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North American natural gas and energy markets in transition: insights from global models

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ABSTRACT

This modeling comparison exercise looks at the global consequences of increased shale gas production in the U.S. and increased gas demand from Asia. We find that differences in models' theoretical construct and assumptions can lead to divergences in their predictions about the consequences of U.S. shale gas boom. In general, models find that U.S. High Shale Gas scenario leads to increased U.S. production, lower global gas prices, and lower gas production in non-U.S. regions. Gas demand in Asia alone has little effects on U.S. production; but together with the shale gas boom, the U.S. can have a large export advantage. Overall, models find U.S. exports level range from 0.06 to 13.7 trillion cubic feet (TCF) in 2040. The comparison of supply, demand, and price changes in response to shocks reveals important differences among models. First is how the demand shocks were implemented and how the model responds to shocks: static and elastic within each time period vs. endogenous to the long-term gross domestic product (GDP) growth. Second is how the supply response is expressed through fuel/technology substitutions, particularly the flexibility of cross-fuel substitution in the power sector. Identifying these differences is important in understanding the model's insights and policy recommendations.

1. Introduction

A "fracking boom" in horizontal drilling and hydraulic fracturing in shale and tight formations in the U.S. has resulted in record increases in oil and natural gas production since 2007 (U.S. EIA, 2014b). It is widely expected that the U.S. will become energy self-sufficient and will likely become a net exporter of natural gas before 2020 (ExxonMobil, 2014; U.S. EIA, 2013, 2015a).

A major increase in natural gas consumption is expected to materialize in Asia over the next several decades. The Energy Information Administration (EIA) estimates that global gas demand will increase by 52–74% from the 2010 level by 2040 (U.S. EIA, 2013) and at least one third of this growth will come from Asia. The average annual growth rate for natural gas demand in the Asia Pacific region is estimated at 5.4% compared to 3.1% for the world as a whole (BP, 2012) due to an increase in economic growth fueled by high income and population growths, as well as by commitments to reduce carbon dioxide (CO_2) emissions and local air pollution in China. The total Asian demand for natural gas is expected to at least double, from 20.6 trillion cubic feet (TCF) in 2010 to 42–52 TCF in 2040 (U.S. EIA, 2013). Approximately two-thirds to three-quarters of the natural gas demand growth in Asia will come from China, with the rest largely from Japan and India. The rest of the global natural gas demand growth comes from the Middle East and North America.

Primary energy demand growth in the Asia Pacific region is still led by coal, which constitutes about one third of the total growth, with natural gas and liquids comprising about 18% each. Since the beginning of the US shale gas boom (ca. 2008), US coal production has decreased steadily by 30%; but the net exports level (after a long steadily decline from 1980 to 2007) have increased from ~2% production level (2004–2007) to 11% of the total production in 2011 and 2012 (U.S. EIA, 2015b). The increased coal exports have gone to Asia (e.g. Japan, China, and India), Europe (e.g. Germany, UK, The Netherlands, and Norway), Middle East, South Africa, and the UAE. The exports level dropped, however, in the last two years due to the drop for coal demand in Japan, China, and some European countries.

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1.1. Estimates of U.S. liquefied natural gas (LNG) exports from U.S. models

Several recent studies have examined the impacts of various levels of U.S. liquefied natural gas (LNG) exports on U.S. gas production, gross domestic product (GDP) and global gas prices using U.S.-only models (Baron et al., 2015; CRA, 2013; ICF, 2013; Montgomery et al., 2012; U.S. EIA, 2014c). For example, EIA examined LNG export scenarios of up to 7.3 TCF/yr (or 20 billion CF, BCF/d), given reference and high/low U.S. shale resource scenarios. It found that LNG exports could result in increases in domestic natural gas prices at the producer level of 4% to 11% and residential natural gas prices by 2% to 5% above the reference case over the 2015–2040 time period. However, it also found that GDP increased by 0.05% to 0.17% in the LNG export scenario, and increased energy production spurred investment that more than offset the adverse impact of somewhat higher energy prices (U.S. EIA, 2014c). The EIA study focused on the response in the U.S. energy market while ignoring how those additional volumes of natural gas exports impacted international natural gas and other energy markets. Similarly, previous studies using U.S. models also examined U.S. domestic impacts *given* an assumed fixed volume of exports by either ignoring linkages with international markets or using relatively simple regional supply and demand curves and elasticity assumptions to represent international responses given increased U.S. shale resources and/or high international demands.

1.2. Estimates of U.S. LNG exports from global models

Several studies that used global models to analyze the development of global natural gas markets reach quite different conclusions regarding the potential for U.S. exports (Arora and Cai, 2014; Baron et al., 2015; Holz et al., 2015; Medlock, 2012). Baron et al. (2015) applied a higher Asian demand shock using the Global Natural Gas Model (GNGM) and the N_{ew}ERA computable general equilibrium (CGE) model for the U.S. *assuming production was restrained in non-U.S. regions* and found U.S. LNG exports up to 12.8 TCF with positive GDP impacts. However, the study found less U.S. advantage when the non-U.S. production restraint was removed. Medlock (2012) built a simple international trade model exploring the important parameter space affecting the long-run equilibrium of international gas markets. These important parameters include the elasticity of U.S. and foreign supply, the role of short-term capacity constraints, and the value of the U.S. dollar. He argues that U.S. LNG exports may not be very large given expected market development abroad, and the impact on U.S. domestic prices will not be large in the long run.

Arora and Cai (2014) use a dynamic global CGE model contrasting the results with *exogenous* export assumptions where predetermined U.S. export levels are forced into the model without increased U.S. natural gas production vs. market determined *endogenous* export levels with increased U.S. natural gas production. The study found that when U.S. exports are forced into the system without a shift in the supply curve, U.S. natural gas prices are likely to rise; whereas an increase in U.S. resource productivity results in lower domestic and international natural gas prices and at the same time displaces exports from other natural gas exporting countries, including Russia.

1.3. Insights of U.S. natural gas response focusing on modeling differences

This modeling comparison exercise is part of the *Energy Modeling Forum (EMF) 31: North American Natural Gas and Energy Markets in Transition* that runs a common suite of scenarios through multiple, disparate models, as summarized in Huntington (forthcoming). This paper focuses on the international aspects of the study results that are not covered in Huntington (forthcoming), including global/regional natural gas production, consumption, exports and prices. We illustrate the connection between model properties and model results by investigating:

- the dynamics between the U.S. and international market responses in consumption, production and trade given a high U.S. resource (supply push) scenario, a high Asian demand (demand pull) scenario, and the combination of these two developments; and
- the direct and indirect feedback in the energy system and the macroeconomy in the U.S. and other regions.

We use four of the EMF 31 scenarios to illustrate the differences across model types. We draw attention to the effects of modeling approaches (model design and mathematical implementation) and implicit assumptions can have on the outcome and policy insights. Our aim is to shed light on how and why the findings from these model types diverge when each uses the same scenario assumptions. There are three models included in this modeling comparison: (1) a dynamic partial equilibrium model of global natural gas production, consumption and trade, (2) a dynamic general equilibrium model of the global economy, and (3) a game-theoretical global energy system and resource market (partial) equilibrium model. The three models represent three different approaches that have been intensively applied in the literature to study global energy markets. The models differ significantly in their theoretical constructs and assumptions, which often lead to contrasting predictions about the consequences of a common scenario. Modelers and researchers do not always explain the importance of model assumptions and the construction of the model in sufficient detail when putting forward their insights and policy recommendations. Therefore, it is important to conduct a comparison in order to address the robustness and sensitivity of the conclusions drawn from the modeling exercise.

