Abstract

Due to the shale gas revolution, North America has the potential to become a major exporter in the burgeoning global market for liquefied natural gas (LNG). Strong LNG demand growth, especially in Asia, could increasingly motivate gas infrastructure development in North America. Nevertheless, opposition to new gas infrastructure is formidable in some of the U.S. states and Canadian provinces that are well positioned to supply LNG to the Asian market. In this paper, we investigate the combined effects of LNG demand growth and export infrastructure restrictions on North American natural gas markets through 2050. To do so, we build an equilibrium model formulated as a mixed complementarity problem with endogenous capacity investments. It is parameterized using only publicly available data sources. Our results show that North American markets can significantly scale up LNG exports to satisfy strong Asian demand growth. Even if new export terminals cannot be constructed on the West Coast, LNG exports largely shift to other regions rather than suffer an overall decline. Increasing external demand for LNG puts upward pressure on regional prices in North America, and directs production and pipeline flows toward the regions that export LNG. These effects are more prominent if infrastructure restrictions concentrate LNG development within fewer regions.

Keywords: Natural gas, LNG, energy markets, market modeling, mixed complementarity problem
1. Introduction

North American natural gas markets have undergone sweeping transformations over the past two
decades. The 2000s witnessed the shale gas revolution, where hydraulic fracturing and horizontal drilling
led to a decline in extraction costs and a surge in natural gas production in the United States (U.S.)
(Huntington, 2016). Consequently, the U.S. became the largest natural gas producer in the world in 2009
(EIA, 2018b), and a net natural gas exporter for the first time in 60 years in 2017 (EIA, 2018a). This
increased supply has kept the Henry Hub natural gas price below $5 per million British thermal units
(MMBtu) for most of the past decade (EIA, 2019c). As U.S. natural gas production has grown, so too
has its capacity to export liquefied natural gas (LNG). In 2007, the U.S. imported 771 million cubic feet
(MMcf) of LNG and exported none. One decade later in 2017, U.S. LNG imports dropped to 78 MMcf
while LNG exports grew to 707 MMcf, signaling a new era of LNG trade for North America.

The first LNG export facility in the continental U.S. was the Sabine Pass terminal on the Gulf Coast,
whose first phase became operational in 2016. It was followed by Cove Point on the Chesapeake Bay,
which commenced commercial operations in 2018. Since then, more LNG export terminals have been
approved to begin construction at Corpus Christi, Freeport, Cameron, and Elba Island on the Gulf and
Atlantic Coasts. These planned additions would bring the total combined export capacity to 10.79 billion
cubic feet per day (Bcf/d) (EIA, 2018a). In Canada, an LNG export facility is currently being constructed
in British Columbia, adding Canada to the list of likely LNG exporters in the near future (NEB, 2019a).

North American LNG infrastructure investment is being fueled by the rapid increase in natural gas
demand around the world. Across the Pacific Ocean, Asian LNG imports are rising rapidly. China’s LNG
imports tripled in just six years from 2010 to 2016. By 2040, China is expected to triple its 2015 natural
gas consumption to reach 57 Bcf/d, supported by roughly 11 Bcf/d of LNG imports. This projected
growth would put China on par with Japan, currently the world’s largest LNG importer (EIA, 2017).
However, looking several decades ahead, it is very difficult to project LNG demand from importing regions.
Demand will depend on uncertain future developments in their own natural gas production, economic
growth, energy and environmental policies, geopolitical goals, and trade relations (e.g., the current trade disputes between the U.S. and China).

These bullish but uncertain projections raise the question of how North American natural gas markets and LNG export infrastructure will be shaped by rising global demand, especially from Asia. All currently operational North American LNG export facilities reside on the Gulf and Atlantic Coasts of the U.S., which increases the time and cost required to transport LNG to Asian markets. A natural solution to secure easier access to these markets would be to build LNG export terminals on the Pacific Coast of North America. However, proposals to construct LNG export facilities along the Pacific Coast of the U.S. and Canada have encountered fierce political and public opposition in line with general resistance to fossil fuel infrastructure development. As an example, activists in Oregon campaigned the state not to issue a proposed LNG project the necessary water quality certification (Brady, 2018), which was denied by Oregon’s Department of Environmental Quality in May 2019 (DEQ, 2019). Whether LNG will be exported from the Pacific Coast of North America, and the resulting implications for North American natural gas markets overall, remain to be seen.

In this article, we investigate how regional natural gas markets in North America will be shaped by the combined effects of LNG demand growth abroad and possible restrictions on LNG infrastructure development in the U.S. and Canada. These two drivers are believed to exert a particularly strong influence on the trajectory of North American natural gas and its relationship with the global LNG market. To conduct this analysis, we construct a nine-region equilibrium model of North American natural gas markets interacting with Atlantic and Pacific LNG demands, formulated as a mixed complementarity problem. Scenario results highlight how regional natural gas production, consumption, and prices, as well as endogenous investments in production, pipeline, and liquefaction infrastructures, vary with assumptions about future LNG demand and infrastructure restrictions.

