

Chapter 3
Monthly Gas Trade in the Atlantic Basin circa 2015
by Mark H. Hayes¹

3.1 INTRODUCTION

The stylized examples in chapter 2 demonstrated the fundamental relationships between LNG supply, gas storage, and non-correlated gas demand in regional gas markets. The destination flexibility of LNG shipments created additional value for this supply option, as LNG supplies are able to respond to seasonal gas demand and substitute for comparatively costly investments in gas storage. In this chapter, supply, demand and geographic parameters for the U.S. and OECD Europe are added to the basic ABMod structure to create a representative, though still generalized, model of month-scale gas trade interactions between these regions.

Long-term energy models consistently project major growth in gas and particularly LNG imports for the U.S. and Europe (Observatoire Méditerranéen de l'Energie (OME) 2001; IEA 2004b; Holz and Hirschhausen 2006; EIA 2006a). Most of these long-term models incorporate detail on the competition between gas and alternative fuels and project strong growth in natural gas demand. The long-term models also show the need for imports to provide additional supplies where domestic production is increasingly costly. Thus, the long term, annual-scale drivers for increasing LNG trade are robust and well studied. The model introduced in chapter 2 of this volume and expanded here attempts to characterize the important intra-annual fundamentals that will shape the growing trade in LNG. Seasonal variability and storage costs in regional gas markets will be critical factors shaping price formation and the utilization of LNG supply infrastructure – particularly ships and regasification terminals.

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The “Atlantic Basin Gas Trade Model” described in this chapter incorporates cost estimates for gas supply, transport, and demand reflective of current technologies. However, the results do not provide precise estimates of future LNG cargo flows or prices in a given year. The model as presented here is intended as a demonstration of concept, representing the important seasonal dynamics that will affect seasonal LNG flows between the U.S. and European markets. Additional detail would differentiate the U.K. from the rest of Europe (discussed in some detail in chapter 5) and would also include the important Asian LNG importers and suppliers. The model framework described here is easily amenable to such extension.

Though the Atlantic Basin Gas Trade Model is simplified in its current form, the insights from the model are robust to realistic adjustments in parameter values or the addition of greater regional market detail. The intra-annual resolution of the Atlantic Basin model shows that production, gas pipelines and liquefaction facilities will tend to operate at or near full capacity at all times. The results suggest that other segments of the system – namely LNG ships, regasification facilities and gas storage are more cost effective than production as a means to meet seasonal swings in gas demand, and therefore can be expected to operate at varying capacity utilization rates over the course of a typical year.

Non-correlated regional gas demand drives seasonal swings in LNG supplies and gas prices in regional markets. The results indicate that LNG can provide a substitute for storage in markets where storage capacity is expensive (as in Europe). Moreover, the seasonal flows of

LNG and storage costs support regional price spreads that vary over the course of the year, reflecting differential capacity costs and constraints in each regional market.

3.2 ATLANTIC BASIN GAS TRADE MODEL STRUCTURE

The focus of Atlantic Basin gas trade model is the month-scale economic fundamentals of gas supply, transport, and storage. The model explores the interaction of these fundamentals across multiple gas markets with heterogeneous characteristics, e.g. non-correlated demand, different storage costs, and geography which influences transit costs. The analysis presented here is a demonstration of the concepts developed in chapter 2, with application to the U.S. and European natural gas markets. The results provide insights on the trade-offs between investment in different flexibility mechanisms – storage, LNG supply, pipeline supply – to meet seasonal variability in natural gas demand.

Gas consumption demonstrates highly seasonal variability. In Europe, total gas consumption in the summer months (June through August) is less than half of consumption in the winter (December through January). Similar trends are observed in the U.S., though to a lesser degree (see figure 3.1). Historically, these regional markets were isolated and gas storage or variations in monthly pipeline supply were used to meet variable gas demand needs. LNG tankers, however, introduce a potentially new mechanism to respond to variations in gas demand. Round-trip transport time for an LNG cargo from Egypt to the U.K. is 15 days. The same ship could continue on to the U.S. with an approximate doubling of total transport time. Thus, a model that allows for month-scale detail in the routing of LNG cargoes can provide some insight on tanker movements that cannot be represented in annual scale models. Similarly, the

operation of gas storage is a response to variation in natural gas demand. A month-scale model provides a generalized framework to analyze both LNG routing and gas storage.

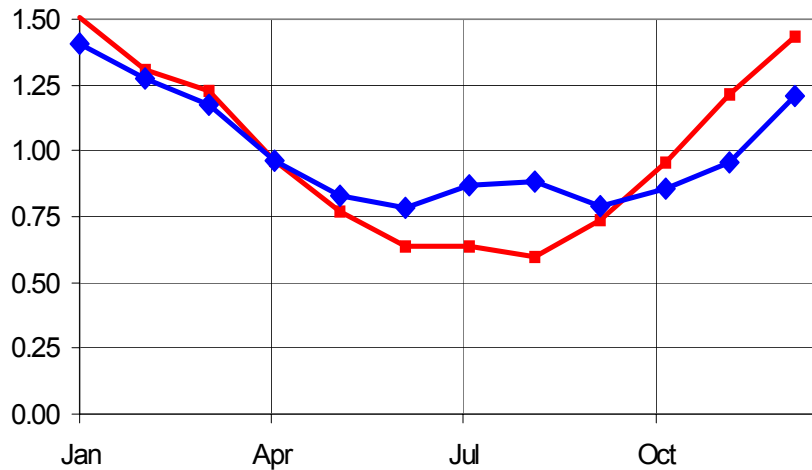


Figure 3.1. Index of Monthly Gas Demand in U.S. and OECD Europe. Average realized monthly consumption for the four-year period 2001-2004, indexed to the average consumption per month over the same four-year period. For example, January consumption in OECD Europe averaged 150% of the average within-year monthly consumption for the years 2001-2004. *Source:* (IEA 2005b; EIA 2006b).

A spatial representation of the Atlantic Basin Gas Trade Model is shown in figure 3.2.

The model includes four supply regions (North American pipeline, European pipeline, Trinidad LNG, and Africa/Middle East LNG) and two demand regions (U.S. and OECD Europe). Supply sources and offtake markets are aggregated. The purpose is to highlight fundamental interactions between these types of sources based on generalized regional data. The framework is easily extendable to incorporate finer detail on country or sub-regional gas suppliers and consumers.