In Section 2, we describe the models and scenarios used for this comparison. We compare model results across a range of scenarios designed to highlight some of the key drivers of global natural gas markets. In Section 3, we compare the model results across the scenarios. We discuss the policy implications of these results and suggestions for further research in Section 4.

2. Methodology

The three models are initially calibrated to generate individual reference scenarios that share the same assumptions about GDP and population growth, as well as natural gas productivity and prices. Subsequently, the models are shocked to simulate a set of three standardized counter-factual scenarios: high U.S. natural gas production, high Asian natural gas demand, and a combination of the two cases.

In this section, we first describe each model's structure and key assumptions pertinent to natural gas modeling (Section 2.1). We then describe the scenarios examined in this study (Section 2.2). We also conduct a simple comparison of key assumptions that are expected to drive differences in the results (Section 2.3).

2.1. The models used in the scenario comparison

2.1.1. The Global Gas Market Model GNGM

The Global Natural Gas Model (GNGM) is a dynamic partial-equilibrium model of natural gas production, consumption, and trade by major consuming and producing regions (Baron et al., 2014, 2015). Each regional market is characterized by its location, availability of indigenous resources, pipeline infrastructure, accessibility to natural gas from other regions of the world, and its rate of growth in natural gas demand. Some regions are connected to other regions by pipelines, others by LNG facilities, and some operate relatively autonomously. In general, a region will meet its natural gas demand first with indigenous production, second with deliveries by pipelines connected to other regions, and third with LNG shipments (Baron et al., 2014). The natural gas supply and demand curves in each region are represented by constant elasticity of substitution (CES) functions.

Table 1
Supply and demand elasticity of natural gas in the GNGM model.

	2014	2015	2020	2025	2030	2035	2040
Demand elasticity							
North America	−0.35	−0.36	−0.39	−0.42	−0.46	−0.50	−0.54
Rest of the world (ROW)	−0.11	−0.11	−0.13	−0.15	−0.17	−0.20	−0.23
Supply elasticity							
North America	0.22	0.24	0.33	0.43	0.53	0.62	0.72
Africa & Europe	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Rest of the world (ROW)	0.22	0.23	0.26	0.30	0.35	0.40	0.46

The supply elasticity varies across regions depending on the ease of accessing gas resources as shown in Table 1. The demand elasticities for Canada and the U.S. are derived based on average delivered price and consumption fluctuations reported in the EIA Study (U.S. EIA, 2014c).

2.1.2. The General Equilibrium Model GTEM-C

The Global Trade and Environment Model-CSIRO (GTEM-C) model is a recursive dynamic global CGE model (Cai et al., 2015) that builds on the Global Trade Analysis Project (GTAP) 9 database (Narayanan et al., 2015; Peters, 2015). The current version of the model has 13 regions and 19 sectors that include five energy sectors (coal, gas, crude oil, refined petroleum products, and electricity) and 14 non-energy sectors. The regions interact with each other through trade and capital flows.

The three primary energy producing sectors in GTEM-C (coal, gas, and crude oil) are also modeled with a CES function with fixed supply resources. Following Hertel et al. (2005) and Beckman et al. (2011), the substitutions between resources, capital and labor are calibrated so that the long-term supply elasticities of coal, gas and crude oil, are 1.0, 0.5, and 0.25, respectively for all regions in the model's base year of 2011. Over time, as capitalization of the three sectors deepens, the long-term supply elasticities will improve but with diminishing return to capital.

The demand for energy in GTEM-C is modeled using the CRESH (Constant Ratios of Elasticities of Substitution, Homothetic) function. The CRESH function is a more general form of the CES function, allowing for different degrees of price elasticities among the fuel types (Cai and Arora, 2015). For this modeling exercise, the price elasticities of substitution for energy demand in GTEM-C are calibrated to reflect the empirical findings of Urga and Walters (2003), RAND (2005) and Stern (2012), as well as the EIA's National Energy Modeling System (NEMS) modeling assumptions (U.S. EIA, 2013) as shown in Table 2.

GTEM-C has aggregated power generations in the GTAP electricity database (Peters, 2015) into 8 technologies: coal, oil, gas, nuclear, hydro, wind, solar, and other renewables.[1] Having these technological details of power generation within a global general equilibrium framework allows GTEM-C to model the rising demand for natural gas in Asia due to, for example, the coal-to-gas switching in the Chinese power sector or the phase-out of nuclear power in Japan, and to evaluate its complex effects on the global energy markets.

2.1.3. The resource market model MultiMod

The energy system and resource market model "MultiMod" is a large-scale representation of the global energy system with particular detail for global fossil resource markets (Huppmann and Egging, 2014). The model's base year (2010) is calibrated to the IEA's World Energy Statistics and Balances (IEA, 2013a, 2013b). Projections for production and sector/fuel consumption are calibrated to EIA's Annual Energy Outlook (U.S. EIA, 2014a) for the North America, European Commission's Reference Scenario 2050 (Capros et al., 2013) for Europe and the World Energy Outlook (IEA, 2014) for the rest of the regions.

Table 2
Demand and supply elasticities assumed in GTEM-C model.

	Gas	Coal	Oil	Electricity
Demand elasticity				
Industrial	−0.50	−0.50	−0.50	−0.50
Household	−0.50	−0.50	−0.50	−0.50
Supply elasticity (long-term)				
	0.5	1.0	0.25	

The model is partial-equilibrium, formulated by deriving first-order optimality conditions for each player and solving them simultaneously as a generalized Nash equilibrium (GNE); mathematically, this yields a mixed complementary problem (MCP). Individual players, representing different actors along the energy supply value chain, maximize their own profits. These players include suppliers of energy carriers or fuels (both fossil and renewable), transportation infrastructure operators (pipelines, the LNG chain, shipping), a transformation sector (power plants, crude oil refineries), and seasonal storage operators. Consumption of energy is modeled as a linear inverse demand curve for services derived from energy consumption; the mathematical formulation incorporates endogenous substitution between different fuels on the final-demand side. Furthermore, each player decides on production and infrastructure capacity investment over time according to its individual inter-temporal optimization rationale (profit maximization with player-specific discount rate), and thereby the model accounts for the changing plant stock in the power sector.

In contrast to the other models, MultiMod uses a logarithmic production cost function for the crude oil and natural gas sector. As a consequence, supply elasticity is high at low levels of capacity utilization, and vice versa. In addition, the logarithmic cost function adds a "learning-by-doing" effect from investment in additional production capacity, because capacity expansion in one period reduces marginal costs in subsequent periods, ceteris paribus. The model also incorporates a reserve horizon constraint, which implies a Hotelling-type extraction path for those suppliers where the reserves are binding over the model horizon.