The remainder of this paper is organized as follows. In Section 2, we briefly review the literature on natural gas market modeling, focusing on previous studies that are methodologically the most similar to
our own. Section 3 outlines our model and explains how it is parameterized and calibrated. Section 4 delineates our scenarios. We present, compare, and discuss scenario results in Section 5. We conclude in Section 6 by summarizing our most important findings and identifying limitations that suggest fruitful directions for future research.

2. Literature review

Boots et al. (2004) constructed the GASTALE model to analyze the effects of downstream trader competition on producer market shares and end-use prices in the liberalizing European natural gas market. Their model distinctly represents upstream suppliers and downstream traders in the natural gas market as an extension of the successive oligopolist model developed by Greenhut and Ohta (1979). Gabriel et al. (2005a) formulated a complementarity model with producers, storage reservoir operators, peak gas operators, pipeline operators, marketers, and consumers as strategic players, and established conditions for the existence of a solution and for the uniqueness of equilibrium prices. Gabriel et al. (2005b) also developed a linear complementarity model of the North American gas market encompassing producers, storage and peak gas operators, third-party marketers, and four end-use sectors. Egging and Gabriel (2006) constructed an equilibrium model of the European natural gas market and applied it to investigate the effects of assumptions about market power, pipeline capacities, and storage.

Lise and Hobbs (2008) extended GASTALE to incorporate endogenous capacity expansion decisions for storage operators, pipeline operators, liquefiers, and regasifiers. They explored the effects of market power in the liberalized European gas market, and then used their model to consider the impacts of LNG trade (Lise and Hobbs, 2009). Holz et al. (2008) developed GASMOD, a static, two-stage successive game theory model, and investigated the effects of market power on upstream and downstream markets. Egging et al. (2008) developed a European natural gas model in which LNG players such as liquefiers, tanker operators, and regasifiers are explicitly represented as players and thus added to the usual sets of players included in previous models. Egging et al. (2010) formulated the World Gas Model, a multi-period
complementarity model that features endogenous capacity investment decisions and the logarithmic production cost functions developed by Golombek et al. (1995).

In their discussion paper, Huppmann et al. (2009) considered a number of scenarios using the World Gas Model. Two of their scenarios, namely increased demand in Asia and banning LNG import facilities on the West Coast of the U.S., would seem to have a lot in common with our analysis. However, in the decade since their study, the shale gas revolution has fundamentally altered the long-run dynamics of the North American natural gas market. In fact, Huppmann et al. (2009) actually analyzed scenarios where the U.S. is a natural gas importer, and thus any infrastructure restrictions apply to import rather than export facilities. Gabriel et al. (2012) employed the World Gas Model to assess the implications of an international natural gas cartel, similar to the Organization of the Petroleum Exporting Countries (OPEC).

Egging (2013) built a stochastic global gas model using an MCP formulation and implemented a Benders decomposition algorithm to solve it. Abada et al. (2013) presented a dynamic generalized Nash-Cournot model for natural gas markets called GaMMES and analyzed the evolution of European gas markets from 2000 to 2035 while considering fuel substitution. Huppmann and Egging (2014) then incorporated endogenous fuel substitution into a market equilibrium model. Arora and Cai (2014) used a computable general equilibrium (CGE) model to investigate the global impacts of U.S. natural gas exports. Moryadee et al. (2014a) studied the effects of U.S. LNG exports on domestic as well as Asian markets under various scenarios using the World Gas Model. Moryadee et al. (2014b) and Moryadee and Gabriel (2016) also employed the World Gas Model to examine the influences of tariffs and expanding the capacity of the Panama Canal on LNG trade. Feijoo et al. (2016) developed the North American Natural Gas Model (NANGAM) with 17 regions and four key players spanning suppliers, storage and pipeline arc operators, and consumers. NANGAM features endogenous capacity investments and suppliers with logarithmic production cost functions. More recently, Feijoo et al. (2018) coupled NANGAM to the GCAM-USA integrated assessment model to study the effects of broader socioeconomic developments on
natural gas markets.

3. Methodology

3.1. Model overview

We formulate and implement a mixed complementarity model of North American natural gas markets that is similar in structure to the World Gas Model (Egging et al., 2010). Our model includes high and low demand seasons in each model period, six player types who act strategically to maximize profits, and nine fairly aggregated regions that interact with one another and with two external LNG markets. Each strategic North American player solves a linear or nonlinear optimization problem, whereas the two LNG markets are modeled via linear demand curves. Market clearing conditions ensure balance between the quantities of gas bought and sold by the players. When the Karush-Kuhn-Tucker (KKT) optimality conditions of the players’ profit maximization problems are combined with market clearing conditions, we obtain a mixed complementarity problem (MCP) whose solution characterizes the market equilibrium prices, production levels, consumption levels, and flows throughout the system. The model is implemented in the General Algebraic Modeling System (GAMS) and solved using the PATH solver (Ferris and Munson, 2000).

This section describes the key elements of our model as well as its parameterization and calibration. For the complete mathematical formulation of the model and its corresponding KKT conditions, please refer to the Supplementary Information file.

