

A Stylized Model of Seasonal Price Formation in Integrated Regional Gas Markets

by Mark H. Hayes¹

I. Introduction

Gas markets were, until recently, regionally isolated. North American gas markets have been largely independent, even in 2005 the U.S. imported just 4% of its gas supply from outside the continent. European gas markets depend on long-distance pipeline imports from Russia, North Africa and the North Sea with LNG imports making up 9% of total gas supply in 2004 (BP 2005). However, LNG trade is projected to grow rapidly over the next two decades. The U.S. EIA estimates that LNG will provide 21% of U.S. gas demand by 2025 (EIA 2005a) and imports by OECD Europe are also projected to increase to 28% of total gas supply over the same period (Hirschhausen 2006).

Simultaneous to the growth in LNG trade, contracting structures for LNG deliveries are also evolving. The expansion of total LNG shipments will make flexible trade more feasible and economically attractive. And an increasingly competitive and robust market for LNG cargoes will mean that cargo destinations and prices will be increasingly determined by the opportunity cost of supply and demand in the offtake markets. This shift will not happen overnight, and indeed the bulk of LNG cargoes traded today maintain oil-price linkages rather than competitive, market-based pricing. However, over time, we may expect that LNG suppliers will seek to maximize their returns, and deliver cargoes to buyers willing to pay the highest price. Such a structure does not necessarily preclude long-term contracts. A buyer with a long-term delivery commitment might agree to the diversion of specific cargoes, so long as he was offered some of

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the profit from the forgone delivery. Evidence of these trends is already becoming evident in the LNG trade today.

The expansion of such flexible LNG trade will interconnect previously isolated markets. The resulting impacts on gas pricing in these regional markets is a subject of interest to both business and policy makers. Some have already begun looking for evidence of price integration, such as Silverstovs (2005) under the assumption that prices should generally move together, and the absolute difference in prices should reflect the transit charge as in equation 2.1:

$$|p_A - p_B| \leq c_{x_{A,B}} \quad (2.1)$$

where P_A and P_B are the prices in the two respective regions, and $c_{x_{A,B}}$ is the cost of transporting gas between the two regions. Most tests for market integration in regional gas markets (De Vany and Walls 1993; Walls 1994) and in other traded commodities [McKenzie] explicitly test for such a relationship. The underlying hypothesis for these tests is that the difference in prices in “integrated” markets should not deviate far from the differential cost of transport.

Given the relatively limited flow of LNG cargoes as a fraction of total gas demand in U.S. and European markets, and the persistence of rigid, oil-linked contract structures for many European gas imports it is perhaps unsurprising that these tests do not show strong integration in prices in these markets in recent years (Silverstovs, L'Hegaret et al. 2005). However, there has been little research that thoroughly analyzes the key determinants of price formation in the developing global market for natural gas.

The fundamentals of the natural gas business, including the capital-intensive nature of gas supply and transport, and the highly seasonal, inelastic characteristics of demand suggest that a more detailed analysis may be required to understand how price formation across regions occurs in a global market for gas. Other authors have examined seasonal storage and gas pricing in a single gas market, including Amundsen (1991) and Chaton et al. (2006), but neither examined the implications for flexible LNG trade or regional market interactions. Williams and Wright (1991), in their thorough text on the theory of commodity storage, include a chapter that discusses the role of trade and the impact of differential storage costs between market regions. Williams and Wright analyze storage responses to uncertainty in supply, and the interaction with storage across two market regions. In the gas market, however, production is generally more stable throughout the year. Seasonality of demand and stochastic demand shifts are the major drivers for gas storage and price variability. This chapter focuses on the fundamentals of storage, trade, and price formation driven by seasonality. Chapter 4 of this volume examines the interactions between of stochastic variability in gas demand and inter-regional gas trade.

The analysis presented here is also unique from the Williams and Wright (1991) work on storage and trade as this model allows for transit costs to vary depending on capacity bottlenecks. More so for gas than most other commodities, transportation is major portion of total delivered gas costs (particularly for LNG). If LNG transport varies throughout the year, transport rates may also be expected to change depending on the availability of spare LNG tankers in a given month.

In the chapter that follows, I develop a system model of two regional gas markets that incorporates the key fundamentals of natural gas supply, transport, storage and demand. The purpose of the model is to characterize the relationships that will determine capital investment and price formation as regional gas markets become inter-connected by LNG supply. The focus here is on the monthly and seasonal time scale, as this is approximately the order of magnitude that is relevant for LNG cargo diversion and seasonal gas storage. Daily demand variations are largely met by high-deliverability gas storage. Annual growth in gas demand is well captured in the numerous long-term estimates of gas supply and demand, including EIA (2005b) and IEA (2004).

First, in section II of this chapter, I describe the general structure for the multi-region gas trade model with capital investment. I present the analytical solution of equilibrium conditions for capacity investment levels and operational decisions that determine prices and quantities when trade is allowed between regions.

In section III of this chapter, I develop a numerical model, ABMod, to demonstrate the fundamentals of seasonal storage, price formation, and the role for LNG trade. Two stylized scenarios are then used to illustrate the potential interaction between LNG and gas storage, and the implications on gas price formation in each regional market.²

² In chapter 3 that follows, I develop a model of the Atlantic Basin, incorporating data from the U.S. and OECD Europe to provide insights about the development of this important market for gas trade and the more complex interactions that should be expected in real world gas markets. The Atlantic Basin model incorporates varying seasonal demand profiles, differential transport costs from LNG supply sources, and heterogeneity in the storage costs between the U.S. and European markets. Results suggest a significant and time-varying price spread between the two markets, in excess of any differential transport costs.

The analytical and numerical models presented in this chapter demonstrate the importance of several additional factors, in addition to long-run transit costs, that are likely to affect intra-annual and inter-regional gas prices in an “integrated” market for natural gas. Differences in seasonal gas demand profiles (e.g. higher winter season gas demand), transit distances, and market area storage costs are each shown to be critical to driving price spreads within and between regional gas markets over the course of a typical year.

II. General Model of Inter-Regional Gas Trade with Storage

In this section I develop the analytical framework that incorporates each of the components necessary to understand the interactions between natural gas supply, transport, storage and demand operating at month-level time scales. The model is unique in that it allows for tradeoffs between capacity investment in the different segments of the gas supply and storage delivery chain. The model solves for the optimal movement of LNG cargoes to regional markets depending on the monthly supply, demand and storage balances in each gas market.

