# THE ROLE OF BANKS IN PHYSICAL COMMODITIES

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*Submitted by:*
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## STUDY PURPOSE AND RESEARCH METHODOLOGY

This study explains and illustrates the important business role that banks play in the commodities sectors of our economy. We highlight the size and significance of these sectors and review their business value chains. We demonstrate how the role of financial intermediaries in physical commodities is beneficial in providing businesses access to capital and related risk management (e.g. hedging) services. We use industry examples to highlight the role of banks in physical commodities and, while we believe the impact is significant, we have not estimated the overall economic or consumer impact of this role as we have done in other studies. This report draws on the multidisciplinary expertise of IHS Inc. The study has been commissioned by the Securities Industry and Financial Markets Association (SIFMA). The analysis and the opinions contained in this report are entirely those of IHS Inc. and we are solely responsible for the contents herein.

The authors conducted interviews with commodity producers, transporters, converters, end users, bank and non-bank traders and others. We also conducted discussions with our own internal and external networks of industry experts. We supplemented primary research with secondary research including a review of the existing literature, public filings and other accounts to document our fact base and to develop industry case studies.

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# I. EXECUTIVE SUMMARY

Banks play an essential role in assuring the smooth functioning of the commodity markets which underpin the $16.6 trillion U.S. economy, and on which consumers ultimately rely. This report seeks to explain that role and how the ability of banks to participate both in financial and physical markets enables them to better contribute to market liquidity and stability, and to meet the needs of companies, consumers, and the overall U.S. economy. This report does so both by explaining the roles that banks play and then demonstrating with five case studies. It also highlights that curtailment of these roles would impair liquidity, increase risk for market participants, reduce energy investment, and make disruptions more likely.

- **Why it Matters: Commodities play a large and important role in the U.S. economy and are the foundation for overall economic activity.**
  - The oil and gas industry alone supports more than 9.6 million jobs in the U.S., and contributes more than $1.1 trillion toward U.S. GDP (7.3% of total economic output); as a separate country, the U.S. oil and gas economy would rank 16th in the world, just ahead of Saudi Arabia.[1, 2]
  - The U.S. enjoys some of the lowest energy prices in the developed world, providing companies with a competitive advantage and supporting a higher standard of living.
  - Security of energy supply brings important strategic benefits to the U.S.
- **The Need: Commodity producers, manufacturers and end users face the risks of commodity price movements, but have different needs, time horizons and incentives.**
  - Commodity price risk is a key concern for participants in the commodity sector, whether buyer or seller. The ability to hedge against adverse commodity price movements improves the ability of each to operate, invest and grow—and in some cases is essential for survival.
  - For example, airlines need stable fuel costs, oil and natural gas producers need revenue certainty to develop reserves, chemical companies need competitive feedstock costs, utilities need reliable sources of energy and developers of wind and electric generation need revenue certainty. Hedging enables small and medium sized companies to maintain more stable cash flow and to raise capital.
- **Bridging Buyers and Sellers: Banks provide liquidity in commodities markets through market making activities, bringing together buyers and sellers that have different needs, risks, time horizons and incentives.**

[1] Excludes direct employment from petrochemical facilities.
[2] "Economic Impacts of the Oil and Natural Gas Industry on the U.S. Economy in 2011", PwC (July 2013); Professor Mark J. Perry, University of Michigan and the American Enterprise Institute (January 8, 2013).

- Producers, consumers, trading companies and investors have different positions, timing, needs and incentives. Market making bridges these differences by creating a counterparty to buyers and sellers, enabling them to transact.

- Market making is especially important for transactions in local, regional or non-benchmark markets, as well as for customized hedges.

- Unlike standardized, exchange-traded futures contracts, customized trades (often in the form of over-the-counter, or OTC, contracts) can be executed with tailored terms (e.g. specific location, time, period, product or grade, etc.). These customized trades reduce "basis risk"—that is, the variability between a standard benchmark commodity price in a hedge and an actual price exposure.

- Market making activity provides liquidity to exchanges and the OTC markets, plus the availability of hedging, financing and other intermediation services. Increased liquidity is associated with lower price volatility, narrower bid-ask spreads and reduced basis risk for hedging strategies.

- **Taking Delivery: The ability to physically settle commodity positions—to take delivery of the product that underlies a contract—is crucial to being able to make markets in commodities and enable industry participants to manage and hedge their risks.**

  - Notwithstanding a relatively small physical footprint (e.g. 10% of U.S. natural gas trading), active participation in physical commodities provides timely and consistent visibility into market dynamics, product movements, inventories, facility outages and other information that is critical to price risk and execute trades.

  - This also ensures that prices for financial contracts ultimately converge with prices for physical commodities, and that futures prices converge with spot prices, which maintains a more stable and efficient market.

- **Financing and Physical Delivery: Commodity producers, manufacturers and end users raise capital in a variety of ways; trade finance often requires banks to be able to take physical delivery of commodities.**

  - Energy and other commodities industries are capital intensive, making it important to be able to raise capital easily and cost-effectively, for example, through project finance. A single production facility may cost billions of dollars.

  - Unlike exchanges and clearing houses that require companies to post margin, banks accept non-standard collateral and extend credit to support long term OTC hedges. In some cases this requires banks to be able to execute physical orders.

  - In many markets, derivative proxies for physical and forwards do not exist. Physical participation can be necessary for structured financing and linked offtake/supply agreements. Some project developments, such as wind farms and infrastructure, would not have otherwise been possible without such services.

  - These services can be especially important for smaller and medium sized companies that do not have the in-house cash flows, expertise or risk-management capabilities that are resident within larger competitors.

- **Commodities Case Studies: We outline the role of banks with five industry case studies.**

  - **Oil: Saving Refineries in the Mid-Atlantic States.** Combined financing, physical oil trade and risk management services enabled the continued operation of three East Coast refineries, plus refineries in other regions. Consumers benefitted through greater availability of refined products, lower absolute gasoline prices, reduced exposure to supply chain disruptions and ongoing employment and economic output.

  - **Jet Fuel: Helping to Keep an Airline Aloft.** A jet fuel supply arrangement for a major U.S. airline—including working capital financing, and a fuel supply outsourcing solution—reduced inventory and fuel costs. In order to fulfill the supply obligations, the bank participated in many different physical jet fuel markets, buying locally or shipping in from more distant markets.

  - **Natural Gas**: **Expanding Supply.** Credit extended through Volumetric Production Payment (VPP) agreements financed the development and production of U.S. natural gas resources, especially for small and medium sized producers. Banks need to be able to take physical delivery of future gas production, since this is the collateral that supports this transaction.

  - **Non-Ferrous Metals: Maintaining Capacity during Extreme Downturn.** Inventory financing and support to the aluminum industry since the 2008-2009 recession helped maintain production. The market environment encouraged the purchase of "excess" production, by financing storage at low rates and hedging future price risk.

  - **Renewable Energy: Powering Up a Wind Farm.** A renewable power developer building a Montana wind farm was provided with a construction loan, revenue hedge, physical power scheduling and a tax equity investment, enabling this project to move ahead. The bank needed to be active in the physical power and transmission markets to price the hedge and physically offtake the power.

- **Bank Regulation: Among market makers, present and potential, banks are subject to a higher degree of oversight than trading firms and other non-bank companies, including oversight by the Federal Reserve, the Securities and Exchange Commission and the Commodities Futures Trading Commission.**

# II. THE ROLE OF BANKS

Banks play an essential, if poorly understood, role in assuring the smooth functioning of the commodity markets that underpin the $16 trillion U.S. economy and on which consumers ultimately rely. They do so by providing capital, enabling companies of all kinds to manage risk, and by bringing disparate buyers and sellers together.

The complex, competitive and capital intensive commodities industries require significant levels of investment in production, transport, processing and marketing facilities to bring energy and products to the American consumer. Financial institutions are at the center of this activity. Physical commodity trade—being able to take or make delivery of the underlying commodity—is often required to provide these services.

The consequences of impairing this role could be far-reaching and negative. The development of new wind farms and natural gas power plants may be curtailed because of the inability of developers to hedge their price risks. Independent oil and gas producers and heating oil dealers would have limited ability to hedge the price risks associated with investment and inventory. Airlines, highly vulnerable to jet fuel prices, could be put at risk. Refineries could be shut down, leading to higher gasoline prices. Overall, competition would be reduced in energy markets and smaller players would be disadvantaged. Higher volatility would lead to a foreshortening of domestic investment leading to increased foreign energy dependence. And consumers—and the U.S. economy—would be hurt by higher and more uncertain prices.

If the banks were not participating in physical commodity markets, their ability to serve clients with risk management and financing services would suffer. It is not at all clear who could replace them or to what extent. Some would be more opaque, less-transparent entities, based outside the United States. Others could be large competitors to the small and medium sized companies being served by the banks. Moreover, all would be much less regulated than banks, which are among the most highly-regulated entities in the United States.