On the demand side, price elasticities for each fuel and consumption sector (see Table 3) yield a weighted price elasticity value for "energy services" (utility derived from the consumption of energy) based on the reference fuel mix in each sector and at every demand node. From this value, a linear inverse demand function for energy services is computed. Cross-fuel substitution is incorporated using linear end-use costs, which mimic the more commonly used CES functions. The linear functions representing the demand side in MultiMod allow substitution between different fuels within a sector. The end-use costs help to avoid "bang-bang" results and force a more gradual shift of the fuel mix. Nevertheless, under very drastic changes of the supply price assumptions, a complete transition of the fuel mix can occur, in contrast to models based on CES functions.

By virtue of being formulated as an integrated equilibrium problem, the model can include Cournot or conjectural-variation market power across multiple fuels by certain suppliers, in particular Russia and Middle East suppliers exerting market power in both crude oil and natural gas markets. A more detailed description of the model and the underlying global data set is provided by Huppmann and Egging (2014).[2] For a more recent study using the MultiMod framework to analyze scenarios on the North American natural gas market and the Mexican energy reform, please refer to Feijoo et al. (2016).

[1] The coal, oil and gas technologies are further divided into conventional thermal sub-technologies and their counter-parts with carbon capture and storage (CCS).

[2] For an overview of recent developments of the MultiMod model, see http://www.diw.de/multimod.

Table 3
Per-fuel demand elasticities assumed in the MultiMod model.

	Gas	Coal	Lignite	Crude oil	Oil products	Biofuels	Electricity
Industrial	−0.45	−0.35	−0.30	−0.25	−0.30	−0.45	−0.50
Residential	−0.35	−0.20	−0.20		−0.30	−0.30	−0.45
Transport	−0.30	−0.20			−0.25	−0.30	−0.30

2.2. Scenarios

2.2.1. Reference (Ref) scenario

The EMF 31 Reference scenario is based on the Annual Energy Outlook (AEO) 2014 reference case (U.S. EIA, 2014a). All models are calibrated to the AEO 2014 projections for world oil prices, U.S. economic growth and population trends, and current energy and environmental regulatory policies-in-place in 2014. Models' international energy systems are calibrated either to the EIA's International Energy Outlook 2013 (U.S. EIA, 2013), the latest IEO available at the time of the exercise, or to other authorities.[3] This *Ref* scenario calibration results in U.S. gas production increasing from 22.5 TCF in 2011 to 37.5 TCF in 2040. Furthermore, the long-term U.S. supply elasticities of natural gas are calibrated to be alike across the three models at around 0.5 (U.S. EIA, 2014a). In GNGM reference scenario, the U.S. becomes a net exporter in 2020 and exports 3.1 TCF of gas in 2040. Both GTEM-C and MultiMod suggests U.S. becomes a net gas exporter only after 2030 at lower volumes (1.3 TCF in 2040 in GTEM-C and 0.05 TCF in 2040 in Multimod). As a reference, AEO estimates of natural gas exports have increased slightly from around 8.0 (U.S. EIA, 2014a) to 8.9–9.2 TCF (U.S. EIA, 2016) including more growth in LNG from 3.5 TCF (U.S. EIA, 2014a) to 6.7 TCF (U.S. EIA, 2016) by 2040.

2.2.2. High U.S. Shale Gas (HiGas) scenario

This scenario represents greater natural gas availability at lower costs than in the reference case. This is implemented via a gradual shift down of the *gas* supply curve (i.e. decreasing the cost of production) from 9% in 2015 to 40% in 2040 following the trajectories of the "high oil and gas resource" scenario in the AEO 2014. The oil supply curves are kept the same as in the reference case. Although the shale revolution has stimulated tight oil expansions and AEO's high resource scenario explores both increased production of oil and gas, this study only looks at the expansion of gas resources. This is done for simplicity, and also because the global oil market is increasingly distinct from the natural gas market. In the sensitivity analysis, we also simulated a high oil and gas resource scenario similar to AEO's, and the results were not qualitatively different. Therefore the results for high oil and gas resources are not reported here. A separate study in this special issue explores the topic of gas price indexing to oil and the results are reported separately (Bernstein et al., 2016). Many shale gas plays are "wet" with high liquid content, but the study does not cover these products.

To model the *HiGas* scenario all three models shift the supply curve outwards (to the right of the Reference curve) by changing the reference supply price (wellhead price). The unit cost incurred along different segments of moving natural gas from wellhead to city gate via pipeline and LNG shipping options remains that same in all models. Hence, we only see roughly 40% reduction in the well-head price and not in the delivered price. In GTEM-C, gas production is a nested CES function of capital, labor and fixed resources (i.e. natural gas reserve), together with other intermediate inputs. The "40% cost reduction" is modeled as an efficiency improvement of the fixed resources, leading to an almost equivalent drop in wellhead costs.[4] In MultiMod, the "40% reduction" only applies to the long-term investment costs and short-term operational costs. The mark-ups along the supply chain (transmission and distribution, LNG export) are not affected. Therefore, a delta in cost is a larger percentage of wellhead price than delivered price when there are other markups present and the cost savings transmitted to the end users is much smaller than compared with GTEM-C and GNGM. As a result, the same "cost reduction" shock on the three models shifts the U.S. natural gas supply curve to the right by different amounts, despite the fact that the three models have been calibrated to similar long-term supply elasticities of natural gas (i.e., slopes of the supply curves).

2.2.3. High Asian Demand (HAD) scenario

This scenario represents a storyline that supposes increases in Asian demand for natural gas by approximately 20% in 2040 compared to the *Ref* scenario. These increments were added to reference consumption levels at the reference price levels, i.e., they represent 20% shifts in the Asian demand curve as a result of preference, policies, or technological change (as opposed to a direct price change). Equilibrium consumption levels are anticipated to be lower than this shift as prices rise. For GTEM-C and MultiMod, where country specific technology details exist, coherent story lines are developed to guide the implementation of this scenario. In the case of GTEM-C, the following changes are introduced:

- Annual coal use in China for electric generation grows by 1% less than in the reference case through 2040 due to exogenous policies.[5]
- Annual nuclear use in the Northeast Asia (Japanese/Korean) grows by 1% less than in the reference case through 2040 due to exogenous policies.

In MultiMod, the following assumptions are made:

- Demand for energy services in all four Asian regions (China, Asia OECD, Indian subcontinent, Southeast Asia) was increased over time, up to a 20% increase in 2040.
- Investment in coal-fired power generation without CCS was restricted to 50% of the *Ref* scenario results in all periods.
- End-use costs for natural gas use in final consumption in China were reduced by 1% in all future periods to mimic regulations and other implicit (i.e., non-market driven) measures to transition towards a less carbon-intensive economy.
- A mandate for natural-gas use in transportation in China was introduced and increased over time, reaching 10% of final energy consumption in the transportation sector in 2050.

For reference, Asian natural gas demand is 40 (GTEM-C)–70 (MultiMod) TCF and world natural gas demand outside the U.S. is 155 TCF in 2040 (GTEM-C and GNGM) and 205 TCF (MultiMod). Based upon these estimates, an Asian shock of 20% translates to about 8–14 TCF. This shock translates to about 5–9% of the world gas demand outside the U.S. in 2040.