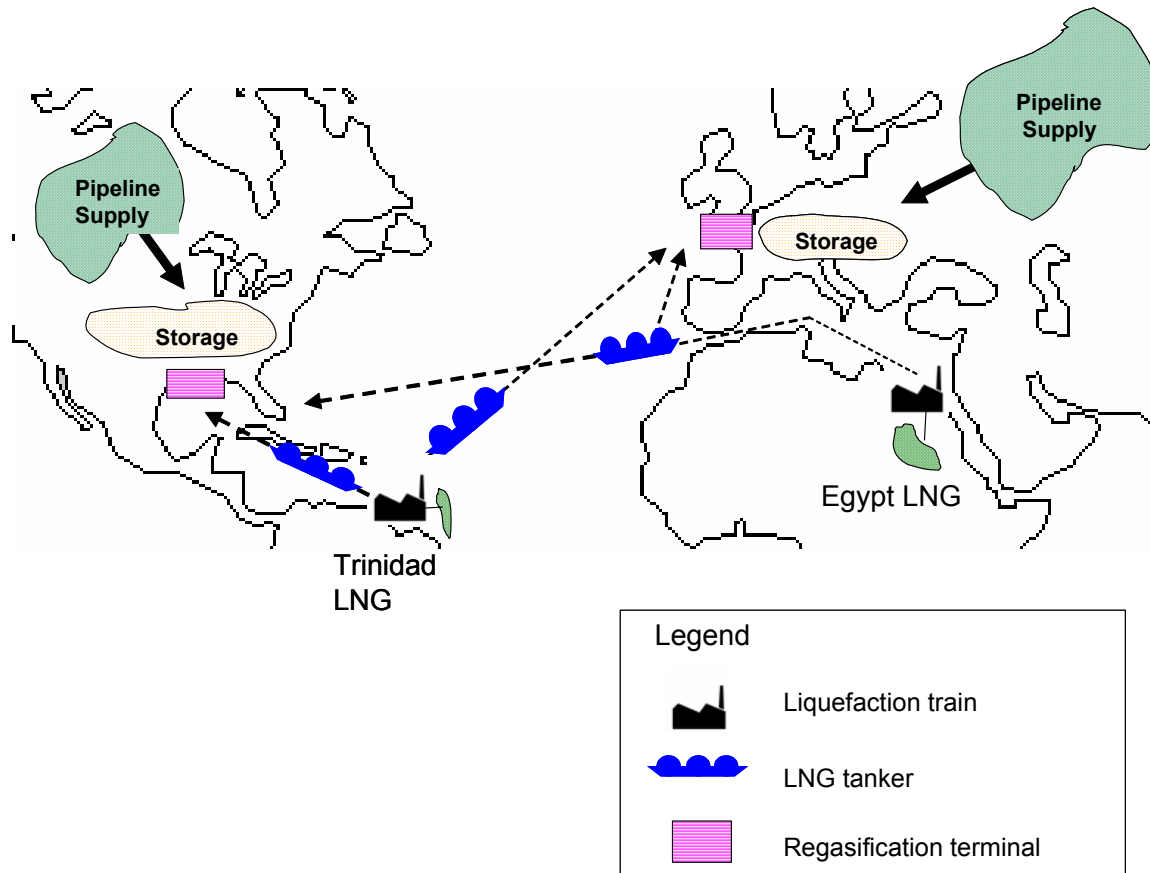


Figure 3.2. Schematic illustration of Atlantic Basin Gas Trade Model.

The Atlantic Basin model represents a typical twelve-month period using the GAMSTM modeling environment. Key parameter values for each of the four supply sources and the two demand regions are assigned in the model. Importantly, capital costs are separated from operating costs for each segment of the supply chain – supply, liquefaction, pipeline transport, shipping, regasification and storage. The twelve-month period is looped, so that December closes with the optimal conditions to begin the following January.

Capital costs are incorporated as discussed below for each segment of the supply chain. The model does not, however, represent the long-term interaction between gas and alternative fuel sources. Thus, this model uses estimates from other long-term energy models (IEA 2004b; EIA 2006a) to provide realistic boundaries for the role of natural gas in the broader energy market and economy. This allows the analysis here to focus on shorter-time scale interactions, assuming that the longer term projections are representative of future gas and LNG growth. The key variables needed to demonstrate intra-annual fundamentals are endogenously determined: investment and operation of LNG tankers, regasification, and gas storage.

The critical assumption drawn from the long-term models is that the LNG trade will grow significantly over the coming decades. However, the insights here are robust across significant variability in future projections (e.g. 50% change in absolute size of the LNG market does not alter the nature of the interaction between high-cost and low-cost storage regions). Similarly, cost estimates used in this chapter for supply, transit and storage are generalized estimates from industry and trade press sources. Parameter estimates are aimed to be accurate to the extent that any insights drawn from the model are robust to reasonable variants of these costs.

The GAMS solver CONOPT uses a gradient search method to find the optimal solution with linear cost functions and non-linear demand function (described below). The optimal model solution maximizes total social welfare – the sum of total consumer welfare less total production costs for all months. In gas market terms, the model finds the optimal level of capital investment, given fixed constraints, that allows for the cheapest delivery of gas supply to meet consumer demand across a typical twelve-month period.

The solution is a competitive equilibrium condition in gas investment and trade. There are assumed to be n players in each segment (supply, transport, storage and end-use demand) each making identical decisions, with identical cost structures. There are no barriers to entry, no information asymmetries, all market participants have complete information, and there is no strategic interaction between participants. The result is the classic equivalence of the competitive market solution to the social planner's outcome. Total supply, transport, and demand are simply the sums of the individual players' investment and operational decisions. For the remainder of this chapter I consider the industry-wide equilibrium, and model each segment of the system in aggregate to solve for the investment and operational conditions that optimize total social welfare.

The Atlantic Basin gas trade model analyzes the expected, seasonal function of interconnected gas markets. The resulting gas flows and prices represent expected values, responding to average realized demand. Chapter 4 addresses questions related to the stochastic variability in

gas demand and the value of flexible LNG supply to respond to unpredictable demand and price variability.

Section 3.3 provides descriptions of the key assumptions made in the Atlantic Basin gas trade model for gas demand, supply, transportation and storage.

3.3 MODEL ASSUMPTIONS

3.3.1. Demand

The focus of the modeling effort is on the interaction at the month-scale between the segments of the supply chain (supply, pipelines, LNG tankers, and regasification terminals), gas storage, and seasonal gas demand. One aggregate demand sector adequately captures the major seasonal demand variability in each respective regional market. More detailed analysis could separate demand by sector – electric power, industrial, commercial and residential – but that is not required to demonstrate the key fundamentals of inter-regional trade.

In its current form, consumer demand in each region is represented by the constant-elasticity, inverse demand function shown in equation 2.21:

$$g_{t,j}(z) = a_{t,j} z_{t,j}^b \quad , \quad (3.1)$$

where z corresponds to monthly gas consumption and $g(z)$ is the market-clearing price for that quantity. Parameter values for a and b are assigned based on an assumed reference price and average monthly demand quantity for each region.

The levels of gas demand and seasonal profiles are determined by an exogenously assigned $a_{t,j}$ parameter. $a_{t,j}$ is assigned to reflect the overall demand for gas and the shift in each region's demand function that occurs over the course of one year. A unique value of $a_{t,j}$ is estimated for each month and demand region, using a reference price (\$5.0 per mcf) and a reference quantity assigned based on an assumed annual level of gas demand and the monthly consumption profile.

Annual levels of gas demand in the model are based on IEA and EIA projections for the year 2015. OECD European gas consumption is projected to grow from 17.3 Tcf in 2002 to 22.6 Tcf in 2015 (from current consumption of 47 Bcf/day to an average consumption of 62 Bcf/day in 2015). U.S. gas consumption is projected to grow from 23.0 to 25.9 Tcf per year over the same period (63 Bcf/day currently to an average of 71 Bcf/day).² The absolute levels of gas demand are less important than the consensus view of continued growth in natural gas demand which creates the opportunity for growth in LNG supplies.

Annual gas demand projections are allocated on a monthly basis using seasonal demand profiles for each market as shown in figure 3.1. Monthly demand “multipliers” distribute the projected future annual demand across twelve months based on the historical monthly distribution of demand in each regional market.³

² OECD Europe projections from IEA WEO (2004b). US projections from EIA AEO (2006a). The estimates for both regions are generally consistent, however each uses slightly different model regions.