Banks create orderly and efficient commodities markets through several specific roles. These include:

- Market making and provision of market liquidity,
- Efficient price formation,
- Risk management solutions,
- Project finance,
- Extension of credit, and
- Bolstering industry competition.

## MARKET MAKING AND MARKET LIQUIDITY

Banks provide a central role in connecting disparate buyers and sellers through combined physical and financial market activities. The commodity markets consist of a broad range of participants, with their own risk profiles and abilities to take on and manage risk. From a broad perspective, we identify four groups in Table 1.

**TABLE 1**

| TYPE | CHARACTERISTICS |
|---|---|
| **Resource Producers** | |
| • Crude producers<br>• Gas producers<br>• Mining companies | • Major investments rely on commodity price<br>• Desires long term (5+ year) price risk management<br>• Basis risk of moderate concern |
| **Consumers** | |
| • Personal end users (e.g. car owners)<br>• Commercial fuel end users (e.g. airline, truck company)<br>• End use products manufactures (e.g. auto companies) | • Risk management of volatile commodity important to competitive position and financial performance<br>• Typical desire six months to one year price risk management<br>• May seek physical supply and risk management outsourcing |
| **Manufacturers/Energy Tranformers** | |
| • Oil refiners<br>• Gas processors<br>• Metals refiners<br>• Petrochemical/fertilizer manufacturers<br>• Power generators | • Sensitive to margin and less so with absolute price<br>• Can be difficult to risk management narrow margin (spread between two larger feedstock and product prices)<br>• Risk management usage varies by industry but commonly involve banks due to complexity<br>• Price takers |
| **Commodity Price Investors** | |
| • Institutional<br>• Individual | • Commonly use exchange products (commodity index finds or direct exchange positions)<br>• Investment focused<br>• More active during period of price increase<br>• Mostly trade near months |

The needs for services vary between groups and companies. For example, an aluminum window frame extruder might want to continually hedge aluminum price risk one year forward for planning and budgeting purposes, while a bauxite mining company may want five-year price protection to undertake major capital investments. In this case, one company is effectively looking to lock in purchase prices while the other needs to lock in sales prices. While both companies care about aluminum prices, there are major differences in timing, tenor, location and the nature of the underlying product (e.g. finished rolled aluminum versus raw alumina).

If all parties had identical but offsetting positions, there would be no need for an intermediary beyond simply connecting back-to-back trades of buyers and sellers through a common platform. In this idealized world, there would be the same number of buyers and sellers, for the same exposure, at the same time, for the same hedge horizon, for the same location. In reality, nearly none of these conditions exist in the commodities markets. Thus, banks create a willing and able counterparty so these companies can meet their needs.

As market makers, banks provide liquidity, or immediacy, because they bear the price risk between the arrival of sellers and buyers, which can lead to temporary accumulations of inventory. Banks provide much needed liquidity by acting as counterparties in trades and by accumulating inventories in anticipation of customer demand.[3] Due to the illiquidity of many commodities exposures, as well as the construct of some commodity risk management solutions, banks must accumulate and net-off various exposures that can require more time to unwind than a traditional market maker's position in highly liquid markets, such as U.S. Treasuries. Thus, banks are the "liquidity providers" in less liquid markets because they see client flow from both producers and consumers over a sufficient time period to effectively intermediate and disseminate the risk. Furthermore, non-bank trading entities generally only participate in times when there is a strong enough arbitrage to do so.

## EFFICIENT PRICE FORMATION

Banks add liquidity and an additional class of participant in the commodities markets—providing an important intermediation service that connects buyers and sellers across locations, time periods and product qualities—that leads to more efficient price formation.

Unlike other financial assets, commodity instruments are related to a physical product. Therefore, financial markets should tie or "converge" to these physical markets at expiry. To the degree that they do not from time-to-time, there will be arbitrage opportunities that market participants will ameliorate by taking offsetting financial and physical positions until prices do converge.

Because banks are in both markets they promote efficient markets and help to maintain pricing relationships—they improve price convergence (future price moving toward spot price at expiry) and price discipline. This is true in both physical and financial commodities markets where banks stand ready to deliver product or take delivery of product in the markets in which they are active. In short, banking entities maintain the efficiency and viability of commodity markets, providing liquidity and helping drive price convergence and alignment.

Banks' trading activities in commodity markets create necessary links among regions, products and delivery of products that foster competitive pricing and efficient allocation of commodities.[4] For example, one bank has electricity transmission capabilities between the Midwest and Georgia, which it can use to "wheel" or move power from an oversupplied and lower-priced area in the Midwest to an undersupplied, higher-priced location in Georgia. This is a low risk activity for banking entities, and helps eliminate price disparities and mitigates supply shortages and price spikes to the benefit of U.S. businesses and consumers.

[3] Ricardo Lagos, Guillaume Rocheteau, Pierre-Olivier Weill, "Crises and Liquidity in Over-the-Counter Markets," *NBER Working Paper* No. 15414 (October 2009).

[4] See, e.g., Scott H. Irwin, Dwight R. Sanders & Robert P. Merrin, Devil or Angel? The Role of Speculation in the Recent Commodity Price Boom (and Bust), 41 J. Agricultural & Applied Economics.

## RISK MANAGEMENT SOLUTIONS

Banks have emerged as the credit worthy counterparty to tailor corporate hedging transactions. This customer-facing role is a natural extension to traditional banking services. This client-facing business model creates a primary impetus for being in the physical commodity markets—on behalf of or in support of client needs.

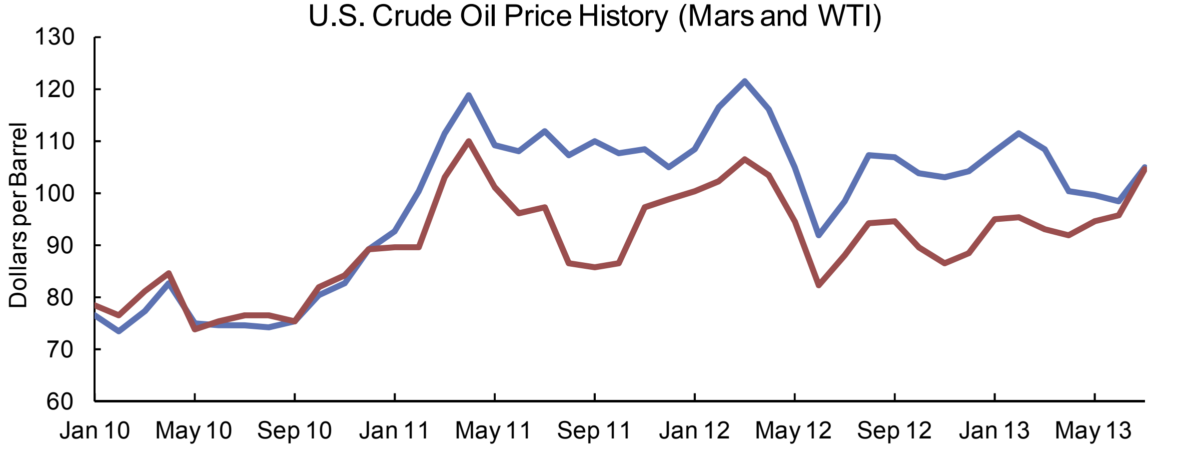
There are many important reasons behind the need for these bank services in the commodities markets. For instance, exchange traded solutions frequently are not available, not sufficiently liquid, not available in sufficient size or not appropriately matching the desired period of time, i.e. they create too much basis risk.

## BASIS RISK

Basis risk is the difference between movements in the price of the underlying commodity and movements in the reference price of the specific commodity product being hedged.

For example, as discussed, there are important product, timing and location differences that have real world consequences to a corporate client. We illustrate the basis risk between two crude oils in the following figure, where Mars is a representative Gulf of Mexico light sour crude oil grade. Quality differences and, more importantly, location differences between U.S. midcontinent oil markets create price differences (for wholly different reasons), as seen below in the large spread between January 2011 and July 2013. This basis risk was not expected by many and certainly not to the magnitude that ultimately occurred. In this case, a buyer or seller of Mars crude has much less basis risk with a bank-provided Mars OTC hedge than a WTI exchange hedge.

Figure 1
U.S. Crude Oil Price History (Mars and WTI)




Source: Platts Monthly Averages

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Banks manage basis risk for clients. OTC market makers offer natural gas swaps that are based on locations other than the Henry Hub (e.g. Panhandle basis swap), and this can help eliminate basis risk for clients. To provide this hedge, banks themselves need to be able to physically settle commodity positions in non-benchmark locations in order to achieve efficient pricing. Banks have become active participants in physical commodity markets to provide the risk management services needed by bank customers.

