Contents

Figures

Tables

1

Introduction

The natural gas industry is a dynamic, complex, and exciting place to be at the current time. Employing more than a million people in North America alone, the market continues to grow due to ever-increasing opportunities, from exploration and production to marketing and trading to transportation and consumption. Although most widely used in North America, natural gas consumption is spreading throughout the world. Many emerging countries and even more advanced industrialized nations are diversifying their energy consumption by encouraging the exploration for natural gas and the development of transmission systems to distribute natural gas throughout their countries for its many uses.

This chapter provides the reader with a general understanding of the evolution of the natural gas market from its early regulated environment to the current stage of the industry. I will refer the reader to other sources for information pertaining to the discovery of natural gas, production methodologies, legal issues stemming from deregulation, and other topics not related to the subsequent material in this book.

Industry Segments

In the United States, the natural gas industry was originally comprised of two segments: exploration and production, and distribution and sales. Initially, the exploration and production segment was not viewed as a part of the industry in need of regulation, but as a natural resource extraction industry. The distribution and sales segment, however, was controlled exclusively by the major natural gas pipeline companies and was viewed as a business in need of regulation primarily because transmission of the product by these pipelines served the public interest most effectively and efficiently. Due to the high cost of entry to the market, geographical limitations, and environmental feasibility, local governments felt a monopolistic threat could develop among these few transmission companies. Consequently, local governments declared authority over the geographic areas containing natural gas pipelines.

As the natural gas market continued to grow, pipelines began to spread from one geographic region to another, crossing state borders and hence local government jurisdictions. The rules governing one state differed from those in others, From the wellhead, gas enters a small-diameter pipeline system called a *gathering system*. Each wellhead in the vicinity is connected to the gathering system. From there, the natural gas is brought to a central location where it can be processed and then measured by a metering device. Volumes are processed to extract liquids and other by-products so the gas will meet standard pipeline specifications. This is usually done by a party other than the operator of the gathering system because there is an active market for bulk quantities of certain by-products, such as butane and propane. The metering device is most important in the context of this text in that this is where title transfer to another party occurs if the gas is resold at this point.

Located on the other side of the processing facility is the *pipeline interconnect*, the point at which the gas is received by a major, larger-diameter pipeline, or *mainline,* as they are commonly referred to. This point is called the *receipt point*, of which there are hundreds on a typical pipeline system, connecting gathering systems from various locations. These pipelines can either be interstate (crossing state lines) or intrastate, and they typically interconnect with several other major, large-diameter pipelines. The vast pipeline network in North America spans from Mexico to Canada, all four corners of the U.S., and almost everywhere in between. Title transfers can and do occur at thousands of interconnects at varying times, for varying quantities, each headed for potentially different destinations.

The mainline, or pipeline, provides the basic transportation of natural gas from one location to another. Pipelines typically connect regions of supply with market areas, and as such, the direction of flow of natural gas on a mainline system is usually from the supply source to the burner-tip. However, some pipelines have been built to bridge the gap between other pipelines and/or storage facilities.

From an operational standpoint, gas volumes will only flow from an area of high pressure to an area of low pressure. Consequently, to move the gas along a pipeline, *compressor stations* are set up along the way to pressurize the gas so that it will flow to the next compressor station or interconnect. Also, each pipeline has a maximum capacity of gas it can handle at any one time and therefore requires that the total volume received at all receipt points should equal the total volume delivered at all interconnects and other delivery points (e.g., burner-tips) along the system.

To help in balancing receipts and deliveries, *storage facilities* are located anywhere from the field (gathering area), along the pipeline systems, to the market areas. Natural gas storage facilities allow a pipeline or other shipper to *inject* or *withdraw* volumes periodically to balance any discrepancies between receipts and deliveries. These facilities are usually operated by the pipeline along which they are located, although some third parties also provide storage services from privately owned facilities. Most storage facilities are located underground, some of which are salt-dome caverns, aquifers, or depleted oil/gas reservoir fields—the most common. These types of caverns have properties that are excellent for maintaining correct pressures, necessary for operational reasons.

Finally, *end-users* are situated at the end of (or various points along) the pipelines. It is at the burner-tip or burning point where the flow of gas stops and is consumed. There are several types of end-users, some of which are regulated depending on what type of business they are in. For example, *local distribution companies* (LDCs) provide a pipeline or distribution system with gas supply for consumers in towns and cities. Since LDCs are considered public utilities, they are subject to rate approval and regulation by their state Public Utility Commission (PUC).