3.2. Regions

Our model includes nine regions (also referred to as nodes), six for the continental U.S. (Northeast, Southeast, Midwest, Southwest, Central, and Western U.S.), two for Canada (Eastern Canada and Western Canada), and one for Mexico as shown in Fig. 1. Offshore gas production in the Gulf of Mexico is assigned to the nearby Southwest region. Furthermore, we represent the destinations for North American LNG exports in a highly aggregated fashion, with Atlantic and Pacific LNG markets. Unlike
the North American regions, the two LNG markets are not home to any strategic players who solve optimization problems. Instead, the LNG markets are represented by simple linear demand curves.

![Map of North America with regions and LNG markets](image)

**Fig. 1.** The nine North American model regions and the two external LNG markets.

### 3.3. Players

Our model features six different types of strategic players, whose roles are as follows:

- **Suppliers:** They extract natural gas from the ground in their region and sell it to the trader in their region with the goal of maximizing their total profit. There is one supplier in each region.

- **Traders:** They buy natural gas from the supplier in their region and sell it either locally to the storage operator, liquefier, or local demand market, or to another trader in a different region; the last one constituting interregional gas flows. Prices in each market between a trader and another player are determined by the dual variables associated with the respective market clearing conditions. There is one trader in each region.

- **Storage operators:** They are the only players in the model who can arbitrage gas across different seasons. Storage operators buy natural gas from their local trader in the low-demand season and sell it to their local...
market in the high-demand season. There is one storage operator in each region.

- **Liquefiers (LNG export terminals):** They buy natural gas from their local trader, liquefy it, and sell it to the LNG markets. All liquefiers have the ability to sell gas to any of the LNG markets, but the shipping costs set by the tanker operator vary with the distance between the liquefier’s region and the LNG destination. There is one liquefier in each region that includes a stretch of coastline (i.e., all except Central and Midwest).

- **Pipeline network operator:** It operates the pipeline network and collects regulatory and congestion fees from traders in exchange for gas transmission. There is one pipeline network operator for the entire system.

- **Tanker network operator:** It operates the tanker network and collects regulatory and congestion fees from liquefiers for gas transshipment to LNG markets. There is one tanker network operator for the entire system.

Note that our simple representation of the LNG markets via linear demand curves is a less computationally and data-intensive alternative to explicitly representing regasifiers in importing regions as strategic players. Although we will consider LNG demand growth as a scenario driver, our focus is on outcomes in the North American natural gas markets.

### 3.4. Time

We run the model from 2017 through 2065 using a time step of three years. Our analysis focuses on the timeframe from 2017 through 2050, with the 2053 through 2065 time periods included in the model runs to overcome effects associated with the end of the model time horizon. The three-year time step corresponds to the frequencies of demand parameter updates and endogenous capacity investment decisions. Each year in the planning horizon is divided into two seasons to crudely capture different system operating conditions in the high-demand and low-demand seasons, and the ability of the gas storage operator to arbitrage the resulting price differentials. Demand parameters as well as operational variables including production levels, flows, prices, and storage injection and extraction are represented by season. We define the high-demand season as the five months from October through February, and the low-demand season as the seven months from March through September. The model time step and
seasonal disaggregation can be tailored to a particular application by compiling appropriate input data, and without modifying the model structure.

3.5. Notable model features

Suppliers face nonlinear production cost functions of the form first developed by Golombek et al. (1995). This function enables the marginal cost to rise to infinity as the production level approaches the production capacity, hence preventing the suppliers from producing at capacity.

Since our analysis focuses primarily on North America, we see no reason to include market power for any of the players, especially given the high degree of regional aggregation. All players are represented as being in perfect competition with one another.

Our model incorporates decision variables for endogenous capacity expansions in production, liquefaction, storage, pipelines, and LNG tankers. This important feature allows us to investigate how North American natural gas infrastructure will evolve under different scenarios considering the strategic interests of the players making these investment decisions. In our model, once the investment decision is made, the capacity expansion becomes operational in the next time step. Huppmann (2013) proved that convexity is preserved under Golombek et al. (1995) cost curves when capacity expansion capabilities are added.

Natural gas demands in each North American region and in the two external LNG markets are modeled with linear demand functions. These functions are specified exogenously, but they shift outward over time to reflect long-run demand growth. Natural gas consumption levels are endogenously determined during the course of a given model run.

3.6. Parameterization and calibration

All model input data are derived from publicly available sources. Primary sources for our parameterization are government bodies such as the Energy Information Administration (EIA) and Federal Energy Regulatory Commission (FERC) for the U.S., Natural Resources Canada (NRCan) and the National Energy Board (NEB) for Canada, and the Comisión Reguladora de Energía (CRE - Energy Regulatory
Commission) for Mexico. In addition to these sources, we also obtained data from periodic reports published by major agencies and corporations such as the International Energy Agency (IEA), Canadian Energy Research Institute (CERI), and British Petroleum (BP).

We chose the 12-month period between October 2016 and September 2017 (spanning one high-demand season and one low-demand season) as our calibration year based on the availability of empirical data. We rely on EIA data for most of the existing capacity parameters such as regional natural gas storage, pipeline, and liquefaction capacities in the U.S. To initialize production capacities in each region, we take the current production level and assume this output to be a certain percentage (i.e., 90%) of the available production capacity. Costs faced by players are parameterized using data from EIA and NEB reports wherever possible. Table 1 summarizes the data sources we use to parameterize the key input data in our model.

