global leader in LNG production and exports. We find that pipeline gas trade cooperation in the GCC can contribute up to $3.1 billion to the regional economy by reducing transportation costs. More accessible gas offers a substitute for liquid fuel consumption and can offset the opportunity costs of using domestic oil to meet domestic energy demands. We also investigate the influence of an integrated gas market and price reforms on the power trade along the GCC interconnector.

1. Introduction

Natural gas development has become a priority for long-term energy security and economic diversification initiatives across the Gulf Cooperation Council (GCC) (Shabaneh et al., 2020). The countries in the GCC region are Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emirates (UAE). Natural gas has played an important role in meeting this region's increasing demand for electricity and supporting the development of energy-intensive industries. Furthermore, the GCC possesses more than 20% of the world's natural gas proved reserves. Nevertheless, the development of these reserves has historically been secondary to that of oil fields. These fields produce the GCC's crude oil for export and significant volumes of associated gas for domestic use (Sartori, 2019).

The GCC is currently pushing forward various economic reforms. Natural gas can be a key enabler of these economic transition plans and long-term sustainable growth owing to its versatility, inherent efficiency and environmental benefits. However, GCC countries administer or fix their gas prices through government regulations; moreover, these prices are often below marginal supply costs. This mispricing has encouraged domestic demand but has undermined domestic supply growth. All GCC countries except Qatar either burn oil or import gas, mostly in the form of liquefied natural gas (LNG), because of gas shortages. Although Saudi Arabia is the largest energy consumer in the GCC, it does not import gas, meaning that its power sector consumes a significant portion of liquid fuel.

GCC members have similar economic structures, aspirations and political systems. Thus, this study investigates whether regional gas cooperation, in the form of cross-border infrastructure and trade, can add economic value within the GCC. Article 4 of the GCC's charter addresses energy cooperation, calling for "… coordination, integration and inter-connection between member states in all fields" (Secretariat General of the GCC, 2020). However, the pipeline gas trade has not expanded in recent years even though most GCC members face natural gas shortages.

GCC agreements have focused on security and economic cooperation rather than energy cooperation. Furthermore, higher oil prices and strong fiscal balances across the GCC have offered little incentive to overcome the hurdles associated with cross-border trade and improving energy efficiency. Nevertheless, the GCC countries have a good foundation for redoubling their energy cooperation efforts and establishing the region as a preeminent energy hub. Doing so can provide benefits now and during the unfolding global energy transition. This transition includes an uncertain outlook for oil, ambitious economic reform

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agendas and uncertainty around the effects of the COVID-19 pandemic on the energy landscape. Energy cooperation can help to navigate this transition.

This study introduces an updated version of the KAPSARC Energy Model for the GCC (KEM GCC). This model has previously been used to investigate the integrated fuel, power and water supplies across the GCC (Wogan et al., 2019). To our knowledge, no previous quantitative analysis addresses the opportunities associated with gas market integration and trade in the GCC. To fill this research gap, we develop energy policy scenarios to address two research questions. First, we investigate the potential economic benefits for the GCC from expanding the cross-border natural gas pipeline infrastructure. Second, we analyze the policy and technical challenges the region faces in realizing gas trade cooperation.

To address these questions, we identify the regional natural gas market reforms that may encourage increased GCC gas market integration. Then, we evaluate these reforms in counterfactual scenarios using 2018 market conditions. One potential pan-GCC reform is coordinating the regional fuel trade to increase the gas use of key energy demand sectors, particularly power and water generation. We also investigate the economic benefits of reducing gas supply costs. Finally, we consider replacing the demand for liquid fuel, particularly crude oil, to mitigate the opportunity cost of foregone exports.

We also elaborate on this core analysis in two ways. First, we investigate the potential effects of new investments and power and water generation sector restructuring on gas trade patterns and benefits. Second, we investigate the potential impact of an interconnected gas market on utilization of the GCC electricity interconnector, a critical piece of pan-GCC energy trade infrastructure.

The remainder of the paper proceeds as follows. Section 2 provides background information on the GCC gas market to provide regional context for the development of the gas grid. Section 3 discusses the development of natural gas markets internationally by considering examples from both Europe and the Association of Southeast Asian Nations (ASEAN). Section 4 describes the gas trade module used in the KEM GCC. Section 5 presents a case study on the GCC gas trade when the cross-border pipeline infrastructure is expanded under different pricing conditions. Finally, section 6 provides concluding remarks and insights for policymakers.

2. Overview of the GCC gas market

The idea of a pan-GCC gas grid has been discussed since the 1990s (NOGA, 2017). However, the Dolphin pipeline is the only cross-border natural gas pipeline in the region. This pipeline began operating in 2007 and transports Qatari gas to the UAE and Oman. This lack of market integration and geopolitical constraints are perhaps the two most significant impediments to investments in cross-border infrastructure for natural gas.

The GCC electric power interconnector is one of the largest energy trade infrastructure projects and connects all six member countries. It provides power supply security and economic benefits across the region. It also offers an alternative to transporting fuel across borders by converting it directly into exportable electricity (i.e., fuel trade by wire). However, discrepancies in administered fuel prices across the GCC and thus, in the marginal value of electricity production, complicate the interconnector's use. In turn, the trade of gas by wire is complicated as well.

The governments of GCC countries often set administered gas prices below the competitive prices observed in international markets. These low prices can help to promote economic activity and social welfare. They serve as a form of rent distribution from the state to the local populations (Tsai, 2018). However, these artificially low prices also impact the expansion of the natural gas supply, as they are lower than the long-term marginal cost of production. In particular, they are below the marginal cost of production from newer sources of non-associated gas. As a result, Kuwait, the UAE and Bahrain have installed LNG import facilities in the last decade to address domestic gas supply shortages. Saudi Arabia, in contrast, relies heavily on oil-based power generation, as it has not developed infrastructure for gas imports.

Fuel price differences across the region also discourage cross-border trade. Qatar, the region's largest gas exporter and lowest-cost producer, therefore seeks higher prices for its gas in international markets by exporting LNG (Krane and Wright, 2014). The fuel price differences also create unintentional fuel subsidy leakages that complicate or block the integration of the region's power sectors through existing interconnector facilities. Wogan, Murphy, and Pierru (2019) model this trade barrier by restricting the benefits of administered fuel prices to national power industries. In this way, they can prevent the cross-subsidization of fuel across member states through the power trade in their model. They show that economic benefits fall by $2.2 billion annually when cross-subsidization is possible.

Geopolitical tensions in the GCC have also interrupted bilateral agreements in the past. For example, a pipeline project between Qatar and Kuwait was halted by Saudi Arabia's refusal to grant passage through its offshore waters (MEES, 2006). Kuwait was therefore forced to use a costlier route to meet its natural gas needs. It installed an LNG import terminal in 2009 with an initial capacity of 5 billion cubic meters per year (bcm/y). Considering both short- and long-term costs, transporting LNG from Qatar to Kuwait this way is much costlier than using a pipeline. Specifically, it would cost up to 10 times more on a dollar per million British thermal unit ($/MMBtu) basis. This estimate considers the variable and fixed operating costs of the pipeline, the maritime tanker and liquefaction and regasification facilities. It also accounts for the relative processing and transportation yields.

Following Kuwait, the UAE installed 8.2 bcm/y and 5.2 bcm/y capacity regasification terminals in 2010 and 2016, respectively. In 2020, Bahrain became the most recent GCC member state to install a regasification terminal. Table 1 presents summary statistics on natural gas in the GCC and illustrates the variations in gas trade within the region.

In 2019, interest in linking the GCC's existing national gas grids with some of its neighbors, such as Iraq, was renewed (Malek, 2019). Furthermore, the strategies of state-owned energy companies shifted toward developing their untapped gas reserves (Shabaneh et al., 2020). A gas pipeline can support the integration of gas prices and expose suppliers to new markets, which may motivate investments in undeveloped resources. However, the COVID-19 pandemic has impacted global gas prices, and the monetization options for LNG export projects in the longer term are now uncertain (Ouki, 2020).

3. International experience in gas trade cooperation

Integrated natural gas markets have been established in other regions, such as Europe and North America. These experiences reveal several benefits from regional cooperation around pipeline trade. However, these regions also had to overcome the regulatory and legal hurdles that are prerequisites for market liberalization. This section provides an overview of gas trade cooperation in Europe and the ASEAN region. Europe offers an example of successful gas grid integration and evolution, whereas ASEAN's attempt failed. Both examples provide insights into the opportunities and challenges that the GCC gas grid may face.

3.1. International trends in gas trading and pricing

The COVID-19 pandemic resulted in a 3.5%–4% reduction in global demand in 2020 relative to that of 2019 (Henderson, 2020). Nevertheless, natural gas remains a key element of the global energy mix, both as an industrial feedstock and as an energy source. Its importance is due to its relatively clean emissions profile, cost competitiveness and increasingly diverse sources of supply, driven by LNG trade growth. The average annual growth in natural gas demand from 2019 to 2025 is

Table 1
GCC natural gas statistics, 2019.

Country	Gas reserves	Gas production	Gas consumption	Net pipeline imports	Net LNG imports	Net imports
Saudi Arabia	6000	113.6	113.6	0	0	0
UAE	5900	62.5	76.0	19.5	−6.1	13.4
Qatar	24,700	178.1	41.1	0	0	−137
Kuwait	1700	18.4	23.5	0	5.1	5.1
Oman	700	36.3	25.0	2.0	−14.1	−11.3
Bahrain	100	16.9	16.9	0	0	0

Note: Units are billion cubic meters (bcm). Negative values denote net exports.
Source: BP Statistical Review 2020.

expected to be approximately 1.5%. By comparison, the International Energy Agency (IEA) projected annual growth of 1.8% prior to the COVID-19 pandemic (IEA, 2020).

As gas consumption resumes growing, its mode of trade is clearly moving toward LNG. Cross-border pipeline gas trade accounted for 22% of total gas trade in 2019, whereas LNG accounted for 11% (Snam, IGU, and BCG, 2019). However, the IEA expects LNG to overtake pipeline gas as the primary mode of international trade before 2030 (IEA, 2019b). In 2018, LNG drove two-thirds of the year-on-year growth in international gas trade (Snam, IGU, and BCG, 2019).

The upsurge of LNG in global gas markets has also significantly impacted gas pricing trends. Between 2005 and 2019, the share of global gas pricing based on gas-on-gas (GOG) competition (i.e., prices linked to global gas hubs or indices) increased from 31.4% to 48.4%. This growth largely came at the expense of oil price escalation (OPE) pricing, or mechanisms that are typically linked to crude oil and oil products. According to the International Gas Union (IGU), OPE pricing declined from 24.3% to 18.5% from 2005 to 2019 (IGU, 2020). The share of LNG spot market procurement has increased (exceeding 30% in 2019), and LNG purchases are increasingly entering traded European gas markets (IGU, 2020).

Benchmark global gas prices fell to multi-year lows in 2020 owing to the COVID-19 pandemic. Henry Hub prices reached $1.9/MMBtu, European gas prices on the Title Transfer Facility reached $1.5/MMBtu and Asian LNG spot prices reached $2/MMBtu (IEA, 2019b). However, prices largely recovered by early 2021. The IEA projects that the long-term marginal cost of LNG is $7.50/MMBtu, with some projects exceeding $10/MMBtu (IEA, 2019b). Thus, the short-term cost dynamics of gas prices in 2020 are not expected to continue. In other words, long-term energy strategies should not necessarily assume that very low-cost LNG imports will remain available.