The structure of the model, as formulated here, solves for the 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’

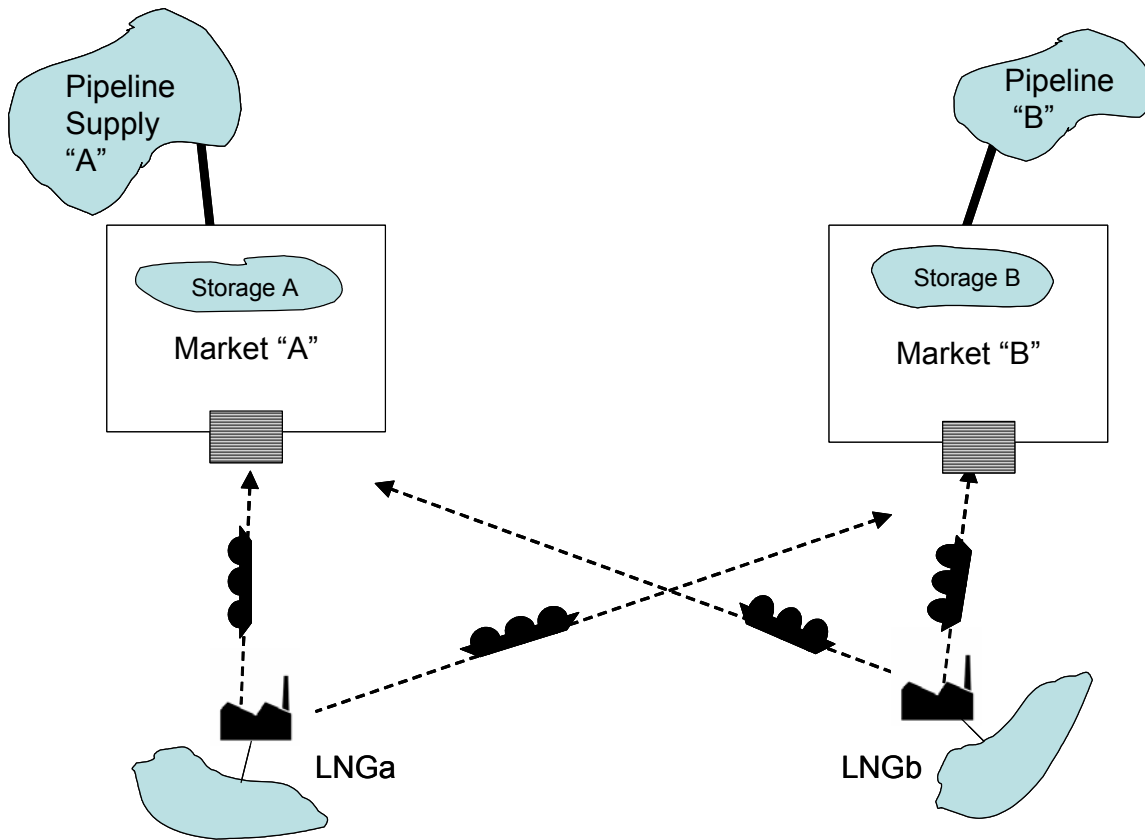
investment and operational decisions. For the remainder of this chapter I consider the industry-wide equilibrium, and model each segment of the system collectively to solve for the investment and operational conditions that optimize total social welfare.

The focus of the model is on the short-term dynamics within the natural gas market only. It does not explicitly incorporate the trade-offs between natural gas and other substitute fuel sources or the economy-wide interactions. Also, the purpose is to derive the stationary characteristics of the gas trade across twelve months of a “standard” year. The model does not incorporate any random, stochastic components. The interaction of stochastic gas demand and price variability with LNG supply and investment decision-making is discussed in chapter 4 of this volume.




Model Structure and Solution

The model framework can accommodate multiple supply and demand regions linked by pipeline and LNG transport. For clarity of exposition here, a simplified model structure is assumed as shown in figure 2.1. We assign two demand regions “Market A” and “Market B” (index j), each of which has a domestic pipeline supply source, pipe A and pipe B (index i). In addition, there are two LNG supply sources LNGa and LNGb (also index i), which may be located at different geographic distances from each of the two demand regions. The demand regions draw supply from their respective domestic pipelines or from either of the two LNG supply sources, depending on the relative costs of each supply option including both operating costs and capacity constraints.

Figure 2.1. Representative Diagram of Gas Trade Model



Legend

-  Liquefaction train
-  LNG tanker
-  Regasification terminal

For supply region i , producers' operating costs are described as the integral of the supply (marginal cost) function $f_{t,i}(y_{t,i})$. In the formulation shown here, production costs for both LNG and pipeline supply are assumed to be constant (c_y) and linear per unit supply. Fixed costs (K_Y) are also assumed to be constant per unit capacity, with capital costs allocated on a levelized, annual basis. Equation (2.2) describes the total cost of supply from region i (pipeline or LNG), including the sum of operating costs and the capital investment costs incurred over the one-year (twelve month) model period.

$$TC_{\text{supply}_i} = \sum_t (c_{y_i} * y_t) + K_{Y_i} * Y_{\text{max},i} \quad (2.2)$$

Operating costs for transport, either by pipeline or by ship as LNG, and regasification capacity are also assumed to be constant with corresponding capital costs assigned for each segment. The functional form for each cost function follows that shown in equation (2.2). Specific parameter values that assign fixed and variable costs may vary by region.

Gas demand is assumed to vary from month to month depending on seasonal characteristics. For demand in region j , consumers' benefits are described as the area below the inverse demand (willingness-to-pay) function $g_{t,j}(z_{t,j})$. The same functional form is assumed across all periods, but the level of demand is expected to vary from month to month.

Seasonal variations in gas demand can be met by adjustments to supplies or by storage in each demand region. Total storage capacity and the operation of storage (to add units to storage or to withdraw gas) are choice variables in the model. Storage costs are also separated into a fixed cost per unit storage capacity (K_s) and unit operating cost for storage additions (c_s) and storage withdrawals (c_w) respectively. Both fixed and variable costs are assumed to be constant with respect to volumes.

Using the formulation for each segment of gas supply and transport, and the general formulation of gas demand for each region, the model seeks to maximize total social welfare for a representative one-year period. The solution seeks the optimal level of capital investment for each segment of the supply chain, and operational decisions follow based on the available capacity for supply, transport and storage and unit operating costs. The optimal solution maximizes the sum of consumers' surplus (the difference between price and willingness to pay) and producers' surplus (the difference between price and total costs) over the twelve month period. The overall maximand may be written as in equation (2.3):

$$\text{Max} \left\{ \begin{aligned} & \sum_{t,j} \left[\int_{z.lb_j}^{z_{t,j}} g_{t,j}(z_{t,j}) dz \right] - \sum_{t,i} (c_{y_i} * y_{t,i}) - \sum_{t,i,j} (c_{x_{i,j}} * x_{t,i,j}) \\ & - \sum_{t,j} (c_{r_j} * r_{t,j}) - \sum_{t,j} (c_{s,j} * s_{t,j}) - \sum_{t,j} (c_{w_j} * w_{t,j}) \\ & - \sum_i (K_{Y_i} * Y_{\max,i}) - \sum_i (K_{X_i} * X_{\max,i}) \\ & - \sum_j (K_{R_j} * R_{\max,j}) - \sum_j (K_{S_j} * S_{\max,j}) \end{aligned} \right\} \quad (2.3)$$

where:

$$\begin{aligned} y_{t,i} &= \text{quantity supplied by region } i \text{ at time } t \\ x_{t,i,j} &= \text{quantity transported from supply region } i \text{ to demand region } j \text{ at time } t \\ r_{t,j} &= \text{quantity regasified in region } j \text{ at time } t \\ s_{t,j} &= \text{storage addition (injection) in region } j \text{ at time } t \\ w_{t,j} &= \text{withdrawal from storage in region } j \text{ at time } t \\ z_{t,j} &= \text{quantity demanded by region } j \text{ at time } t \end{aligned} \quad (2.4)$$

and c_y , c_x , and c_r are the per unit variable costs for supply, transit, and regasification. K_Y , K_X , and K_R are the fixed costs per unit capacity for supply, transport, and regasification capacity, respectively.