Other end-users include non-regulated *industrial consumers* that burn natural gas to generate heat to power machines that manufacture their products—or they burn it outright as part of a chemical process. Also, *cogeneration* plants utilize natural gas in an energy conversion process whereby water is heated to produce steam that in turn generates electricity. *Commercial* end-users burn gas at their place of business to provide spacing heat and to boil water. These types of consumers include offices, schools, hotels, and restaurants. *Electric utilities* are the single largest end-users of natural gas in terms of the volume of natural gas consumed per user. Electric utilities burn huge quantities of natural gas to generate electricity. In turn, these utilities sell to all types of electricity buyers: residential, industrial, and commercial consumers. But, because they are utilities, the price they can charge for electricity is regulated by their state's PUC. (The electricity market is currently being deregulated, and this may not be the case for long.) Consequently, if natural gas prices rise to the point where it is no longer economical to make the energy conversion based on the price received for the electricity, the utility will switch to alternate fuels such as coal or maybe heavy fuel oil to generate electricity.

Although they are not technically producers or end-users, *merchant energy companies* play a big role in the business activity along a pipeline. Also known as resellers or third parties, these companies are in the business of capturing profitable opportunities that present themselves in any of the business activities. For example, some merchants provide services, such as acting as an agent for a large industrial end-user by procuring supply, or as agent for a producer by selling supply. Another opportunity is performing administrative functions for either or both of these parties.

Perhaps the best-known function of merchant energy companies is their role as *trading companie*s. Trading companies are those that are in the business of buying and reselling natural gas for a profit. These companies are not paid a fee by anyone but earn the difference or take a loss between what they can buy natural gas for versus what they can sell it for. (Some companies will act as both service marketing companies and trading companies.) As a result of deregulation, any company is free to buy and sell natural gas to anyone. Also, it is entitled to enter into a contract for pipeline capacity on almost any pipeline system. The ability to enter the market with opportunities like these has led to the explosive growth in the number of natural gas trading companies. There are hundreds of these trading companies which provide services such as those mentioned above, as well as buying and selling with other market participants, trying to "make a spread". A *spread* is the difference between the buy price and the selling price. Many producers, LDCs, and electric utilities have established marketing or trading departments within their respective businesses to participate in these profitable opportunities or to specialize in administering the services necessary to conduct their business with natural gas.

Each day, these trading companies are looking for areas of excess supply or high demand. If they find a region that is temporarily oversupplied, for example, they can buy and take title to the supply from one counterparty (producer, another trader, or even an end-user) and sell and transfer title to another counterparty, capturing a profitable spread in between. Transactions like this can occur either at the same interconnect or at another location after transporting the supply on as few as one or as many as five or more pipelines. In the end, the goal is to earn a profitable spread.

Service marketing and trading companies are important to the natural gas industry for several reasons. As a service provider, these companies can perform many of the necessary administrative business procedures at a low cost for those companies that don't have established departments, or the know-how to perform these functions. As traders, they keep the supply and demand balance in constant equilibrium by searching for profitable arbitrage opportunities where discrepancies between supply and demand exist. In general, they help the market by providing efficiency, competition, and liquidity.

Beginning with the "Physical Transactions" section of this chapter, and throughout the remainder of this book, the material presented in this text will be most useful to those who are more interested in how trading companies, or those companies which have this function within their organization, conduct their business through the use of trading tools, trading techniques, and risk management concepts. First, however, the most important section to understand when looking for trading opportunities is the analysis of the fundamentals of supply, demand, and storage.

Supply

Supply Fundamentals

Natural gas is an underground natural resource. As such, it must be found, drilled for, and extracted to use, similar to crude oil. Natural gas is most commonly found wherever oil has been located, as it is a natural petroleum by-product. Natural gas, however, because of its composition, is usually found at shallower depths from the ground surface than crude oil and is therefore considered easier and less expensive to drill for and extract. Another characteristic of natural gas that is different from oil is that in its original state, natural gas is both odorless and colorless. When it has been brought up to the wellhead and gathering system, a sulfur-like perfume is added to the pipeline to give it an odor so its presence can be more easily detected by the smell in the case of a leak.

Natural gas production in the United States has grown considerably over the past 20 years; the highest rate of growth occurring since 2008 through the most recent data for 2019. My definition of *Total Supply* is dry production plus imports from Canada plus LNG imports. The table below shows the annual U.S. supply of natural gas in billion cubic feet per day (Bcf/d).