Countries pursuing domestic gas development or regional pipeline trade rather than exclusively LNG imports are trending toward GOG pricing. However, significant regional heterogeneity is observed (IGU, 2020). In the Middle East, domestic gas pricing is typically regulated according to social and political policies, whereas pipeline gas imports follow a bilateral monopoly arrangement. The region has no precedent for market-based gas price formation. While regional pipeline gas trade is possible and does incur occur in the Middle East, this market structure can face significant startup costs.

3.2. European trends in gas trading

Regional cooperation has become a mainstay of European energy policy. This cooperation supports the five dimensions of the European Union's (EU) energy strategy: security of supply, internal energy market security, energy efficiency, climate policy and research and development (CEEP, 2018). Historically, the European gas industry has relied on long-term contracts to develop gas fields and finance long-distance, cross-border pipelines and transmission and distribution systems (Chyong, 2019). These contracts reduce the risk inherent in large-scale infrastructure investments. However, to promote energy efficiency and market integration and improve end-user service, the EU adopted gas liberalization as one of its reform policies. Specifically, the 1991 Gas Transit Directive introduced a competitive market framework to provide supply security and efficiency (Blyhammar et al., 2018).

The EU gas market was slow to start. However, the First and Second Gas Directives of 1998 and 2003, respectively, and a third energy package in 2009 addressed many regulatory and legal hurdles. For example, they unbundled gas supply companies, allowed third-party access (TPA) to gas infrastructure and instituted tariff regulations to reflect the network's operating costs. Additionally, Europe's pricing regimes have significantly changed since 2005, when OPE dominated its gas pricing structure. The prevalence of GOG pricing increased from 15% in 2005 to 78% in 2019 (IGU, 2020).

Empirical research shows that Europe's integration policies have been successful, with the major gas markets achieving full integration by 2013 (Chyong, 2019). This improved cross-border transmission capacity allowed the EU to handle gas disruptions effectively (Rodriguez-Gomez et al., 2016). TPA to pipelines and underground storage facilities made the system more flexible and diversified the supply sources away from European LNG import terminals. Europe's import capacity for LNG increased from 64.3 bcm to 225.6 bcm between 1999 and 2016. LNG accounted for 50% of total gas consumption in 2016 (Chyong, 2019). Liberalization has been central to removing destination clauses from LNG contracts in Europe. This removal increased the liquidity of spot and futures trading in Europe's major gas hubs and displaced contractual pricing of LNG and pipeline imports.

Despite Europe's progress in liberalizing the gas market, its gas pricing mechanisms are not homogenous across the continent. In Northwest Europe, almost all gas pricing is GOG pricing, with only 5% of gas pricing based on OPE (IGU, 2020). In Central Europe, the prevalence of GOG pricing increased from almost zero in 2005 to 80% in 2019. The Mediterranean region and Southeastern Europe are lagging, as OPE pricing comprises 47% and 41% of pricing, respectively, in these regions.

In contrast to Europe, gas prices in the GCC are still regulated, and third parties have not been granted access to LNG terminals, pipelines and storage. Gas storage infrastructure is limited in the GCC. Only the UAE has any storage capacity volume, whereas Europe has around 140 storage facilities (CEDIGAZ, 2019). Contracts for importing LNG into the GCC are typically short-to medium-term contracts. It is unclear whether these contracts offer any destination flexibility. However, LNG has not been re-exported from the Middle East since the first LNG terminal was installed in Kuwait in 2009.

Europe's experiences can be summarized into three important elements that are essential to efficiently implement cross-border gas trade in the GCC. These elements are unbundling the gas sector, providing fair access to gas infrastructure (including pipelines, storage and LNG terminals) and adopting a market-based pricing mechanism. An integrated gas infrastructure in the GCC can provide an outlet for surplus regional gas. Further market restructuring can support open access to LNG export terminals. Additionally, access to existing regasification terminals via the gas grid can expand import options for GCC members facing gas shortages.

3.3. Southeast Asian trends in gas trading

Gas market integration has not proceeded as smoothly in Asia as it has in Europe. The closest the continent has come to developing a functional gas grid is the Trans-ASEAN Gas Pipeline (TAGP). Like the GCC, ASEAN was founded to promote economic, political and security cooperation among its members. The TAGP was identified as an ASEAN policy priority and is expected to bring significant economic and environmental benefits to the region (IEA, 2015; 2019a). The organization's vision for cooperation also includes the ASEAN Power Grid (APG), which is a key energy infrastructure program (Xunpeng et al., 2019).

In 1997, ASEAN Vision 2020 outlined plans for constructing new gas pipelines and connecting existing ones to turn the TAGP into a regional gas grid (Fünfgeld, 2019; Sovacool, 2009). To expedite the TAGP's development, ASEAN members signed a memorandum of understanding. This document covered financing options, gas transit rights and contract design, network security and environmental protection (Sovacool, 2009). By 2015, 13 cross-border ASEAN gas pipelines had been built, with four more pipeline projects under consideration (Anggraeni, 2019). However, these pipelines have been used for bilateral trade agreements, whereas the initial intention was a multilateral framework.

Many technical, economic, legal, political, social and environmental issues contributed to the stagnation of the TAGP's progress (Anggraeni, 2019; Sovacool, 2009). Such issues are common in multi-stakeholder energy megaprojects (Van de Graaf and Sovacool, 2014). The TAGP has also faced declining regional gas output (ACE, 2017), which was not anticipated when the project was first considered. For example, Indonesia's East Natuna gas field is the largest unexploited gas field in Asia and a key source of natural gas for the TAGP. However, it contains more than 70% carbon dioxide, which makes its development very expensive and technically challenging (IEA, 2015). Consequently, the economics of developing domestic ASEAN gas resources became concerning, and ASEAN shifted its focus to LNG imports (Fünfgeld, 2019).

ASEAN LNG imports are expected to increase more than fivefold from 2018 to 2030, with Vietnam and the Philippines becoming new importers (IEA, 2020; Kumar and Stern, 2020). The Asia-Pacific Economic Cooperation (APEC) projects that Malaysia will start importing LNG in the 2040s (APEC, 2019). In October 2019, ASEAN had a total LNG import capacity of 36 million tonnes per annum (mtpa), with infrastructure for 75 mtpa of additional capacity under development (Ooi, 2019). With these developments, the key value driver of the TAGP has shifted away from domestically produced gas toward the trade of imported LNG (Xunpeng et al., 2019). One of the original motivations for the TAGP was access to natural gas to meet the rapidly growing demand for power. With increased LNG imports, however, the focus of ASEAN energy infrastructure has shifted to regional power trade via the APG.

The TAGP experience shows that the inherent complexity of multilateral gas pipeline projects can impede or halt progress. Like ASEAN, the GCC sought LNG imports to address regional shortages and continues to encourage its members to trade electricity via the regional power interconnector. Unlike ASEAN, however, the GCC has rapidly developed its domestic gas infrastructure to utilize its economically viable gas reserves. Nevertheless, regional policy reforms are needed to establish significant cross-border trade, particularly for power and industry. With such reforms, the region can collectively benefit from increased gas production. Because of contextual differences, a GCC gas pipeline may provide more value to GCC member countries than the TAGP has provided to ASEAN. However, quantifying this value is important to help balance the potential benefits with the significant costs of developing a GCC gas grid.

4. The KEM GCC gas trade model

In this section, we present a regional integrated energy model. The model includes oil and gas production and the transportation, power and water sectors as major gas (and oil) consumers in the GCC. This model can measure the economic benefits from expanding the GCC's cross-border gas pipeline grid in different market reform scenarios.

4.1. Model overview

We build upon the existing KEM GCC (Wogan et al., 2019). The model was previously used to analyze the benefits of electricity trade coordination via the regional power grid operated by the GCC Interconnector Authority (GCCIA). We expand the model by introducing a modified fuel supply optimization module that minimizes fixed and variable costs and maximizes export revenues. We do not model endogenous investment in new fuel production capacity. However, we do incorporate investments in gas trade infrastructure, including cross-border pipelines and liquefaction and regasification facilities. Investments in maritime tankers are not included; instead, we consider them available for charter at a long-term marginal cost. Infrastructure configuration and investment costs are described in the calibration section (see Table 3).

The standard approach for modeling gas infrastructure development is bottom-up optimization (Egging and Gabriel, 2006; Feijoo et al., 2016; Gabriel et al., 2005; Holz et al., 2008). The World Gas Model developed by Nexant Inc. provides an optimization framework for simulating global supply and trade of LNG. This model has been used to analyze gas market failures in East Asia (Xunpeng and Variam, 2017). It has also been applied to measuring the effects of uncertainties in China's gas market on global LNG trade (Xunpeng et al., 2017). Xunpeng, Variam, and Shen (2019) consider the evolution of ASEAN gas markets using a global framework. They capture international trade dynamics and the restructuring of LNG imports to assess the potential benefits of liberalization within the ASEAN natural gas market.

Our approach differs from those of these previous studies in a few ways. First, unlike Xunpeng et al. (2019), we do not model global gas trade. The GCC contains sufficient gas to satisfy regional demand without relying on international suppliers. LNG market dynamics do impact the economics of the region owing to its role as a global supplier. However, we focus on the economic value of the regional GCC gas trade and disregard the destinations of exports outside of the GCC. Although we do not model global gas trade dynamics directly, we do conduct a model sensitivity analysis with respect to international LNG prices.

Second, many previous studies assume that demand for gas is fixed. Meanwhile, we take a bottom-up approach, incorporating the GCC power and water supply industries as independent modules that comprise most of the regional fuel demand. On a temporal scale, we characterize gas demand and infrastructure constraints across three seasons: summer, fall/spring and winter. These seasons are derived from the representation of power demand, which is also broken down into hourly load blocks. We treat gas demand from all other industrial end users as fixed.

Natural gas optimization models often include gas storage activities (e.g., Egging and Gabriel, 2006; Feijoo et al., 2016). Matar and Shabaneh (2019) investigate the role of natural gas storage in Saudi Arabia. Our model, however, excludes the development of storage facilities, as our primary focus is the development of a regional gas grid. Modeling the benefits of storage would require a more detailed representation of regional supply and demand than is used in this analysis.

To date, the region has only one gas storage facility, which is located in the UAE (CEDIGAZ, 2019). Another facility is under development in Saudi Arabia (Sertin, 2020). Increased gas grid connectivity may encourage GCC producers to send surplus gas to storage hubs during low demand periods (e.g., winter). This gas could then be used during the peak summer season. However, demand in the GCC region is countercyclical to that in the international LNG market. Demand in the Northern Hemisphere peaks during the cold winter months. Thus, storage may compete with LNG export opportunities.

Appendix A.1 provides a complete mathematical description of the

Table 2
Natural gas production, consumption, imports, exports and pricing in the *2018 Calibration* scenario.