The following constraints apply:

$$\sum_{i,j} x_{t,i,j} \leq y_{t,i} \quad \forall t \quad (\text{supply balance for source } i) \quad (2.5)$$

$$y_{t,i} \leq Y_{\max,i} \quad \forall t \quad (\text{supply capacity constraint for source } i) \quad (2.6)$$

$$\sum_{i,j} x_{t,i,j} \leq X_{\max,i} \quad \forall t \quad (\text{transport capacity constraint}) \quad (2.7)$$

$$r_{t,j} \leq R_{\max,j} \quad \forall t \quad (\text{regasification capacity constraint for region } j) \quad (2.8)$$

$$z_{t,j} \leq \sum_i x_{t,i,j} - s_{t,j} + w_{t,j} \quad \forall t, j \quad (\text{demand balance}) \quad (2.9)$$

$$Sto_{t,j} = Sto_{t-1,j} + s_{t,j} - w_{t,j} \quad \forall t, j \quad (\text{storage balance constraint, time } t, \text{ region } j) \quad (2.10)$$

$$Sto_{t,j} \leq Sto_{\max,t,j} \quad \forall t, j \quad (\text{storage capacity constraint, time } t, \text{ region } j) \quad (2.11)$$

$$\begin{aligned} -(y, x, Sto) &\leq 0 \\ z_j &\geq z.lb_j \geq 0 \\ Sto_{t=0}, Sto_T &= 0 \end{aligned} \quad (\text{boundary conditions for solver}) \quad (2.12)$$

Solving the maximization problem subject to the constraints yields first-order conditions that determine the optimal levels of investment in supply, transport and regasification capacity for all supply sources, and the optimal levels of supply and demand volumes for each period. In general, investment in capacity occurs until the shadow prices on each of the respective capacity constraints—plus the variable costs of operation—match the willingness to pay for each time period. This general condition is provided in equation (2.13):

$$g_{t,j}(z_{t,j}) = (c_{y_i} + \lambda_{Y_{t,i}}) + (c_{x_{ij}} + \lambda_{X_{t,i}}) + (c_{r_j} + \lambda_{R_{t,j}}) \quad (2.13)$$

where $g_{t,j}(z_{t,j})$ is the price in market j in period t , and c_y , c_x , and c_r represent the variable costs of production, transport, and regasification, respectively. The λ 's represent the shadow costs on each of the respective capacity constraints for each period.

Capacity investment also occurs in each segment of the supply chain until the shadow costs on each respective constraint for each period totals to the per unit capital costs for the respective supply segment. Equation (2.14) shows the first-order condition that determines the level of investment of supply in region i . The same general result follows for transportation (pipeline and LNG) and for regasification capacity investment.

$$K_{S_j} = \sum_t \mu_{t,j} \quad (2.14)$$

In equilibrium, capacity investment occurs in each segment of the supply chain up to the point where consumers' benefits from a unit increase in gas delivery capacity over the twelve month period exactly matches the annualized unit cost of capacity for the respective segment (supply, transportation, and regasification). For any lower investment levels the total of the shadow costs on the respective supply, transit or regasification constraint would be in excess of the unit cost of capacity for that segment, reflecting the ability to improve overall welfare with additional capacity expansion. For any higher investment levels, consumers' willingness to pay would not justify the additional capital outlay.

Storage Equilibrium

Storage within each of the regional markets provides for inter-temporal allocation of scarce supply capacity to meet seasonal variations in demand. Storage in each of the two regions is independent, and can only serve domestic demand, although storage/withdrawal operations affect total system supply availability in each period.

The first-order conditions with respect to storage operations and total capacity levels guarantee an equilibrium condition where gas is stored in low demand periods and withdrawn in high demand periods, up to the point that no additional storage would improve the total welfare of the system. Shadow prices, $\phi_{t,j}$, for each month transmit the opportunity cost of gas consumption and storage across low and high demand periods. For illustrative purposes in this text, I describe two months of a typical twelve-month period, one low period representing a low demand month and a high demand period representing a typical month of high gas demand. Figure 2.2 illustrates these results for two periods for a single region with no trade.

During the representative low demand period, the first-order conditions provide that the current price, $g_{low,j}(z_{t,j})$, be equal to the marginal value of adding a unit to storage, less the variable cost of storage injection, as in (2.15):

$$g_{low,j}(z_{t,j}) = \phi_{low,j} - c_{s,j} \quad (2.15)$$

In the representative high demand period, equilibrium in the storage market provides that an incremental unit of gas be withdrawn from storage until willingness to pay for gas is equal to the

shadow price of gas plus the variable cost of withdrawing that unit of gas in region j ($c_{w,j}$), as in equation (2.16):

$$g_{high,j}(z_{t,j}) = \phi_{high,j} + c_{w,j} \quad (2.16)$$

The difference between the shadow prices ($\phi_{t,j}$) in the low and high demand periods is determined by the unit capital cost of storage. The value of gas in storage in the high demand period, or the willingness to pay for gas in the high demand period, must compensate for the fixed cost of storage capacity. Thus the shadow prices evolve according to the following:

$$\phi_{t+1,j} = \phi_{t,j} + \mu_{t,j} - \varepsilon_t \quad (2.17)$$

In this stylized example with one low and one high period, the high demand shadow price would be exactly μ greater than the shadow price of storage in the low demand period. (ε_t is the dual variable representing the boundary condition constraint, requiring that storage start and end the twelve-month period empty. This causes the shadow price of storage to decline after the final period.)

As with the other capacity decision variables, investment in storage capacity will occur only if the shadow prices on the storage capacity constraint for all periods sum to the total unit capital cost of storage for the respective region. If the incremental value of increasing storage capacity is below the unit cost, no storage will occur. If the sum of shadow prices exceeds the fixed cost of storage, then overall welfare could be improved by increasing storage and thereby

reducing the marginal value until the sum of the shadow prices matches the cost of storage capacity, as in (2.18):