³ Monthly average consumption levels were used to distribute future demand across twelve months. However, changing composition in gas demand – particularly the shift to the greater use of gas in electric power generation in both the U.S. and Europe could change the seasonal demand profile of these markets over time. Further analysis could analyze the implications of such a shift.

In addition to seasonality, the model also incorporates the general lack of flexibility of gas-users to respond to short-term price changes. Demand flexibility is reflected in the b parameter in equation (3.1), where $1/b$ is the own-price elasticity of demand (ϵ_p). ϵ_p is assumed to be -0.1 in both regions in all months, e.g. a 10% increase in gas prices yields a 1% decrease in gas consumption. This estimate is broadly consistent with total demand responsiveness used in other short-term gas market models (Sieminski 2003; EIA 2003a).⁴

3.3.2. Supply

The structure of gas supply in the Atlantic Basin gas trade model follows that described in the general model presented in chapter 2 with added detail to reflect differential transit distances and realistic constraints on volume supplies from each region.

The model represents four broad supply regions: North American domestic production, European domestic production, Middle East/Africa LNG, and Trinidad LNG. Aggregation at this level allows for important inter-regional interaction, but abstracts from details of each particular supply country or project. Again, the model structure is extendable to include such additional detail.

Each regional pipeline supply can serve only the local market, e.g. North American pipeline can only deliver supply to the U.S., and European pipeline supplies only OECD Europe.

⁴ Residential gas demand is even less responsive to monthly price increases than assumed here. The U.S. EIA does not include any response by residential consumers to gas price increases in the short term (EIA 2003a). According to the EIA, the most flexible sector of U.S. gas demand in the short-run – electric power generation – has an estimated own-price elasticity (ϵ_p) of -0.15. Here $\epsilon_p = -0.1$ is a reasonable proxy for total demand responsiveness. Results show that this parameter value creates realistic incentives for investment in flexible supply capacity and gas storage.

LNG supplies can move from either source to either demand region, depending on prices and capacity constraints on shipping and regasification.

The collection of Middle East and African LNG suppliers into one supply source is an approximation with parameter values assigned to broadly represent the geographic and geologic characteristics of the major suppliers of that region. LNG supplies for Europe and the U.S. will come from projects in Nigeria, Algeria, Egypt, and Qatar among several other suppliers.⁵ The Middle East/Africa supply node approximates these sources collectively, assuming all originate from one mid-point, here assumed to be Egypt.

Fixed and operating costs are assumed constant and linear, respectively, for each of the four supply sources (see figure 3.3). The functional forms are consistent with those used in the generic ABMod described in chapter 2. One capacity level is chosen for each of the respective supply segments in the model is chosen for the twelve-month period such that overall welfare is maximized. However, as shown in figure 3.3, equilibrium supply costs from all sources are below the assumed reference price of \$5 per mcf. One approach would be to increase the complexity of this model in attempt to better represent the long-term development of capacity. However, the focus here is on short-term, monthly interactions and *relative* capital costs of LNG, pipelines and storage to meet this demand variability. Thus, projections from other well-established, long-term models are incorporated exogenously and used as constraints for this short-term model (IEA 2004b; EIA 2006a).

⁵ Various consultant reports provide updates on the numerous liquefaction projects currently operating, under construction, or planned. For a recent, publicly available estimate of future LNG suppliers see: <http://www.eia.doe.gov/oiaf/analysispaper/global/exporters.html>

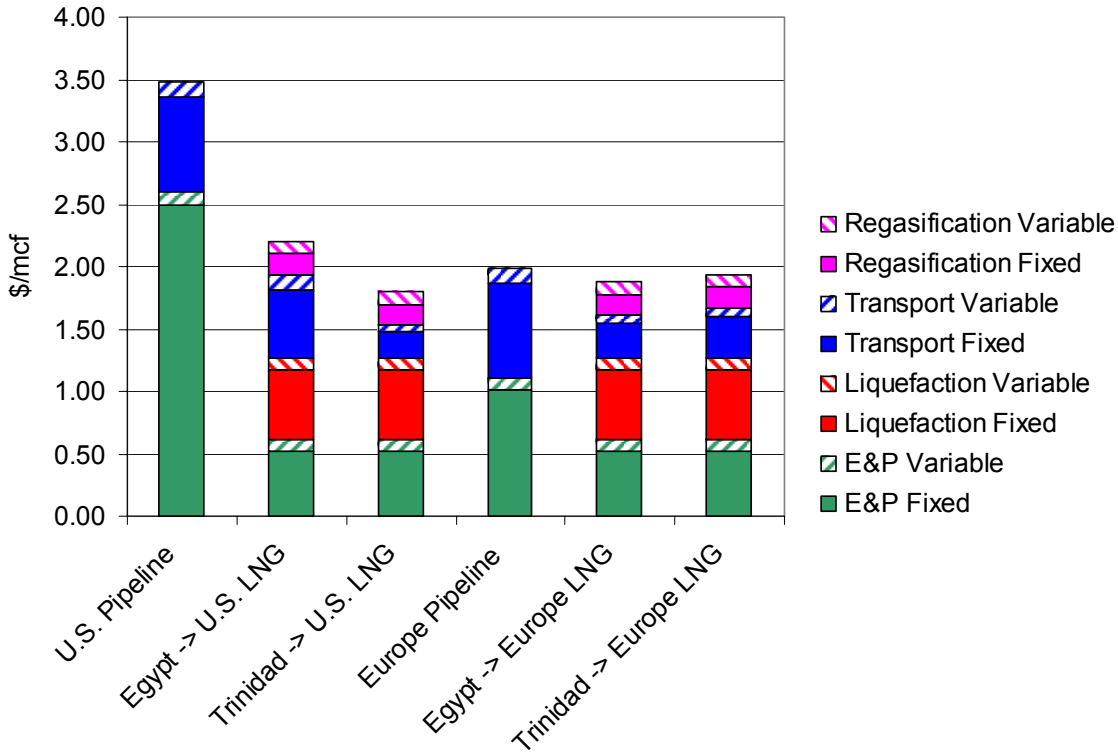


Figure 3.3. Assumed unit gas delivery costs by supply segment.*

*Unit costs presented here calculated based on full capacity utilization. Less than full utilization of a particular segment of the supply chain increases the effective unit capital cost. However, the model solves for total optimal capital expenditure, separating fixed and operating costs for each segment. Capacity utilization is thus a model output.

Sources: Costs estimates based on subjective assessment from various industry, trade press and government sources including: EIA (2001), OME (2001), IEA (2003), IEA (2004b), Jensen (2004); production operating costs from EIA (2003b); pipeline operating costs from Transcanada (2004); LNG tanker costs from various trade press reports, e.g. (WGI 2005a); regasification costs from BG (2004).

The only critical assumption with respect to long-term supply development is that LNG is assumed to be the low cost supplier relative to domestic pipeline sources. Thus, all new incremental supply growth comes from new LNG supplies. This assumption is broadly consistent with long term projections (IEA 2004b; Holz and Hirschhausen 2006; EIA 2006a).

Domestic production is maintained at current levels through 2015 for both North America and Europe. While not explicitly represented in the model, this assumption requires that new supplies be developed and brought on line in both markets to keep domestic output at current levels. Pipeline supplies to the U.S. are capped at 59 Bcf/day and pipeline supplies to Europe are capped at 49 Bcf/day.