Natural Gas (QBtu)	BAH	KSA	KUW	OMN	QAT	UAE	GCC
Production	**0.545**	**3.350**	**0.651**	**1.445**	**6.143**	**2.196**	**14.330**
Consumption	**0.542**	**3.327**	**0.798**	**0.908**	**1.259**	**2.493**	**9.328**
Power and Water	0.238	2.226	0.415	0.300	0.391	1.568	5.139
Other	0.304	1.101	0.383	0.608	0.868	0.925	4.189
Imports		**0.010**	**0.154**	**0.070**		**0.673**	**0.907**
Pipe				0.070		0.638	0.708
Tanker (LNG)		0.010	0.154			0.035	0.199
Exports				**0.532**	**4.432**	**0.331**	**5.295**
Pipe					0.648	0.071	0.719
Tanker (LNG)				0.532	3.784	0.260	4.576
Administered prices[a] ($/MMBtu)	3.25	1.25	3.9	3.28	1	2.42	–

[a] The prices for some countries are estimates of the internal prices applied to end users.
Sources: Facts Global Energy, KAPSARC Analysis.

Table 3
Capital (capex) and operating (opex) expenditures of natural gas pipeline and LNG activities.

Type	Units	Capex[a]	Opex[b]	Losses	Lifetime (years)
Pipeline (onshore)	$/km/MMBtu/year	0.005	0.00001	0.003 (%/km)	35
Pipeline (offshore)	$/km/MMBtu/year	0.01	0.00001	0.003 (%/km)	35
LNG tanker	$/km/MMBtu/year	–	0.00011	0.00015 (%/km)	–
Floating liquefaction plant	$/MMBtu/year	16.4	0.65	10%	20
Regasification plant	$/MMBtu/year	2.7	0.5	2%	20

Sources: Pipeline capital expenditure (capex) cost—World Bank (2013) (see Appendix B.2). LNG tanker operating expenditure (opex) costs—Timera Energy (2018). Capex and opex of liquefaction and regasification facilities—Songhurst (2019). Processing losses—Tavares et al. (2018).

extended KEM GCC fuel supply module. We use the model in a static single-year framework, but it is also designed for use in dynamic multi-year analyses.

4.2. Natural gas pricing

An optimization model for gas trade planning with endogenous demand reflects a regional market under perfect competition with fuel priced at its marginal value. However, end users of gas in the GCC are subject to administered fuel prices. As we discussed, administered fuel prices can complicate trade coordination.

The KEM is constructed as a partial equilibrium model that can directly capture these regulated prices. Each gas-consuming sector and country in the GCC is modeled as an independent optimization agent. The model is solved simultaneously as a single mixed complementarity problem (MCP). Murphy, Pierru, and Smeers (2019) discuss the types of price controls that can be modeled using an MCP and measure their economic impacts. Several studies investigate these impacts in real markets. These studies focus on administered fuel prices in Saudi Arabia's energy-intensive industrial sectors (Matar et al. 2015, 2017), price caps in China's power sector (Rioux et al., 2017) and the natural gas supply chain (Rioux et al., 2019).

We use the model to simulate the influences of different fuel price reform strategies on fuel demand and trade over the GCC gas grid. We also revisit the analysis conducted by Wogan et al. (2019) of the limiting or enabling effects of such reforms on the economic benefits of utilizing the GCC power grid. We apply the same constraints as they do to restrict the benefits of administered fuel prices within national power sectors. These constraints prevent fuel subsidy leakages through power trade, as discussed in section 2.

4.3. Model calibration

The fuel supply, power and water sectors are calibrated to 2018 data (our reference year) for the six GCC countries: the Kingdom of Saudi Arabia (KSA), the UAE and the Kingdoms of Bahrain (BAH), Kuwait (KUW), Oman (OMN) and Qatar (QAT).

Table 2 reports total natural gas production, consumption (power and water and other industries), imports and exports (by pipeline or tanker). We report these quantities in units of quadrillion British thermal units (QBtu) for each country. We use these values to construct our reference *2018 Calibration* scenario. The efficiencies of the power and water sectors, total power demand and demand from other industries are the primary factors used to calibrate the model. When the administered prices are applied, fuel allocation quotas are enforced because the prices do not reflect scarcity. The administered prices paid in 2018 for natural gas quotas supplied to the power and water sectors are listed at the bottom of Table 2. Appendix B lists the quotas and prices for other fuels (Table B10).

Table 3 lists the fixed capital (capex) and variable operating (opex) expenditures of the natural gas transportation and processing infrastructure. We use the expected facility lifetimes to calculate the annualized capital cost of infrastructure investments and assume a 6% interest rate. Matar et al. (2015) apply the same interest rate to Saudi Arabia's investments in oil and gas infrastructure projects.

Appendix B describes the regional gas grid development configuration and the power transmission, liquefaction and regasification capacities and costs. The gas grid includes the existing Dolphin pipeline connecting Qatar, the UAE and Oman. It also includes the master gas systems of Saudi Arabia and the UAE, both of which are split into four administrative regions. We use calibration data for the KEM power and water sector modules that were originally presented by KAPSARC (2015).

We set international prices for LNG and crude oil to $10/MMBtu (Drahos, 2019) and $71/barrel (Statista, 2020), respectively. We conduct sensitivity analyses in the counterfactual scenarios described in the next section by reducing the opportunity cost of fuel exports. Fuel exporters may assign different values to the opportunity cost of domestic demand depending on different factors. These factors include the volatility of oil prices and the world oil market's response to a change in oil supply, among others. For example, Karanfil and Pierru (2020) suggest that the opportunity cost of domestic demand can range from $15 to $59 per barrel. This range applies to projects with long-term impacts on domestic demand for liquids (e.g., increasing access to natural gas). We also conduct sensitivity analyses for regional LNG export prices. We draw on recent trends in natural gas markets, which followed declining international oil prices. In 2018, LNG spot prices fell below $6/MMBtu

(Froley, 2019) and stayed below $5/MMBtu during the COVID-19 pandemic.

5. Results: GCC gas trade scenarios

We compare different counterfactual scenarios to a reference calibration scenario that reflects the regional gas trade in 2018. These scenarios are called *Existing Tech*, *Current Policies*, *Liberalized* and *Liberalized Price Cap*. We summarize the scenarios in Table 4.

In each counterfactual scenario, gas suppliers can invest in new cross-border pipelines and liquefaction, regasification and LNG transportation infrastructure. We hold the oil and gas production capacities, the total demand for power and water and other exogenous industrial gas demand constant. Gas-consuming sectors can also procure fuel at liberalized prices above their quotas by, for example, importing from neighboring countries at competitive prices. Power producers can also sell electricity from conventional thermal generation across the existing GCC power interconnector without fuel subsidy leakages, as in Wogan et al. (2019).

Our first counterfactual, the *Existing Tech* scenario, investigates the expansion of the GCC gas grid to increase the utilization of gas. No new investments in power and water generation or transmission are made; only existing capacity is used (Tables B7 and B.8). However, generating units can be reconfigured to burn gas instead of oil or refined products to satisfy power and water demand, which are fixed at their 2018 values. Existing Dolphin pipeline contracts are honored and quotas for crude oil and its products at administered prices are removed to prioritize gas for domestic use.

Next, we run counterfactual scenarios investigating the impacts of investments in the power and water sectors, including transmission capacity investments (GCC interconnector), on pipeline trade. We start by maintaining current 2018 administered fuel prices and quotas for oil and gas (*Current Policies*). Then, we fully lift the quotas in two liberalized market scenarios to investigate the longer-term impacts of price reforms on the fuel demand infrastructure.

First, in the *Liberalized* scenario, we set oil and gas prices equal to their marginal supply values (e.g., netback of export prices). Second, the *Liberalized Price Cap* scenario integrates gas prices relative to a reference price cap of $4/MMBtu, which is set in a regional gas hub. This scenario offers a more modest price reform strategy for gas consumers, as discussed in section 5.2. Appendix A.3 explains how the price cap can be represented in our integrated MCP using complementary slackness.

Table 5 provides an overview of the results from the four counterfactual scenarios described above. We present the annual economic gain for all GCC countries and changes in oil and LNG exports for specific countries. We define the economic gain as the difference in each scenario's objective value (collectively for the fuel supply, power and water sectors) relative to the *2018 Calibration* scenario. In the following subsections, we take a closer look at each scenario. We also consider each scenario with and without cross-border pipeline investments in the GCC to measure the added economic value of this infrastructure. The natural gas supply and demand balances in each scenario are provided in Appendix B (Table C1).

Table 4
Descriptions of the model scenarios.

Scenario	Power and water sector investments	Fuel price reform
Calibration	No	no
Existing Tech	No	Fuel quotas under administered prices are removed, and the power and water sectors optimize their fuel mixes using existing technology.
Current Policies	Yes	Current administered fuel prices are applied, but power and water producers can purchase fuel above their quotas at liberalized prices.
Liberalized	Yes	Prices are fully liberalized.
Liberalized Price Cap	Yes	Reformed prices are capped at $4/MMBtu in a regional gas hub, selected as Qatar.

Table 5 shows that the *Existing Tech* scenarios produce the lowest economic gains ($4.1 billion). In this scenario, inefficient generation units are not updated. Gains are primarily driven by a reduction in the demand for crude oil for power generation. This reduced demand causes exports to grow by more than 1.0 million barrels of oil per day (MMb/d), primarily in Saudi Arabia. [1] Overall, Qatar's LNG exports decrease with the growth in pipeline trade across the GCC. The economic gains are greater in the scenarios with power and water sector investments. These gains are highest in the *Liberalized* scenario, as reformed fuel prices increase efficiency and investments in renewables. In the *Liberalized Price Cap* scenario, which has competitive gas prices, an increase in GCC pipeline imports offsets LNG exports, reducing the total economic gains.

5.1. GCC gas trade: existing technologies

The *Existing Tech* scenario provides an estimate of the value of increasing regional gas demand through GCC pipeline trade using the existing power and water generation capacity. However, Qatar's LNG exports decline considerably in this scenario. (Table 5). Thus, it is worth considering the impacts of alternative LNG trade strategies by GCC members on the economic gains from gas grid development. For example, in the ASEAN market, LNG import facilities have been developed to achieve energy security. These facilities can substitute for new regional gas production, influencing the use of the regional gas grid. Although LNG transport is generally more expensive than pipeline gas deliveries are (across distances within the GCC), LNG offers greater flexibility. Imports of LNG are likely to continue supporting the gas supplies in countries with production shortages.

To reflect this reality, we run the alternative *Existing Tech Qatar LNG* scenario. In this scenario, Qatar secures a contract supplying a minimum of 3 mtpa (0.15 QBtu) of LNG to Kuwait based on recently announced agreements (Hagagy, 2020). Qatar also chooses to prioritize regional demand for its LNG liquefaction facilities rather than building new cross-border pipelines.

Table 6 lists the economic gains and the changes in the power and water sectors' demand for gas observed in the *Existing Tech* scenarios. To disaggregate the impacts of pipeline investments, we also calculate the annual economic gains with respect to the same counterfactual scenarios without pipeline investments. The table also includes changes in total capex for cross-border pipelines and LNG infrastructure and LNG exports.

Of the *Existing Tech* scenario gains, $3.13 billion are only achieved when the GCC gas grid is expanded. This expansion helps to optimize regional gas supply costs under higher demand (1.5 Qbtu or 29%). Without an expanded gas grid, the higher cost of importing LNG in areas experiencing shortages offsets the economic gains from freeing oil for export.[2] Developing the gas grid not only reduces gas transport costs but also increases the demand for gas by 0.75 QBtu by improving accessibility. This increased demand frees approximately 0.6 MMb/d of the total 1.0 MMB/d of crude oil for export (Table 5). Appendix C provides a more detailed breakdown and discussion of the gains achieved by each sector and country in each scenario (see Fig. C.2).