Table 2–1. Total U.S. supply

Year	Total Supply	=	Dry Production	+	Canadian Imports	+	LNG Imports
2000	62.7		52.4		9.7		0.6
2001	64.6		53.7		10.2		0.7
2002	62.9		51.9		10.4		0.6
2003	63.1		52.3		9.4		1.4
2004	62.4		50.8		9.9		1.8
2005	61.3		49.5		10.1		1.7
2006	62.1		50.7		9.8		1.6
2007	65.3		52.8		10.4		2.1
2008	65.8		55.1		9.8		1.0
2009	66.7		56.5		9.0		1.2
2010	68.6		58.4		9.0		1.2
2011	72.2		62.7		8.5		1.0
2012	74.2		65.7		8.1		0.5
2013	74.2		66.3		7.6		0.3
2014	78.3		70.9		7.2		0.2
2015	81.6		74.2		7.2		0.3
2016	80.9		72.7		8.0		0.2
2017	83.1		74.8		8.1		0.2
2018	91.7		83.8		7.7		0.2
2019	99.7		92.2		7.4		0.1

Notice the jump in U.S. dry natural gas production since 2008 and the resulting drop in Canadian imports and LNG imports. The jump in production is due to the widespread utilization of a horizontal drilling technique known as hydraulic fracturing, or *fracking*, which has given rise to the term *shale revolution* to describe the massive growth in U.S. natural gas production from shale plays since 2008. To put it simply, fracking is the process of stimulating production from an underground rock formation (shale) rich in natural gas (or crude oil) reserves, by drilling horizontally through the play and then injecting fluid under extremely high pressure to expand the fissures in the shale to allow the natural gas (or crude oil) to escape more freely. Needless to say, it has been wildly successful.

Supply Components

There are two main categories of my definition of Total Supply of natural gas: production and imports. Each has its components, and I have listed them below, after which I will discuss in more detail.

1. Production
    a. Wet
    b. Dry
2. Imports
    a. Canadian Pipeline
    b. LNG

Natural Gas Production and Producing Regions

In terms of product characteristics, natural gas reserves, when discovered, contain varying quantities of natural gas and have varying "life spans" depending on how much pressure the reserves are under. In other words, a small reserve that is under high pressure will produce at a faster rate, thereby depleting faster, than would a large reserve under moderate pressure. There really is no way of pumping natural gas out of the ground; it must simply flow from its higher pressure area (underground) to an area of lower pressure (gathering system) until the two pressures are equal. The pressure in the gathering system is, however, maintained at the lowest possible level, thereby maximizing the amount of natural gas able to be produced from a reserve.

When initially discovered and brought to the surface, natural gas (ethane) contains varying amounts of other hydrocarbon compounds and is usually referred to as *wet gas* in this condition. Wet gas must be processed to strip out these other elements to meet standard mainline pipeline specifications. The difference, or *shrink*, is roughly 7 Bcf/d for the country as a whole; wet gas or *marketed production* for 2019 was 99.2 Bcf/d vs dry production of 92.2 Bcf/d. State-by-state data is only available for *marketed wet gas* production. However, throughout the rest of this book, with the exception of state-level data, I will be referring to dry natural gas when citing statistics, data, quantities, or any other numerical references to natural gas production, consumption, storage, or transportation. In addition, all of the data cited has been pulled from the publicly accessible www.EIA.gov website unless otherwise noted.

At the moment, there are several prolific natural gas supply regions in North America. The largest U.S. reserves are located in the Appalachian Basin—specifically, the Marcellus and Utica shale plays. These two plays overlap the states of Pennsylvania, Ohio, and West Virginia. For 2019, of the 92.2 Bcf/d of production, 69.2 Bcf/d was from shale production, and of that, 29.6 Bcf/d was from PA, OH, and WV.

This next table shows annual marketed production in Bcf/d for the largest of the lower 48 states:

Table 2–2. Lower 48 states with largest annual marketed production in Bcf/d

	Marketed Production Bcf/d			
State	2019	2014	2009	2004
TX	24.6	21.9	18.7	13.8
PA	19.1	11.7	0.8	0.5
OK	8.7	6.4	5.2	4.5
LA	8.6	5.4	4.2	3.7
OH	7.1	1.4	0.2	0.2
WV	5.9	2.9	0.7	0.5
CO	5.4	4.5	4.1	2.9
NM	5.0	3.4	3.8	4.5
WY	4.0	4.9	6.4	4.4
Gulf Mex	2.7	3.4	6.7	10.8
ND	2.4	0.9	0.2	0.2
AR	1.5	3.1	1.9	0.5

According to the data for 2004, offshore production in the Gulf of Mexico was the second-largest producing region after Texas. However, the gulf has since dwindled to one of the smallest regions as less expensive shallow plays onshore in the shale basins have become the favored targets.