## CORPORATE HEDGES

Bank customers seek “good hedges” that will adequately reduce the specific commodity price exposures they face. As discussed, exchange-traded hedge instruments can be too different from the actual exposure of the physical commodity being hedged by customers. In these cases, banks play an important service in providing a bridge between the benchmark exchange commodity stream to the customer non-benchmark commodity stream. Banks are able to provide customized OTC instruments that more closely match the actual physical stream being produced, purchased or processed. In most cases, companies do not physically trade in the same commodity location that is active on exchanges. Exchanges have a very limited number of products with sufficient liquidity.

This is a fundamental service without which markets would be less smooth and investment is at more risk—and thus less likely to be made. In many cases, banks are only able to provide these customized risk management services for these off-exchange physical commodities by active participation in the same physical commodity markets. Only through physical commodity ownership, or the possibility of physical ownership, can banks effectively provide customized OTC solutions.

Providing hedge instruments in specific non-benchmark markets is more complex than simply executing exchange market trades; non-benchmark locations can be “physical settlement” markets—meaning that market participants settle forward contracts through making or taking physical delivery of the specific commodity stream, not through a financial payment—as is common for exchanges. Banks that provide hedging solutions need to be able to make physical settlement in order to be an effective counterparty to the customer.

Risk management solutions often draw from execution in both the financial and physical commodities markets and can involve numerous elements. As a result, banks tend to be stable market participants that serve customers through market cycles, making markets even in times of stress and when other trading participants may be unwilling or unable to trade. Thus banks are a “stabilizer” during times when uncertainty and risk are high. Particularly in less active markets, risk management providers need to develop price expertise, understand market depth and test price response to demand/supply. Further, a bank without the ability to make or take physical delivery would be in an untenable position because it would have widely known obligations to certain market participants without the ability to physically settle, opening the bank to price risks that may be too large to warrant providing the service to the customer in the first place.

A good example of a bank risk management solution that included a price hedge, working capital financing and a fuel supply outsourcing solution, is depicted in the following fuel supply arrangement for a leading airline. In order to fulfill supply obligations, the bank must participate in many different jet fuel markets, buying locally or shipping in from more distant markets.

**CASE STUDY: LEADING U.S. AIRLINE JET FUEL SUPPLY ARRANGEMENT**

*As part of a Chapter 11 restructuring, a leading U.S. airline sought a major bank's help to reduce its operating costs, working capital requirements and balance sheet usage associated with its jet fuel supply. Prior to bankruptcy, the airline managed a large jet fuel supply operation in which it maintained up to a month's inventory, creating significant operational overhead and a need for costly financing. To reduce these expenses, the bank provided the airline a long term contract for delivery of jet fuel, typically one day prior to the airline's daily need to service its fleet. It also provided all logistical support and sold the airline jet fuel at a lower price than it was paying previously. This enabled the airline to reduce its operating expenses, reduce the size of its balance sheet and lower its overall interest expense.*

*The bank was able to provide the airline with this service because the expertise in jet fuel markets required to price and structure the transaction was developed by actively trading in these markets.*

*Many of the 80 different jet fuel markets are highly illiquid, and the bank was only able to price the transaction by acting as a market maker, building inventory of physical product, engaging in transactions for related products in multiple markets and engaging in other transactions in anticipation of demand from the airline. These included transactions in forward contracts. Moreover, to obtain the most effective hedge for its own risk management, the bank needed to trade in illiquid jet fuel and the related, but not identical, liquid heating oil markets.*

## PROJECT FINANCE

Bank-led project finance is critical in the resources sector (including commodity related infrastructure) of the economy for development projects such as power plants, renewable power generation, gas fields and floating storage and regasification units. In many instances, the hedging activities necessary to support these financings are inherently physical in nature. Project finance helps renewable energy project developers finance the construction and operation of wind and solar facilities—services especially critical in deregulated power markets. Banks offer a wide range of services, including:

- Long term fixed price hedges that reduce risk from price volatility,
- Credit extension, with inventory or hard assets serving as collateral to lower the cost of financing, and
- Other hedges such as currency and interest rates hedges.

In order to provide these services banks are active in both the physical and financial markets.

For example, many renewable power developers prefer an integrated set of services, potentially including a tax equity investor, a construction loan and full-service power scheduling into real-time markets. Perhaps most critically, developers also often require a revenue hedge to assure investors that the project will produce a minimum level of cash flow, in order to enable debt financing. In deregulated power markets, some or all of these services are likely to be required by many wind developers before projects can move forward. Absent the presence of banks that can provide these services, wind development in the U.S. would slow overall, undermining a major national objective, and become more costly as individual services are procured from various alternative sources.

As an illustration of this bank role, in terms of expertise and operational capabilities in the power markets, a single bank was able to provide a wind farm developer in Montana an integrated set of services, including a power price hedge to assure the minimum revenue stream. This enabled the extension of credit to move ahead to the construction phase of the project.

To provide the power price hedge (as requested by the wind farm developer), the bank engaged in physical power transactions. In order to provide these services, banks need to be active participants in the physical power, gas and transmission markets to assess forward price and volatility curves, correlations, market depth, availability of hedging alternatives and associated transaction costs.

Active physical market participation enables banks to be ready to respond to client needs with the expertise and execution capabilities to manage the risks associated with a transaction. This includes understanding local markets, not only to price each hedge and manage risks, but also to provide the required power scheduling services. In order to provide these services, banks need to build an inventory of hedging positions prior to each customer transaction and engage in transactions subsequent to each transaction, to manage the banks' risk. Given the significant illiquidity of many power markets, these transactions often include a combination of trades in similar but not fully correlated products. These combined physical and financial commodity trade activities are essential for banks to service wind farm developers. Revenue hedges enable more efficient capital formation for these projects and companies. Without the physical commodity revenue hedges it is unlikely the wind farms could secure debt financing and they likely could not be built.

## CASE STUDY: U.S. EAST COAST REFINING

*The Delaware River corridor from the Atlantic Ocean to the Philadelphia Metro Area represents the largest concentration of refineries in PADD I (East Coast Region). At its peak in 2002, PADD I contained 1.8 million B/D of crude oil refining capacity, with 70% of that capacity located along the Delaware River corridor. Since 2002, a variety of structural factors gradually made East Coast refineries less competitive, both globally and domestically, resulting in capacity contraction. By 2011 and 2012, the U.S. government had become deeply alarmed at the prospect of PADD I refinery shutdowns in terms of gasoline prices, loss of jobs and increased vulnerability to regional supply disruptions.*

*The pace of capacity rationalization accelerated in 2010 when Sunoco, Valero and Western shuttered 390,000 B/D of refining capacity. In 2011, Sunoco and ConocoPhillips (now Phillips 66) announced plans to close three additional Delaware River corridor refineries. Two former Valero refineries, located in Paulsboro, New Jersey and Delaware City, Delaware, were purchased by PBF Energy[1] with financing, a working capital loan and physical offtake support from a large U.S. bank. The Paulsboro Refinery operated continuously throughout this period, but the Delaware City Refinery was shut down in November 2009. After 18 months of being idle, the Delaware City Refinery was restarted due, in part, to the physical and financial structure provided by its banking partner. The ConocoPhillips Trainer Refinery was purchased by Monroe Energy, a subsidiary of Delta Airlines. This facility was idled for the first three quarters of 2012, but eventually restarted in late September. In the case of the Trainer Refinery, the crude supply and physical offtake agreement services are being provided by BP,[2] the integrated oil major. The Sunoco Philadelphia Refinery Complex (the largest refinery complex on the East Coast) operated continuously and was purchased by the newly-formed Philadelphia Energy Solutions (PES), a joint venture between The Carlyle Group and Sunoco Logistics. Similar to PBF, the PES arrangement to purchase and operate the Philadelphia Refinery is being supported by a unique combination of physical crude oil supply and product offtake services provided by a bank in addition to traditional financing activities.*

**TABLE 2**
PADD I COASTAL REFINERY SUMMARY (SEPT 2013)
Barrels per Day

| Owner | City | State | Capacity | Configuration | Status |
|---|---|---|---|---|---|
| **Philadelphia Energy Solutions** | **Philadelphia** | **PA** | **335,000** | **Light Sweet Cracking** | **Operating, New Ownership September 2012** |
| Phillips 66 | Linden | NJ | 238,000 | Light Sweet Cracking | Operating |
| Monroe Energy LLC | Trainer | PA | 185,000 | Light Sweet Cracking | Operating, Shutdown December 2011 New Ownership April 2012, Restarted October 2012 |
| **PBF Energy Partners** | **Delaware City** | **DE** | **182,000** | **Medium Sour Coking** | **Operating, Shutdown December 2009 New Ownership June 2010, Restarted May 2011** |
| **PBF Energy Partners** | **Paulsboro** | **NJ** | **160,000** | **Light Sour Coking** | **Operating, New Ownership December 2010** |
| NuStar | Thorofare | NJ | 74,000 | Asphalt | Operating |
| NuStar | Savannah | GA | 28,000 | Asphalt | Operating |
| Sunoco | Marcus Hook | PA | 178,000 | Light Sweet Cracking | Shutdown 2011, Converting to LPG Terminal |
| Sunoco | Westville | NJ | 145,000 | Light Sweet Cracking | Shutdown 2010, Converted to Terminal |
| Chevron | Perth Amboy | NJ | 80,000 | Asphalt | Shutdown 2008, Converted to Terminal |
| Western Refining | Yorktown | VA | 66,000 | Heavy Sweet Coking | Shutdown 2010, Converted to Terminal |
| Hess | Port Redding | NJ | 0 | Sweet Cracking | Shutdown February 2013, Converting to Terminal Catcracker Only, No Crude Oil Distillation, For Sale |