Compared to the *Existing Tech* scenario, the *Qatar LNG* scenario offers lower economic gains relative to the *2018 Calibration* ($2.91 billion). However, even with Qatar prioritizing LNG trade, cross-border pipeline investments provide $1.65 billion in annual gains.

[1] We do not explicitly model refining activities; thus, we do not account for potential export revenues from a reduction in the domestic consumption of refined products.

[2] The LNG tanker trade reaches 1.1 QBtu (22.3 MTPA) without pipeline investments.

Table 5
Scenario results relative to the 2018 *Calibration* scenario.

Economic gains, Billion $		Change in oil exports, MMb/d		Change in LNG exports, QBtu				
Scenario Region	GCC	KSA	KUW	BAH	KSA	OMN	QAT	UAE
Existing Tech	4.1	1.02	0.02	0	0	0.07	−1.69	0.06
Current Policies	9.1	0.27	0.02	0	0	0.03	0.03	0.01
Liberalized	18.1	1.14	0.02	0.09	0.14	0.03	0.60	0.15
Liberalized Price Cap	14.2	1.14	0.02	0	0	−0.10	−0.33	−0.26

Table 6
Comparison of the *Existing tech and the Existing Tech Qatar LNG* scenario.

Billion $ Scenario	Relative to the 2018 Calibration scenario		Relative to the same counterfactual scenario without pipeline investments				
	Economic gains	Gas demand QBtu[a] (%)	Economic gains	Pipeline capex	LNG capex	Gas demand QBtu (%)	LNG exports QBtu (%)
Existing Tech	4.10	1.50 (29%)	3.13	1.90	−1.71	0.75 (13%)	−1.45 (−32%)
Existing Tech Qatar LNG	2.91	1.26 (25%)	1.65	0.99	−4.94	0.51 (8%)	−0.45 (−10%)

Notes: The annual economic gains and the change in total pipeline and LNG capex are measured in billion $. The change in the power and water sectors' demand for gas and LNG exports are measured in QBtu. a) Total demand in 2018 (*Calibration*) was 9.63 QBtu, with 5.15 QBtu used by the power and water sectors.

Fig. 1 depicts the cross-border pipeline and LNG tanker trade for the *Calibration*, *Existing Tech* and *Existing Tech Qatar LNG* scenarios. In the *Existing Tech* scenario, Qatar covers the growth in gas demand via a trunk line to Saudi Arabia (1.7 QBtu) and Kuwait (0.54 QBtu). This supply offsets LNG shipments in the *Calibration* scenario.[3] Overall, LNG trade, including with international buyers, declines by 32% in this scenario.

In the *Qatar LNG* scenario, Kuwait imports 0.47 QBtu of LNG. This amount is equivalent to 9.5 mtpa and is more than three times the reported contract with Qatar. Although Qatar does not build a new pipeline, Saudi Arabia and, to a lesser extent, Kuwait still import gas. These imports are provided via new pipelines connected to the UAE and the existing Dolphin pipeline with Qatar. Bahrain also builds a pipeline to Saudi Arabia to provide LNG imported through existing regasification facilities. New regasification facilities may still need to be built in the future. However, this result illustrates that pipelines can support sharing and the greater utilization of existing LNG facilities.[4]

In total, $1.9 billion is spent to develop new cross-border pipelines in the *Existing Tech* scenario ($1 billion in the *Existing Tech Qatar LNG* scenario). This amount is around 2.4% of the estimated discounted capital development cost of all non-associated gas projects in the GCC over the next 30 years. According to UCube, these projects have an estimated total value of $79.5 billion (Rystad, 2019).

The economic gains in Table 6 may be sensitive to the fuel export prices of oil ($72/bbl) and gas ($10/MMBtu), which are assigned exogenously. We therefore run a sensitivity analysis on the opportunity cost of domestic fuel demand. Specifically, we discount oil and gas export prices by 50% to $36/barrel and $5/MMBtu, respectively. We find that the devaluation of lost LNG export revenues (from increased domestic gas demand) offsets the lower opportunity cost of additional GCC oil exports. In fact, the economic gain from pipeline investments increases slightly to $3.27 billion. This outcome does depend on the relative opportunity costs of oil and gas. Assuming that oil is at a premium, a gas grid provides significant annual gains through the increase in regional gas demand.

[3] Qatar and Oman were the major exporters of LNG to Kuwait in 2018. Kuwait also imported LNG from outside the GCC. However, we make the simplifying assumption that Kuwait's LNG is supplied from within the GCC.

[4] The storage component of Bahrain's regasification unit is on a floating barge. However, the regasification unit is fixed on land and cannot be relocated to places with greater demand (i.e., KSA).

5.2. GCC gas trade: power and water sector investments

In the next set of scenarios, the power and water sectors are able to invest in new technologies under different fuel pricing policies. Fig. C1 in Appendix C describes the investments that they make. The economic gains, demand for gas, capital expenditures and gas exports in each scenario are listed in Table 7.

Under the *Current Policies* scenario, the power and water sectors continue to buy crude oil and liquids at administered prices. They largely do not substitute oil with gas. Given the lower overall demand for gas relative to the *Existing Tech* scenario, pipeline investments fall to $0.18 billion. The gains in this scenario are only $0.54 billion. Most of these gains result from replacing Kuwait's expensive LNG imports with cheaper pipeline imports from Saudi Arabia. Qatar continues to sell gas to the UAE and Oman.

Finally, we explore the gas grid's role in the transition to a liberalized fuel market. These scenarios consider the longer-term impacts of price reforms and industrial restructuring on the gas trade based on 2018 power and water demand. Both the power and water sectors purchase gas (and liquid fuels) at a nominal price determined by regional supply networks (i.e., pipelines and LNG). Thus, consumers are exposed to the opportunity cost of oil and gas exports. Table 8 compares fuel prices under the *Current Policies and Liberalized* scenarios. In the *Liberalized* scenario, gas prices are more than double the administered 2018 levels in many GCC countries. This result reflects the netback of LNG export prices minus liquefaction and transportation costs.

Under these price reforms, conventional thermal power and water generation are less competitive. Gas demand declines by 1.22 QBtu, or 24% relative to the *2018 Calibration* scenario (Table 7). In this scenario, 68 GW of solar photovoltaic (PV) power and 15 GW of wind power are developed. Energy-efficient reverse osmosis water desalination is also operating (Figure C1). This scenario achieves the highest overall economic gains ($18.7 billion). However, the reduced demand for gas limits the additional economic gains from pipeline investments to $0.13 billion. The expansion of the gas grid partially offsets additional the LNG capex for exporting the unused gas ($2.4 billion).

The *Liberalized Price Cap* scenario addresses the impact of higher gas prices on the near-term competitiveness of end users. In brief, regionally integrated prices are discounted. This discount reflects the difference between the opportunity cost of gas (netback of LNG export prices) and a price cap set in a regional hub. As the region's major LNG exporter, Qatar is chosen as the gas hub. We set a cap of $4/MMBtu as the long-term marginal production cost for the region, following Matar and Shabaneh (2019). This price is close to the highest administered gas prices in the GCC (see Kuwait in Table 8).

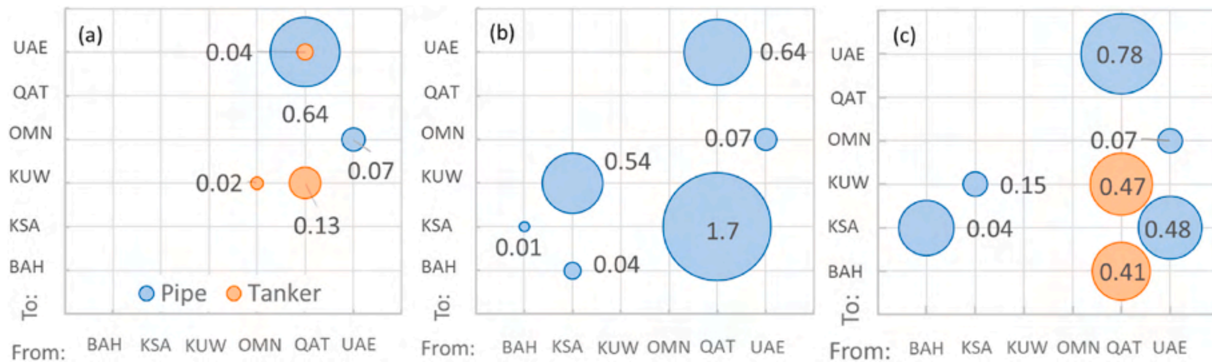

Fig. 1. Pipeline and tanker shipments in different scenarios.
(a) *2018 Calibration*, (b) *Existing Tech* and (c) *Existing Tech Qatar LNG(c)* scenarios. All numbers are in units of QBtu. Source countries are on the horizontal axes and destination countries are on the vertical axes.

Table 7
Results for the *Current Policies and Liberalized* scenarios.

Billion $ Scenario	Relative to 2018 Calibration		Relative to counterfactual scenario without pipeline investments				
	Economic gains	Gas demand QBtu[a] (%)	Economic gains	Pipeline capex	LNG capex	Gas demand QBtu (%)	LNG exports QBtu (%)
Current Policies	9.10	−0.75 (−15%)	0.54	0.18	0	−0.03 (−0.6%)	−0.11 (−2%)
Liberalized	18.73	−1.22 (−24%)	0.13	0.17	−2.41	0.16 (4.3%)	−0.15 (−2.6%)
Liberalized Price Cap	14.24	0.64 (12%)	1.06	1.05	0	0.21 (3.7%)	−0.40 (−9.3%)

Economic gains and the changes in total pipeline and LNG capex are in units of billion dollars. The changes in gas demand (power and water) and LNG exports are in units of QBtu.

Table 8
Average industrial natural gas prices for each GCC country in $/MMBtu.

Scenario	BAH	KSA	KUW	OMN	QAT	UAE	Average[a]
Current policies	3.28	1.25	3.90	3.28	1.00	2.42	2.08
Liberalized	7.60	7.82	7.75	7.60	7.60	7.71	7.72
Liberalized price cap	4.08	4.43	4.33	4.00	4.00	4.1	4.23

[a] Average weighted by consumption.
Source: KAPSARC analysis.

The *Liberalized Price Cap* scenario generates the second-highest overall economic gains ($14.2 billion). Demand for gas increases by 12% relative to the *2018 Calibration* via the substitution of liquid fuel for power generation. In these scenarios, the gas grid provides $1.1 billion in annual gains (Table 7) by reducing energy transportation costs.

Another way to construct a liberalized scenario with lower fuel prices is to reduce the opportunity cost of fuel, as in the previous sensitivity analysis. Reducing this opportunity cost increases the additional economic gains provided by gas grid expansion to $1.7 billion in both scenarios with liberalized prices. When LNG exports have a lower value, GCC members increase their regional gas consumption and trade.

Our analysis illustrates that the value of expanding the GCC gas grid is sensitive to several factors. These factors include domestic and international fuel pricing, the impact of prices on regional gas demand and the opportunity cost of exports. If GCC members can individually achieve gas self-sufficiency through production expansion, technology improvements or prioritizing liquid fuel consumption, the grid may deliver less value.