Table 2–3. Largest natural gas shale plays

		Dry Shale Production Bcf/d			
Shale Play Name	State(s)	2019	2014	2009	2004
Marcellus	PA, WV, OH, NY	22.2	13.2	0.2	0.0
Utica	OH, PA, WV	7.4	1.2	0.0	0.0
Permian	TX, NM	9.9	2.8	0.9	0.6
Haynesville	LA, TX	9.0	4.1	1.2	0.1
Eagle Ford	TX	4.3	4.3	0.0	0.0
Barnett	TX	2.3	4.3	4.3	0.9
Woodford	OK	3.1	1.8	0.8	0.0
Bakken	ND, MT	1.9	0.8	0.1	0.0
Niobrara-Codell	CO, WY	2.5	1.0	0.5	0.4
Mississippian	OK	2.8	1.1	0.7	0.8
Fayetteville	AR	1.2	2.8	1.4	0.0
Rest of U.S. Shale	various	2.5	2.0	1.7	1.4
	Totals	69.2	39.4	12.0	4.1

result, Eric needs to sell 30 April futures contracts because he bought a total of 30 contract equivalents as a swap, so he quickly places an order to sell 30 April at $2.31, and the order fills. Eric can count his money now that this trade is closed, effectively unwinding the previous trade. Figure 4.3 illustrates what the two transactions look like together, and the schedule of payments and receipts that follows shows the total profit/loss for the two trades. Dotted lines represent futures contracts, not physical gas.

Receive from 1st swap (+)	**$2.26**
Pay to 1st swap (-)	**LD1**
Receive from 2nd swap (+)	**LD1**
Pay to 2nd swap (-)	**$2.305**
Futures bought (-)	**$2.255**
Futures sold (+)	**$2.310**
Profit/loss on trade	**+$0.01 per contract x 30 contracts = $3,000**

Liquidating, in terms of a commodity or security, is the process of eliminating a futures position created from a previous trade or series of trades, accomplished by buying or selling the futures contracts in the equal and opposite direction of the position.

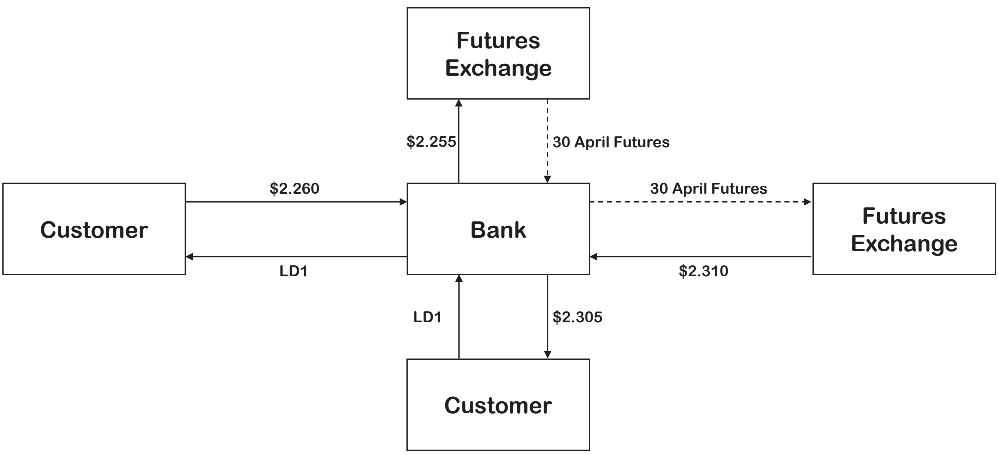

Fig. 4–3. Unwinding Futures Swap and Offsetting Futures Contract Position

The other way for Eric to liquidate is not quite as easy. Eric has the difficult task of selling his futures contracts at a price equal to or better (higher) than LD1 April, assuming he hasn't been able to unwind the original futures swap by selling another futures swap. There are two ways to do the job: 1) Speculate by selling the futures before the last trading day expiration period (final 30 min of trading) at a price hopefully equal to or higher than LD1, or 2) Attempt to replicate LD1 April by selling the contracts during the settlement period on expiration day. The first alternative needs no explanation, just some expert forecasting abilities—and lots of luck! The second alternative, however, is the most common method of liquidating futures contracts, aside from unwinding the position with another futures swap.