Since the total cost of delivered LNG supplies is estimated to be well below the reference prices for demand in each region, these capacities must also be constrained in the model. LNG supplies from Trinidad (and the western Atlantic Basin) are constrained to 3.3 Bcf/day. LNG supplies to the Atlantic Basin markets from Africa and the Middle East are constrained at 21.4 Bcf/day. The latter is an approximation that roughly half of newly developed Middle East cargoes are shipped west to the Atlantic Basin, and half of new supplies are delivered east to Japan and other Asian markets.

The exogenous constraints adopted for pipeline and LNG supply allow the model to yield reference prices and supplies broadly consistent with the projections long-term models (Jensen 2004; Holz and Hirschhausen 2006; EIA 2006a). The rate of LNG supply capacity expansion is apparently constrained in these long-term models, as the cost assumptions used in this model (which are generally reflective of industry sources) suggest that LNG can be supplied for less than the projected prices in the long-term models. Regardless, the exogenous constraints do not sacrifice any of the important month-scale interactions between LNG supply, shipping and storage that are the focus of the month-scale analysis.

3.3.3. Transportation

The transportation of gas via pipeline and LNG are each represented as distinct segments in the Atlantic Basin gas trade model, with capital and operating costs assigned for each supply source and destination pair. This representation allows for comparison of the cost of swing capacity in gas pipelines, LNG shipping, and gas storage for the respective regional markets. Total pipeline and LNG supply capacity is constrained for each supply region, but there are no constraints on investment and utilization of shipping capacity.

Supply constraints for each of the domestic supply regions in the model do effectively constrain pipeline capacity investment in the model. Investment in pipeline capacity occurs up to the supply capacity level. Any additional pipeline capacity would never be unutilized. However, the results in chapter 2 – which uses similar cost structures – show that pipeline supply is a less attractive source of swing capacity than LNG diversion or gas storage.

LNG shipping capacity is unconstrained in the model. A new-build 150,000 m³ LNG ship (carrying 3.3 Bcf of natural gas in vapor state) is estimated to cost \$180 million USD. Total cargo deliveries in any month (in Bcf-nautical miles) cannot exceed the total available shipping capacity, as determined by the investment level. Total shipping capacity is determined based on the shadow costs (or marginal value) of delivering an additional unit of gas in each month. The optimal shipping capacity for the representative year is determined when the sum of the incremental value of LNG delivery just cover the capital costs of the last unit of tanker capacity.⁶

⁶ Tanker capacity is assumed to be a continuous variable. Treatments aimed at precision in prices and flows would treat tankers as discrete variables.

The variable cost of shipping is dominated by the daily boil-off of the liquefied cargo, and is thus proportional to distance traveled (\$0.04 to \$0.12 per mcf depending the trade pairs).⁷

In general, LNG is cheaper to deliver to Europe, reflecting the proximity of that market to the larger Middle East/Africa LNG supply source. The U.S. is assumed to be twice the distance from North Africa/Middle East producers as Europe. The shortest haul in the model is from Trinidad to the U.S. Gulf Coast, 25% shorter than the Middle East/Africa to Europe route.

3.3.4. Storage

Current gas storage capacities are assumed to be maintained in the U.S. and in OECD Europe by placing lower boundaries on these capacity levels in the model. The operation of gas storage is largely unconstrained. In 2006, U.S. working gas storage capacity is estimated at 3.4 Tcf, and end-of-winter working gas levels have rarely fallen below 0.7 Tcf (EIA 2006b). Thus, 0.7 Tcf is added as a lower boundary on the stock of gas in storage. The lower boundary has little effect other than to shift storage capacity needs upward to cover lower boundary requirements. In equilibrium, the 0.7 Tcf stays in storage for all months and has no effect on prices or quantities.

OECD Europe is estimated to have 2.3 Tcf of working gas storage capacity (IEA 2004b). According to IEA data, the total annual cycling of gas for the whole OECD region averages

⁷ To be exact, the cost of boil-off during transport would adjust depending on the netback price of delivered gas. This feedback is not included in the model, but does not affect the fundamental results. The opportunity cost of tanker capacity (measured in days or nautical miles of travel time) far outweighs the variation in the variable cost of shipping.

approximately 1.4 Tcf suggesting that significant gas storage is not used annually (IEA 2005b). Non-market factors likely govern the holding of such storage stocks year-over-year. In this model storage levels in Europe are not allowed to fall below 0.5 Tcf.

The cost for storage capacity expansion and operation of existing facilities are based on both engineering cost estimates and market data for competitively bid storage capacity in both the U.S. and in Europe (especially the U.K.). Engineering cost estimates – referenced by the IEA in its World Energy Investment Outlook (IEA 2003) indicate relatively low costs of expanding gas storage capacity compared to other studies and also recent evidence from futures market prices. The IEA has estimated the cost of new gas storage to be roughly \$1.66 per mcf per year in Europe, and roughly \$0.58 per mcf per year in the U.S.

As of August 22, 2006, futures contracts for gas at the National Balancing Point in the U.K. were selling for approximately \$6.50 per MMBtu for September 2006 delivery and \$14.75 per MMBtu for delivery in January 2007. Thus, an owner of storage capacity in the U.K. could earn in excess of \$8.00 per MMBtu for holding gas for 4 months. Similarly, the U.S. “seasonal spread” on the NYMEX was in excess of \$4 per MMBtu (\$7.10 for September 2006 delivery, and \$11.36 for January 2006 delivery). Futures prices in competitive markets like the U.K. and U.S. change on a daily basis – however these prices are generally reflective of market behavior in recent years. With free and competitive operation of storage capacity, the seasonal spread should roughly correspond to the value of storage capacity. (This relationship is discussed in further detail in chapter 2).

In addition to the futures price data, other consulting reports suggest that the cost of European gas storage capacity might be significantly greater than the IEA estimates. A report commissioned in 2005 by the U.K. Offshore Operators Association found that the cost of new storage capacity in the U.K. could be in excess of \$3.00 per mcf per year (ILEX 2005).

The ILEX report and futures market data suggest substantially higher costs (and values) of storage than the IEA data. All sources suggest that that gas storage capacity is more limited and significantly more expensive in the OECD Europe region than in the U.S. Industry sources cite several reasons for this cost differential. The limited availability of depleted gas reserves and significantly more intense environmental and siting scrutiny in the U.K. and continental Europe are cited as two key factors (IEA 2003).

In this chapter, annual gas storage costs are assumed in excess of the IEA estimates, but less than current market rates might suggest. In the long run, we should expect additional investment in storage capacity (and increasingly flexible LNG trade) to bring the market value of storage closer to cost estimates. Table 3.1 includes the assumed annualized costs of gas storage capacity (for seasonal storage) and the operating costs associated with gas injection and withdrawal. In the case of storage costs, as with other assumptions, the intention is to be generally reflective of important regional gas market fundamentals. More detailed analysis of the costs of storage in continental Europe compared to the U.K., or even within continental Europe could provide additional insight into the operation of these markets.

Table 3.1. Annualized gas storage costs

	U.S. \$/mcf per year	Europe \$/mcf per year
Fixed	0.92	2.34
Injection	0.04	0.08
Withdrawal	0.04	0.08
Total seasonal cost of storage	1.00	2.50

Sources: ILEX (2005), IEA WEIO (2003) and other industry sources.