Note 1 - Does Not Include Inland PADD I Refineries (United Warren PA, American Bradford PA, Ergon Newell WV)
Note 2 - Refineries **Bolded in Blue** Utilized Banks for Supply, Offtake and Financial Services

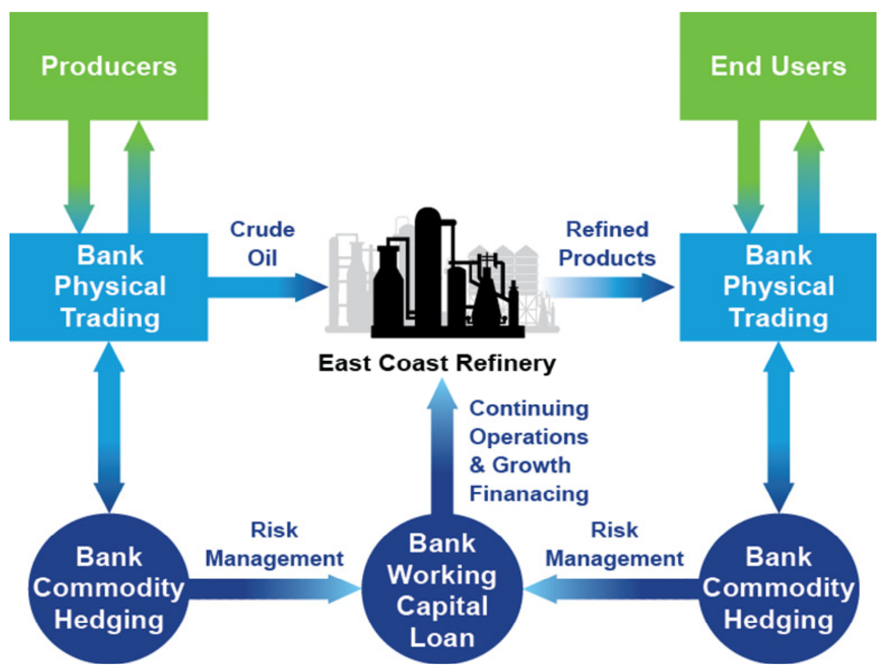
[1] PBF was originally established as a joint venture between Petroplus, Blackstone and First Reserve.
[2] The previous owner Phillips 66 has also entered into an agreement to provide product offtake services.

**CASE STUDY: U.S. EAST COAST REFINING CONTINUED**

*Each of these three cases[3] share several similarities. The former owner of each was a well established participant in U.S. refining industry but had decided to exit the East Coast region due to deteriorating market conditions. In each case, the new owners/operators were a first-time entrant into the U.S. refining sector. Though the specific details of each arrangement vary between the refineries, in two of the three cases a key element of facilitating the deal was the participation of a large financial institution in providing both financial and physical commercial solutions that kept these core infrastructure assets operating. The combination solution developed by the banks for these two cases[4] contained these following core elements:*

- *Direct crude oil and feedstock procurement by the bank with commodity ownership transfer to the operating entity at the refinery fence line reducing the balance sheet burden to the newly formed operating entity.*
- *Refined product purchasing and offtake by the bank from the operating entity directly after processing, not only reducing the balance sheet burden to the newly formed operating entity, but also leveraging the physical trading network of the bank to facilitate efficient distribution of the refined product.*
- *An asset-based working capital revolving credit line to support continuing operations and facility upgrades, improving long term competitiveness and viability. Additionally, the banks provided their financial trading services through proprietary hedging instruments allowing mitigation of price risk on both the crude oil feedstock and refined product side.*

FIGURE 2




Source: IHS Energy
30899-6

[3] Four refineries total.
[4] Three refineries total.

**CASE STUDY: U.S. EAST COAST REFINING CONTINUED**

*The combination of these physical and financial services is made possible through industry expertise in physical trading and a well established network of counterparties. The value provided by this combination of services is primarily to reduce the working capital requirements for a nascent company that may not have the balance sheet or credit rating to cost-effectively borrow the capital necessary to fund ongoing operations.*

*Two of these arrangements led to direct tangible benefits for the public. Three large U.S. refineries were kept in operation, representing 55% of active U.S. East Coast refining capacity. Competition has also increased for U.S. East Coast refining as the number of participants has increased from four to five. Without these new market entrants, and their banking partners, the East Coast refining sector could have been reduced to just two participants. Keeping these large industrial facilities in operation provides high-paying manufacturing jobs for the region in which they operate. Published estimates are that the survival of three of these refineries preserved 2,000 direct jobs while supporting an additional 16,000-20,000 indirect jobs. Because of the working capital freed up by banks, each new operating entity could use its capital to grow or upgrade its investments, potentially leading to even more employment. Additionally, with the continued operation of the refineries, the substantial local and federal tax receipt base provided by the facilities is preserved.*

*Additional benefits for the general public include lowering absolute gasoline prices by shortening the supply chain for a portion of East Coast refined product demand and reducing the exposure associated with supply chain disruptions by maintaining a diversified supply portfolio. Without these four refineries operating, alternative sources of supply would need to materialize in the form of pipeline transfers from the U.S. Gulf Coast, marine transfers from the U.S. Gulf Coast or to incentivize higher refinery utilization in Europe and marine imports. In each of these alternative supply cases the additional refined product production would need to be incentivized in the form of higher regional prices necessary to cover the operating and logistics costs of that additional supply and longer supply chain.*

*Recent regional experience with Hurricanes Sandy and Irene further highlights the importance of having a diversified refined product supply landscape and shortening the length of the supply chain in satisfying regional demand. Much of the physical damage to regional petroleum facilities was to the electrical infrastructure and independent storage and import terminals. Local refineries played a pivotal role in minimizing the impact and duration of the supply disruption. All four refineries discussed during this section were able to maintain partial operation during the climate events and were able to return to normal operations within 7-10 days of storm landfall. With the majority of damage concentrated to the independent storage terminals, if 700,000 B/D of area refining capacity had been permanently shut down the supply system shock would have been far more disruptive than what occurred. Without the role of the banks, much of this refining capacity would have been padlocked and inoperative with negative consequences for consumers in the Mid-Atlantic states.*

## CREDIT EXTENSION

Banks have long been in the business of financing working capital in commodities. Commodities companies often need to access credit that is extended on the basis of the value of the capital invested in their business. Banks extend credit against assets because they are able to value the underlying commodity positions and manage price risk. The provision of risk management services to commodity market customers is a logical extension of this traditional lending practice. Banks are able to provide unique risk management services to diverse commodity market participants due to their credit capabilities and commodities market expertise. Examples include:

"Pure play" market participants such as independent producers that need to "sell forward" their production to finance drilling operations,

- Provision of "over-wing" jet fuel supplies at major airports for a single customer,
- Long-term structured financing and working capital facilities to independent refiners, and
- Financing and inventory support to producers during periods of market upheaval, providing indirect price stabilization.

Banks have traditionally provided financial advisory services and many forms of financing to energy firms for mergers, acquisitions and other large capital transactions. Over the past decade, banks have enhanced their expertise in both the financial and physical segments of the energy markets. They have developed this expertise through the extension of financing and hedging services to their clients, as well as through participation in physical product supply and marketing operations.

For example, some banks have become market participants in crude oil and refined product supply. Expertise gained through financial markets, physical supply, trading and risk management operations have made banks especially qualified to provide a broad range of risk management and intermediation services not otherwise available. The industry expertise gained by banks through their participation in commodity markets gives them the tools to arrange customized financing structures. These structures provide the framework for new market entrants to acquire and sustain continuing operations of capitally intensive energy related assets. Credit extension allows the following key items:

- Client does not have to post cash collateral like they do when hedging with futures which frees up cash for operations, and
- Clients can post non-standard collateral such as assets to support their hedging activity with banks (secured interest in producing properties, air planes, etc.).

Banks can extend this credit because they view the exposure as "right way risk"—when the client owes the bank money it is because the underlying prices have moved to benefit their business. For example:

- A natural gas producer sells future productions – when the natural gas price goes up, they owe the bank money, but their overall business is performing well and they are able to sell the gas at a higher price,
- An airline buys jet fuel hedges – when the jet fuel prices go down, they owe the bank money, but their overall business is performing better as their input costs are now lower.