$$K_{S_j} = \sum_t \mu_{t,j} \quad (2.18)$$

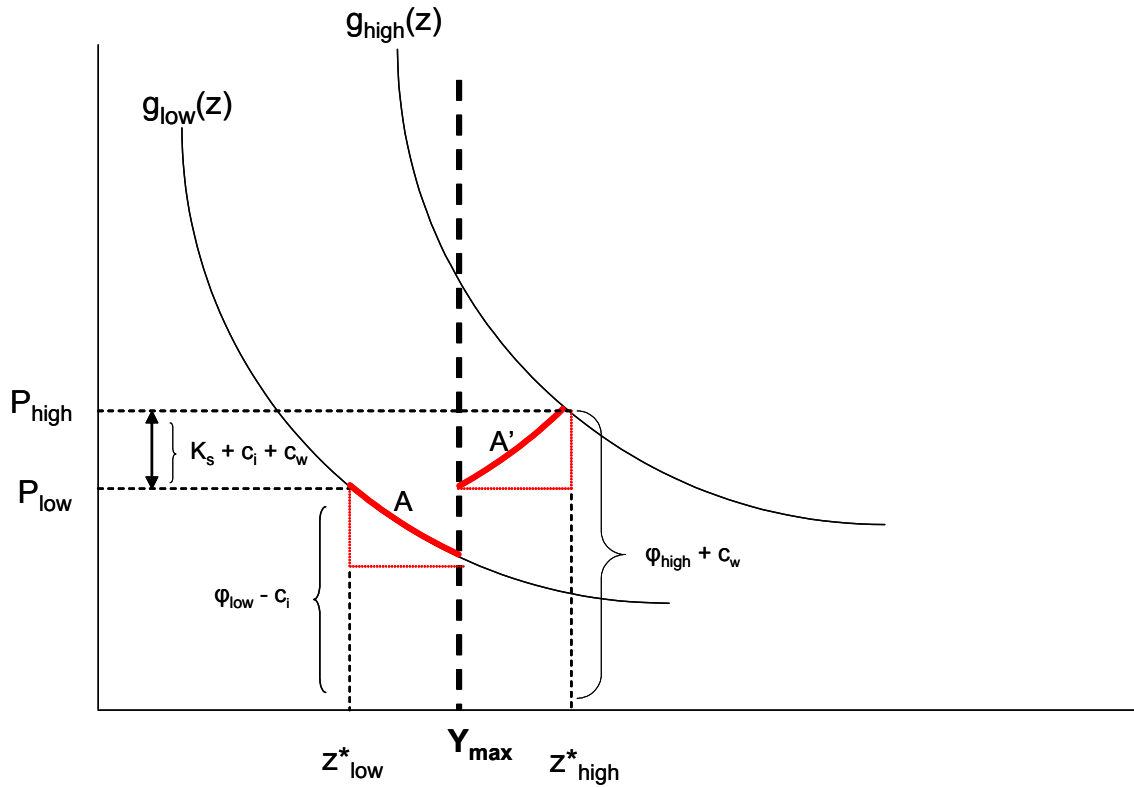
As shown in figure 2.2, the level of investment in supply capacity (Y_{\max}) determines the maximum production and transport capacity in all periods. Each marginal unit of gas is added to storage in the low period, reducing consumption from Y_{\max} to z^*_{low} , resulting in increased prices with each unit addition to storage along segment “A” of the demand curve. Additional storage is added in the low demand period, so long as the willingness to pay in the high period exceeds the unit cost of storage capacity, the variable cost of storage and withdrawal, and the benefits of within period consumption. This can be shown by subtracting equation (2.15) from (2.16):

$$g_{\text{high},j}(z_{t,j}) - g_{\text{low},j}(z_{t,j}) = (\phi_{\text{high},j} - \phi_{\text{low},j}) + c_{w,j} + c_{s,j} \quad (2.19)$$

For the two period example shown in figure 2.2, the seasonal difference is enough to induce storage, and storage is added in the low period until the shadow price μ is equal to the capital cost of storage. In equilibrium, the difference in the shadow prices between the low and high periods ($\phi_{\text{high},j} - \phi_{\text{low},j}$) is exactly the fixed cost of storage K_{S_j} .

$$g_{\text{high},j}(z_{t,j}) - g_{\text{low},j}(z_{t,j}) = K_{S_j} + c_{s,j} + c_{w,j} \quad (2.20)$$

Figure 2.2. Gas Storage in a Regional Market, No Trade



Graphically in figure 2.2, it is helpful to think of A' as the ‘supply of storage’ curve for the high demand period that determines the equilibrium level of storage and thus gas demand in both periods. A' is a supply curve with a price elasticity equal and opposite to A , shifted upward by the total cost of storage. Storage is added in the low period, increasing consumption in the high period, until high period prices match low period prices plus the total cost of storage.

$$g_{high,j}(Y_{max} + w_{t,j}) = g_{low,j}(Y_{max} - s_{t,j}) + (K_{S_j} + c_{s,j} + c_{w,j}) \quad (2.21)$$

Interactions between Storage and Trade

The solution to the analytical model provides two key insights that are particularly worthy of making explicit. First, the competitive equilibrium solution provides for no-arbitrage conditions inter-temporally within each region. No additional storage capacity or storage level additions or withdrawals can be made in any period that would garner positive returns in a future period. In an open, competitive market for storage, investment in new storage capacity and seasonal storage injection occurs up to the point that the seasonal price spread covers the capital and operating cost of storage capacity.

If capital costs (K_s) or operating costs of storage (c_s, c_w) vary across regions, the relationship in (2.20) suggests that each market should have its own unique seasonal price spread. The market with higher storage costs would have higher winter season prices and lower summer season prices compared to the low storage cost market. Price spreads between the regions would thus vary depending on the season as well.

Such variation in regional price spreads would necessarily have to be supported by the first-order conditions that govern investment in supply, transit and regasification capacity in each market. This leads to the second insight to be drawn from the analytical model solution. The competitive equilibrium condition also provides for spatial no-arbitrage conditions for any given period. The market price in each region and time period is consistent with the marginal cost of delivering gas to the respective region, including supply, transit and regasification costs (including variable costs and any shadow prices on binding capacity constraints). In equilibrium, gas cannot be diverted from one region in the model to another without lowering the overall

welfare of the system. For two market regions, A and B, the first-order conditions that determine prices and the supply capacity levels in each region are the following:

$$\begin{aligned} g_{t,A}(z_{t,A}) &= (c_{y_i} + \lambda_{Y_{t,i}}) + (c_{x_{iA}} + \lambda_{X_{t,A}}) + (c_{r_A} + \lambda_{R_{t,A}}) \\ g_{t,B}(z_{t,B}) &= (c_{y_i} + \lambda_{Y_{t,i}}) + (c_{x_{iB}} + \lambda_{X_{t,B}}) + (c_{r_B} + \lambda_{R_{t,B}}) \end{aligned} \quad (2.22)$$

If differential storage costs (or variations in the seasonality of demand) drive price differences in the regions, these seasonal prices would also be in equilibrium with seasonal variations in the shadow costs on the supply constraints. For example, a market with winter peaking demand but with relatively high storage costs would tend to preferentially pull supplies in the winter months. In a market with flexible LNG, this would likely mean the stronger winter peaking market would pull more cargoes in the winter to avoid building high-cost storage capacity. We would thus expect the regasification constraint in this market to be binding in the winter season, further supporting higher winter prices in the high cost storage market.³ These results are best illustrated with numerical examples in section III that follows.

³ In practice, such shadow costs on the respective capacity constraints should reflect the rents charged (or earned) by the holders of such capacity in periods when supply, transport (ships), or regasification is scarce. For vertically integrated operators, such scarcity rents would be captured in the sales price of gas. In the charter ship market, we would expect rates to fluctuate depending on the availability of shipping capacity. The latter may be an aggressive assumption, e.g. it seems unlikely that tanker charter rates would fall to zero when all tankers were not in use. However, we would expect to see monthly variation in charter rates to at least partially reflect this scarcity value.

III. Modeling Seasonal Gas Storage and Trade using ABMod

The following section illustrates the general analytical results from section II with ABMod—a numerical model of gas trade and storage in two markets (region “A” and region “B”). First, I describe the structure of ABMod and then I employ the model to generate two stylized scenarios that illustrate fundamental interactions between monthly gas demand, storage, LNG supply and price formation across two market regions. Model #1 compares the optimal supply and storage arrangement for the two markets: region “A” with smooth monthly demand throughout the year, and region “B” which has winter-peaking gas consumption. Average demand across twelve months is equal in markets “A” and “B”.

In model #1, all supply and storage costs are equal to both regions and the equilibrium solution suggests that both markets remain isolated and depend only on regional supply sources. The comparison of storage and price formation in these two markets illustrates the function of seasonal storage and seasonal price spreads, independent any of inter-regional trade.