3.4. MODEL RESULTS

3.4.1. The European role in the Atlantic Basin gas trade model

Using the assumptions defined above, the Atlantic Basin Gas Trade Model generates results that are consistent with the long-term model projections and illustrate the important month-scale interactions for which the model is intended. For the twelve-month period circa 2015, total European gas consumption is 22.7 Tcf/year or an average of 62 Bcf/day. These numbers are nearly identical to EIA and IEA median projections (IEA 2004b; EIA 2006a). Since these long-term projections were used to constrain the model outcome, these results neither support the long-term projections nor validate the results here. The consistency of the results does suggest that this monthly model is well-tuned to those inputs.

The seasonal variation in consumption projected in the model (see the line plot in figure 3.4) also closely follows the historically observed seasonal trends (see figure 3.1). Projected monthly consumption in Europe for June, July and August is 64% of the twelve-month average, compared to 63% observed in the period 2001-2004. The relatively price inelastic demand for

gas drives the model solution to provide capacity to meet the seasonal swing, rather than to curtail the strong demand for winter gas consumption.

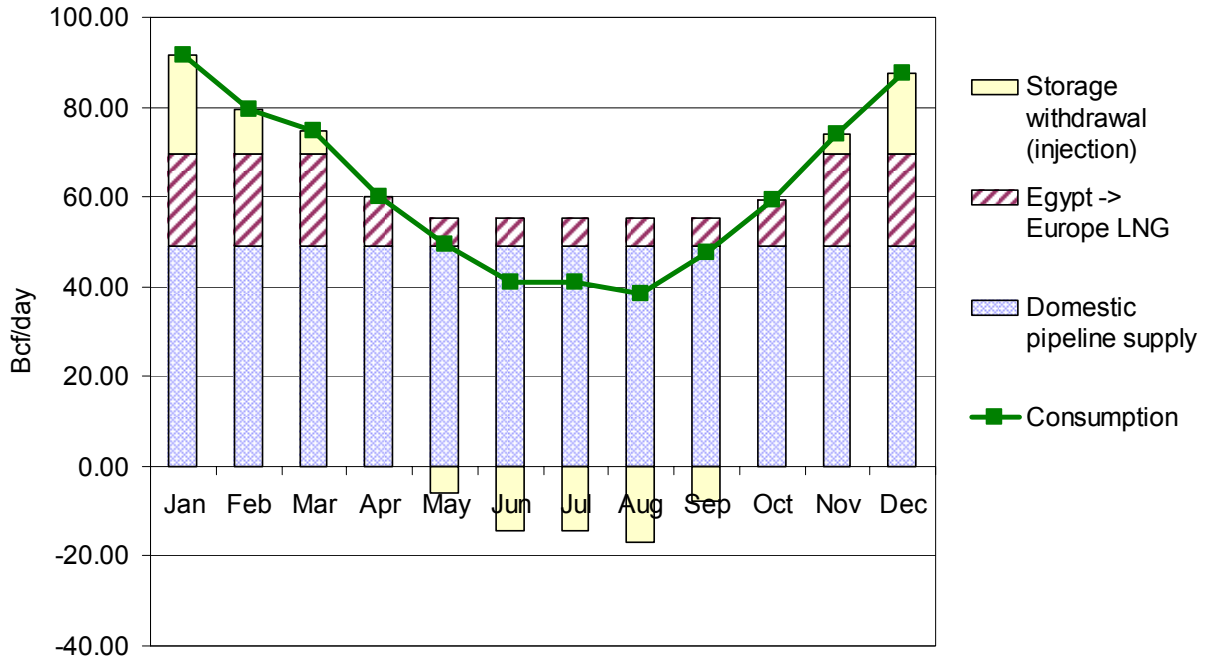


Figure 3.4. Model results: monthly gas balance in OECD Europe circa 2015.

In Europe, strong demand for winter gas is largely met by increasing LNG imports. LNG flows provide 20.5 Bcf/day of supplies in the winter months (November through March) and then decrease in the summer months with falling demand for gas. LNG imports in May through October average just 6 Bcf/day (see figure 3.4).

Seasonal swing in LNG supplies allows Europe to meet over half of its incremental winter gas consumption needs with swing LNG. In a typical January, pipeline supplies provide 49 Bcf/day, LNG imports provide 20.5 Bcf/day, and withdrawals from storage provide the

remaining 22 Bcf/day required to meet 91.5 Bcf/day of gas consumption. If LNG deliveries were smoother throughout the year additional investment in gas storage would be required to meet winter peak demand. Justifying such storage investment would require overall higher prices (and less consumption).

However, the avoided cost of gas storage does require the purchase of relatively expensive winter LNG cargoes and investment in “excess” regasification capacity. LNG cargoes in the winter months have a greater value, as these cargoes are also sought by the winter-peaking U.S. market (see section 3.4.2 below). Regasification capacity in Europe must also be scaled to meet winter peak winter LNG import needs. Europe’s 20.5 Bcf/day of regasification capacity is fully utilized in November through March, but then only 35% utilized in the remaining seven months of the year. Thus, on a unit cost basis, the regasification capacity is significantly more (approximately 150%) expensive than the estimate based on full capacity utilization shown in figure 3.3.

The model results show, that at the margin, it is cheaper for Europe to purchase expensive winter LNG cargoes and invest in additional LNG capacity, than to make additional investments in gas storage. In fact, despite the 30% increase in European gas consumption from current levels, the model suggests that no additional storage capacity is economically attractive (see figure 3.5). 2.3 Tcf of existing European storage capacity is assumed to be maintained, taking summer supplies in excess of summer demand levels and storing it for winter use.

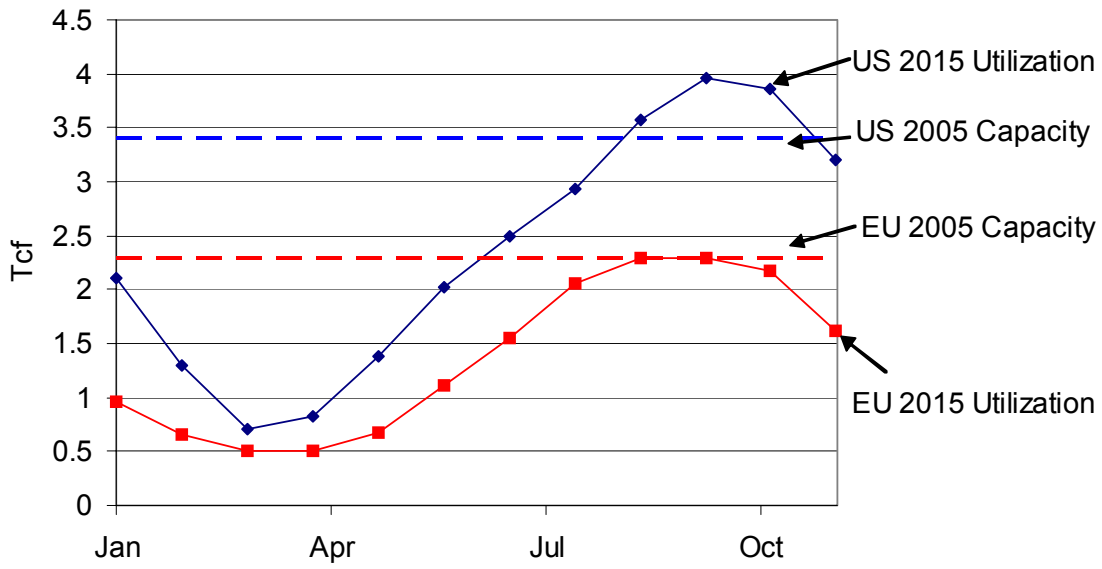


Figure 3.5. Model results: current gas storage capacity and projected capacity needs and utilization, circa 2015, in Europe and the U.S.