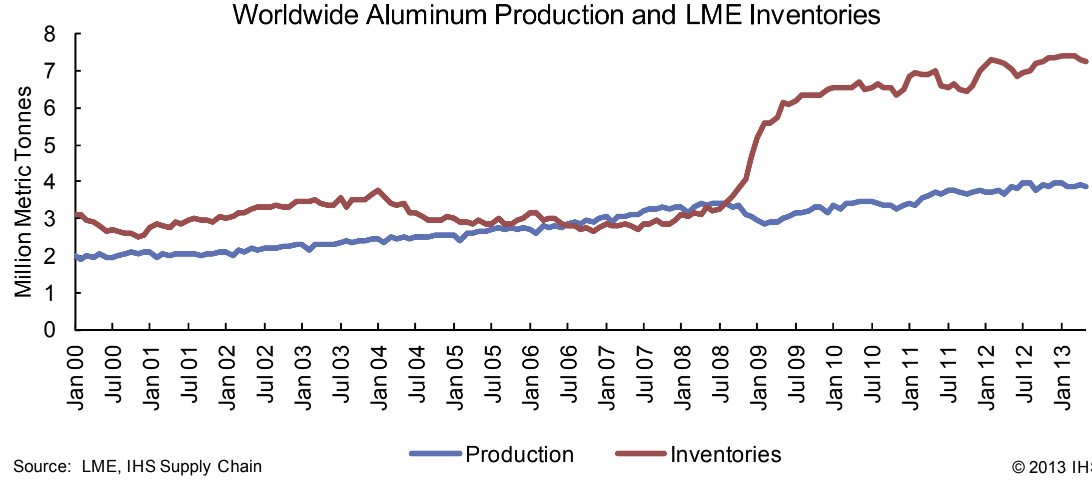
During the recent domestic shale gas boom, a major U.S. natural gas producer approached a bank for a price hedge on its future production. The producer needed funds to expand its drilling operations and develop new gas fields. To meet the customer's needs, the bank helped the producer hedge by purchasing a large volume of long dated natural gas call options from the producer. The bank did not require the producer to post margin as the price of natural gas changed; instead, it took a secured interest in the producer's assets. This permitted the producer to use available cash to immediately develop new gas fields and invest future cash in new gas field developments while ensuring its future production margin was still profitable. The increase in gas supply during this period has led to low prices in natural gas.

## CASE STUDY: NON FERROUS MARKET SUPPORT VIA METALS INVENTORY

*Financial institutions provide cost effective credit (i.e. inventory-based lending) to their customers that support market prices and "level" production through inventory builds and draws. While reacting to market price signals, banks and other market participants' actions in non-ferrous commodity storage absorb surplus production during periods of rapid demand contraction and then reduce the inventory levels during peak demand. Producers typically do not want to hold excess quantities of inventory and may not be able to do so.*

*The global aluminum market has been in a surplus supply condition since the recession of 2008-2009. Initially, producers reduced production moderately in 2009. As credit became available again, banks provided a significant service to their metals clients by purchasing aluminum output and providing storage in warehouses. Production stabilized by mid-2010 and began to increase again, while inventories increased significantly, indicating sluggish demand. Global aluminum production declined 6.7% between 2008 and 2009 or by 2.6 million metric tonnes (MMT). Over the same time, visible LME aluminum inventory increased by 2.6 MMT. Without banks willing to finance and hold inventory, the reduction in aluminum production would likely have been twice as severe, potentially reducing future supply. A decline in production would have had a larger negative economic impact as production facilities could have been shut down and there would have been a corresponding loss of jobs and manufacturing output. Even with the stabilizing intermediation from the banks, the strong downdraft in global demand during the 2008-2009 recession resulted in a 35% decline in the LME benchmark cash price of aluminum. The figure below shows the history of production and inventory stocks since 2000.*

Figure 3
Worldwide Aluminum Production and LME Inventories




Source: LME, IHS Supply Chain © 2013 IHS

*Aluminum inventories have increased markedly due to the convergence of four factors: overcapacity of aluminum production, "contango" market structure where future prices on exchanges are higher than current prices, low interest rates and low storage costs. Through the market contraction of late 2008 and into the recovery the following year, the market environment encouraged the purchase of "excess" production by financing the storage at low rates and hedging the future price risk—an "inventory arbitrage." Trading companies have done this.*

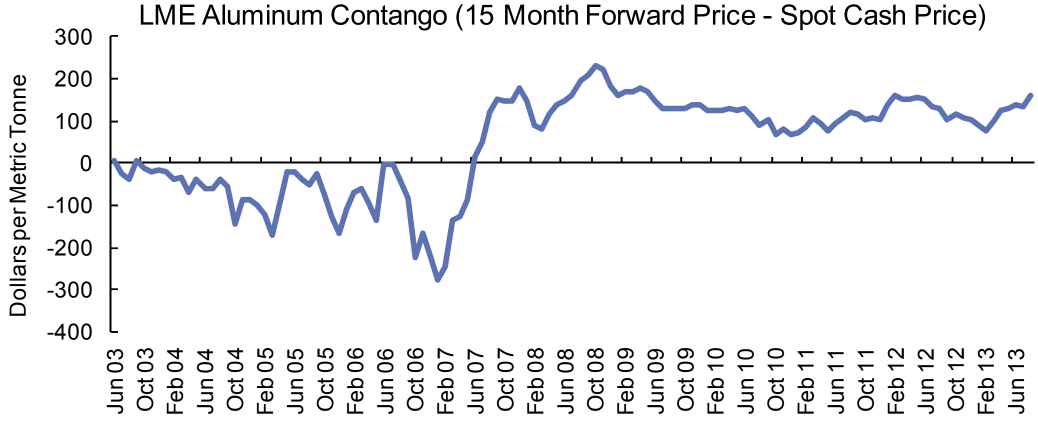
*The rapid contraction in demand and resulting low aluminum price environment pushed the LME futures market into strong contango. Shown in the following figure, starting as early as 2007, LME 15-month futures price averaged between $100 and $200 per metric tonne above the LME current spot cash price. The storage cost of aluminum typically ranges between $0.45-$0.50 per metric tonne per day in an LME bonded warehouse, or approximately $175 per metric tonne annually. In many cases warehouse owners attract new storage customers with a discount on storage for the first year which can*

**CASE STUDY: NON FERROUS MARKET SUPPORT VIA METALS INVENTORY CONTINUED**

*be as high as 50%. Unlike some other commodities, such as petroleum and natural gas, aluminum is relatively easy to store. It does not require specialized facilities with large cost barriers to entry and the higher operational risks associated with handling hazardous or combustible materials. Additionally the high atmospheric corrosion resistance of aluminum allows it to be stored for long durations without degradation of the commodity's physical properties.*

Figure 4

LME Aluminum Contango (15 Month Forward Price - Spot Cash Price)




Source: LME

© 2013 IHS

*This activity creates a ready store of material in usable form, so that when industrial production recovers and near-term aluminum prices increase there is a depot ready to do business on demand. In this way, the bank helps facilitate an objective/transparent/real-time price signal for all market participants in the form of the forward spreads, as well as the solution to rapid improvement in demand, as contangos narrow and inventories start to be drawn down for use.*

## INDUSTRY COMPETITION

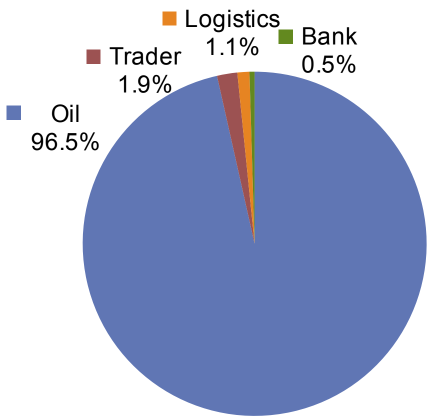
Banks promote greater industry competition in the commodities sectors in two ways: first, as direct industry participants; and second, as providers of financing and risk management services to support the health of small and medium sized industry players that lack the financial resources of the large integrated multinationals.

## DIRECT PARTICIPATION

For the four commodities discussed in this report, financial institutions participate primarily in the financial risk management, physical trading and logistics activities of these commodities industries.[5] We classify the asset owners into three groups: production and processing, logistics and trade focused organizations. The groups with the highest level of asset ownership are also the largest players in the physical commodities trading segment. We use the example of U.S. crude oil imports as a proxy for participation in crude oil physical trading.

[5] Several of the larger financial institutions have non-operational equity minority stakes in the hard asset owning entities related to the large financial institutions' merchant banking functions.