**Table 1. Sources for key model input data.**

<table>
<thead>
<tr>
<th>Data</th>
<th>Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Consumption</td>
<td>EIA (2019c), Natural Resources Canada (2018), Statistics Canada (2019)</td>
</tr>
<tr>
<td>Price</td>
<td>EIA (2019b), CRE (2017)</td>
</tr>
<tr>
<td>Pipeline capacity</td>
<td>EIA (2019c), NEB (2018)</td>
</tr>
<tr>
<td>Liquefaction capacity</td>
<td>EIA (2019c)</td>
</tr>
<tr>
<td>Storage capacity</td>
<td>EIA (2019c), NEB (2019b)</td>
</tr>
<tr>
<td>Production cost</td>
<td>IEA (2017), CERI (2016)</td>
</tr>
</tbody>
</table>

In our model, linear demand curves represent the total demand (residential, commercial, industrial, electricity generation) in each region, model year, and season. The linear demands in the base year are parameterized by anchoring the lines to the actual end-use consumption and price data, then determining the slopes so as to yield point elasticities of -0.2 and -0.3 for North American regional demands and external LNG demands, respectively to reflect greater flexibility LNG buyers have. We obtained state-level end-use consumption data from EIA, along with the natural gas spot prices that EIA uses as input.
parameters for its National Energy Modeling System (NEMS)\(^1\), which informs its Annual Energy Outlook (EIA, 2019a).

The total external LNG demand satisfied by North American exports in 2017 was very limited, since only one North American export terminal was operating in that year. However, EIA projects rapid and substantial growth in U.S. LNG shipments as new export facilities come online (EIA, 2019a). To align our LNG demand growth trajectory with EIA projections into 2050, we multiply the \(y\)-intercept of the empirically calibrated base year LNG demand line by seven. All changes in demand over time are done by exogenously modifying the \(y\)-intercepts of demand curves while leaving the slopes unchanged.

Capacity expansion costs are primarily gathered from publicly available industry reports and news sources. Heterogeneity in regional costs is accounted for by applying regional cost multipliers based on figures published by the Interstate Natural Gas Association of America (2016). Production capacity expansions are only allowed in regions with significant natural gas production, up to a percentage of their existing production capacity.

LNG tanker capacity is assumed to be ample, since any LNG tanker in the world can theoretically be used for LNG transshipment from North America. Similarly, total available natural gas reserves are also assumed to be ample, since reserves are not expected to be fully depleted during our planning horizon. Natural gas market models that include reserves simply impose them as an intertemporal constraint on total production over the model timeframe, rather than as a determinant of current production capabilities or costs. Therefore, our ample gas reserves assumption does not affect the optimal decisions unless it is actually expected that reserves will be fully depleted during the analysis period.

In addition to endogenous capacity expansion decisions, we exogenously include pipeline and LNG export facility expansions that are currently approved and/or under construction. They are added to the available capacities in the model as of their anticipated completion dates. Lists of these projects are

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\(^1\)These prices are in units of $/MMBtu; however, throughout this paper, we use $/Mcf as our price unit unless otherwise indicated. A conversion factor of 1.037 is used to convert $/MMBtu to $/Mcf, so the numbers are quite similar.
provided in the Supplementary Information file.

Production and pipeline transmission costs are treated as calibration parameters to obtain base year results that are reasonably close to observed prices, production, consumption, and flows in the base year. Pipeline transmission costs are primarily based on the distances between regions, whereas production costs are primarily based on IEA and CERI reports. Parameter values assumed for production cost functions in the model are documented in the Supplementary Information file, which also includes illustration of our base year model calibration compared with actual production, consumption and flow data of the corresponding year.

4. Scenarios

We consider five scenarios in this analysis. Four of them feature the same North American natural gas demands but varying assumptions about external LNG demand growth and restrictions on new LNG export facilities. We then compare these four scenarios to a fifth scenario where natural gas demand increases more substantially within North America. The five scenarios are defined as follows:

- **Reference (REF):** This scenario is built on our calibration of the model to base year data and increases in natural gas demands that are close to the reference case findings of the Annual Energy Outlook 2019 (EIA, 2019a). The compound annual growth rates (CAGRs) applied to demands in each region and LNG market are given in the Supplementary Information file.

- **No West Coast (NWC):** This scenario makes the same assumptions as REF, except that no new LNG export facilities are permitted to be built in Western Canada and Western U.S. The intent is to consider the effects of potential political and public opposition to new gas infrastructure development in these regions.

- **High LNG Demand (HLN):** This scenario makes the same assumptions as REF, except that the assumed CAGRs for the two LNG demands are doubled. That is, HLN assumes that Atlantic and Pacific LNG demands grow at 0.6% and 6% annual rates, respectively. The intent is to consider the effects of more significant LNG demand growth, especially from Asian markets.
- **No West Coast and High LNG Demand (NWH):** This scenario is a combination of HLN and NWC with high LNG demand growth and no new LNG export facilities permitted to be built in Western Canada and Western U.S.

- **High Overall Demand (HOD):** This scenario features the same assumptions as HLN except that the annual demand growth rates in North American regions are increased by 66.67% relative to the values in the Reference scenario.