Equilibrium prices in the model indicate that current storage capacity in Europe is slightly in excess of that which a competitive market for storage investment would support. Figure 3.6 shows prices extended over two years for illustrative purposes. Winter prices peak in Europe, reflecting the high willingness-to-pay in winter months and the scarcity cost of storage and LNG supplies to meet winter peak demand. Summer prices are low, as demand falls, access to regasification terminals is cheap, and storing gas for winter consumption is expensive.

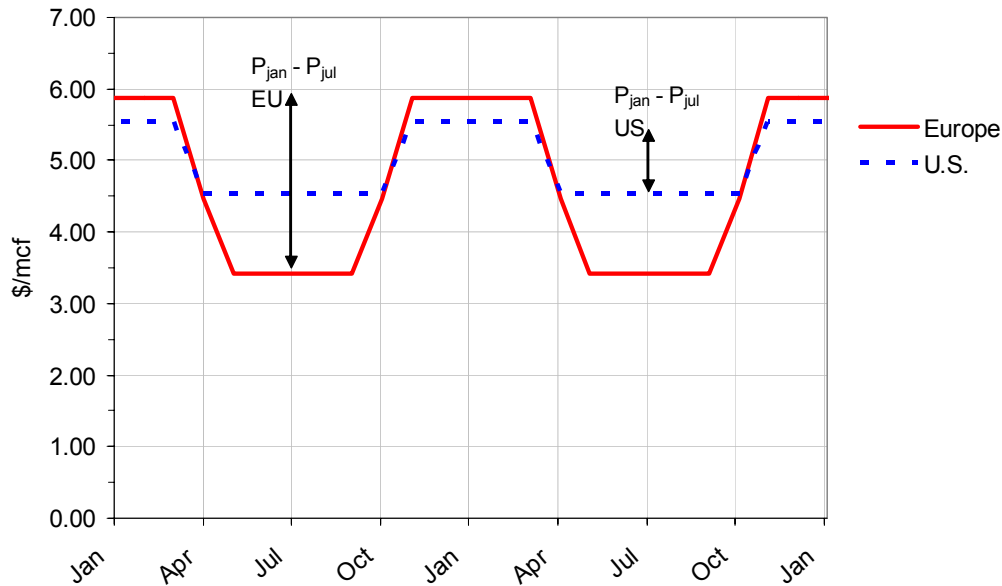


Figure 3.6. Model results: expected price levels circa 2015. Equilibrium prices for one twelve-month period are extended over two years for illustrative purposes. Note, seasonal spread in European prices (\$2.44 per mcf) is larger than U.S. seasonal spread (\$1.00 per mcf).

Winter peak prices in Europe (\$5.86 per mcf) are \$2.44 higher than expected summer peak prices (\$3.42 per mcf). When the storage market is in equilibrium, the winter-summer spread in gas prices would match the cost of building and operating new storage capacity (see chapter 2). The fact that the European seasonal price spread is less than the assumed cost of storage ($\$2.44 < \2.50 per mcf per year) implies that, at the margin, the cost of procuring winter LNG cargoes and “excess” investment in regasification terminals is cheaper than the cost of building additional storage capacity in Europe. The lower bound on storage capacity in Europe effectively provides more storage than would be built in an unconstrained model solution.

3.4.2. The U.S. role in the Atlantic Basin gas trade model

Annual U.S. gas consumption in the model is consistent with projections from the long-term models. U.S. gas consumption rises from current consumption of 22.4 Tcf in 2005 to nearly 26 Tcf per year in 2015 (from an average of 61 Bcf/day to 71 Bcf/day). LNG imports meet all incremental supply requirements, rising to supply an average of 12 Bcf/day or 17% of total U.S. gas demand, up from 1.7 Bcf/day in 2005.⁸ Seasonal demand swing also reflects observed monthly gas consumption trends (see figures 3.7 and 3.1, respectively).

The model results show U.S. LNG imports peaking in the summer months. These LNG cargoes provide gas supplies well in excess of summer gas consumption needs (see figure 3.7). Summer LNG imports are effectively added to storage (either directly or by displacing pipeline gas supplies for consumption) and then used in winter months when LNG imports decline significantly. As a result, over one-third of January gas demand is met by storage withdrawals (36 Bcf/day) with the remainder largely provided by domestic pipeline gas supply.

⁸ These LNG projections are slightly in excess of U.S. EIA 2006 Annual Energy Outlook, but nearly identical to EIA's projections in 2005.

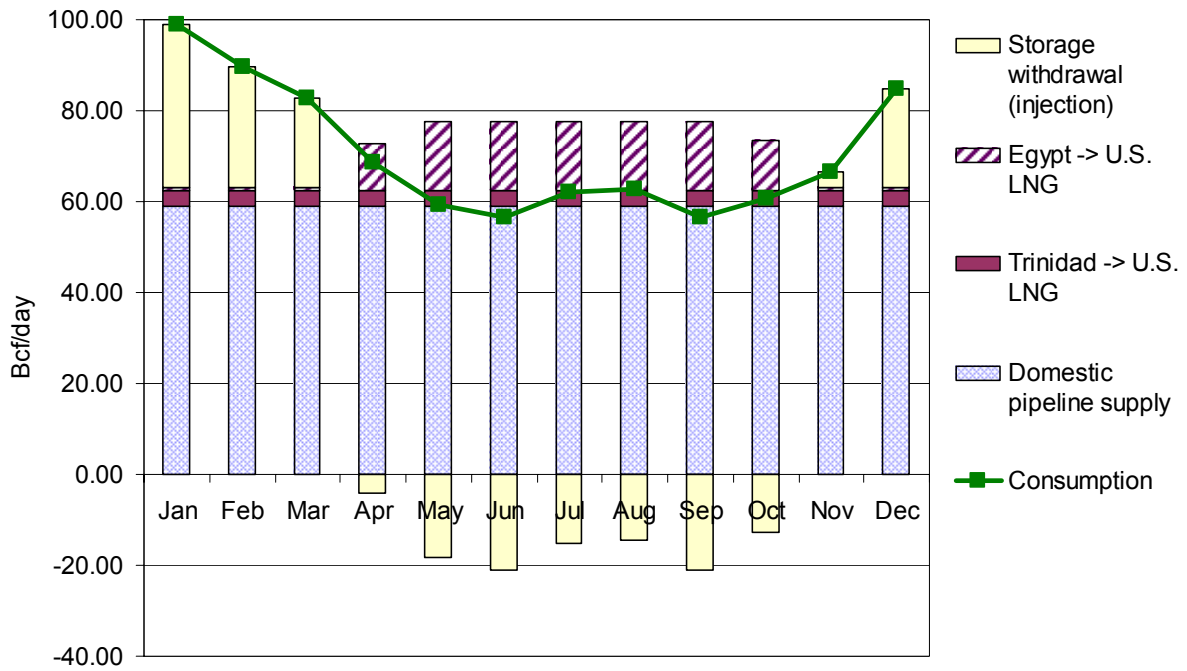


Figure 3.7. Model results: monthly gas balance in the U.S. circa 2015.