The modeling teams also simulate the combined scenario of *HAD* and *HiGas*. The purpose is to observe the robustness of the *HAD* scenario to a different assumption about natural gas supplies. An overview of all the scenarios is presented in Table 4.

2.3. Expected differences among the modeling results

Although the three models simulated the same set of scenarios, significant differences were anticipated among their results. Each of the three models demonstrated different U.S. and global natural gas supply responses due to the different modeling constructs and assumptions about the gas supply and demand responses, and intersectoral fuel substitutions domestically and in the rest of the world. Depending on the slope of the U.S. natural gas demand curve, the

[3] The MultiMod model uses the European Commission's Reference Scenario 2050 (Capros et al., 2013) for Europe and the World Energy Outlook (IEA, 2014) for the rest of the regions.

[4] Empirically the shadow price of fixed resources dominates the wellhead costs in GTEM-C, ensuring that the resource constraint is always binding.

[5] Please see a separate study in this special issue by Arora et al. (in preparation).

Table 4
Description of scenarios.

Name	Description
Reference (*Ref*)	U.S. projections consistent with AEO 2014 reference case (U.S. EIA, 2014a); International projections calibrated to IEO 2013 (U.S. EIA, 2013) in GTEM-C and GNGM; MultiMod calibrates international projections to European Commission's Reference Scenario for Europe (Capros et al., 2013) and the World Energy Outlook (IEA, 2014) for the rest of the regions.
High U.S. Shale Gas (*HiGas*)	U.S. gas production shock consistent with AEO 2014 "high oil and gas resource" scenario (U.S. EIA, 2014a). This is implemented via a shift down in the natural gas supply curve (decreased costs of production) starting from 9% in 2015 and reaching 40% in 2040.
High Asian Demand (*HAD*)	Expand the Asian demand for natural gas by 20% (~14 TCF) in 2040.
High Asian Demand and High U.S. Shale Gas (*HAD + HiGas*)	A combined scenario of *HAD* and *HiGas* to observe the robustness of the *HAD* scenario to a different assumption about natural gas supplies.

equilibrium natural gas price and production differ across the models, as illustrated in Fig. 1.

The internal dynamics and macroeconomic linkage of each model will also lead to differences in the results. This is more important when considering the economic consequences of each scenario. For instance, in GNGM and MultiMod, GDP is exogenous and energy demand only responds to price changes based on the assumed elasticity. GNGM is a partial equilibrium model, hence it does not explicitly model the income effects (US and other world regions) as a result of lower natural gas prices, although its natural gas price elasticity could implicitly include the effect of higher GDP. In contrast, natural gas demand is endogenously estimated in GTEM-C and mainly driven by changes in GDP (income effect) in the long term. Under the *HiGas* scenario, lower U.S. and international natural gas prices can benefit non-energy sectors of the economy and contribute positively to regional GDP. This can increase global demand for natural gas. Similar to GNGM, GDP is exogenous for the MultiMod model. But unlike GNGM it covers the entire energy system and applies inverse demand functions for aggregate energy consumption per sector. As a consequence, the demand effects (price sensitivity of energy demand) and the intra-sector substitution (cross-price elasticity between fuels used in a sector) cannot be directly disentangled in this framework. Supply price increases of one fuel lead to a reduction of overall energy demand, but at the same time to a shift in the fuel mix of each sector towards the relatively cheaper alternative fuels.

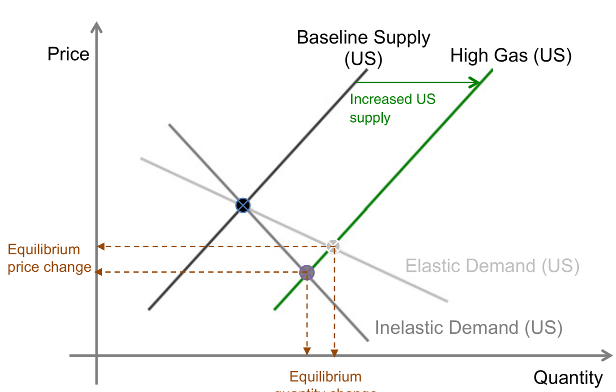

Fig. 1. Shifts in the U.S. supply curve in the *HiGas* scenario.

3. Results

3.1. High Shale Gas (HiGas) scenario

3.1.1. Production and demand change

The costs of U.S. production are lowered gradually by up to 40% in 2040 in the *HiGas* scenario. This results in an increase in U.S. natural gas production by 13.8, 15.4 and 6.4 TCF in GNGM, GTEM-C and MultiMod, respectively, in 2040 (Fig. 2). The production increases in GNGM and GTEM-C are greater than the change suggested by the AEO 2014 (8 TCF, or 21% increase in U.S. production in 2040)(U.S. EIA, 2014a), while that in MultiMod is smaller. As we will show shortly, these quantity changes are consistent with the price changes predicted by different models.

The effects on other world regions in GNGM, MultiMod and GTEM-C vary. In GNGM, U.S. natural gas production increases by about 40% since the natural gas is available at lower wellhead prices (about 40% lower) relatively to the reference case. Lower U.S. natural gas prices supports more LNG exports from the U.S. displacing indigenous production from other world regions (Fig. 2, top) resulting in lower natural gas prices everywhere by about 10% (Fig. 3), increased demand (Fig. 2, bottom) and lower production everywhere else.

In the CGE framework of GTEM-C, higher U.S. supply at lower prices has two effects on the rest of the world from 2015 through 2040. One is the first-order substitution effect in displacing and reducing natural gas production in other countries. Another is the second-order income effect of increasing natural gas demand globally and economic growth of gas importing countries, both of which over the long-term help to restore the initial declines of gas productions in non-U.S. gas exporting regions. The two effects happen at the same time, although one may dominate the other. In GTEM-C *HiGas* scenario, the first-order effect dominates pre-2020.[6] For each extra TCF that is produced in the U.S., it replaces almost 0.1 TCF that is produced in the rest of the world. However, as the second-order effect builds up over time, cheaper natural gas price is boosting overall demand growth that is almost comparable to the growth in U.S. production. Post 2020 the substitution effect diminishes; and for each extra TCF that is produced in the U.S., it replaces less than 0.05 TCF that is produced in the rest of the world. So the rest of the world produces only slightly lower than in the baseline, despite the competition from cheaper U.S. natural gas (Fig. 2, bottom). The overall impact is slightly larger demand growth and lower decline in production for the rest of the world compared to GNGM.

As discussed before, MultiMod is also a partial equilibrium model like GNGM, where GDP effects are not included, hence price (and welfare) changes in previous periods have no impact on the demand in the current period. MultiMod uses an inverse demand curve for aggregate energy services by sector in each time period, and the model has a detailed representation of the power sector that can shift to new fuels/technologies under different supply and demand situations. Therefore, the power sector absorbs price shocks easily, and the model exhibits very little price or quantity change given a shock in high U.S. natural gas resource. Lower costs for gas lead to higher gas consumption in North America, while less coal is consumed domestically compared to the Base Case. Having lower shipping costs than gas, it is economical to export the surplus of coal to other regions, which crowds out natural gas consumption in the *HiGas* scenario in other world regions relative to the *Ref* scenario (Fig. 2, bottom).