In model #2, storage costs are increased only in market “B” (the seasonal market). With rising storage costs in market “B”, diverting cargoes to “B” from market “A” becomes the least means to meet B’s seasonal demand. Flexible LNG supply substitutes for storage in market “B”, drawing winter cargoes that would otherwise have gone to market “A”. Storage is thus added in market “A” to maintain smooth monthly consumption. This competition for LNG cargoes interconnects prices in the regional gas markets. The comparison of these results to the isolated seasonal storage model provides insights on the fundamentals of price formation in integrated regional markets with LNG trade.

ABMod Description

ABMod uses the GAMSTM modeling environment to calculate a numerical solution to the multi-period optimization problem of capacity investment and operations described in section II above. Using a gradient search method, the GAMS solver CONOPT searches for the set of capacity investments and storage levels that maximizes the sum of consumer benefits less producer costs over all months and regions.

The supply/demand setup follows the diagram shown in figure 2.1. There are two markets, A and B, each served by its own respective domestic pipeline supply source (pipe A or pipe B) and LNG supply from either of two LNG sources (LNGa and LNGb). The markets are assumed nearly identical, except for the specific deviations described in detail here. In both models market “B” has seasonal demand, and in model #2 market “B” incurs increased storage costs.

Consumer demand in both regions is modeled in aggregate according to the inverse demand function shown in equation (2.23), with assumed constant elasticity of demand:

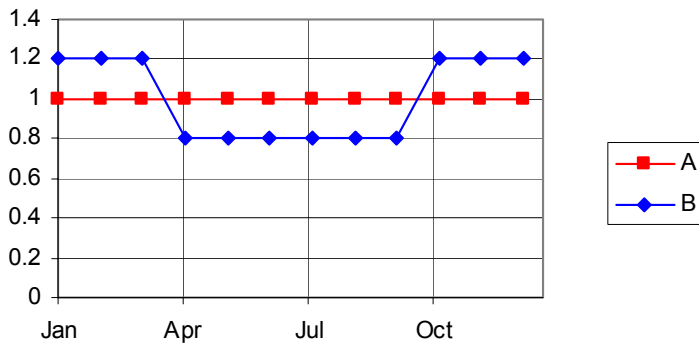
$$g_{t,j}(z) = a_{t,j} z_{t,j}^b \quad , \quad (2.23)$$

where z corresponds to monthly gas consumption (in trillion cubic feet, Tcf) and $g(z)$ is the market-clearing price for that quantity. Parameter values for a and b are assigned exogenously

and then prices and quantities for each region and time period are solved for in the model solution.

$a_{i,j}$ is the time-varying parameter that adjusts each region’s demand function to reflect the seasonal shift in gas demand that occurs over the course of a year. A unique value of $a_{i,j}$ 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 monthly consumption profile. In the stylized models, the reference quantity is equal to 2 Tcf per month for both markets. Monthly demand is constant in market “A”, while “B” experiences a seasonal swing in demand represented by indexed demand curve shown in figure 2.4

Figure 2.4. Indexed Demand for Regions “A” and “B”.



Demand responsiveness to price changes is captured in the b parameter of the demand function, where $1/b$ is the own-price elasticity of demand (ϵ_p) and is assumed constant across all months

and both regions. ϵ_p is assumed to be -0.2 in both regions in all months, e.g. a 10% increase in gas price yields a 2% decrease in gas consumption.⁴

The supply and transport structure assumed in ABMod follows the structure in the general analytical model described in section II. In the stylized models presented in this section, supply costs for the two regions are assumed equal. LNG is assumed to be the low cost supplier to both markets, with one LNG source for each market preferred due to its proximity (see tables 2.1 and 2.2). Pipeline supplies for each market are fixed exogenously at 1.5 Tcf per month for both “pipe A” and “pipe B”. In the model solution, pipeline capacity is treated as a sunk cost, and only operating costs are considered in the solution. The low variable costs of pipelines thus means that these will supply continuously in any realistic model scenario. Without assuming fixed pipeline supplies exogenously, LNG supplies would be the only supply source for either region due to the lower total cost assumed for LNG supply.⁵ In the solution, LNG is the marginal supply source and critical to price formation in both markets. Unlike pipeline supply, LNG capacity incurs the full cost of investment, and thus in equilibrium it is the shadow prices on LNG capacity constraints that determine prices in all periods.

⁴ The appropriateness of the demand elasticity parameter will be discussed in further detail in chapter three.

⁵ Supply cost assumptions will be discussed in further detail in chapter three.

Table 2.1. Supply, Transport and Regasification Costs by Segment for Stylized Models

	Annual Fixed Costs (\$ per mcf/month capacity)	Variable Costs (\$/mcf)
Pipe supply (a & b)	NA	0.10
Pipe transport (a & b)	NA	0.12
LNG supply (a & b)	1.08	0.20
LNG shipping (a to A)	0.28	0.06
(b to B)	0.28	0.06
(b to A)	0.43	0.12
(a to B)	0.43	0.12
Regasification (A&B)	0.17	0.10

Table 2.2 Total Marginal Supply Costs for Respective Supply Sources

Supply Source	Total Supply Costs (\$ per mcf)
Marginal pipeline cost (a or b)	0.22
Total LNG cost (b to B, a to A)	1.89
Total LNG cost (b to A, a to B)	2.10

In model #1, storage costs are also assumed to be equal in both markets “A” and “B”. Annualized fixed costs of storage are assumed \$0.50 per year for one mcf of capacity. Injection and withdrawal incur operating costs of \$0.04 per mcf in each region. The GAMS code allows the model to use January as the initial month, but solves the problem as if the solution were continuously repeated or looped, so year-end storage in December is optimal if the model were re-started in January again.

Other than the fixed pipeline supplies, all other capacity levels and supply decisions are unconstrained. The results of the optimization represent a competitive equilibrium.

Model #1: Equilibrium with Seasonal Storage

Model #1 compares the optimal supply and storage arrangement for two regions: “Market A” with smooth monthly demand and “Market B” with winter-peaking consumption. All other parameters in the model—supply, transport, and storage costs—are equivalent with respect to both demand regions. In equilibrium, investment in supply occurs up to the point that a constant flow of gas delivers the optimal quantity of gas to meet the smooth monthly demand in market “A”. Pipeline and LNG supply for market “B” are also smooth, with storage injection occurring in “B” during low demand months and withdrawal occurring during peak-demand periods. In general, prices are low in both markets and consumption in excess of the reference quantities (see figure 2.5a). This result is driven by free investment in LNG capacity at delivered costs of \$1.89 per mcf, compared to the reference demand price of \$5 per mcf.

The assumptions for this stylized model—with an unconstrained, and preferred LNG supply available to two regional markets with equivalent storage costs—drives a least-cost solution of isolated markets, with no inter-regional diversion of LNG cargoes throughout the year (see figures 2.5b and 2.5c). Market “A” depends on the proximate source—LNG_a, and market “B” only receives cargoes from LNG_b. Since pipeline capital costs are assumed as sunk, prices in each market are thus determined independently based on marginal costs of supply for the proximate LNG source.