From the sound of it, liquidating a futures position over the final 30 minutes of trade on the last trading day by trying to buy or sell and match the settlement price seems like a daunting task. First, the settlement price (the weighted-average price of all trades done during the settlement period) is a moving target by its very nature. Second, how does a trader know the volume trading at each price over the settlement period, to attempt to get a feel for what the settlement price might be? Lastly, how does a trader know (depending on the position), when to buy or sell during the settlement period? This confusion is known as liquidation risk—the risk that a trader cannot successfully eliminate an open futures position at a price exactly equal to LD1. Liquidation risk must be managed unless the positions are offset with futures and futures swaps before expiration.

Helpful Hints for Liquidating Futures

a. Break down the number of contracts that you need to buy or sell into 30 equal tranches.
b. Buy or sell (depending on the open position) one tranche every minute, no matter what the market is doing.
c. Keep your fingers crossed that your final average price comes out close to the final futures settlement price!

As a general rule, if it comes down to it and you have to liquidate during the closing range, the more rhythmically you can execute the trades over the 30 minutes, the better chance you have of matching the settlement. (I would rather pay $0.001 and trade an exchange of futures for swap-EFS that allow for giving up futures for a swap with a counterparty that has the opposite position.)

Example of Hedging a Physical Trade with a Futures Swap

Let's suppose that during October (Oct.), FJS trading company has sold gas to a market at Henry Hub in Louisiana for November (Nov.) with this pricing structure:

Price = LD1 Nov. + $0.02

The sale price is the settlement price for the November futures contract at expiration plus a $0.02 / MMBtu premium. As a result, FJS has made a physical sale for Nov. at a floating price (LD1 + $0.02), which it must cover with physical supply before the end of Nov bid-week. To demonstrate the use of a fixed-float

Table 5–1. Storage spreadsheet Example 1.

Storage Example #1

		Current Month		31 days		Next Month		30 days
	Day	Inject Volume	Withdrawal Volume	Daily Balance	Day	Inject Volume	Withdrawal Volume	Daily Balance
								300,000
	1	0	0	0	1	0	-10,000	290,000
	2	0	0	0	2	0	-10,000	280,000
	3	0	0	0	3	0	-10,000	270,000
	4	0	0	0	4	0	-10,000	260,000
	5	0	0	0	5	0	-10,000	250,000
	6	0	0	0	6	0	-10,000	240,000
	7	0	0	0	7	0	-10,000	230,000
	8	0	0	0	8	0	-10,000	220,000
	9	0	0	0	9	0	-10,000	210,000
	10	0	0	0	10	0	-10,000	200,000
	11	0	0	0	11	0	-10,000	190,000
	12	0	0	0	12	0	-10,000	180,000
	13	0	0	0	13	0	-10,000	170,000
	14	0	0	0	14	0	-10,000	160,000
	15	0	0	0	15	0	-10,000	150,000
	16	0	0	0	16	0	-10,000	140,000
	17	0	0	0	17	0	-10,000	130,000
	18	0	0	0	18	0	-10,000	120,000
	19	0	0	0	19	0	-10,000	110,000
	20	0	0	0	20	0	-10,000	100,000
	21	0	0	0	21	0	-10,000	90,000
	22	30,000	0	30,000	22	0	-10,000	80,000
	23	30,000	0	60,000	23	0	-10,000	70,000
	24	30,000	0	90,000	24	0	-10,000	60,000
	25	30,000	0	120,000	25	0	-10,000	50,000
	26	30,000	0	150,000	26	0	-10,000	40,000
	27	30,000	0	180,000	27	0	-10,000	30,000
	28	30,000	0	210,000	28	0	-10,000	20,000
	29	30,000	0	240,000	29	0	-10,000	10,000
	30	30,000	0	270,000	30	0	-10,000	0
	31	30,000	0	300,000				
Total Inject / Withdrawal		300,000	0			0	-300,000	
Inject fee / Withdrawal fee		$0.025	$0.025			$0.025	$0.025	
Total Inject / Withdrawal Costs		$7,500	$0			$0	$7,500	
		Average Daily Balance		53,226				155,000
		Carrying fee		$0.050				$0.050
		Total Carrying Costs		$2,661				$7,750

Total Storage Costs:	
Inject / Withdrawal Current Month	$7,500
Inject / Withdrawal Next Month	$7,500
Carrying Costs Current Month	$2,661
Carrying Costs Next Month	$7,750
	$25,411