3.1.2. Change in natural gas wellhead price

Natural gas wellhead prices in the reference case and price changes in alternative scenarios in 2040 are shown in Fig. 3. GTEM-C only presents indexed price changes from the base year 2012 therefore we take the 2015 prices in GNGM as the base year price for GTEM-C. GTEM-C shows fairly high natural gas price for Europe, China, and Rest

[6] The results are not shown in the paper, but available upon request from the authors.

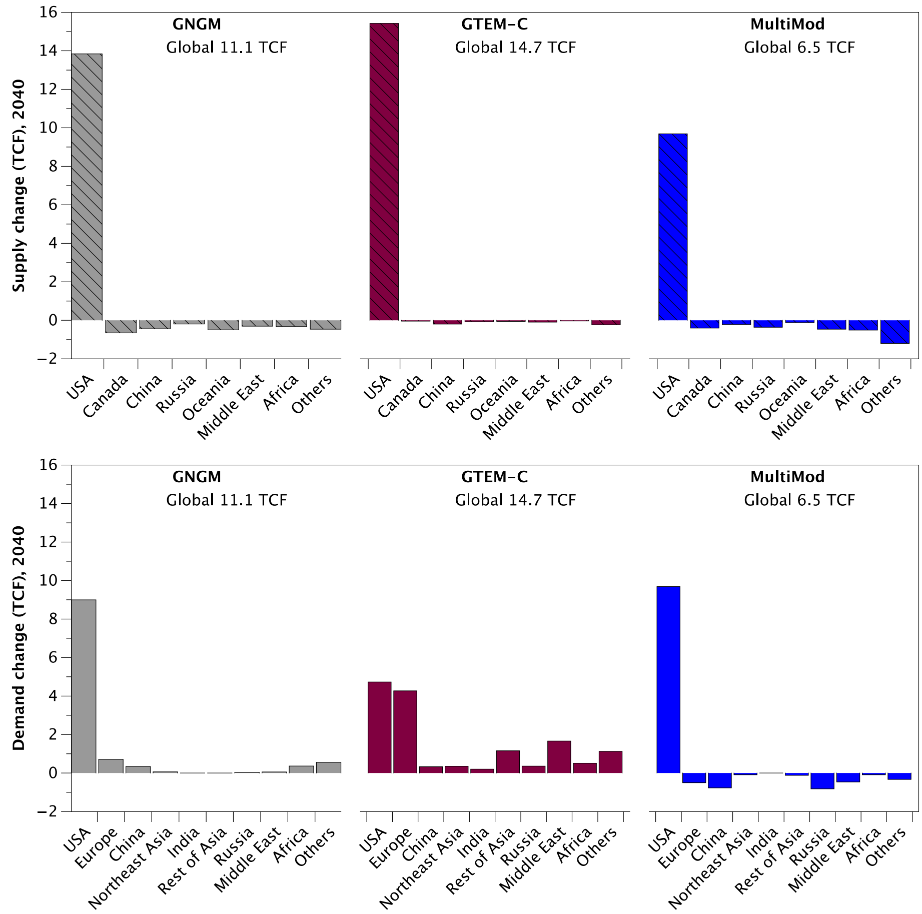

Fig. 2. Production (top) and demand changes (bottom) in *HiGas* scenario compared with the *Ref* scenario in 2040. Numbers shown below the model names are the total changes globally.

of Asia (Southeast Asia) in 2040. In equilibrium, U.S. wellhead price is estimated to be \$3.9–\$11.6/Mcf in 2040 across the three models in the *Ref* scenario and \$3.0–\$11.2/Mcf in *HiGas* scenario, or 39%, 24%, and 3.3% lower compared to the reference case in GNGM, GTEM-C, and MultiMod, respectively (Fig. 3). These differences can be explained by the models' different structures. Under GNGM's partial equilibrium framework, the 40% cost reduction is almost fully passed on to the market price; while under GTEM-C's general equilibrium framework, lower supply price leads to excess demand, so the equilibrium price will increase in order to clear the market. In MultiMod, natural gas price hardly changes since the mark-ups along the supply chain are unaffected and the very elastic domestic gas demand (in particular power generation being the most flexible part of natural gas demand) results in a very small price increase in the aggregate.

Gas prices in the other countries were also lower, with most regions falling < 10% for GNGM[7] and GTEM-C and < 1% for MultiMod in 2040.

3.1.3. Change in export level

GNGM estimates U.S. exports to increase by 4.8 TCF in 2040 from 3.1 TCF in the reference case to 8.0 TCF in the *HiGas* scenario (Fig. 4). GTEM-C estimates U.S. exports to increase by 10.7 TCF in 2040 from 1.3 TCF to 12.0 TCF in the *HiGas* scenario. Both GNGM and GTEM-C expect lower export levels from other natural gas exporting regions due to the competition from U.S. exports. In contrast, MultiMod shows no significant changes in export levels from any region between the two scenarios. This is mainly driven by MultiMod's model design that results in a very flexible power sector that switches fuel mix easily. Due to the lower shipping costs of coal, the U.S. absorbs almost all of the increased natural gas production domestically, resulting in almost no net change in gas export levels.

3.2. High Asian Demand (HAD) scenario

Total Asian demand is shifted by 20% in (14 TCF) in 2040 in this scenario, but the equilibrium change is lower, about 12–20% (4.1–14 TCF) (Fig. 5). Global consumption level changes are significantly lower for GNGM (5.1 TCF) and GTEM-C (1.8 TCF) while they remain closer to the initial shock for GNGM (Fig. 5). The consumption increase is mainly in China in GTEM-C, due to how the scenario was set up initially (as described in Section 2.2.3); while the increase is more evenly spread between China, Northeast Asia, and Rest of Asia in GNGM. MultiMod implemented the Asian demand increase through both an increase in overall energy demand (shift of the aggregate energy demand curve for each sector) as well as a number of policies to support the transformation of natural gas, like a mandate for natural-gas vehicles and limits on coal-fired power plant investments. This induces a shift in Asian natural gas consumption from India, where coal replaces natural gas because of less stringent assumptions regarding these additional policies, to China and other Asian countries. Overall the model differences in demand change are mainly caused by how the scenario was setup by the modelers.

Higher Asian demand raises global natural gas prices (Fig. 3) by between 5 and 30% (\$0.8–\$1.86/MCF) in most regions, with the increases being more significant in Asian countries and Europe. GNGM also expects higher percentage increases in natural gas prices in Rest of Asia (Southeast Asia), Oceania (Australia) and Africa. As a result of

[7] Except South America and Europe (12%) and Australia (17%).