For market “A”, with smooth monthly demand, the willingness to pay is the same in all periods and thus the shadow prices on the capacity constraints are also equal in all periods. The

equilibrium price is thus equal to the total cost of supply from LNGa (\$1.893 per mcf), with fixed costs allocated evenly across all periods:

$$g_{t,A}(z_{t,A}) = (c_{y_{LNGa}} + \lambda_{y_{LNGa}}) + (c_{x_{LNGa,A}} + \lambda_{x(LNG)_t}) + (c_{r_A} + \lambda_{r_{t,A}}) = 1.893 \quad (2.24)$$

For market B, the proximate LNG source, LNGb, is also the cheapest source of supply at the margin in all periods and the standard first-order condition determining prices still holds in all periods:

$$g_{t,B}(z_{t,B}) = (c_{y_{LNGb}} + \lambda_{y_{LNGb}}) + (c_{x_{LNGb,B}} + \lambda_{x(LNG)_t}) + (c_{r_B} + \lambda_{r_{t,B}}) \quad (2.25)$$

However, the seasonal swing in demand in market “B” places additional value on peak season supply, shipping, and regasification. Thus, the shadow prices on each of those constraints (λ_y , λ_x , λ_R) are higher during the winter peak demand than in the summer low demand periods. Variable costs are constant across months, so the difference between winter and summer prices and winter and summer shadow prices must be equal:

$$g_{jan,B}(z_{jan,B}) - g_{jul,B}(z_{jul,B}) = \left[(\lambda_{y_{jan,b}} + \lambda_{x(LNG)_{jan}} + \lambda_{r_{jan,B}}) - (\lambda_{y_{jul,b}} + \lambda_{x(LNG)_{jul}} + \lambda_{r_{jul,B}}) \right] \quad (2.26)$$

Moreover, inter-temporal equilibrium requires that the seasonal price difference correspond to the cost of storage (capital plus operating), as shown in the analytical solution in section I. Since a non-zero amount of storage occurs in market “B” (nearly 2.5 Tcf), the seasonal price spread must also justify the cost of storage in market B, so:

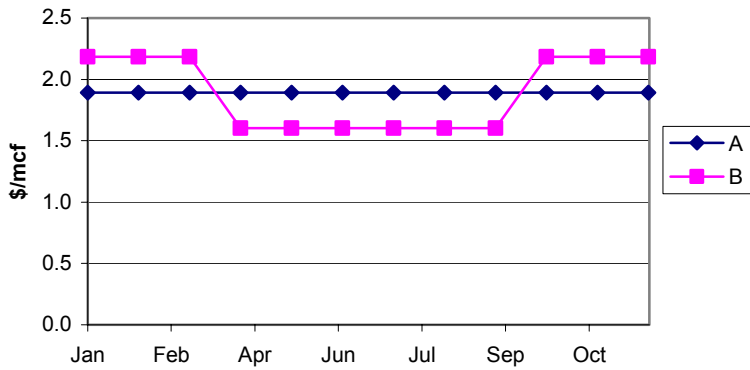
$$g_{jan,B}(z_{jan,B}) - g_{jul,B}(z_{jul,B}) = K_{S_B} + c_{s,B} + c_{w,B} \quad (2.27)$$

Combining (2.26) and (2.27), we can see that the difference in the sum of the shadow prices for the supply chain must also be equal to the full cost of storage. This relationship defines an equilibrium between the level of investment in each segment of supply chain and the cost of storage, as shown in the following equation:

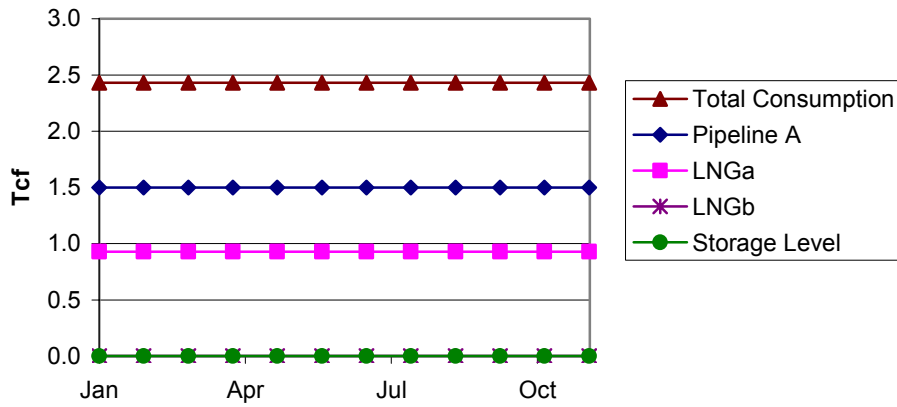
$$\left[(\lambda_{Y_{jan,b}} + \lambda_{X(LNG)_{jan}} + \lambda_{R_{jan,B}}) - (\lambda_{Y_{jul,b}} + \lambda_{X(LNG)_{jul}} + \lambda_{R_{jul,B}}) \right] = K_{S_B} + c_{s,B} + c_{w,B} \quad (2.28)$$

Equation (2.28) is the key relationship that determines the best means to meet seasonal demand for market “B”. If, for example, the capital costs of LNG supply, transport, and regasification were sufficiently lower than those in the current model form, an alternative solution to the seasonal demand problem would be to further increase LNG capacity to meet peak winter demand, replacing the need for seasonal storage. Model #2, presented below, explores the dynamics of this solution by increasing storage costs in “B” and comparing the results to this model.

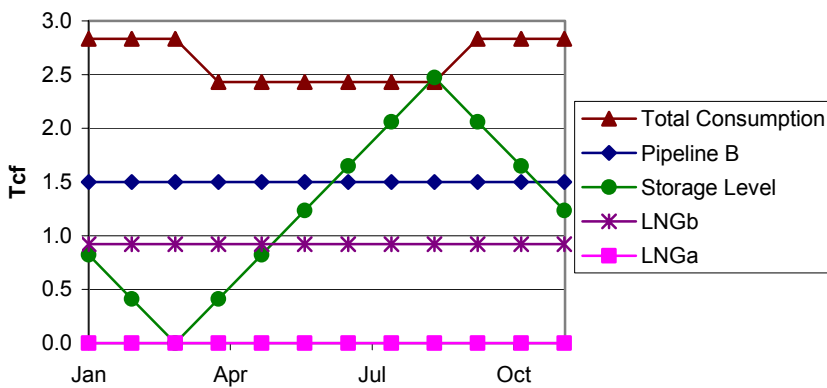
Figure 2.5. Model #1 Results: Stylized Seasonal Model
(a) Prices



(b) Market "A" Volumes



(c) Market "B" Volumes



Model #2: Equilibrium with Heterogeneous Storage Costs

In this stylized scenario, one adjustment is made relative to the seasonal storage model discussed above. The cost of storage in the market with seasonal demand (market B) is more than doubled, with annualized capital costs increased from \$0.50 to \$1.5 per mcf storage capacity, and operating costs increased from \$0.04 to \$0.08 per mcf for both injection and withdrawal. This cost shift is consistent with market data showing differential storage costs between major gas markets, such as the U.S. and Europe. IEA (2003) cites capital costs for new gas storage in the U.S. at roughly one-third the cost of new storage in Europe, due in part to the limited availability of suitable storage sites in Europe and also due to more stringent health and safety regulations in Europe than in the U.S. Such regional differences in storage costs yield important implications for LNG capacity investment, storage, and price formation when LNG interconnects these regional markets. This stylized model investigates these implications—including the role for LNG supplies to act both as a substitute and complement to natural gas storage.