5. **Results and discussion**

In this section we present, compare, and discuss results from our five scenarios. We first analyze how natural gas market trajectories vary across the scenarios with respect to production, consumption, and prices. We then assess how our alternative assumptions about gas demand growth and infrastructure restrictions affect investments in North American natural gas infrastructure.

5.1. **Natural gas markets**

Fig. 2 offers a snapshot of the North American natural gas market in 2050, the end of our analysis timeframe, in the first four scenarios differentiated by assumptions about LNG demand growth and restrictions on new West Coast LNG export terminals. The maps report annual model outputs including regional production, consumption, and prices, as well as flows through the pipeline network and via tankers to the two LNG markets.

5.1.1. **Reference scenario (REF)**

The REF scenario (Fig. 2a) projects a gradual increase in total LNG exports from North America, which reach 4.77 Tcf in 2050. More than half of the total export volume is shipped by the liquefier in Western Canada. Among the three regions situated on the Pacific Coast of the continent, Western Canada is the only one whose initial gas production capacity exceeds its initial consumption. Therefore, Western Canada is uniquely able to take advantage of a lower cost of shipping gas to the Pacific LNG market without having to import gas produced in other regions. As a result, Western Canada supplies
Fig. 2. Annual production, consumption, prices, and flows in 2050 in the first four scenarios, differentiated by assumptions about LNG demand growth and restrictions on new West Coast LNG export terminals.

75.18% (2.60 Tcf) of LNG exports from North America to the Pacific market in 2050, with the Western U.S. supplying the remaining 24.82% (0.86 Tcf).

In REF, we observe that LNG exports are geographically split depending on the destination market. The Southwest region exclusively satisfies all Atlantic LNG demand, whereas the Pacific demand is split between exports from the Western U.S. and Western Canada. This outcome is intuitive, as there are no restrictions on where LNG facilities can be built in the REF scenario, so export terminals are constructed in regions that offer lower shipping costs to destination LNG markets and/or ample local gas production.

Increased LNG exports to the Pacific market alter gas flows within the North American pipeline
network. Under the REF scenario, 51.21% of end-use gas consumption in Western U.S. was satisfied from Western Canada in 2017. However, since the rising Pacific LNG demand drives Canadian gas to be exported as LNG, Western Canada no longer exports any gas to the Western U.S. in 2050. To compensate, Western U.S. starts to import gas from the Central region, which was not an exporter to Western U.S. in 2017. Another significant flow shift occurring in this scenario involves Southeast. This region becomes almost entirely dependent on gas flowing from Northeast, which constitutes 87.77% of its end-use consumption in 2050. This contrasts with the situation in 2017, when Southeast’s gas supplies were more diverse with significant imports from the Midwest and Southwest regions. This shift is enabled by 6.73 Bcf/d of currently planned gas pipeline projects from Northeast to Southeast which were not yet operating in 2017. Now that it does not ship gas to Southeast, the Southwest region exports more gas to Mexico, whose demand increases the fastest of all the North American regions. Pipeline exports from Southwest to Mexico increase from 2.82 Tcf in 2017 to 4.48 Tcf in 2050.

5.1.2. No West Coast scenario (NWC)

The NWC scenario results (Fig. 2b) reveal the effects of prohibiting new LNG export facilities on the West Coast of the U.S. and Canada. In 2050, prices in the U.S. and Mexico are only slightly different in this scenario than in REF, while prices in Canada are more strongly affected. Compared to the REF results, 2050 prices are 7.08% lower in Eastern Canada and 9.54% lower in Western Canada. These prices decline because LNG exports from Western Canada fall, a direct consequence of the restriction on new export infrastructure. This increases the supply of gas available to satisfy local demand in Western Canada, and also allows this region to increase its pipeline shipments to Eastern Canada and continue to export gas to Western U.S. in 2050 (a flow that disappears by 2050 in REF).

A notable development in NWC is that Mexico becomes an LNG exporter, which is not the case in REF. Mexico accounts for almost 14% (0.47 Tcf) of LNG exports from North America to the Pacific market in NWC, partially compensating for the decline in exports from Western U.S. and Western Canada. The rest of their decline in exports is largely absorbed by the Southwest region, which now
supplies LNG to both the Atlantic and Pacific markets. Southwest already has large-scale export terminals operating and under construction. Despite the higher transshipment cost, the liquefier in the Southwest region still finds it profitable to export LNG to the Pacific. Compared to the REF case, total North American LNG exports to the Pacific market in 2050 fall by only 2.26% due to the restriction on new West Coast export facilities in the NWC scenario. Overall LNG exports to both markets decline by just 1.34%. These findings suggest that prohibiting new LNG infrastructure along the West Coast of the U.S. and Canada would not significantly diminish North American LNG export potential. The primary market response to such restrictions is for export capacity to simply relocate to other regions.

5.1.3. High LNG Demand scenario (HLN)

We now compare the HLN scenario results (Fig. 2c) to those from REF to analyze the effects of higher LNG demands on North American gas markets. The 2050 LNG export flows in HLN are the same as those observed in REF, but the volumes are substantially higher. LNG exports to the Pacific market from Western Canada increase from 2.60 Tcf to 7.19 Tcf, and from Western U.S. from 0.86 Tcf to 3.80 Tcf. Exports from Southwest to the Atlantic LNG market exhibit a relatively minor increase, from 1.32 Tcf to 1.57 Tcf. These findings demonstrate that North American natural gas markets have the potential to significantly scale up LNG exports to the Pacific in order to satisfy strong Asian demand growth. Assumptions about Atlantic LNG demand growth have a more subtle impact on North American markets, because Atlantic demand growth is generally weaker and price differentials are less attractive.