The import of LNG counter-cyclical to the swing in U.S. seasonal gas demand drives additional investment in both regasification and storage capacity compared to a scenario where the U.S. received smooth annual deliveries of LNG. LNG imports to the U.S. peak from May to September, with deliveries averaging 18.5 Bcf/day. U.S. regasification capacity must be scaled to match summer peak imports and is then underutilized other months. In total, U.S. regasification capacity operates at a 63% capacity factor. Conversely, one-third of the total available capacity is not used on an annual basis.

Counter-cyclical LNG imports also require additional investment in storage capacity to meet winter peaking gas demand. Unlike Europe, where no additional investment in gas storage

was realized in the model – U.S. gas storage capacity increases from 3.4 Tcf to nearly 4 Tcf (see figure 3.5). Storage capacity additions in the U.S. are driven by the interaction between U.S. and European markets through the LNG trade.

The model results indicate that U.S. buyers purchase LNG cargoes in the summer when market prices are depressed in Europe (see figure 3.6). U.S. buyers would need to pay an LNG supplier at least the European summer price to win the cargo (\$3.42 per mcf). Delivering that cargo to the U.S. would also require the U.S. LNG buyer to pay for the additional shipping costs and access to regasification terminals in the U.S. Both shipping and regasification costs are higher in summer months. The increase in long-haul LNG cargoes from the Middle East to the U.S. means that shipping capacity becomes constrained from May to September – allowing owners of ships to increase rates for ship charters (see section 3.4.3 below). Similarly, U.S. regasification capacity is also constrained in summer months and owners would seek rates to cover the bulk of capital costs in these months.

The value of summer LNG cargoes delivered to the U.S. is determined by winter demand for gas and the cost of storage. Because summer gas supplies are well in excess of consumption needs, marginal gas supplies to the U.S. market are added to storage for higher-value winter consumption.

The low cost of U.S. gas storage facilitates a seasonal and regional arbitrage between the U.S. and Europe. Because U.S. gas storage is relatively cheap, U.S. buyers can afford to pay more to attract summer LNG cargoes than their European counterparts. (Conversely, the high

cost of storage in Europe makes summer cargoes less attractive to European importers.) U.S. LNG importers buy summer LNG cargoes and pay to store gas for winter – this has the effect of driving investment in new storage capacity and moderating winter prices in the U.S. This arbitrage continues until the value to an LNG importer of storing gas in the U.S. (the seasonal price spread) is equal to the annualized cost of storage (\$1.00 per mcf per season).

3.4.3 Gas supply and transportation in the Atlantic Basin gas trade model

Gas supply

The model results show that it is most cost effective to scale and operate domestic gas production and LNG supply to meet annual average demand requirements, and to use other infrastructure segments such as transport and gas storage to meet seasonal swings in gas demand. Domestic gas production in North America and Europe and gas production and liquefaction from all LNG sources runs at full capacity in all months (see figures 3.4, 3.7 for respective pipeline supplies and figure 3.8 for LNG supplies).

The economic driver for high capacity utilization of the upstream segments of the gas supply chain are the proportionately high capital costs of these segments. Figure 3.3 illustrates the total delivered supply costs for each of the supply sources in the Atlantic Basin gas trade model. Fixed costs of gas production and liquefaction (for LNG supplies) are over half of total capital costs for all potential supply pipeline and LNG supply sources.

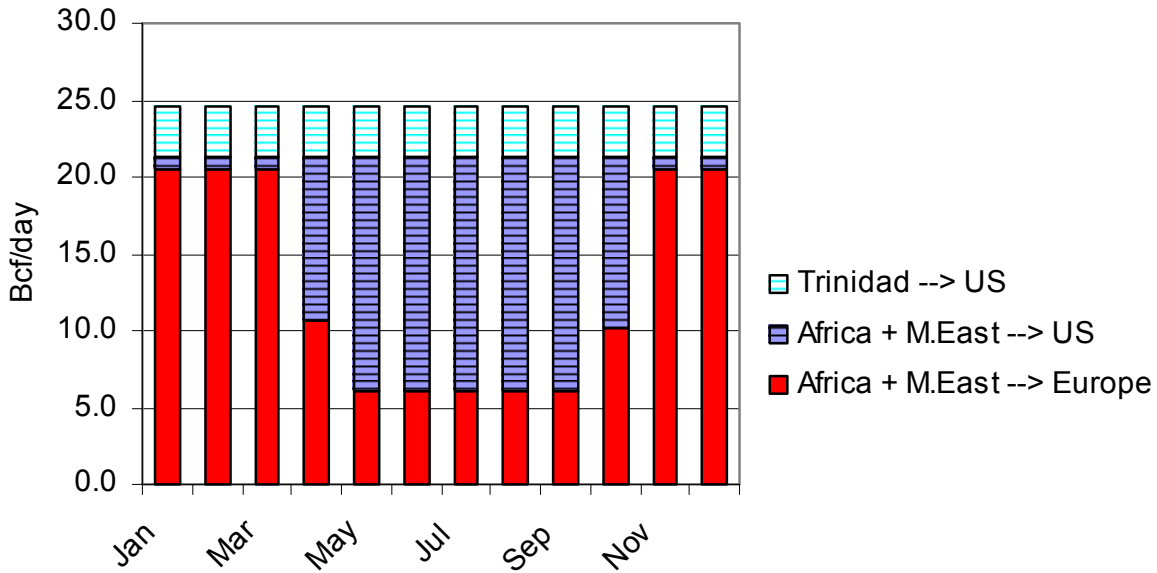


Figure 3.8. LNG supply and transport in the Atlantic Basin circa 2015.

Gas transport

In the spatially simplified the Atlantic Basin trade model – as in real gas networks – pipelines have no destination flexibility. Production from small gas fields may vary over time due to geological factors. However, long-haul pipelines can only transport gas from major production areas to market demand centers along a route determined by the location of steel pipe. There is no benefit from building pipeline capacity in excess of maximum gas production capacity. Total pipeline delivery capacity is scaled to match production capacity upstream of the pipeline.

LNG tankers, however, can be directed to deliver gas to the market with the highest netback value (market price less shipping and regasification costs). The model result also reflects a trade which minimizes shipping costs for a given set of delivery requirements. Figure

3.8 shows that the bulk of LNG supplies are delivered to Europe in the winter months (see figure 3.8). Thus, during from October to April there is an excess of LNG tanker capacity as the transit time for African and Middle Eastern LNG ships to Europe is roughly one-half the transit time needed to deliver those cargoes to the U.S. Meanwhile, LNG supply from Trinidad to the U.S. is constant throughout the year. Since a small amount of Middle East cargoes are still delivered to the U.S. in the winter, it is more economical to divert any remaining Middle East to the U.S. cargoes than to ship Trinidad cargoes to Europe. In effect, the model illustrates an efficient trade result where no fully loaded tankers cross paths at sea.

In the summer, U.S. gas buyers purchase three-fourths of total African and Middle East LNG output. Delivering these cargoes to the U.S. requires nearly twice the LNG tankers that delivering those same volumes to Europe requires.