Increasing the cost of storage in market “B” shifts the fundamental relationship that determines prices and storage. The equilibrium prices shown in figure 2.6(a) show that the seasonal spread in market “B” (\$2.718 - \$1.068 = \$1.65 per mcf) is no longer sufficient to justify the total cost of storage in market “B” (\$1.66 per mcf).

$$g_{jan,B}(z_{jan,B}) - g_{jul,B}(z_{jul,B}) < (K_{s_B}^2 + c_{s_B}^2 + c_{w_B}^2) \quad (2.29)$$

As previously, the prices and seasonal swing in “B” are still determined by the differential shadow prices between the peak winter and summer low demand periods:

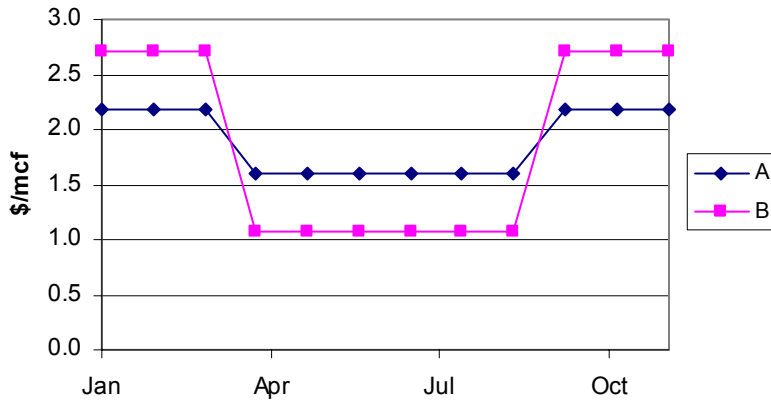
$$\left[(\lambda_{Y_{jan,b}} + \lambda_{X(LNG)_{jan}} + \lambda_{R_{jan,B}}) - (\lambda_{Y_{jul,b}} + \lambda_{X(LNG)_{jul}} + \lambda_{R_{jul,B}}) \right] < K_{S_B} + c_{s,B} + c_{w,B} \quad (2.30)$$

However, with the increased cost of storage, equilibrium is reached with shadow prices on the supply constraints that do not justify storage in market “B”. Rather than building high cost storage, a lower cost solution to meeting seasonal demand in “B” is to shift LNG cargoes between market “A” and market “B” over the course of the year (see figures 2.6(b) and 2.6(c)). LNG cargoes from both LNGa and LNGb are attracted to market “B” in the winter due to the relatively high willingness to pay in that market in those months. During the summer, cargoes from both LNG sources are delivered to market “A” where they are added to storage and provide for increased consumption due to reduced market prices.

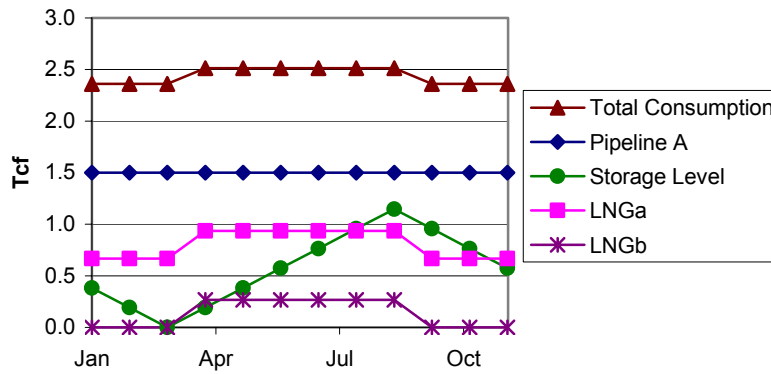
The shift to “seasonal” LNG shipments from both LNGa and LNGb requires additional capacity investment in LNG tankers and regasification, compared to the model #1 results. Delivering equivalent volumes from LNGa to market “B” in the winter, and from LNGb to market “A” in the summer requires 50% more tanker capacity than shipments to the respective proximate markets. The seasonal variation in LNG shipments also requires additional regasification capacity to be increased to meet supply levels with peaks in excess of the smooth monthly deliveries, as in model #1. However, such additional investment is justified following equation (2.30) above. Expansion of LNG shipping and regasification capacity to meet the seasonal swing occurs, so long as the cost of such investment is less than the cost of building expensive storage in market “B”.

Figure 2.6. Model #2 Results: High Cost of Storage in “B”

(a) Prices



(b) Market “A” Volumes



(c) Market “B” Volumes

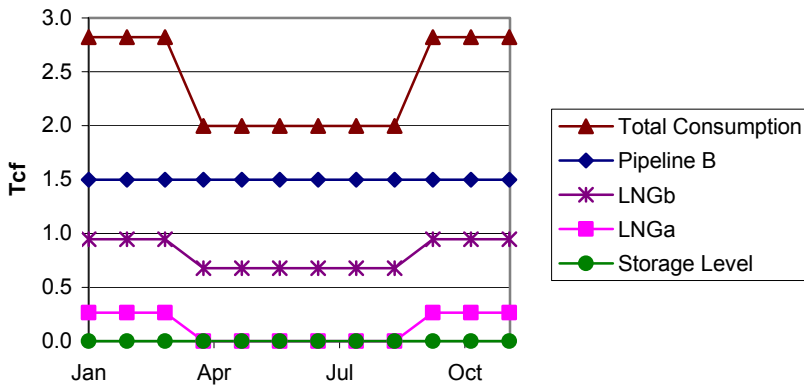


Table 2.2 shows the incremental capacity requirements for seasonal LNG trade relative to the isolated market solution. Total capital costs are increased in model #2 compared to model #1—but are significantly lower than if storage were constructed in market “B” to meet its seasonal demand swing at the increased storage costs. (Maintaining 2.472 Tcf of storage in “B” as in model #1, at the increased \$1.5 per mcf capital cost, would require an additional \$2.472 billion of additional investment, significantly more costly than the \$1.43 billion of additional investment in ships and regasification in the equilibrium solution).

Table 2.2 Capacity Investment Levels and Costs for Stylized Models

	Model #1—Seasonal Storage in “B”			Model #2—High Cost Storage in “B”		
	Capacity (Tcf/mo.)	Unit cost (\$/mcf/mo. annualized)	Total Cost (\$billion)	Capacity (Tcf)	Unit cost (\$/mcf/mo. annualized)	Total Cost (\$billion)
Liquef-a	0.929	13.0	12.08	0.936	13.0	12.17
Liquef-b	0.921	13.0	11.97	0.945	13.0	12.29
Tankers	1.849	3.4	6.29	2.014	3.4	6.85
Regas-A	0.929	2.0	1.86	1.202	2.0	2.40
Regas-B	0.921	2.0	1.84	1.211	2.0	2.42
Storage-A	0	0.5	0	1.146	0.5	0.57
Storage-B	2.472	0.5	1.24	0	0.5	0
Total CapEx			\$35.27			\$36.70

The move to LNG trading between the regions fundamentally alters price formation in both markets. “A” and “B” are now interconnected, though as figure 2.6(a) shows, the price differential is not constant over the course of the year. Nevertheless, these prices represent an arbitrage-free equilibrium, with prices within each market and between the markets internally consistent and reflecting the shadow costs of supply, transit and regasification in each period.

The new price inter-linkage between markets is evident in the seasonal price swing in market “A” despite the constant demand for gas in “A”. “A” now sees a seasonal price effect, as winter demand in “B” pulls cargoes from both LNG_a and LNG_b, increasing the shadow prices for both supply sources. Market “A” must pay competitive prices with market “B” to obtain LNG supplies.