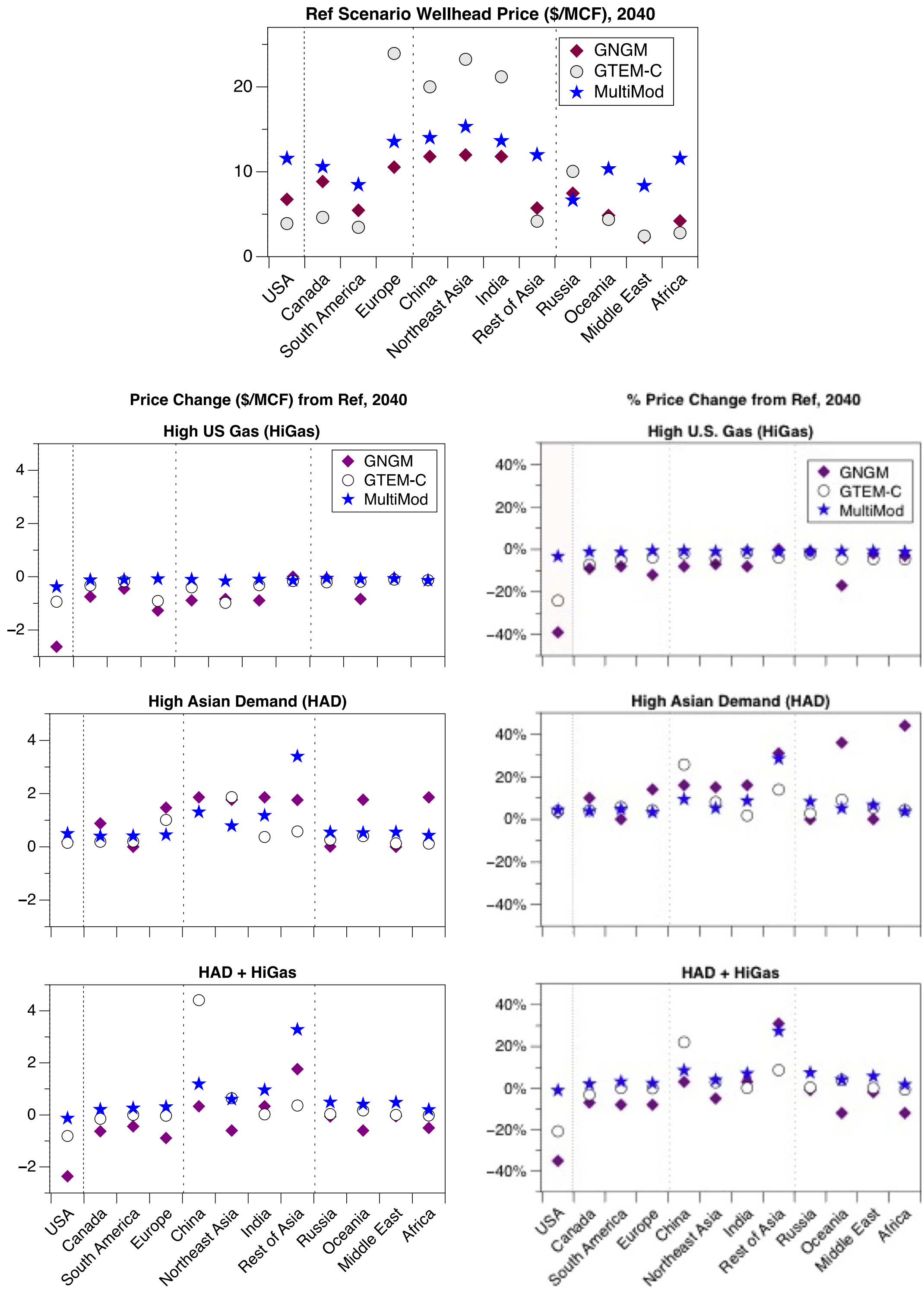

Fig. 3. Natural gas wellhead price (top) and price changes in alternative scenarios compared with the *Ref* scenario in 2040. Left: absolute change. Right: percent change.

generally increasing prices, demand levels in non-Asian countries decrease (Fig. 5). In particular, domestic demand in natural gas supply regions (e.g. Africa, USA, Russia and Middle East) and key consuming regions (e.g., Europe and India) are negatively impacted by higher natural gas prices. The reductions in gas use in other regions, in particular Russia, Middle East and Europe, are due to higher prices for fossil fuels globally due to higher demand in Asia.

GNGM suggests that the increased Asian demand will be met by increased production from Rest of Asia countries (Indonesia and Malaysia), Australia, China, U.S., and Africa, in decreasing order (Fig. 5, top). GTEM-C on the other hand, suggests the increased production will come from China, U.S., Rest of Asia, Australia, Middle East, and Russia. MultiMod suggests production increases in Southeast Asia, China, Middle East, Russia, U.S., Canada, Africa and Australia. In *Ref* scenario, Southeast Asian countries double production gradually from 5.75 TCF in 2015 to 11.8 TCF in 2040. Because of the strong push towards gas in China, Southeast Asian countries ramp up production far more quickly – and then runs dry towards the end of our model horizon

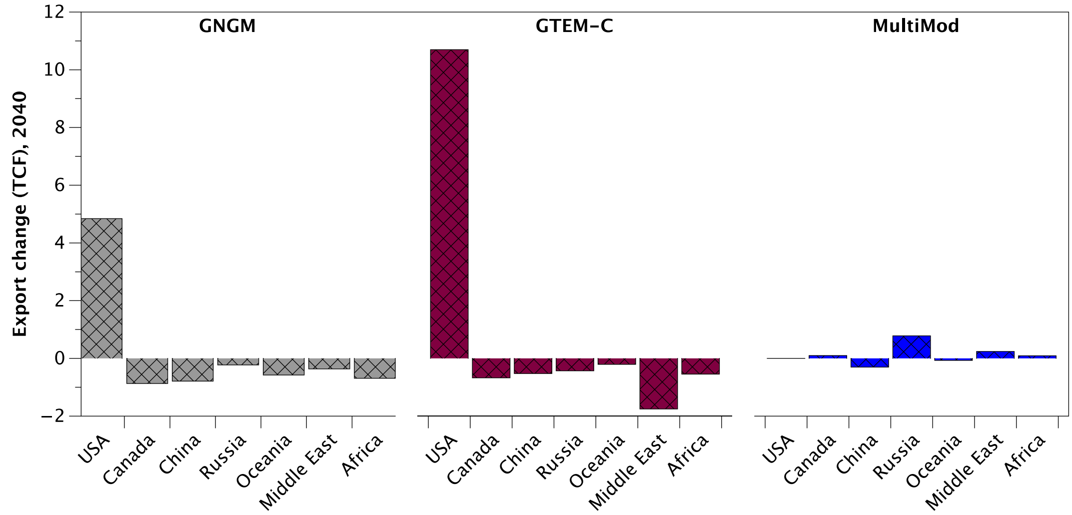

Fig. 4. Changes in net export levels in the *HiGas* scenario compared with the *Ref* scenario in 2040.