Pipeline flow from Central to Western U.S. in HLN is 2.5 times higher than in REF in 2050. This additional gas flowing west is exclusively used to feed LNG exports, as consumption in Western U.S. actually decreases by 5.54% compared to REF. Due to strong gas demand from the liquefier in Western U.S., the 2050 price in this region is 8.33% higher under the HLN scenario than under the REF scenario. Western U.S. experiences the sharpest increase in price, but prices in all North American regions increase by at least 5.64% due to additional demand from LNG exporters. This leads to a decline in end-use consumption in all regions, proportional to the increases in price.
To enable the higher LNG exports in HLN, production in this scenario expands significantly in the Western Canada, Central, and Midwest regions. Although Southwest has the greatest ability to increase its production capacity, it does not do so, as the increased LNG demand is mainly concentrated in the Pacific market. Western Canada and Western U.S. are the preferred locations for LNG export terminals shipping gas to the Pacific, which favors expanding production in Western Canada itself and the neighboring Central and Midwest regions.

5.1.4. No West Coast and High LNG Demand scenario (NWH)

The combination of high LNG demand and no new LNG export facilities in Western Canada and Western U.S. induces major shifts in 2050 gas flows in the NWH scenario results (Fig. 2d). Similar to what is observed when LNG infrastructure restrictions are imposed to move from REF to NWC, imposing these same restrictions to move from HLN to NWH causes most of the lost LNG exports from Western Canada and Western U.S. to relocate to the Southwest and (to a lesser extent) Mexico. However, under the steeper LNG demand growth of the HLN and NWH scenarios, the volume of West Coast exports that relocates is larger and the ripple effects throughout North American markets are stronger. The Southwest region switches from supplying LNG to only the Atlantic market in HLN to only the Pacific market in NWH, since increased Pacific demand causes the price differential available there to more than offset the additional transshipment cost. From HLN to NWH, Southwest LNG exports in 2050 increase from 1.57 Tcf to 8.34 Tcf. Mexican LNG exports more than double, but remain small in relative terms.

With Southwest LNG export capacity exclusively satisfying Pacific demand, the Northeast region begins supplying LNG to the Atlantic market (and a negligible amount to the Pacific). LNG exports from Northeast are not seen in any of the previous scenarios. Due to Northeast entering the LNG export market in the NWH scenario, the 2050 pipeline flow from Northeast to Southeast is approximately 35% lower than in the other scenarios (this flow remains in the narrow range 2.75–2.94 Tcf in REF, NWC, and HLN). This decline is partially compensated by a flow of 0.61 Tcf from Midwest to Southeast, which is virtually non-existent in the other cases.
When there is high LNG demand, restricting West Coast LNG development leads to the highest 2050 prices observed across all scenarios in every region except for Western Canada (where the NWH scenario prevents the liquefier from growing as a demand-side player). The high prices in NWH translate into lower consumption. Compared to HLN, prohibiting new LNG export facilities on the West Coast affects prices in the Southwest most severely, as its 2050 spot price under NWH is 15.08% higher. This is a direct result of the additional 6.77 Tcf of LNG that are shipped from this region. The next largest increase in price (11.94%) occurs in Mexico, whose LNG exports to the Pacific also expand in this scenario.

The decline in overall North American LNG exports in 2050 due to the West Coast infrastructure restrictions is very small under high LNG demands similar to under the baseline demands. Total LNG exports in NWH are 12.23 Tcf compared to 12.56 Tcf in HLN, a decrease of only 2.67%. Our findings suggest that North American LNG exports can scale up significantly to satisfy strong Asian demand growth even if new export infrastructure is prohibited on the West Coast, with LNG terminals in other regions absorbing nearly all of the West Coast reduction.

5.1.5. High Overall Demand scenario (HOD)

Lastly, we briefly compare the results from HOD against those from HLN to examine what happens if North American demands increase more significantly, similar to the LNG demands. The most interesting result in this case is that prices in 2050 are lower in every region under HOD than under HLN (the reductions vary from 0.88% to 3.48%), even though the regional gas demands are higher in HOD. Changes in production patterns explain this seemingly counterintuitive outcome for prices. Compared to HLN, stronger North American demand in HOD leads to significant increases in 2050 production. In the Southwest, Central, Western Canada and Midwest regions, the relative increases in production are 58.50%, 46.15%, 17.14%, and 9.37%, respectively. The more abundant natural gas supplies counteract the higher regional demands. The largest consumption increase compared to the HLN scenario occurs in Mexico (70.78%), while the smallest increase occurs in Southeast (15.63%). The HOD scenario results indicate that higher North American demands do not necessarily lead to higher North American prices, whereas
higher external LNG demands in isolation always cause prices to rise in our scenarios.