Figure 5
U.S. Crude Oil Importers 2008-2012 Average




| | |
|---|---|
| Oil[1] | 8,920 |
| Trading | 177 |
| Logistics[2] | 105 |
| Bank | 44 |
| Total | 9,245 KB/D |

Source: Energy Information Agency (EIA)

1 - Oil companies includes petrochemical companies
2 - Logistics includes end users, blenders, utility companies



The data show that physical trading of crude oil is largely performed by crude oil producing and refinery owning companies and that the other groups of participants play only a minor role. Although public data is not available to perform a similar analysis for global crude oil production and trade, based on IHS experience, the data analysis would be similar with the largest share of the physical trade of crude oil being performed by producing and processing asset owning entities on the order of 70-75% market share. On the global level the data show that the large trading houses play a more active role in the physical trading of crude oil and refined products. A review of publicly available information on the activities of seven large petroleum focused trading merchants suggest that their involvement or market share is on the order of 10-15% of global crude oil trade.

**TABLE 3**

| Trading Company | Crude Oil Million B/D | Oil Products Million B/D |
|---|---|---|
| Glencore | 3.2 | 2.1 |
| Vitol | 2.4 | 3.0 |
| Noble | 1.3 | 1.4 |
| Gunvor | 1.0 | 1.5 |
| Trafigura | 0.8 | 1.2 |
| Mecuria | 0.8 | 0.8 |
| Phibro (Occidental) | -- | -- |
| Koch S&T | 0.2 | 0.3 |
| Total | 9.7 | 10.3 |
| Global Total | 73.9 | 79.0 |
| % of Global Total | 13.1% | 13.0% |

The remaining market share (10-20%) is comprised of smaller merchants, dedicated brokers and financial institutions with sufficient balance sheet strength to participate in the capital intensive business of commodities trading. Our empirical analysis does confirm that these sectors are far more competitive than some believe. For example, the largest natural gas producer in North America, ExxonMobil, has just a 5% market share of production.

**TABLE 4**
COMMODITIES INDUSTRY SEGMENT COMPETITIVENESS

| Industry Segment | Approximate # of Participants | Largest Participant | % Market Share | Herfindahl Hirschman Index |
|---|---|---|---|---|
| NA Crude Oil Production | 200 | ExxonMobil | 8.5 | 0.037 |
| NA Crude Oil Pipelines | 50 | Plains All American | 12.7 | 0.042 |
| US Crude Oil Imports | 75 | ExxonMobil | 12.9 | 0.059 |
| NA Refineries | 60 | Valero | 10.5 | 0.054 |
| NA Refined Products Pipelines | 30 | Magellan | 9.1 | 0.043 |
| NYH Petroleum Storage | 15 | IMTT | 19.7 | 0.133 |
| HSC Petroleum Storage | 11 | Kinder Morgan | 30.2 | 0.160 |
| US Refined Product Imports | 250 | Valero | 11.7 | 0.049 |
| NA Natural Gas Production | 500 | ExxonMobil | 5.0 | 0.023 |
| NA Natural Gas Pipelines | 160 | Kinder Morgan | 14.0 | 0.044 |
| NA Natural Gas Storage | 130 | Dominion | 9.0 | 0.031 |
| NA Natural Gas Marketing | 30 | BP | 18.0 | 0.076 |
| Bauxite Production | > 6 | Rio Tinto | 18.3 | 0.065 |
| Alumina Production | > 8 | Alcoa | 16.3 | 0.090 |
| Aluminum Production | > 9 | Chalco | 8.9 | 0.031 |
| Aluminum Storage | 30 | C. Steinweg | 24.5 | 0.163 |

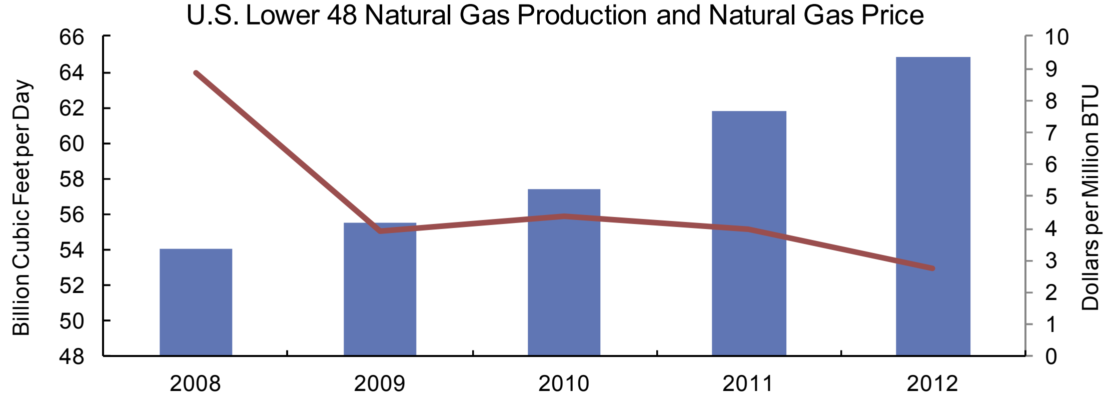
## SUPPORTING THE HEALTH OF SMALLER INDUSTRY PLAYERS

Banks promote greater industry competition in the commodities sectors by providing financing and risk management services to support the health of small and medium sized industry players that lack the financial resources of the large integrated multinationals. The U.S. natural gas producers are one such example.

## CASE STUDY: U.S. NATURAL GAS PRODUCTION

*The figure below shows the total U.S. gas production and the average annual U.S. natural gas price over the last five years.*

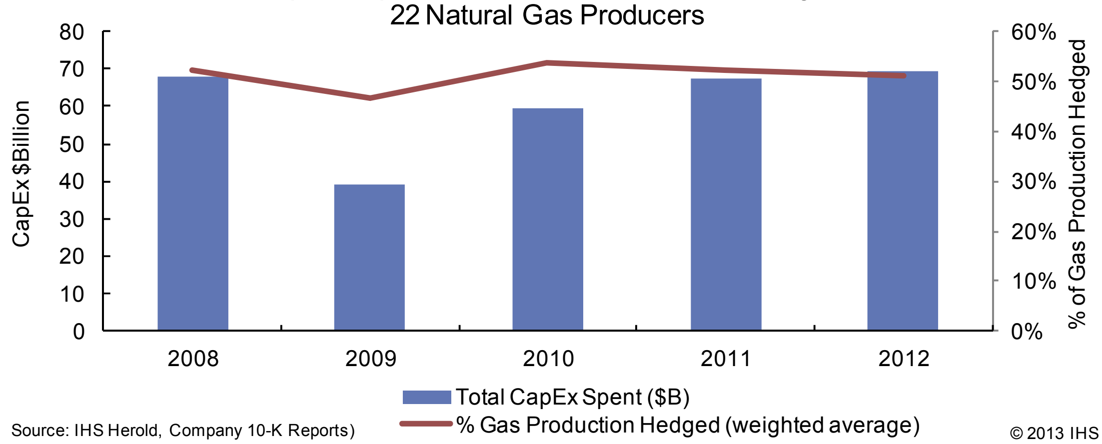
Figure 6
U.S. Lower 48 Natural Gas Production and Natural Gas Price




Source: Energy Information Agency (EIA) © 2013 IHS

*While total gas production continued to increase over the last five years, the spot natural gas price sharply decreased from its 2008 level and continued to decline below $3 per Million BTU (MMBTU) in 2012. In part, these small natural gas producers were able to withstand the prolonged depression in gas price and continue to invest in shale gas development through continued cost reduction and improved well productivity. But they bought the time to achieve these improvements by hedging to lock in prices for future gas production at a fixed price in advance, thereby reducing uncertainty associated with future earnings and guaranteeing a minimum return on investment. This enabled companies to plan their capital investment with confidence and execute drilling programs. The figure below shows the percentage of gas production hedged among major U.S. gas producers and their total capital investment over the last five years.*

Figure 7
Capital Expenditure and Gas Production Hedged
22 Natural Gas Producers




Source: IHS Herold, Company 10-K Reports) © 2013 IHS

## CASE STUDY: U.S. NATURAL GAS PRODUCTION CONTINUED

*Gas producers hedge about one-half of their production. In 2009, there was a drop in gas production hedged (five percentage points drop compared to 2008) with a 43% reduction in capital investment for these companies. While the natural gas price continued to decrease after initial decline in 2009, prices in 2013 have risen from the lows, and capital investment has completely recovered, exceeding the pre-crash level for the first time in 2012.*[1]

*For example, Chesapeake is a leading U.S. gas producer with more than 3 Bcfd of gas production. Since 2007, the company raised a much needed $6 billion for development through Volumetric Production Payment (VPP).*[2] *In VPP transactions, sellers (usually natural gas producers) agree to deliver a certain amount of production over a set period of time, ranging from 5-15 years. Buyers (usually large banks) pay a fixed price for gas, as a lump-sum payment in advance. The seller of the VPP is responsible for delivering gas up to the agreed upon amount and the operating cost to produce the gas. Sellers can use the upfront cash payment to fund their drilling program, make acquisitions or perform other activities to benefit their shareholders. This credit extension has been important to the development and production of domestic resource plays. The banks' source of repayment in this transaction is the physical delivery of future gas production.*

1 We picked large and medium independent exploration and production companies according to IHS Herold classification, that are majority gas producers (more than half of their production is natural gas). Total of 22 companies were included that had five years of historical data. They are, in alphabetical order, Anadarko Petroleum Corp., Cabot Oil & Gas Corp., Chesapeake Energy Corp., Cimarex Energy Co., Devon Energy Corp., EnCana, EOG Resources, Inc., EP Energy LLC, Forest Oil Corp., Linn Energy LLC, Newfield Exploration Co., Noble Energy, Inc., Pioneer Natural Resources Co., QEP Resources, Inc., Quicksilver Resources, Inc., Range Resources Corp., Rosetta Resources Inc., SandRidge Energy, Inc., SM Energy Company, Southwestern Energy Co., Talisman Energy Inc., Ultra Petroleum Corp. CapEx represents total finding and development cost from IHS Herold Financial and Operations Database.