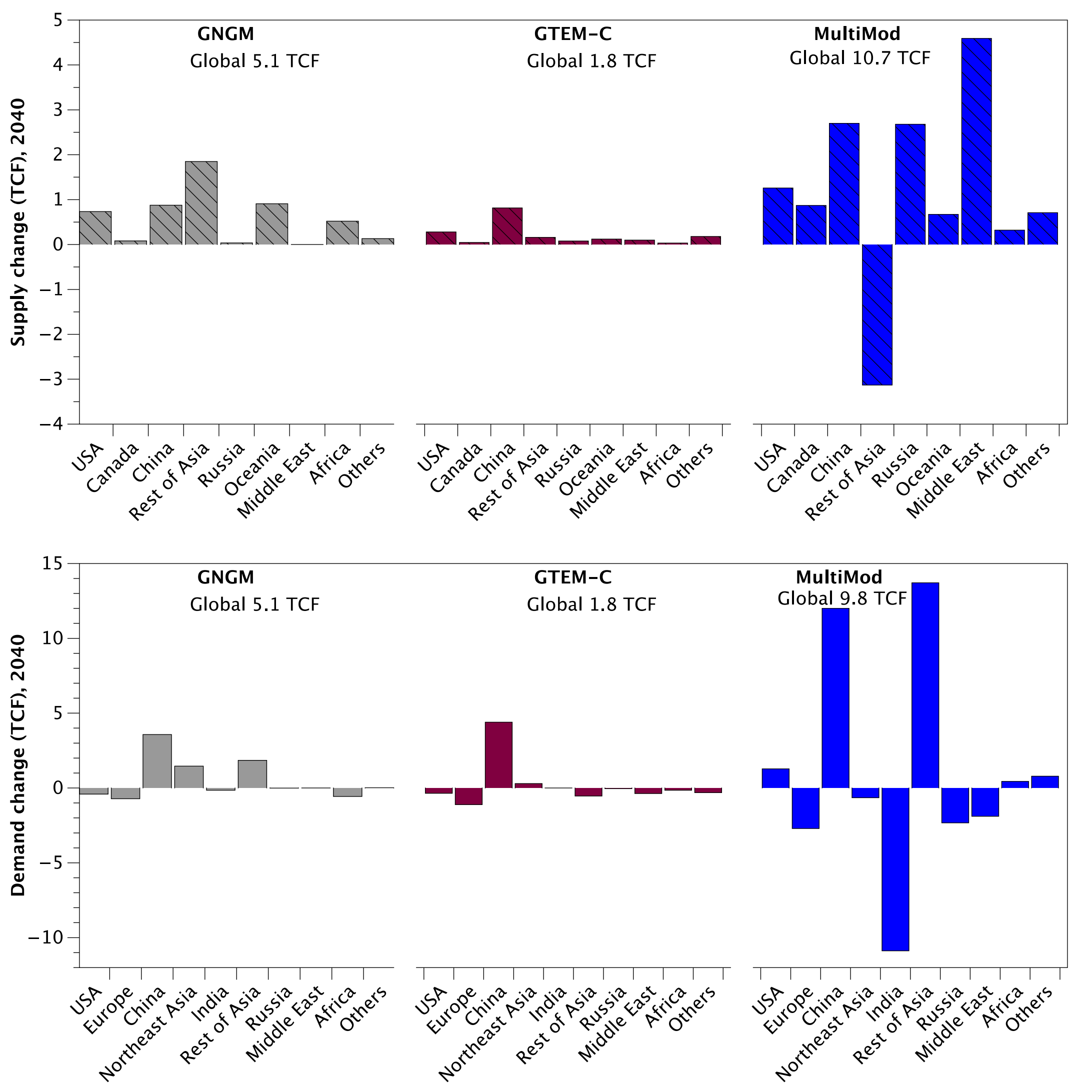

Fig. 5. Supply (top) and demand (bottom) changes in *HAD* scenario compared with the *Ref* scenario in 2040. Numbers below model names are the total changes globally.

as seen in Fig. 5, suggesting a production drop in year 2040 compared to the *Ref* scenario. Total gas production in Southeast Asia increased by 40% during this period (2015–2040) relative to the *Ref* scenario.

The net changes in U.S. export level are small: 1.1, 0.63 and −0.02 TCF in GNGM, GTEM-C and MultiMod, respectively, in 2040 (Fig. 6). Countries with large export increases (Fig. 6) are U.S., Australia, Africa, Russia (MultiMod) and the Middle East (MultiMod), with various degree of estimates by different models.

3.3. High Asian Demand and High Gas (HAD + HiGas) scenario

The results of *HAD + HiGas* scenario mimic *HiGas* scenario in both GNGM and GTEM-C. In MultiMod, the results of *HAD + HiGas* scenario is similar to *HAD* scenario except the increased production from the U.S. In GNGM, overall global demand is 16.8 TCF higher than in the *Ref* scenario, with supply increases from the U.S. and Rest of Asia (Maylasia and Indonesia), and production decreases in Canada, Australia, South America and the Middle East. Lower U.S. natural gas prices make the U.S. competive in the European natural gas market relative to other suppliers (e.g. Africa) and high Asian demand provides an opportunity for U.S. LNG exports to fill in some of the demand in China and India which is not possible under the reference case.

Gas prices are lower similar to the *HiGas* scenario except slightly higher prices in Asian countries for GNGM and GTEM-C where demand growth is stronger by assumption in this scenario. MultiMod, on the other hand, estimates higher gas prices as the demand stimulus offsets the effect from higher U.S. gas resources. Both prices and production increase relative to the reference case with results more similar to *HAD*. Increased U.S. production in the *HAD + HiGas* scenario reduces production from Russia and the Middle East.

The estimated U.S. export levels across all scenarios are summarized in Fig. 7 below. Overall, MultiMod estimates very little U.S. exports in all scenarios. U.S. export levels are estimated to be the highest at around 12–14 TCF in *HAD + HiGas* scenario in both GNGM and GTEM-C in 2040, compared to 1.3–3.1 TCF in the *Ref* scenario in 2040.

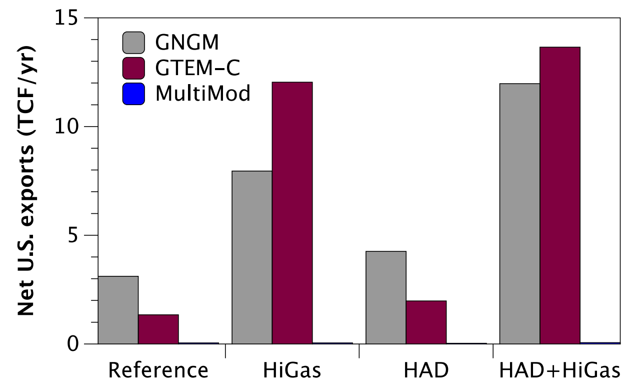

Fig. 7. U.S. natural gas export levels in 2040 across three models for all scenarios.

4. Discussion of modeling results

The results of the study reflect changes relative to a baseline scenario and hence are not forecasts that project future changes based on past observations. It is difficult to predict the exact nature of shocks and other changes that may also occur at the same time, either as a result of or independent of the shocks examined in this study. Therefore the impacts of the changes cannot be precisely predicted. Yet this modeling exercise offers a useful way to isolate the effect of a specific shock and the ripple effects that propagate through the complex energy system reflected by different structured views of the world through the framework of a partial equilibrium model that assumes perfect market competition (GNGM), a CGE model (GTEM-C) that captures the feedback effects between energy systems and economic growth, and a game-theoretical partial equilibrium model that maximizes individual players' profits (i.e., assumes imperfect competition in fossil fuel markets) with detailed technology substitution options in the power sector (MultiMod). These differences in model structures and model assumptions can explain some of the major differences in the results, particularly direct impacts on natural gas prices and indirect effects through the feedback on demand and production changes due to the endogenous changes in GDP levels in both consuming and producing regions. Such differences can influence and drive the numerical results of models used for projections and scenario simulation. We first discuss our observations on the importance of modeling differences in Section 4.1 and offer our concluding remarks in Section 4.2.