5.1.6. Summary statistics

Fig. 3 shows how total North American natural gas production (left) and consumption (right) evolve over time in the five scenarios. The HOD scenario leads to the most production in 2050 by a wide margin, demonstrating that increases in North American demands are more powerful drivers of production expansion than increases in external LNG demands. The effect of high LNG demand on North American production is weaker if LNG export facilities cannot be built in Western Canada or Western U.S. North American end-use consumption is also much higher in HOD than in the other scenarios, a result of higher regional demands that stimulate expansions in production capacity and supply. High LNG demand without high regional demands in North America puts upward pressure on prices but does not lead to significant supply increases. Therefore, North American consumption declines in the HLN and NWH scenarios. The drop in consumption is larger in NWH, where the locations of new LNG export facilities are restricted and thus exports are concentrated in fewer regions. Despite some numerical differences, our results in Fig. 3 are generally consistent with the trends and magnitudes revealed by other studies on the future of natural gas in North America (Feijoo et al., 2018; Moryadee et al., 2014b).

Fig. 3. Comparison of total production and total end-use consumption in North America across the five scenarios.
Trends in total LNG shipments from North America to the Atlantic and Pacific LNG markets are plotted in Fig. 4. These results clearly demonstrate our major finding that North American gas markets can significantly increase LNG exports to the Pacific to satisfy strong Asian demand growth, even if new export facilities cannot be built on the West Coast. The decline in total LNG shipments to the Pacific market due to the infrastructure restrictions is barely visible in the figure.

Fig. 4. Comparison of total LNG shipments to both markets across the five scenarios.

Long-run price trajectories in the five scenarios are plotted in Fig. 5. These prices are averages across all North American regions, weighted by regional consumption levels. The REF and NWC scenarios feature lower LNG demand growth, and thus lead to similar prices that are lower than those in scenarios with higher LNG demand. The HOD scenario, which includes high demands for both LNG and North American gas, induces the highest prices through the 2041 model period. However, as discussed in Section 5.1.5, HOD eventually stimulates significant production expansions that limit the price escalation toward the end of the analysis timeframe. By 2050, the NWH scenario yields the highest average price.

5.2. Natural gas infrastructure

Fig. 6 illustrates the cumulative additions to North American natural gas infrastructure from 2017 through 2050 in the first four scenarios, distinguished by assumptions about LNG demand growth and restrictions on new West Coast LNG export facilities. The maps show cumulative additions to pipeline, LNG export, and production capacities in each region. These results include both exogenously specified
5.2.1. Pipeline capacity

While the REF scenario results (Fig. 6a) include additions to many pipeline links in the network, the vast majority of the added capacity is currently approved and/or under construction. In fact, the only endogenous pipeline expansion in REF is the link from Western Canada to Eastern Canada. This remains the only network arc to receive endogenous pipeline investment in the NWC scenario (Fig. 6b), but the capacity added in this case is nearly double the capacity added in REF. The restrictions on scaling up LNG exports from Western Canada in NWC make more gas available for pipeline transmission to other regions, which incentivizes pipeline investment to Eastern Canada.

If LNG demand is high and new facilities can be located anywhere (HLN scenario, Fig. 6c), there is substantial motivation to transmit gas through the pipeline network to the West Coast for liquefaction and export. This leads to very significant cumulative pipeline capacity additions of 9.20 Bcf/d from Central to Western U.S. Pipeline investment from Western Canada to Eastern Canada decreases because a larger share of gas produced in Western Canada is shipped to the Pacific LNG market (64.72% in HLN vs. 40.91% in REF).
Fig. 6. Comparison of cumulative pipeline, production, and LNG export capacity additions from 2017 through 2050 under the first four scenarios. These results include exogenously specified additions that are currently approved and/or under construction.

In the NWH scenario (Fig. 6d) with high LNG demand and new West Coast LNG facilities prohibited, pipeline gas flows shift toward the Southwest, which is the dominant LNG exporting region in this case. Total pipeline capacity added is lower in NWH because the Southwest region scales up its own gas production to feed its liquefaction facilities, and because this region is better served by projects currently approved and/or under construction than the Western U.S. Unsurprisingly, the higher North American gas demands in the HOD scenario induce the most total pipeline investment. The HOD results include significant pipeline additions from Central to Western U.S. (9.52 Bcf/d), similar to HLN, and from Southwest to Mexico (12.01 Bcf/d).
5.2.2. Production capacity

The only production capacity expansions observed in the REF and NWC scenarios with baseline gas demand projections occur in the Midwest region (0.07 Bcf/d in REF and 0.79 Bcf/d in NWC). Demand growth in these scenarios does not justify large-scale production capacity investment given capacity expansion costs and the assumption of some idle capacity in the base year, previously discussed in Section 3.6.

High LNG demand in the HLN and NWH scenarios significantly increases cumulative production capacity additions. Total additions to North American production capacity are 20.26 Bcf/d in HLN and 14.26 Bcf/d in NWH. Whether new LNG export terminals are allowed to be built on the West Coast strongly influences where production capacity is added. In the HLN scenario where LNG facilities can be constructed anywhere, production capacity expansion focuses on Western Canada where gas is liquefied and exported to the Pacific LNG market. There is no production capacity added in Southwest.