2 IHS Herold Financial and Operations Database; IHS Herold M&A Transactions Database.

# III. THE INTERPLAY OF PHYSICAL AND FINANCIAL MARKETS

In this section we illustrate the importance of linkages between the physical and financial segments of a commodity market.

For example, the U.S. natural gas industry has experienced fundamental changes in recent years. Fueled by growth in unconventional supply, principally shale gas production, U.S. gas production increased 20% to 65 billion cubic feet per day (Bcfd) in 2012 over production in 2008. Shale gas production accounts for much of this growth (i.e. 44% of total production, compared to 2% in 2000). This dramatic increase in gas production in just several years brought unprecedented level of industrial activity, spurring close to $90 billion dollars of capital investment in total unconventional oil and gas development, creating jobs and tax revenues for the U.S. Shale gas also had a significant impact on the nation's energy policy and regulatory landscape. For example, regulators for gas importation through LNG terminals must now address gas export through LNG liquefaction plants.[6]

The impetus behind this growth in shale gas production is not household name energy companies. Rather, much of the original innovation and activity was led by smaller companies that tend to be pure play natural gas producers (as opposed to larger integrated companies, which not only produce oil and gas but also own pipeline, refineries and retail gasoline stations). The small gas producers' ability to invest in drilling and completing wells to continue producing natural gas hinges on the price for their main product, natural gas.

## ROLE OF PHYSICAL MARKETS FOR HEDGING

There are more than 120 natural gas delivery locations—hence, pricing points—in the U.S.[7] Depending on the natural gas supply and demand balance in a local market and the available infrastructure, such as gas plants and pipelines, the price at certain gas delivery locations can behave quite differently from a central clearing price. While Marcellus gas tracked the Henry Hub benchmark price closely for the first quarter of 2012, the local gas price started diverging significantly from the Henry Hub price movement, trading as much as $2 below the Henry Hub price in the summer of 2013.[8] Rapid ramp up of gas production in the Marcellus area and the lack of pipeline capacity to take this gas into the market triggered this change. In fact, the high-volume Marcellus production might have completely altered the local gas market such that the local gas is expected to trade at a discount to the Henry Hub price for the foreseeable future.[9]

Naturally, local producers want to hedge their production to protect themselves against unexpected price swings and/or prices that would undermine their investments. Counterparties require knowledge of the many local markets. However, potential counterparties may be reluctant to take on price risk due to the uncertainty and lack of visibility of local pricing. Hedging production volume can become either very expensive or even unavailable. In order to offer competitive hedging solutions to natural gas producers, counterparties need direct experience with local markets, such as having the option to buy the gas at local delivery points. Counterparties with a physical footprint can be an ideal partner for these transactions. They have not only have expertise to construct financial transactions but also have a stake in the local physical markets.

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[6] America's New Energy Future: The Unconventional Oil and Gas Revolution and the U.S., IHS, October 2012, EIA.
[7] "Daily Index Graph and Chart Generator," NGI Intelligence Press Inc., http://intelligencepress.com/data/daily/, retrieved 21 August 2013
[8] "Spot natural gas prices at Marcellus trading point reflect pipeline constraints," U.S. Energy Information Administration Today in Energy, July 23, 2012, retrieved August 21, 2013.
[9] "IHS CERA North American Monthly Gas Briefing: Supply Surprises," IHS CERA, July 2013.

Another challenge for counterparties is the increasing need to customize hedging transactions. For example, while producers may want the flexibility to lock in a selling price for their gas in the long run (e.g. three plus years), most of the standard forward contracts transacted in the open exchange tend to be shorter in duration. Transaction data from Chicago Mercantile Exchange (CME/NYMEX), the largest commodity exchange along with Intercontinental Exchange (ICE), shows that 80% of Henry Hub Natural Gas Financial Futures volume traded were within a two-year maturation date for a five-day trading period in August 2013.[10] Lack of liquidity in long-dated hedging solutions in open exchange requires private transactions with institutions that are willing to provide these longer term hedging solutions. VPP transactions serve as a good example that meet the needs of long term hedges, as the buyer and seller can customize the duration of the contract period. Most VPP transactions are at least five years in duration while some VPP transactions cover more than a ten year period. In the case of large VPP transactions in Asia, which effectively serve as long term supply contracts, the contract duration is reported to be as long as 25 years.[11] The critical ingredient in VPP transactions is that the buyer has a physical ownership interest in the natural gas resource, which will ultimately be monetized through gas sales.

As banks offered customized risk management solutions to their natural gas clients, they also became actively involved in physical trading of natural gas.[12] Physical trading of the commodity for these banks allows them to avoid prematurely offloading their financial positions due to lack of physical volumes; they compete against trading companies who can engage in both physical and financial trading of commodities.[13] Banks mitigate the risk they take as the counterparty to these hedging transactions by fully participating in both financial and physical commodity trading.

The U.S. natural gas industry relies on commodity hedges and financing to mitigate their exposure to volatile prices and to raise money to pay for their drilling programs. Risk management lowers the cost of capital for natural gas producers and makes the natural gas investment less cyclical and sensitive to short term gas price movement. Just a 10% reduction of capital investment by 22 natural gas producers would mean a reduction of $7 billion dollars of investment, translating into a reduction in U.S. gas production of 2.3 Bcfd, a 3% average reduction over the next three years. In the long run, this raises the marginal cost of supply for producers and would raise natural gas prices. Raising cost of capital by 1%, measured in weighted average cost of capital (WACC), for these gas producers could raise the long run marginal cost of supply by about 20 cents per MMBTU.[14]

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[10] "Henry Hub Natural Gas Last Day Financial Futures," CME Group, http://www.cmegroup.com/trading/energy/natural-gas/henry-hub-natural-gas-swap-futures-financial_quotes_settlements_futures.html, retrieved August 22, 2013. Transaction volume by maturity date was not available from the Intercontinental Exchange (ICE): "Product Search," ICE. https://www.theice.com/productguide/Search.shtml?productGuide=&advancedKeyword=Henry&contractType=Futures&productSpec.micCode=IFED, retrieved 21 August 2013

[11] IHS Herold M&A Transactions Database.

[12] "U.S. Natural Gas House of the Year: JP Morgan," Risk.net: Financial Risk Management News and Analysis, "http://www.risk.net/print_article/energy-risk/feature/2179152/natural-gas-house-jp-morgan," May 23, 2012, retrieved August 21, 2013.

[13] "Order Approving Notice to Engage in Activities Complementary to a Financial Activity," Federal Reserve System internal memo, http://www.federalreserve.gov/boarddocs/press/orders/2003/20031002/attachment.pdf, October 2003, retrieved August 19, 2013.

[14] IHS analysis.

## AGGREGATE BANK FINANCIAL + PHYSICAL RISK PROFILE

As described in the prior sections, a bank's ability to make markets to clients who require tailored hedging solutions is greatly enhanced by being active in local physical markets as well as financial markets. A critical component of being able to trade both financially and physically is that a bank's overall risk profile is smaller when trading both. At least one bank interviewed for this study pointed to examples of how its own risk profile has reduced since it ramped up physical trading. Having a fulsome physical trading ability generally includes the ability to store and ship those physical commodities in addition to making or taking delivery of the commodity. These abilities enable a bank that has provided a financial hedge to a client in a lightly traded location, or commodity grade, to have a natural backstop to that financial risk.