Conversely, new opportunities may emerge. Industrial demand growth, further substitution of liquid fuels, strategic infrastructure developments (e.g., LNG processing hubs) and trade with neighboring GCC countries may provide opportunities. Our scenarios provide policymakers with a benchmark for the potential added value of cross-border gas pipeline investments. Future economic benefits, trade patterns and infrastructure options can also be considered using dynamic forward-looking analyses based on regional supply and demand projections.

5.3. Power sector integration

This final analysis investigates the interplay between gas grid integration and the GCC electricity interconnector. In the *Liberalized Price Cap* scenario, regions with gas shortages face prices exceeding $6/MMBtu without the expansion of the regional gas grid. These prices arise because of premiums on LNG imports. However, instead of buying additional LNG, these countries can import power generated by their neighbors with gas surpluses at a lower cost. When investments in power generation and transmission are possible, GCC members can use lower cost power instead of LNG.

This opportunity involves a significant expansion of the regional power interconnector and regional generation capacity for export. In this situation, the GCC electricity trade reaches 101 TW h (TWh), whereas it is only 34 TWh when a gas grid is in place. Pipelines are clearly the lowest cost option for large cross-border energy flows. In the previous sections we show that optimizing pipeline infrastructure investments for efficient localized electricity production provides $1 billion in economic value. [5] Fig. 2 shows the power trade in the *Current Policies* and *Liberalized* scenarios.

In an economically efficient system, the power grid should still provide marginal economic benefits when energy trade volumes are smaller. Such volumes may include the electricity trade during peak demand periods or other supply shortages. Power maybe provided to a country with a shortage using the available efficient capacity in a neighboring country. The challenge facing the GCC power trade is that discrepancies in administered fuel prices across the region can significantly distort or obstruct the potential benefits. Wogan, Murphy, and Pierru (2019) identify fuel subsidy leakages as a major trade barrier.

[5] The incremental gains provided by GCC gas pipeline investments are lower (compared to $3.1 billion in the *Existing Tech* scenario) when power sector investments are included. One reason is that pipelines substitute for power instead of the more expensive LNG trade. If the GCC interconnector is not expanded, the gains from pipeline investments in the *Liberalized Price Cap* scenario are $1.6 billion.

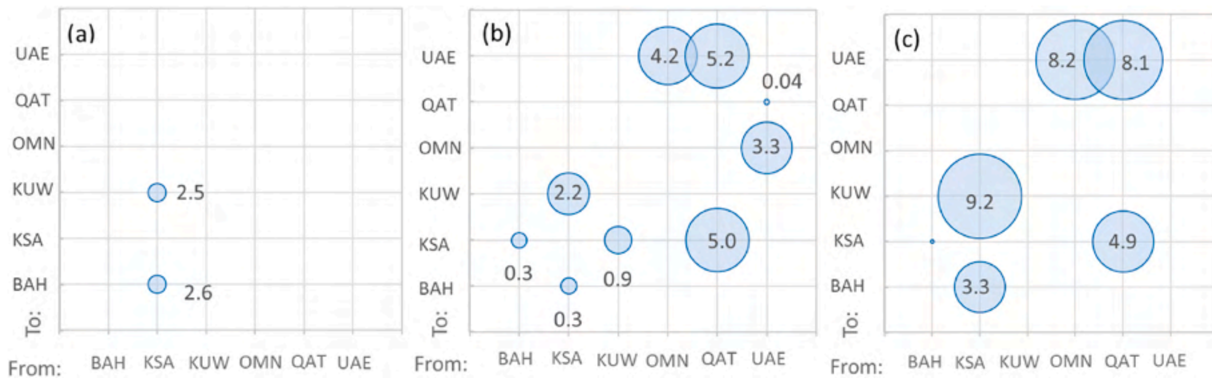

Fig. 2. Regional power trade (all seasons) in different scenarios. (a) *Current Policies*, (b) *Liberalized* and (c) *Liberalized Price Cap* scenarios. Numbers are in units of TWh. Source countries are on the horizontal axes and destination countries are on the vertical axes.

Combining a regional gas grid with competitive end-user prices (as in the *Liberalized Price Cap* scenario) can help to resolve the fuel subsidy leakage barrier in the *Current Policies* scenario. Power trade between GCC countries significantly increases as a result. Only 5 TWh are traded in the *Current Policies* scenario. In contrast, 21 and 34 TWh are traded in the *Liberalized* and *Liberalized Price Cap* scenarios, respectively.

6. Conclusion and policy implications

This study investigates the value that developing a gas grid can bring to the GCC region. We quantify the value of a trans-GCC gas grid under different regional policy assumptions and price reform strategies based on 2018 conditions. The economic gains from the cross-border gas pipeline trade have two key drivers. First, the region can reduce costs associated with energy transportation. It can shift to pipelines rather than using more expensive LNG shipments or expanding the cross-border power trade, which is capital-intensive. Second, the region can substitute oil for gas in domestic use, increasing oil export revenues. Countries can avoid the high opportunity cost of domestic oil consumption for power generation. We find the that natural gas pipeline infrastructure can foster and sustain regional energy trade and cooperation and provide further economic benefits.

In our *Existing Tech* (for power and water production) scenario, gas is prioritized for domestic production by the existing power and water facilities. The GCC gas grid must be expanded to achieve a majority ($3.1 billion) of the $4.1 billion in economic gains. The grid can reduce transportation costs and increase the accessibility of gas to free additional oil for export.

If investments in new power and water facilities are made, a continuation of current pricing policies limits the substitution of liquid fuels. Thus, the overall value of expanding the gas grid is significantly lower. In a restructured market with liberalized gas pricing (i.e., the *Liberalized Price* Cap scenario), expanding the GCC gas grid provides $1.1 billion in gains. The total economic gains in this scenario are $14.2 billion. The incremental gains provided by pipeline investment are higher in the *Existing Tech* scenario because total gas demand is higher. Thus, the gas grid is larger and provides additional economic benefits. Power and water demand are fixed in the model. However, the longer-term economic value of a gas pipeline grid should be increasing with the demand for gas from these and other industrial sectors.

Past experience suggests that non-commercial factors, such as geopolitics and the pursuit of national interests, will play a significant role in developing the GCC gas trade. For example, a scenario in which Qatar prioritizes LNG trade reduces but does not eliminate the value generated by the gas grid. The value offered by the gas grid also varies significantly if the gas supply and demand balance changes (e.g., if the gas demand is restructured). In the *Current Policies* scenario, incentives for the power and water sectors to consume liquid fuel and lower gas demand reduce the grid's value to $0.5 billion.

In the two scenarios with liberalized prices, the integration of regional fuel prices also helps eliminate barriers (i.e., fuel subsidy leakages) to the electricity trade. The lack of barriers encourages greater use of the existing GCC power grid. Wogan, Murphy, and Pierru (2019) expect annual gains of up to $1 billion from increased utilization of the GCC electricity interconnector.

These gains are not unique to the region. The IEA highlights the power trade as a policy priority for the ASEAN market even as regional interest in the gas trade wanes. However, other countries' and regions' experiences show that realizing these benefits requires deep market reforms. Moreover, experiences vary across regions. Gas market liberalization helped Europe to achieve an integrated gas network. However, the ASEAN market is still far from realizing the potential of the proposed TAGP network. The growth in the availability and flexibility of LNG from the international market is an important factor in both Europe and the ASEAN region. However, the evolution of Europe's regulatory and market structure facilitated efficient gas use and trade via the pipeline network.

In summary, this study demonstrates the economic potential of an integrated GCC gas market. We consider the value of natural gas for current domestic industrial use and that of avoiding the opportunity cost of burning liquid fuels for electricity. However, we do not consider fuel switching by other industrial sectors or energy transition opportunities. Such opportunities may include LNG bunkering for clean maritime transport or blue hydrogen (i.e., natural gas reforming with carbon capture) for global export. Changes in supply and demand will also impact the gas trade. As the GCC continues to cultivate its natural gas resource base, these opportunities may prove valuable. The short-term development of a GCC gas grid may create an important regional asset in the years ahead. This study contributes regional policymakers with new insights into the possible economic value of a gas grid.

CRediT authorship contribution statement

Bertrand Rioux: Conceptualization, Methodology, Formal analysis, Resources, Data curation, Writing – original draft, Writing – review & editing, Visualization. **Rami Shabaneh:** Conceptualization, Data curation, Writing – original draft, Writing – review & editing, Resources. **Steven Griffiths:** Conceptualization, Writing – original draft, Writing – review & editing, Resources.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2021.112449.

Appendix

A. KEM GCC gas trade module

Table A.1
Model components.

Indices	
a	Gas production asset
c, cc	Country
f	Fuel: *crude oil*, *natural gas* (CH_4)
r, rr	Region within a country
s	Season
Variables	
z	Objective value
$d_{f,r,s}$	Fuel demand by the power and water industries.
$e_{f,r,s}$	Fuel exports in season s
f_r^{liq}, f_r^{reg}	Building activity for daily liquefaction and regasification capacities
$q_{a,r,s}$	Fuel production in season s
$l_{f,r,s}^{in}, l_{f,r,s}^{out}$	Tanker shipment loading/unloading (e.g., liquefaction/regasification) of fuel
$t_{f,r,rr,s}^{pipe}, t_{f,r,rr,s}^{tank}$	Pipeline and tanker transport of fuel f in season s
$u_{f,r,rr,s}$	Pipeline building activity
Coefficients	
$C_{a,f,r}$	Marginal production cost of fuel f from asset s in region r
$Q_{a,f,r}$	Existing daily production capacity of fuel f from asset a
F_r^{liq}, F_r^{reg}	Existing daily liquefaction and regasification capacities
K^{liq}, K^{reg}	Liquefaction and regasification capex
$K_{f,r,rr}^{pipe}$	Pipeline capex
N_s	Number of days in season s
O_f^{in}, O_f^{out}	Marginal cost of tanker loading/unloading (e.g., liquefaction/regasification)
$O_{f,r,rr}^{pipe}, O_{f,r,rr}^{tank}$	Marginal pipeline and tanker transport cost for fuel f from region r to region rr
$P_{f,s}$	International fuel price (seasonal)
$U_{f,r,rr}$	Existing daily pipeline capacity for fuel f from region r to region rr
$Y_{f,r,rr}^{pipe}, Y_{f,r,rr}^{tank}$	Pipeline and tanker transportation yields
Y_f^{in}, Y_f^{out}	Tanker shipment yield for loading/unloading (e.g., liquefaction/regasification)

A.1. Fuel supplier's optimization problem

$$\max z = \sum_{f,r,s} e_{f,r,s} P_{f,s} - \sum_{a,f,r,s} \left(q_{a,f,r,s}\ C_{a,f,r,s}\right) - \sum_{f,r,rr.s} \left(t_{f,r,rr,s}^{pipe} O_{f,r,rr}^{pipe} + t_{f,r,rr,s}^{tank} O_{f,r,rr}^{tanker} + u_{f,r,rr,s}\ K_{f,r,rr}^{pipe}\right) - \sum_{r} \left(\sum_{f,s} \left(l_{fr,s}^{in} O_f^{in} + l_{fr,s}^{out} O_f^{out} \right) + f_r^{liq} K^{liq} + f_r^{reg} K^{reg} \right) \tag{A1}$$