This outcome is reversed in NWH, which restricts the expansion of LNG exports from Western Canada. In NWH, no production capacity is added in Western Canada, but substantial capacity is added in Southwest, which exports LNG to the Pacific market in this scenario. Production capacity is also expanded in the Central and Midwest in HLN and NWH. The HOD scenario with high LNG and North American gas demands leads to the largest cumulative production capacity expansion at 60.19 Bcf/d.

5.2.3. LNG export capacity

Our analysis projects that most LNG export infrastructure development will occur in Western Canada and Western U.S. unless new facilities are restricted in these regions. The Pacific LNG market is growing much faster than the Atlantic market, and the West Coast regions are well positioned to take advantage of lower transshipment costs to the Pacific. On top of the 3.72 Bcf/d of LNG export capacity already under construction in Western Canada, we observe an additional 4.25 Bcf/d of cumulative endogenous capacity investment in REF. This additional amount increases to 17.67 Bcf/d in HLN, with higher LNG demand. Similarly, 2.35 Bcf/d and 13.95 Bcf/d of LNG export capacity are added to the Western U.S. in the REF
and HLN scenarios, respectively. HOD leads to slightly less investment in total LNG export capacity than HLN because higher North American demand in HOD intensifies competition for gas supplies between North American consumers and liquefiers seeking gas to export.

The Southwest region is home to 6.11 Bcf/d of LNG export capacity that is currently approved and/or under construction. The only scenario that induces endogenous investment in additional Southwest LNG export capacity is NWH, where 19 more Bcf/d of export capacity is added to Southwest in addition to other scenarios. This is a consequence of NWH prohibiting new LNG infrastructure in Western Canada and Western U.S., thus shifting new export capacity to Southwest. NWH is also the only scenario that results in endogenous LNG export investment in Northeast.

Total cumulative LNG export capacity expansion over the analysis timeframe are plotted in Fig. 7. When new West Coast LNG facilities are prohibited, total North American export capacity investment declines slightly. Capacity is actually more affected than LNG export volumes because the infrastructure restrictions cause the Southwest export terminals currently under construction to be used at higher rates.

![Cumulative LNG export capacity expansion in North America](image)

**Fig. 7.** Comparison of cumulative LNG export capacity expansion in North America across the five scenarios.
6. Conclusions

The primary goal of this paper has been to investigate the combined effects of LNG demand growth and restrictions on West Coast LNG export facilities on the development of North American natural gas infrastructure and markets. To carry out this analysis, we constructed an equilibrium model comprised of nine North American regional gas markets interacting with one another as well as with two external LNG markets in the Atlantic and Pacific. The strategic players in the model make endogenous capacity investment decisions, which ties together our scenarios variables and their effect on future infrastructure development. The model is parameterized using only publicly available data sources.

The results show that North American gas markets can significantly scale up LNG exports to satisfy strong demand growth, particularly in Asia. Without any restrictions on new LNG export facilities, the Western Canada and Western U.S. regions are well positioned to export LNG to the Pacific market due to their closer proximity and lower shipment costs. Production expands in Western Canada and pipeline flows adjust to transmit gas to the Western U.S. to supply the liquefaction terminals.

If new LNG export infrastructure cannot be built along the West Coast of the U.S. and Canada, then LNG exports to the Pacific market largely relocate to the Gulf Coast of the U.S. and (to a lesser extent) the Pacific coast of Mexico. The total volume of North American LNG exports is thus quite robust to the possibility that opposition to gas infrastructure development on the West Coast would prevent new facilities from being constructed there. By shifting LNG exports to the Gulf Coast, these infrastructure restrictions also direct production and pipeline gas flows away from Western Canada and Western U.S., and toward the Southwest U.S.

Increasing external demand for LNG puts upward pressure on regional prices within North America, an effect that is stronger if infrastructure restrictions concentrate LNG development within fewer regions. The resulting higher prices can cause North American end-use gas consumption to fall even as demand rises. However, high LNG demand coupled with higher gas demand within North America incentivizes additional production capacity investments that counteract price escalation. As a result, under strong
LNG demand, regional prices within North America in 2050 can actually be lower even if North American demands are higher.

As with any model-based analysis, our findings should be interpreted in light of the limitations of the methodology. The nine-region representation of North America entails a high degree of spatial aggregation that neglects potentially relevant details of the pipeline network and the distances separating players and facilities within each region (e.g., production areas, consumption clusters, liquefaction facilities). Two LNG markets are incorporated in a simple fashion via linear demand curves. Without implementing a comprehensive global model in which North America competes with other LNG exporting regions around the world, it is difficult to parameterize the demand that can be satisfied by LNG exports from North America alone. Although we capture nonlinear costs in gas production, all other costs in our model are linear. This structure can yield winner-take-all model outcomes that concentrate investment and activity in one or a few regions more than is the case in reality. Our model projects natural gas infrastructure and market developments under various scenarios, but it does not shed light on the desirability of different outcomes. This would require a broader scope that considers social welfare inclusive of economic and environmental results.

These limitations suggest fruitful directions for future research. Despite these limitations, our analysis yields several important and novel insights about the future of North American natural gas markets, and how they will be shaped by LNG demand growth and regional restrictions on North American LNG export infrastructure.

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