In a perfectly competitive and fungible tanker market, where all tanker charters are individually owned and available for spot charter, summer tanker charter rates would include most of the capital costs for each ship. Summer charter rates would reflect the binding capacity constraints in those months. As the bulk of LNG cargoes are imported by the U.S. – the U.S. bears a disproportionate share of the capital cost of tankers. The availability of excess tankers would drive winter charter rates down to include only operating costs.

The fluctuation in tanker charter rates may not be as dramatic in the real marketplace as in this theoretical model. Nevertheless, spot charter rates should be expected to reflect scarcity when a greater fraction of cargoes are going to long-haul markets (likely summer U.S.) and

charter rates are likely to fall when short-haul deliveries dominate (winter to Europe). Even vertically integrated suppliers who own LNG supply, ships and regasification facilities would realize the largest benefit from additional tanker capacity in the summer months. For an integrated supplier, this benefit would come from the ability to deliver more supplies to a long-haul, higher netback gas market.

3.5 DISCUSSION

Stationary results

The results from the Atlantic Basin gas trade model in this chapter build on the insights from the stylized models in chapter 2. The model provides insights for the expected monthly trade in LNG cargoes and the interaction with domestic gas storage markets and gas prices.

The model shows that the destination flexibility of LNG cargoes is a cost effective mechanism to provide swing capacity to markets with highly seasonal gas demand and relatively high storage costs. In the Atlantic Basin, Europe has more seasonal demand and relatively high gas storage costs. These factors tend to drive European gas buyers to preferentially procure LNG cargoes in the winter.

Importing LNG to match seasonal demand comes at a cost. In the Atlantic Basin, Europe must outbid other markets with winter peaking gas demand. Shifting LNG imports to match winter gas demand also requires investment in regasification capacity to meet peak import needs.

In an integrated market, price and supply affects in one market are felt by all other importers. In this simplified model of global trade, all importers were in the Northern Hemisphere and use gas heavily for residential heating, primarily in the winter months. The comparatively low-cost of storage in the U.S. encourages U.S. buyers to import LNG in the summer months (when gas is less sought after by Europe) and store that gas for winter consumption. A richer model of global trade would also include such LNG importers as Japan, Korea, Taiwan. Japan and Taiwan, in particular, use gas primarily for power generation and have flat to summer peaking gas consumption. For markets with such non-correlated demand, swing LNG cargoes can avoid storage investment for both importers.

Dynamic effects

The Atlantic Basin gas trade model is a representation of equilibrium conditions and expected gas flows for twelve months of given year, here assumed to be 2015. This structure is well suited to describe the fundamental interactions that will drive monthly gas trade. In addition to the predictable seasonal cycles, gas markets will also be exposed to growth and structural change, and also to unpredictable, stochastic variability. In chapter 4, I consider the implications of stochastic gas demand and price variability on LNG trade. The expected gas flows and prices predicted by the Atlantic Basin gas trade model are used as a basis upon which gas demand and price variability are introduced.

Growth and structural change are typically the purview of the long-term, annual-scale gas and energy models (IEA 2004b; EIA 2006a). The Atlantic Basin gas trade model uses the outputs of those models to set the context for the analysis of intra-annual trade and month-scale

price formation. Important structural shifts will occur as gas markets move from currently low-levels of LNG trade, to a robust trade with significant seasonal shifts of gas supplies from one region to another following the fundamentals described in this chapter. The month-scale Atlantic Basin gas trade model also yields some insights about the transition from regionally isolated markets to the equilibrium conditions provided by the model results.

Examples from Europe highlight the dynamic transitional forces at work in the development of an integrated Atlantic Basin gas market. As discussed above, gas futures prices and market data in the U.K. and Spain suggest that the market value of annual gas storage is currently in excess of the \$2.50 per mcf assumed in the model here. Seasonal spreads in the U.K. during the summer of 2006 suggest a value of seasonal gas storage in excess of \$8.00 per mcf.⁹ If the storage cost assumptions here are roughly correct, the market is providing a strong signal to drive investment in new storage capacity.¹⁰

The expansion of gas storage capacity will tend to reduce seasonal spreads. However, while this investment is being realized in regional markets, we should expect seasonal LNG flows much greater than reflected in the model with assumed \$2.50 per mcf storage costs. Higher storage costs create a greater incentive for buyers in markets like the U.K. and Spain to seek winter LNG cargoes – and for sellers to deliver gas to earn spiking winter prices for gas.

⁹ Competitive bidding for reserving gas storage capacity supports the seasonal price spread in future prices.

¹⁰ The economics of storage expansion are not purely technological, however. A significant component of the cost of building gas storage capacity is the “cushion gas” that is required to maintain pressure for withdrawal. The amount of cushion gas required varies depending on the geology of the particular storage field. ILEX (2005) estimated that the cushion gas could be in excess of 50% of the total cost of expanding U.K. storage capacity.

Recent evidence supports this interpretation. In the winter of 2006, storage constrained markets in Spain procured spot LNG cargoes to meet winter demand, paying in excess of U.S. Henry Hub prices. Then, in the summer of 2006, spot LNG imports to the U.S. were at an all time high, while “LNG vessels are backed up at Spanish LNG terminals due to sparse storage capacity” and “the largest attraction to the U.S. market (Nelson and American University (Washington D.C.). Foreign Area Studies.) its easy access [with plenty of regasification capacity], volume gas market, and big storage capacity” (WGI 2006d). The institutional factors that may have prevented similar winter LNG imports to the U.K. in 2005-2006 are discussed in chapter 5.

In addition to the dynamics of changing storage capacity – the structure of gas demand may also shift over time. This model assumed seasonal demand profiles in 2015 were similar to recent historical data. However, changes in the composition of gas demand – particular the potential growth of gas for use in electric power – could change the seasonal variation in gas demand. Increased use of gas for power demand has “flattened” the seasonal consumption of gas in the U.S. over the last decade. The growth of gas use for power generation has generally been slower in Europe, but is projected to increase over the coming decade (IEA 2004b) though considerable uncertainty remains about this future trend in Europe (Honore 2006). Increased gas consumption in the power sector would likely increase summer demand for gas in Europe. The economic drive to land winter cargoes in Europe is likely to persist, so long as storage capacities are relatively constrained there and the cost of access to those facilities remains higher than in the U.S.

The structure of the Atlantic Basin gas trade model showed how constraints in the gas supply chain determine the shadow prices (and market values) for access to capacity in each respective segment. Evidence from the stylized gas trade model in chapter 2 and the Atlantic Basin model in this chapter suggests that the supply of LNG, including gas production and liquefaction in distant regions, is likely to be the key limiting factor in the development of future trade in LNG. The proportionately high capital cost of gas production and liquefaction suggest that investors are unlikely to build supply capacity in excess of shipping, regasification, or gas demand needs. This interpretation is confirmed by current market evidence (WGI 2005a).

While from a capacity perspective, LNG volumes will always be the key constraint, seasonal and investment cycles are more likely to affect the market values of LNG tankers and regasification capacity. Inter-regional, seasonal arbitrage will drive the demand for LNG tankers, affect the utilization of regasification terminals, and determine the monthly market rates for access to both ships and terminals. While not analyzed explicitly here, cycles of capacity investment in each of these segments are also likely to drive temporary surpluses or shortages of ships and regasification capacity that will also affect rents to owners of capacity in each segment.

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