Subject to

$$Q_{a,f,r} - q_{a,r,s} \big/ N_s \geq 0 \quad \perp \alpha_{a,f,r,s} \geq 0 \tag{A1.1}$$

$$F_r^{liq} + f_r^{liq} - \sum_{f=CH_4} l_{f,r,s}^{in} \Big/ N_s \geq 0 \quad \perp \rho_{r,s}^{liq} \geq 0 \tag{A1.2}$$

$$F_r^{reg} + f_r^{reg} - \sum_{f=CH_4} l_{f,r,s}^{out} \Big/ N_s \geq 0 \quad \perp \rho_{r,s}^{reg} \geq 0 \tag{A1.3}$$

$$U_{f,r,rr} + u_{f,r,rr,s} \geq t_{f,r,rr,s}^{pipe} \big/ N_s \quad \perp \lambda_{f,r,rr,s} \geq 0 \tag{A1.4}$$

$$l_{f,r}^{in} - e_{f,r,s} - \sum_{rr} t_{f,r,rr,s}^{tank} \geq 0 \quad \perp \sigma_{f,r,s} \geq 0 \tag{A1.5}$$

$$\sum_{rr} t_{f,rr,r,s}^{tank} Y_{f,rr,r}^{tank} Y_f^{out} - l_{f,r}^{out} \geq 0 \quad \perp \varphi_{f,r,s} \geq 0 \tag{A1.6}$$

$$\perp \pi_{f,r,s} \geq 0 \tag{A1.7}$$

$$\left(\sum_a q_{a,f,r,s} + l^{out}_{f,r,s}\right) Y^{pipe}_{f,r,r} + \sum_{rr}\left(t^{pipe}_{rr,r,s} Y^{pipe}_{f,rr,r} - t^{pipe}_{r,rr,s}\right) - l^{in}_{f,r,s} \Big/ Y^{in} \geq d_{f,r,s}$$

Equation block (1) defines the fuel supplier's optimization problem for all GCC member states, which are composed of different regions r. The fuel supplier maximizes export revenues minus operating and annualized capital expenses for the production and transportation of all fuels f between regions r and rr in each season s. The supplier is subject to constraints (A1.1) to (A1.7). As a convention, we include the marginal values or dual variables associated with each constraint on the right-hand sides of equations as orthogonal complementarity conditions. Thus, when the primal constraint is binding, the corresponding dual variable takes a non-negative value; otherwise, it is equal to zero. We use these equations to construct the optimality conditions for the fuel supplier's problem in the following section.

Table A1 lists and defines all indices, variables and coefficients used in the model. The first term in equation (1) defines the revenues from fuel exports to the international market $e_{f,r,s}$ at fixed price $P_{f,s}$. The second term subtracts the variable production cost $C_{a,f,r,s}$ of fuel production $q_{a,f,r,s}$ from each linear supply activity, indexed by a. The next term subtracts the aggregate variable transport cost $O^{pipe}_{f,r,rr}$ of pipeline shipments $t^{pipe}_{f,r,rr,s}$ between regions. This term also subtracts the cost of maritime tanker shipments $t^{tank}_{f,r,rr,s}$ and the annualized capital cost $K^{pipe}_{f,r,rr}$ of building new pipeline capacity $u_{f,r,rr,s}$. Finally, we subtract the variable operating costs O^{in}_f and O^{out}_f of loading fuel into maritime tankers $l^{in}_{fr,s}$ and unloading it from maritime tankers $l^{out}_{fr,s}$. We also subtract the related annualized capital costs K^{liq} and K^{reg} of building new liquefaction b^{liq}_r and regasification b^{reg}_r facilities, respectively.

Constraint (A1.1) sets the existing daily production capacity for each linear supply activity $Q_{a,f,r}$. This capacity is the upper bound on the seasonal fuel production divided by the number of days in the season N_s. Constraints (A1.2), (A1.3) and (A1.4) set the available total capacities for liquefaction, regasification and pipeline transportation, respectively. We include both existing and newly built infrastructure for each activity. Constraint (A1.5) sets the upper bound of exports and regional maritime transport as the amount of fuel loaded into tankers in each region. Constraint (A1.6) requires the total amount of fuel unloaded from tankers to be less than incoming tanker shipments. This quantity includes the regional transportation and unloading (e.g., regasification) yields, or $Y^{tank}_{f,rr,r}$ and Y^{out}_f, respectively. Finally, constraint (A1.7) describes fuel delivered by pipeline. We sum total production, fuel unloaded from tankers (accounting for the intraregional delivery yield $Y^{pipe}_{f,r,r}$) and net pipeline flows into each region. This quantity less the fuel loaded into tankers (accounting for loading yields, such as liquefaction) must exceed the seasonal fuel demand $d_{f,r,s}$.

A.2. Optimality analysis of competitive gas pricing

Table A.2
Dual variables from the fuel supplier's constraints in equation block (1).

$\alpha_{a,f,r,s}$	Scarcity premium on linear fuel supply activities
ρ^{liq}_r	Scarcity premium on liquefaction
ρ^{reg}_r	Scarcity premium on regasification
$\lambda_{r,rr}$	Scarcity premium on pipeline transportation
$\sigma_{f,r,s}$	Marginal value of tanker loading and fuel exports
$\varphi_{f,r,s}$	Marginal value of regional tanker deliveries
$\pi_{f,r,s}$	Marginal value of pipeline deliveries, or competitive pipeline prices

$$P_{f,s} - \sigma_{f,r,s} \leq 0 \quad \perp e_{f,r,s} \geq 0 \tag{A2.1}$$

$$\pi_{f,r,s} - \alpha_{a,f,r,s} \leq C_{a,f,r,s} \quad \perp q_{a,r,s} \geq 0 \tag{A2.2}$$

$$\sigma_{f,r,s} - \rho^{liq}_{r,s} N_s \Big|_{f=CH_4} - \pi_{f,r,s} \Big/ Y^{in} \leq O^{in}_f \quad \perp l^{in}_{f,r,s} \geq 0 \tag{A2.3}$$

$$\pi_{f,r,s} Y^{pipe}_{f,r,r} - \rho^{reg}_{r,s} N_s \Big|_{f=CH_4} - \varphi_{f,r,s} \leq O^{out}_f \quad \perp l^{out}_{f,r,s} \geq 0 \tag{A2.4}$$

$$\pi_{f,rr,s} - \pi_{f,r,s} - \lambda_{f,r,rr,s} N_s \leq O^{pipe}_{f,r,rr} \quad \perp t^{pipe}_{f,r,rr,s} \geq 0 \tag{A2.5}$$

$$\varphi_{f,rr,s} Y^{tank}_{f,r,rr} Y^{out}_f - \sigma_{f,r,s} \leq O^{tank}_{r,rr} \quad \perp t^{tank}_{f,r,rr,s} \geq 0 \tag{A2.6}$$

$$\lambda_{r,rr} \leq K^{pipe}_{r,rr} \quad \perp u_{f,r,rr,s} \geq 0 \tag{A2.7}$$

$$\rho^{liq}_r \leq K^{liq} \quad \perp f^{liq}_r \geq 0 \tag{A2.8}$$

$$\rho^{reg}_r \leq K^{reg} \quad \perp f^{reg}_r \geq 0 \tag{A2.9}$$

We derive orthogonal complementary pairs for each variable in equation block (A1) using the dual variables listed in Table A2. These pairs are defined in equations (A2.1) to (A2.9). We combine these pairs with the original primal constraints, (A1.1) to (A1.7), to construct the fuel supplier's linear complementary problem (LCP).

Next, we combine the LCP of the fuel supply sector with the LCPs of the power, water and transmission sectors (not shown). These sectors define the exogenous industrial fuel demand $d_{f,r,s}$. Matar et al. (2015), Matar et al. (2017) and Wogan et al. (2019) describe the other industrial sectors included in the KEM. In this structure, different pricing rules can be assigned to the exogenous fuel demand, as can different regional fuel allocation constraints. Thus, we have an MCP model of the integrated energy sectors under existing regulatory constraints.

Rioux et al. (2020) provides a technical description of the construction of a multisector MCP with price regulation. They use an extended mathematical programing framework within a general algebraic modeling system.

A.3. Complementarity slackness conditions for the Liberalized Price Cap scenario

$$\pi_{f,r^*,s} - L_{f,r^*,s} \le \delta_{f,s} \quad \perp \varepsilon_{f,r^*,s} \ge 0 \tag{A3.1}$$

$$1 \ge \sum_{r} \varepsilon_{f,r^*,s} \quad \perp \delta_{f,s} \ge 0 \tag{A3.2}$$

To construct the *Liberalized Price Cap* scenario, we add the complementarity slackness conditions defined in (A3.1) and (A3.2) to the fuel supplier's problem. First, we select a single regional gas hub r^*, and we set a reference price cap on natural gas in this hub. The independent variable $\delta_{f,s}$ in (A3.1) is the difference between the marginal supply value $\pi_{f,r^*,s}$ and the price cap set in the hub, $L_{f,r^*,s}$. End-user fuel prices in all regions are equal to $\pi_{f,r,s} - \delta_{f,s}$. Thus, the fuel price in r^* is bounded by $L_{f,r^*,s}$, and the prices in all other regions are discounted by $\delta_{f,s}$. This setup preserves regional price differentials due to transportation costs and scarcity premiums. We pair (A3.1) with the dual variable $\varepsilon_{f,r^*,s}$ defined in (A3.2). Thus, if the marginal supply in the hub exceeds the price cap and $\delta_{f,s}$ is positive, (A3.1) must be binding ($\pi_{f,r^*,s} - L_{f,r^*,s} = \delta_{f,s}$).

B. Calibration data

B.1. Gas production and demand

We model fuel production as a linear activity characterized by marginal supply costs. We assume that production capacity is constant. We use a simple linear representation of upstream production activities that includes both oil and gas. We calibrate the cost of producing crude oil and sales gas (methane) and the corresponding capacities to the 2018 Rystad UCube database for each country. The costs include the short-term costs of non-associated gas and crude oil production and the costs of associated gas production. We also extract projections of future production capacities and costs from Rystad for running dynamic scenarios (not presented in the current analysis).

We account for seasonality in gas demand through the characterization of the load curves used in the power transmission model. The seasons are summer, fall/spring and winter. All other industrial demand is treated as fixed. Gas demand is calibrated to data from publicly available reports from the GCC countries. We also use reports accessed through a subscription to Facts Global Energy, Middle East & North Africa Gas.

B.2. Pipeline and LNG tanker networks

The average pipeline capital cost is \$0.005/MMBtu/km for onshore pipelines (Table 3). The World Bank (2013) reports this cost for Arab pipeline projects with a diameter of at least 36 inches. We double this cost for onshore pipelines. The average operating costs are \$0.01/1000 km, with a loss rate (internal use for compressors) of 0.003%/km. For discounting purposes, we set the lifetime of a pipeline project equal to 35 years.

For LNG processing, we use data from Songhurst (2019) on the capital and operating costs of floating liquefaction and regasification facilities. We assume liquefaction losses of 10% through internal consumption. We take operating costs and processing losses for LNG imports from Tavares et al. (2018). For LNG tanker transport, we estimate tanker charter and fuel costs using the values reported by Timera Energy (2018). With these costs, we can estimate the long-term marginal costs of using LNG tankers for trade within the GCC.