4.1. Important modeling differences contributing to direct impacts

The comparison of supply, demand, and price changes in response to shocks reveals some important differences among these models. The first major difference is how the demand levels were estimated and

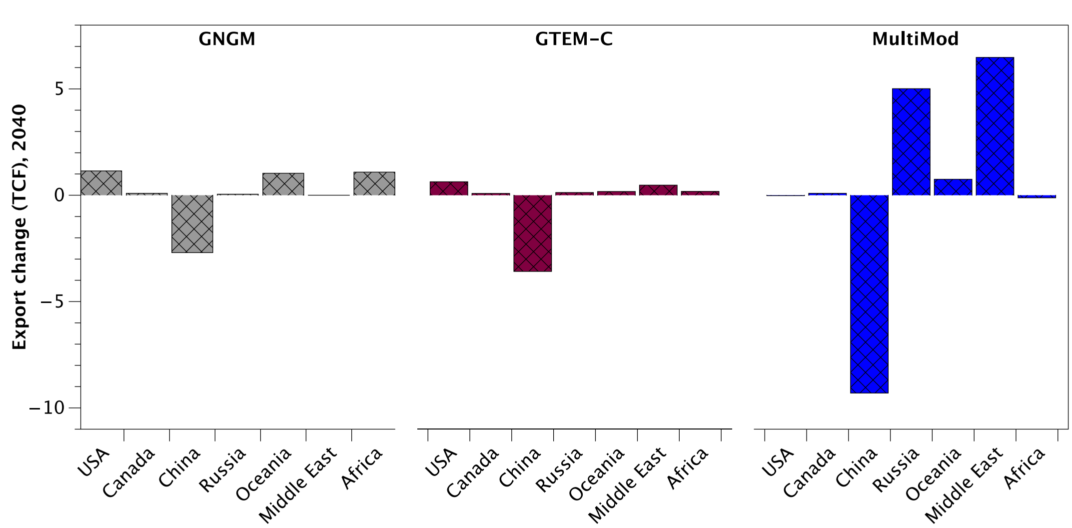

Fig. 6. Export change in *HAD* scenario compared with the *Ref* scenario in 2040.

the demand sector responds to shocks. Partial-equilibrium models (GNGM and MultiMod) usually assume a given demand curve for each period without any intertemporal dependence, while the dynamic CGE models (such as GTEM-C) incorporate the feedback loop between prices and demand through endogenous economic growth (GDP). The second major difference is how the supply response is expressed through fuel/technology substitutions. In the GNGM model, which only considers global natural gas markets, upward shifts in demand in one region will induce more trade to that region and have a global, mostly uniform, impact on prices. In contrast, a model (such as MultiMod) that incorporates multiple fuels and endogenous substitution may find a more nuanced impact because of substitution and investment effects in final demand and the power sector. In addition, if the power sector is modeled using CES or CRESH functions (GTEM-C and GNGM) which allow only imperfect substitution between different fuels, even drastic shifts in the relative prices of different input fuels will typically have a limited impact, because the share of different fuels in the power generation mix responds more gradually. On the other hand, if the power sector (or energy demand in general) is modeled using linear functions (MultiMod) which allows substitution between different fuels more realistically than CES function, shifts in the relative prices can lead to "bang-bang"-results, with very drastic changes in the fuel mix across different scenarios.

4.2. Concluding remarks

This modeling comparison exercise is part of the EMF 31, looking at the global consequences of increased shale gas production in the U.S. We find that differences in the models' theoretical construct and assumptions can lead to divergences in their predictions about the consequences of the shale gas boom in U.S. Identifying these differences is important in understanding the model's insights and policy recommendations.

The key insights observed from this study include the following:

- In the *Ref* scenario, the U.S. is expected to become a net exporter in 2020 in GNGM and 2030 in GTEM-C and MultiMod. Total exports are estimated to range from 0.05 to 3.1 TCF of gas in 2040 across three models.
- Models suggest the U.S. High Shale Gas (*HiGas*) scenario leads to increased U.S. production, lower global natural gas prices, and lower natural gas production in non-U.S. regions. In a general equilibrium model where the natural gas resource base is raised in the U.S., however, global natural gas markets adjust to reflect the first-order (US exports displacing domestic production in Non-U.S. countries) and second-order (income) effects. In the short-run, production in non-U.S. regions is displaced by increased U.S. production and exports. In the long run, the second-order effect becomes more important as lower natural gas price is boosting overall demand growth. Therefore, the initial production decline in non-U.S. regions will gradually regain and bunch back to close to (although still lower than) the baseline level.
- With flexible fuel/technology substitutions for the power sector, MultiMod suggests that *HiGas* scenario leads to higher gas consumption in North America. In addition, given lower shipping costs of coal than gas, it is economical to export coal to other regions than gas. This leads to lower gas demand in the rest of the world, compared to higher gas demand due to lower gas prices estimated by the other two models.
- The *High Asian Demand* (HAD) scenario has little effect on U.S. production (< 1 TCF), even though higher Asian demand raises global natural gas prices and reduces demand levels in all other regions. Models have different estimates of which regions would increase production to meet the increased Asian demand, but some candidates include the U.S., Asia (China, Indonesia, and Malaysia), Australia, Africa, Russia and the Middle East.
- When the *HAD* scenario is combined with the *HiGas* scenario, U.S. production increases by 11.8–17.5 TCF in 2040 and net exports increase by 12–14 TCF/year in both GNGM and GTEM-C. No net change in U.S. exports is observed in MultiMod as net export levels are essentially zero in all scenarios in MultiMod.

There are still many unanswered questions in the academic literature that could help to further improve our understanding of the potential levels of U.S. gas export and the likely impacts in the U.S. and globally, including:

- How would the prospect of shale gas resource development in other regions of the world affect the projections of U.S. export? Does the U.S. have a first-mover advantage as the pioneer of shale gas development?
- How would geopolitical uncertainties in Iran, Russia, and Africa, and regulatory uncertainty globally affect shale gas development in the U.S. and elsewhere in the world?
- How would the evolution of different natural gas pricing schemes impact U.S. LNG exports?
- Will natural gas be traded internationally as a homogeneous good similar to crude oil, or will an Asian hub for natural gas emerge in the next decade? If so, how would it impact LNG exports from the U.S.?

More detailed modeling work can shed further light on these questions, which can have an important influence on the dynamics of future global gas markets. Equally important is the understanding that the model type chosen for projections or scenario simulation can play an important role in determining the general direction of the results and policy recommendations derived from them. Policy-makers and academics need to gain an increased awareness of the potential gaps or biases that could exist given the strengths and the weaknesses of these different modeling approaches and paradigms. We believe that model comparison exercises such as those led by the *Energy Modeling Forum* are of paramount importance for more thorough understanding of the key drivers of the global energy system.

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