In addition to the increased shadow prices for winter LNG cargoes, the rest of the market price in “A” is built up from transportation and regasification costs. In the winter months, Market “A” LNG takes cargoes only from LNG_a and thus pays reduced fixed and variable transit costs relative to market “B”, which must pay increased capacity charges for the additional ships required to move gas from distant LNG_a to market “B”. Finally, regasification utilization peaks during the summer in “A”, so this constraint is not binding in the winter months. LNG importers to “A” would be expected to pay reduced charges (here variable costs only) relative to the summer peak period. The individual pieces of the price build-up for a winter month in market “A” are shown in here:

$$\begin{aligned}
 g_{jan,A}(z_{jan,A}) &= (c_{y_{LNGa}} + \lambda_{y_{jan,LNGa}}) + (c_{x_{LNGa,A}} + \lambda_{x(LNG)_{jan}}) + (c_{r_A} + \lambda_{r_{jan,A}}) \\
 2.183 &= (0.20 + 1.540) + (0.06 + 0.283) + (0.10 + 0.0) \quad (2.31)
 \end{aligned}$$

Winter prices in market “B” are also built off the competition for LNG supplies, LNG tankers, and access to regasification terminals. “B” draws cargoes from LNG_a during the winter months, and must pay competitive prices with “A” LNG at the source. “B” then pays increased cargo charges (fixed and variable) given the increased travel distance, and import costs are

higher as the regasification constraint is binding in the winter months. In total, winter prices in “B” are increased relative to “A” by the difference in fixed capacity charges (shadow costs) for transport and regasification, and the additional variable costs of transporting LNGa to market “B”.

$$\begin{aligned}
 g_{jan,B}(z_{jan,B}) &= (c_{y_{LNGa}} + \lambda_{y_{jan,LNGa}}) + (c_{x_{LNGa,B}} + \lambda_{x(LNG)_{jan}}) + (c_{r_B} + \lambda_{r_{jan,B}}) \\
 2.718 &= (0.20 + 1.540) + (0.12 + 0.425) + (0.10 + 0.333)
 \end{aligned} \tag{2.32}$$

In the summer months, binding constraints on shipping and regasification for market “A” drive prices above market “B”, a reversal of the winter the regional price spread (or basis differential). Summer demand is relatively stronger in market “A” than “B”, and thus “A” attracts supplies from both LNGa and LNGb. However, the shadow prices on supply from LNGa and LNGb are reduced in the summer without the peak winter demand pull from market “B”. Equations (2.33) and (2.34) show the build-up of prices for typical summer month in markets “A” and “B”. Ultimately, summer prices are higher in “A” than in “B”, due to the increased shipping charges for moving LNGb to market “A” and the binding constraint on regasification capacity.

$$\begin{aligned}
 g_{jul,A}(z_{jul,A}) &= (c_{y_{LNGb}} + \lambda_{y_{jul,LNGb}}) + (c_{x_{LNGb,A}} + \lambda_{x(LNG)_{jul}}) + (c_{r_A} + \lambda_{r_{jul,A}}) \\
 1.603 &= (0.20 + 0.425) + (0.12 + 0.425) + (0.10 + 0.333)
 \end{aligned} \tag{2.33}$$

$$\begin{aligned}
 g_{jul,B}(z_{jul,B}) &= (c_{y_{LNGb}} + \lambda_{y_{jul,LNGb}}) + (c_{x_{LNGb,B}} + \lambda_{x(LNG)_{jul}}) + (c_{r_B} + \lambda_{r_{jul,B}}) \\
 1.068 &= (0.20 + 0.425) + (0.06 + 0.283) + (0.10 + 0.0)
 \end{aligned} \tag{2.34}$$

In model #2, seasonal storage is shifted to market “A”. In equilibrium investment in storage capacity in “A” occurs until the seasonal price spread (itself a function of the differential shadow prices on LNG supply, transport and regasification) matches the cost of storage:

$$g_{jan,A}(z_{jan,A}) - g_{jul,A}(z_{jul,A}) = K_{S_A} + c_{s,A} + c_{w,A} \quad (2.35)$$

$$(2.183 - 1.603) = 0.5 + 0.04 + 0.04 = \$0.58$$

The increase in storage costs in model #2 fundamentally alters gas trade and price formation in the two market regions. Storage in “B” is no longer the most cost-effective means to meet the seasonal swing in demand. Rather, seasonal LNG flows substitute for gas storage. The movement of cargoes between regions inter-connects prices in markets “A” and “B”—but the price relationship, or regional basis, varies over the course of the year. The summer spread between “A” and “B” is positive, while the winter price spread favors “B”.

The competition for LNG cargoes creates a seasonal price swing in “A” substantial enough to justify storage investment in that market, despite the fact that demand is constant in “A” throughout the year. Storage in “A” thus acts as a complement to LNG, allowing seasonal LNG supplies to be added to storage during the summer and withdrawn in the winter when higher priced LNG is preferentially attracted to market “B.” The seasonal shift of LNG cargoes between markets “A” and “B” is the most efficient means to meet gas demand in both markets and represents both an inter-regional and inter-temporal arbitrage free equilibrium.

IV. Conclusions

The seasonal nature of gas demand and the costly, specialized infrastructure required to provide gas supplies to meet that seasonal demand are critical to price formation. The rapid growth and increasingly flexible trade in LNG cargoes will fundamentally alter the mechanisms of gas price formation in regional markets. The analyses presented in this chapter sought to characterize the interactions between LNG, gas storage and price formation at the monthly time-scale.

Three main insights can be drawn from the analyses presented in this chapter:

First, as shown in the analytical model, gas price formation in a market with free movement of LNG will be determined by costs along the entire gas delivery chain. These costs are likely to vary by month, depending on the capacity constraints on respective segments of the gas delivery chain. Competitive markets for LNG supplies, LNG tankers and access to regasification terminals are likely to drive temporal and regional price spreads that will depend on demand characteristics in all offtake markets.

Second, both analytical and numerical model results showed that where a competitive market for gas storage exists, we should expect the seasonal price spread within a given market to reflect these costs. Price spreads in excess of full cycle storage costs would represent an arbitrage opportunity, inducing additional investment in storage capacity. Seasonal price spreads below the annual cost of storage would not be sufficient to attract investment in new storage capacity.

Third, the results of the stylistic model with heterogeneous storage costs (model #2) show how flexible LNG supply can substitute for high cost gas storage in a particular market. If the incremental capital costs for “excess” LNG tankers and regasification facilities are less than the cost of storage, flexible LNG supply can substitute for in-market storage. Where storage costs differ between markets, the shift to seasonal LNG flows also creates an incentive to expand storage in the low-storage cost market. Storage capacity in the low cost market is thus a substitute for storage in the high storage cost market.

This result may have particular policy implications. Policies that encourage storage via subsidy or regulatory mandate would serve to depress the seasonal price spread within that particular domestic market, as storage capacity would be built in excess of the market benefits provided by storage (the sum of shadow prices on supply capacity constraints). Thus, we might expect the expansion of storage in one market would actually result in reduced incentives for storage investment in other inter-connected regional markets. These and other policy implications will be considered more thoroughly in chapter five.

Collectively, these insights point to the dynamic interaction between gas markets created by the flexible movement of LNG cargoes. The emergence of a competitive global market for gas will interlink capital investment, LNG cargo flows, storage decisions and ultimately prices in all markets. However, the model results also suggest that interconnected gas markets are not likely to exhibit the tight and time-consistent linkages often thought to characterize so-called “integrated” markets. Rather, seasonal differences in gas demand and heterogeneity in storage

costs, in addition to the more commonly considered transit cost differences, are likely to yield price spreads between markets that vary on throughout the year.

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