LNG shipping opex are based on values reported by Timera Energy (2018) and include tanker charter costs. We do not explicitly model LNG tanker capacity stocks or investments. Doing so ensures that the model captures the economic value of fixed pipelines relative to more flexible LNG tanker shipments.[6] Pipeline transportation losses reflect internal energy consumption (gas shrinkage) from powering compressors along the pipeline. LNG tanker losses reflect the boil-off from LNG tanker containers. This boil-off is roughly 0.1% per day when traveling at an average speed of 15 knots.

Table B1 lists the existing pipeline capacities. Table B2 presents the installed liquefaction and regasification units. Finally, Table B3 lists the distances used to configure the regional gas grid. When calibrating the model, we enforce Dolphin pipeline gas contracts of 0.64 QBtu from Qatar to the UAE and 0.07 QBtu from the UAE to Oman. After running the reference scenario, we also set lower bounds on tanker shipments of 0.056 QBtu from Qatar to Kuwait and 0.021 QBtu from Oman to Kuwait. However, we remove these constraints when running the counterfactual scenarios described in our numerical analysis of the GCC gas grid. We implicitly assume that members' LNG tanker shipments within the GCC are not subject to long-term contracts. Nevertheless, as we discuss in the main text, we investigate a scenario in which Qatar secures a 3 mtpa LNG contract with Kuwait, the major LNG importer in the region.

Table B.1
Annual interregional pipeline capacities.

From–To	Volume (QBtu)
Qatar to UAE (TAQA)	0.80
UAE (TAQA) to (FEWA)	
UAE (FEWA) to OMN	0.74
KSA (East) to (Cent)	3.60
KSA (Cent) to (West)	

Notes: Kingdom of Saudi Arabia (KSA). United Arab Emirates (UAE). Regions: Abu Dhabi (TAQA), Dubai (DEWA), Fujairah (FEWA) and Sharjah (SEWA).
Source: KEM.

[6] Tankers can be leased for exports to consumers outside of the GCC, whereas fixed pipelines cannot. Embedding the sunk cost of the existing GCC tanker capacity into the transport cost reflects the value gained from this flexibility of chartering tankers for trade outside the GCC.

Table B.2
Annual liquefaction, regasification and pipeline capacities.

Country	Liquefaction (mtpa)	Regasification (mtpa)
Bahrain	–	9
Kuwait	–	9.6
Oman	10.8	–
Qatar	77.4	–
UAE	8.4	10.8

Source: Global Gas & Oil Network (2020).

Table B.3
Pipeline and tanker transportation distances.

Legend: Maritime tanker or subsea pipe; Onshore pipe; Maritime tanker or onshore pipe

Country	Region	BAH	KUW	OMN	QAT	KSA CENT	KSA EAST	KSA SOUT	KSA WEST	UAE TAQA	UAE DEWA	UAE FEWA
Bahrain (BAH)												
Kuwait (KUW)		450										
Oman (OMN)		1000	1300									
Qatar (QAT)		250	600	850								
Saudi Arabia (KSA)	CENT											
	EAST	160	400	1000	400	400						
	SOUT	4000	4500	3000	4000		1700					
	WEST	4500	5000	3500	4500	900	2200	650				
United Arab Emirates (UAE)	TAQA	450	850	650	500		700	1500	4900			
	DEWA	500	850	575	750		600	4200	4850	120		
	FEWA	550	850	500	450		850	4000	4700	250	130	
	SEWA									220	100	140

Regions: Abu Dhabi (TAQA), Dubai (DEWA), Fujairah (FEWA) and Sharjah (SEWA).

B.3. Power and water sector data

Tables B4, B5 and B.6 list the calibration coefficients (i.e., costs and operational parameters) of the technologies used by the power and water (desalination) sectors. These technologies include steam turbines (ST), gas turbines (GT), combined cycle gas turbines (CC), nuclear power and several renewable technologies. The renewable technologies are photovoltaic power (PV), concentrated solar power and wind power. Each unit can also be configured as a water cogeneration unit using the available thermal desalination technologies defined below. We estimate renewable resources' profiles station data across the Arab peninsula, as reported by Matar et al. (2017) and Matar et al. (2015). We use the solar calculator developed by the Masdar Institute (Tuomiranta et al., 2017). We use a 6% discount rate to calculate the annualized investment costs during a project's expected lifetime, as in Matar et al. (2017).

Table B5 includes the gain output ratio (GOR) and the internal electricity consumption rates of two desalination technologies. These technologies are multiple effect distillation (MED) and multi-stage flash distillation (MSF). The GOR values are used to calculate internal fuel consumption when accounting for boiler efficiency and the energy content of the generated steam. Both MED and MSF plants can be combined with ST, GT or CC units to form power and water cogeneration units with specific power-to-water ratios (PWRs). They can also form cogeneration units with variable PWRs. Details about these plants are listed in Table B6. The total existing capacities for power and water generation in each country are listed in Tables B7 and B.8, respectively.

Table B.4
Power plant costs, efficiency and expected lifetimes.

Technology	Capital cost ($/KW)	Fixed cost ($/KW)	Variable cost (non-fuel) ($/MWh)	Net thermal efficiency %	Lifetime years
Steam turbine (ST)	1026	11.2	1.87	37%	30
Gas turbine (GT)	882	11.2	4.56	30%	25
Combined cycle GT (CC)	1032	12.4	3.76	50%	30
Conversion of GT to CC	240	12.4	4.33	42%	20
Nuclear	5288	68.8	2.56	33%	35
Photovoltaic (PV)	1250	9	–		25
Concentrated solar power	5204	70	3.08		30
Wind	1400	35	–		20

Source: KEM.

Table B.5
Cost, GOR, energy consumption and lifetimes of water desalination technologies.

Technology	Capital cost ($">$/m3/day)	Fixed cost ($">$/m3/day)	Variable non-fuel ($">$/Mm^3)	GOR; energy use (kwh/m^3)	Lifetime years
Multiple effect distillation (MED)	1485	33.0	80	10; 2	30
Multi-stage flash distillation (MSF)	2104	33.0	80	8; 3	30
Saltwater reverse osmosis (SWRO)	2723	48.0	100	-; 5	25

Capital and fixed costs are in units of dollars per cubic meter per day (m^3/day) and variable costs are in units of thousand cubic meters (Mm^3).
Source: KEM.

Table B.6
PWR and net thermal efficiency of water cogeneration plants.

Technology	PWR (MW/MIGD)	Efficiency (%)
Fixed PWR		
ST Co (MSF)	5	0.23
GT Co (MSF)	8	0.28
CC Co MED	10	0.42
CC Co MSF	16	0.42
Variable PWR (minimum)		
ST CoV	10	0.28
GT CoV	8	0.28
CC CoV (MED)	12	0.45
CC CoV (MSF)	19	0.45

PWR is reported in MW per million gallons per day (MIGD). a) Technologies: Steam cogeneration (ST Co), gas turbine cogeneration (GT Co), combine cycle cogeneration (CC Co), variable cogeneration (CoV), multiple-effect distillation (MED), multi-stage flash (MSF).
Source: KEM.

Table B.7
Power and water (cogeneration) capacities in gigawatts (GW).

Technology (GW)	KSA	UAE	QAT	KUW	BAH	OMN
ST	29.61			1.20		
GT	33.15	5.70	1.25		0.71	1.42
CC	16.03	2.38	2.01	2.30	0.95	8.05
PV	0.02	0.51		0.13		0.10
ST Co (MSF)	4.96	2.23				
GT Co (MSF)	0.20	0.00	1.67			
CC Co MED	3.44	5.00				
CC Co MSF	2.12	13.34	4.51	2.30	1.03	0.47
ST CoV	2.27			8.97		
GT CoV				4.80		
CC CoV MED	2.23					
CC CoV MSF	0.53					

Source: KEM.

Table B.8
Standalone water generation capacities in million m^3 per day (MMm^3/day).

Technology (MMm^3/day)	KSA	UAE	QAT	KUW	BAH	OMN
MED	0.08				0.02	
MSF			0.31		0.07	
SWRO	3.51	1.47	0.16	3.20	0.52	0.87

Source: KEM.

The power transmission submodules use the same demand structure and regional breakdown as Wogan et al. (2019) use. The national grid in the KSA includes the central, eastern, southern and western operating areas. Additionally, the UAE includes the electricity and water authorities of Abu Dhabi (TAQA), Dubai (DEWA), Fujairah (FEWA) and Sharjah (SEWA). The Kingdoms of Bahrain (BAH), Kuwait (KUW), Oman (OMN) and Qatar (QAT) are characterized as single regions.

Power demand is organized into eight-hourly load blocks for each season (i.e., summer, spring/fall and winter). These blocks are constructed from hourly load profiles reported by state-owned electricity companies in the years prior to 2018. We then rescale them to reflect each country's aggregate power demand, as shown in Table B9. We also provide desalinated water demand for 2018.

The GCC interconnector includes a 1.2 GW trunk line connecting Kuwait, the eastern region of Saudi Arabia, Qatar and the UAE (TAQA). It also has a 0.6 GW branch linking Saudi Arabia to Bahrain. Saudi Arabia's national grid includes a 4.8 GW line from the eastern and central regions and a 1.2 GW linking the central and western regions. It also has a 2.5 GW line from the western to the southern region and a 0.25 GW line from the central to the southern region. The UAE national grid includes a 1.15 GW line linking TAQA, DEWA and SEWA and a 1 GW line linking TAQA, SEWA and FEWA. Finally, it has a 1.2 GW line from DEWA to FEWA and a 0.4 GW line linking FUWA to Oman, completing the GCC grid.

Table B.9
Power and water demand in 2018.

	KSA	UAE	QAT	KUW	BAH	OMN
Electricity demand, TWh	339	135	37	75	16	37
Water demand, bm^3	2.00	2.01	0.55	0.61	0.24	0.24

Note: Electricity demand is in units of terawatt hours (TWh) and water demand is in units of billion cubic meters (bm^3).
Source: KEM.

Table B.10
Regional fuel demand (quotas) in 2018 for the power and water sectors and administered fuel prices.

Fuel	Country (region)a	Price	Quota
Crude oil MMb	KSA	$6.35/b	131.5 MMb
	KUW	$25/b	7.9 MMb
Diesel million tonnes (mt)	KSA	$116.8/ton	2.856 mt
	KUW	$200/ton	0.61 mt
Heavy fuel oil mt	KSA	$31.82/ton	21.42 mt
	KUW	$175/ton	8.1 mt
Natural gas QBtu	BAH	$3.28/MMBtu	0.249 QBtu
	KSA	$1.25/MMBtu	2.226 QBtu
	KUW	$3.9/MMBtu	0.415 QBtu
	OMN	$3.28/MMBtu	0.332 QBtu
	QAT	$1/MMBtu	0.391 QBtu
	UAE	$2.42/MMBtu	1.568 QBtu

Source: KEM.

C. Additional scenario results

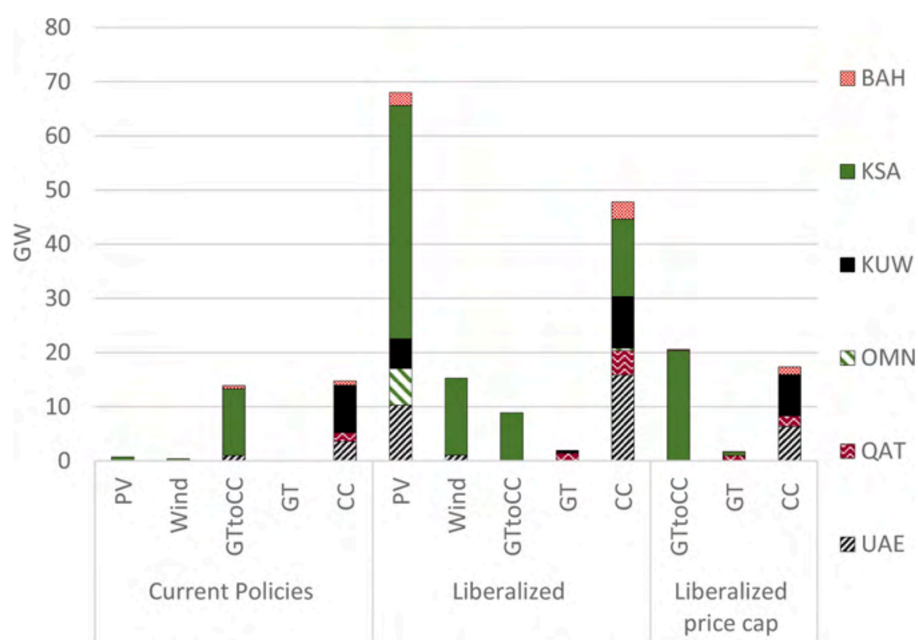

Fig. C.1. Power sector investments in gigawatts (GW).
Countries: Kingdom of Saudi Arabia (KSA); United Arab Emirates (UAE); Kingdoms of Bahrain (BAH), Kuwait (KUW), Oman (OMN) and Qatar (QAT). Technologies: Concentrated solar power (CSP), photovoltaic power (PV), gas turbine (GT), combined-cycle gas turbine (CC), GT to CC conversion (GTtoCC).Source: KAPSARC analysis.

Fig. C1 summarizes the cogeneration power sector investments in the *Current Policies* and the two scenarios with liberalized prices. All of the scenarios show pent-up levels of plant conversions from open-cycle to the more efficient combined-cycle turbines (GTtoCC). We also observe more use of renewables and combined-cycle turbines in the *Liberalized* scenario.

As renewables are more competitive under liberalized prices (Table 8), the PV and wind capacities increase by 68 GW and 15 GW, respectively. Furthermore, significant investments are made in more efficient gas-fired units. With increased investment in solar and wind power generation, existing single-cycle GTs are valued as spinning reserves to balance the intermittency of renewable energy. The development of the gas grid therefore plays an important role in supporting gas availability and power grid reliability with the increased penetration of intermittent renewables.

The water sector (not shown) also invests in more efficient saltwater reverse osmosis units to phase out the use of energy-intensive thermal desalination. We assume that approximately 1 and 6.6 million cubic meters of new capacity per day are added under the *Current Policies* and *Liberalized* scenarios, respectively.

Thus far, we have not addressed how the gains from expanding the gas grid may be distributed among the GCC countries. We have also not discussed how they may impact different sectors. Figure C.2 depicts the changes in economic value in four counterfactual scenarios by country and sector. We consider the fuel production and transport (fuel supply) sector separately from other sectors that drive fuel demand (i.e., the electricity production, power transmission and water production).

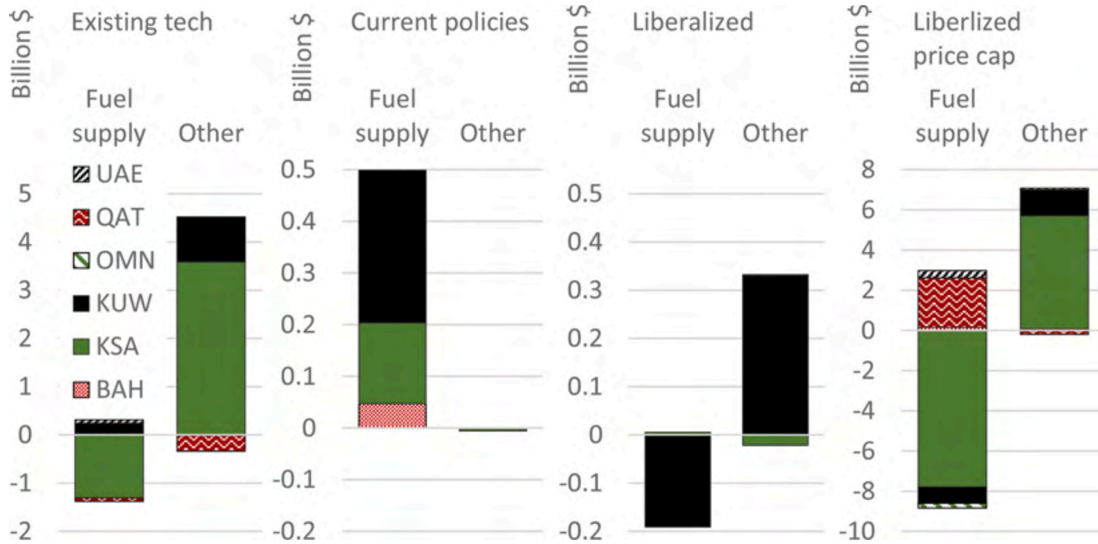

Fig. C.2. Breakdown of economic gains from pipeline investments in counterfactual scenarios by country and sector.
Countries: Kingdom of Saudi Arabia (KSA); United Arab Emirates (UAE); Kingdoms of Bahrain (BAH), Kuwait (KUW), Oman (OMN) and Qatar (QAT).Source: KAPSARC analysis.

In practice, the division of the gains depends on trade agreements among countries and sectors, such as fuel sales to the electricity and water sectors. We construct these figures by assuming that all cross-border and inter-sectoral trade is priced at its marginal value. We also assume that sectoral fuel sales align with the given scenario (i.e., administered or liberalized prices), as described in the main text. To facilitate rent sharing, parties may make alternative agreements. Examples include the long-term bilateral trade agreement adopted by the Dolphin pipeline and most TAGP countries.

Recall that in *Existing Tech* scenario, existing liquid fuel quotas (subject to administered prices) are lifted. We determine the optimal allocation of gas based on the current technology mix. First, the fuel consumption sectors (other) experience a net economic gain from the gas grid expansion in Kuwait and Saudi Arabia. This gain is due to the increasing accessibility and availability of gas, which offsets the cost of consuming more expensive liquid fuel. In Kuwait, midstream fuel purchases, which are part of the fuel supply sector, benefit from a reduction in more expensive maritime LNG shipments. They also benefit from higher export revenues. However, the Saudi fuel supply sector loses value by selling gas to the power and water sectors below its marginal value (cost of imports).

In the *Current Policies* scenario, Kuwait's fuel supply sector is the main beneficiary from the reduction in the cost of importing more expensive LNG. As net exporters, Qatar and Saudi Arabia do not gain or lose significantly. They may seek out different trade structures to share the gains secured by Kuwait.

In the *Liberalized* scenario, the gains secured by the fuel supply and other sectors nearly balance out. Kuwait receives marginal gains from the lower gas purchasing costs for other fuel-consuming sectors. When integrated gas prices are capped ($4/MMBtu in Qatar), fuel-consuming sectors in Kuwait and Saudi Arabia benefit from cheaper gas prices by investing in new cross-border pipelines. The pipelines also help offset capital-intensive power sector investments, including the expansion of the GCC interconnector and the power trade. However, the upstream and midstream sectors in Kuwait and Saudi Arabia face increasing costs from trading gas. Additionally, Qatar (and to a lesser extent, the UAE) increases its rents from pipeline exports of natural gas both within and outside the GCC.

Table C.1
Natural gas supply and demand balances in each counterfactual scenario in QBtu.

Scenario	Country						
	BAH	KSA	KUW	OMN	QAT	UAE	Total
Existing tech							
Production	**0.556**	**3.350**	**0.651**	**1.521**	**6.143**	**2.196**	**14.417**
Demand	**0.580**	**4.403**	**1.184**	**0.908**	**1.407**	**2.396**	**10.878**
Power/Water	0.276	3.302	0.801	0.300	0.539	1.471	6.689
Other	0.304	1.101	0.383	0.608	0.868	0.925	4.189
Imports	**0.041**	**1.722**	**0.536**	**0.070**		**0.638**	**3.008**
Pipeline	0.041	1.722	0.536	0.070		0.638	3.008
Tanker						0.000	0.000
Exports	**0.014**	**0.584**		**0.600**	**4.473**	**0.388**	**6.059**
Pipeline	0.014	0.584			2.376	0.071	3.046
Tanker				0.600	2.096	0.317	3.013
Current policies							
Production	**0.556**	**3.350**	**0.651**	**1.521**	**6.143**	**2.196**	**14.417**
Demand	**0.510**	**3.233**	**0.798**	**0.954**	**1.235**	**2.406**	**9.136**
Power/Water	0.206	2.131	0.415	0.300	0.367	1.481	4.901
Other	0.304	1.101	0.383	0.654	0.868	0.925	4.235

(*continued on next page*)

Table C.1 (*continued*)

Scenario	Country						
	BAH	KSA	KUW	OMN	QAT	UAE	Total
Imports		0.075	0.150	0.070		0.598	0.894
Pipeline		0.075	0.150	0.070		0.598	0.894
Tanker							
Exports	0.043	0.152		0.558	4.453	0.343	5.549
Exports Pipeline	0.043	0.152			0.640	0.071	0.906
Exports Tanker				0.558	3.813	0.272	4.643
Liberalized							
Production	**0.556**	**3.350**	**0.651**	**1.521**	**6.143**	**2.196**	**14.417**
Demand	**0.454**	**2.923**	**0.860**	**0.867**	**1.236**	**1.733**	**8.073**
Power/Water	0.150	1.899	0.477	0.213	0.368	0.808	3.915
Other	0.304	1.024	0.383	0.654	0.868	0.925	4.158
Imports		**0.000**	**0.212**	**0.000**		**0.010**	**0.222**
Pipeline			0.212	0.000		0.010	0.222
Tanker							
Exports	**0.089**	**0.355**		**0.574**	**4.389**	**0.414**	**5.821**
Pipeline		0.214		0.011			0.225
Tanker	0.089	0.140		0.564	4.389	0.414	5.596
Liberalized price cap							
Production	**0.556**	**3.350**	**0.651**	**1.521**	**6.143**	**2.196**	**14.417**
Demand	**0.493**	**4.068**	**0.905**	**1.022**	**1.267**	**2.182**	**9.935**
Power/Water	0.189	3.044	0.522	0.368	0.399	1.257	5.777
Other	0.304	1.024	0.383	0.654	0.868	0.925	4.158
Imports		**1.055**	**0.257**	**0.000**		**0.000**	**1.312**
Pipeline		1.055	0.257				1.312
Tanker							
Exports	**0.061**	**0.260**		**0.434**	**4.462**	**0.000**	**5.217**
Pipeline	0.061	0.260			1.007		1.328
Tanker				0.434	3.455		3.889

Source: KAPSARC analysis.

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