For example, the U.S. natural gas market regularly sees short term spikes in a particular location due to supply and demand imbalances often caused by unpredictable weather related events. When a price spike occurs, a bank that has the ability to ship gas to that location via a pipeline can profit on physical delivery to offset financial contract losses and, by bringing supply into the market, may also limit the severity and duration of the sales spike. When banks contract storage and transportation contracts, they often do so as effective "insurance" policies. That is, they pay fees for those contracts, but then obtain the optionality to inject or withdraw from storage, or move gas from one location to another. This optionality reduces the overall risk profile of the transactions which the bank has entered with clients. The benefits of these agreements are clear. It enables the bank to make both physical *and* financial prices to its client base at the lowest possible transaction cost while greatly mitigating the residual risk left with the bank. In other words, it enables effective portfolio management.

Without the insight and offsetting risk gained from trading in physical markets, banks would either:

- Stop providing financial solutions to specific locations or commodity types and grades, or
- Materially increase the cost of providing financial solutions.

Either of these would impact the ability of clients to manage their risk leading to higher uncertainty around producer projects and lower investment, as well as higher costs to consumers. Additionally, as discussed, option b) would lead to higher risks remaining with banks—an undesirable outcome.

# IV. REGULATORY OVERSIGHT

Banks operate under a different, more complex and, in many ways, more rigorous regulatory framework than commercial companies that conduct extraction, refining and distribute energy, metals and other commodities. Entities that are neither bank holding companies nor foreign banking organizations may enter into new commodities activities or acquire an entity that engages in such activities with few requirements other than to meet the licensing requirements that all market participants in jurisdictions that require a license must meet. In the case of a bank holding company that is a financial holding company (FHC), prior to engaging in commodities activities or acquiring an entity engaged in commodities activities, the FHC must first determine whether such activity or acquisition is permissible under the Bank Holding Company Act of 1956, as amended, and the relevant rules and regulations of the Board of Governors of the Federal Reserve System (the Federal Reserve). In some cases, the determination of whether such activities or acquisitions are permissible may require that the FHC first obtain the approval of the Federal Reserve. While FHCs are subject to the laws and regulations that govern the commodities activities of all market participants, the commodities activities of FHCs are subject to additional levels of regulatory and supervisory oversight by the banking regulators.

Aside from determining whether the activities are legally permissible, financial firms are held to a higher regulatory standard in two key aspects:

- Their activities must not pose unacceptable risks to the safety and soundness of depository institutions or the financial system in general,[15] and
- Regulators have the authority to intervene in the bank's business, as needed.

There are other distinctions as well but these two provide important context to understand the role of financial holding companies in the commodities sectors of our economy.

## REGULATORY ENVIRONMENT

Several regulators are involved with various aspects of the trading of physical commodities for financial holding companies. Chief among these regulators is the Federal Reserve, which has both broad supervisory and regulatory authority over the players in the financial system.[16] For both financial holding companies and nonfinancial institutions, the Securities and Exchange Commission (SEC) and Commodities Futures Trading Commission (CFTC) also play roles in the regulations of the trading of commodities and commodities-linked financial products.

[15] U.S. Congress. Senate. Committee on Banking, Housing and Urban Affairs. Subcommittee on Financial Institutions and Consumer Protection. *Examining Financial Holding Companies: Should Banks Control Power Plants, Warehouses, and Oil Refineries.* Randall Guynn, July 23, 2013.

[16] http://www.federalreserve.gov/pf/pdf/pf_5.pdf

## FEDERAL RESERVE BOARD

The supervisory authority of the Federal Reserve is unique. It is allowed to monitor, inspect and examine any of the banking organizations in its purview to assess their financial condition and compliance with laws and regulations. Through this supervisory role, the Federal Reserve has authority to take formal or informal actions to have any problems corrected. This supervisory authority is distinct from its regulatory authority to set rules and guidelines governing the operations and activities of the banking entities it oversees.

This supervisory authority creates a significantly different and additional level of oversight of bank holding companies engaged in commodities trading compared to non-financial firms.

In order to ensure the safety and soundness of both the bank holding company and the financial system as a whole, the Federal Reserve requires appropriate risk management practices for credit, market and operational risks. The physical commodities activities of FHCs are also subject to limits based on either the FHC's risk based capital or consolidated assets, depending upon the relevant legal authority by which it is conducting or investing in physical commodities related activities.[17]

## SEC AND CFTC

The SEC and CFTC are responsible for regulating the swaps markets in the U.S. Specifically the SEC's mission is to:

> *"Protect investors, maintain fair, orderly, and efficient markets, and facilitate capital formation."*[18]

While the CFTC's role is to:

> *"Protect market users and the public from fraud, manipulation, abusive practices and systemic risk related to derivatives that are subject to the Commodity Exchange Act, and to foster open, competitive, and financially sound markets."*[19]

While both have similar missions, each plays a separate and distinct role in the financial markets. Generally the SEC has authority over "security based swaps" while the CFTC has authority over other swaps.[20] The SEC and CFTC act jointly to set regulatory boundaries between the two. Both also work in concert with the Federal Reserve as needed. Both regulators have enforcement authorities to ensure against fraud and provide for orderly, fair and competitive markets. The SEC and CFTC play leading roles in the investigation and enforcement actions against entities alleged to have engaged in price manipulation.

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[17] U.S. Federal Reserve System, Citigroup Inc., Order Approving Notice to Engage in Activities Complementary to a Financial Activity (2003). See also 12 U.S.C. §(o).
[18] http://www.sec.gov/about/whatwedo.shtml
[19] http://www.cftc.gov/About/MissionResponsibilities/index.htm
[20] A swap typically is the contractual exchange of cash flows between two parties. The exchange can be over-the-counter (OTC) or securities based. OTC swaps involve the direct exchange of cash flows between two parties while securities based swaps are the exchange of cash flows through a financial instrument such as a derivative.

The comprehensive regulatory oversight by the Federal Reserve, SEC and CFTC of banks, bank holding companies and their financial and nonfinancial affiliates, provide a different regulatory environment than for other commodities market participants. The role of the Federal Reserve in particular, and especially in concert with the CFTC and SEC, allows it to undertake examinations and set capital standards to ensure that these companies are not posing a risk to themselves or the broader market. Other non-banking entities do not need to conform to the same requirements. Though non-banking firms need to comply with individual regulators, including the SEC and CFTC, depending on the nature of the transaction they are engaging in, there is no similar level of comprehensive regulatory or supervisory oversight relative to the banks. The table below summarizes the regulatory oversight each are subjected to related to physical commodities trading.

**TABLE 5**
REGULATORS FOR COMMODITY TRADING BY BUSINESS

| Risk | U.S. Banks, holding companies and affiliates | Other U.S. Public Companies | Private/International Trading Firms |
|---|---|---|---|
| Market | Fed, SEC, CFTC, others | NA | NA |
| Credit | Fed, SEC, CFTC, others | NA | NA |
| Operational | Fed, SEC, CFTC, others | OSHA/EPA/others | OSHA/EPA/others |
| Public Disclosure | SEC filings of material risks | SEC filings of material risks | SEC filings of material risks |

Based on the supervisory and regulatory authority of the Federal Reserve and other bank regulators, banks have a much higher degree of oversight than either private trading firms or publicly traded non-bank companies.

# V. CONCLUSIONS

This study explains and illustrates the important role that banks play in the commodities sectors of our economy. We outline the industry structure and the role of financial intermediaries in providing access to capital and hedging services, and the interplay between the physical and financial segments of the markets in these commodities sectors.

The commodities and resources sector of the U.S. economy is very large and important. For example, the U.S. oil and gas industry alone directly employs 2.6 million people and contributes $1.2 trillion to the U.S. GDP, which represents 8% of our economy. Banks play an important business role in this sector of our economy. They directly provide capital, and assist in the raising of capital, for our commodities and resource producers, converters and manufacturers and end users.

As a natural extension, banks also help these same companies manage their commodity price risks through hedging, and other related risk management services, to enable planning, financing and sustaining the large capital projects required in these industries over a full business cycle. Commodity and resource producers face large, natural “long” positions. Companies that are end users of commodities and resources face large, natural “short” positions. Companies that convert or manufacture commodities and resources face both natural long and short positions that are not perfectly correlated or off-setting.

Banks provide important risk management and intermediation services in connecting buyers and sellers of risk across locations, time periods and product qualities. Through non-benchmark physical market participation, banks provide the long-dated revenue assurance necessary to effectively fund projects in commodity markets, such as power generation and oil and gas field development. Banks provide credit extension of the assets and inventory of bank customers. Banks also play a role in the sale of energy supply assets that may otherwise be shuttered. Structured financing arrangements, including feedstock supply, product offtake and working capital arrangements are made possible through combined bank financing capabilities and physical commodity participation.

In order to fulfill bank services (e.g. financing and hedging) in the commodities and resource sectors of the economy, banks must execute supporting trades in the financial and physical commodities markets. Banks assume exposures that their clients are unwilling or unable to manage. They manage this risk through offsetting client positions and by using futures or OTC instruments. In some cases these trades can be executed solely through financial markets, in other cases they may need to be executed through the physical markets; there are also cases where the best available execution is through a combination of both financial and physical markets. Thus, banks need to be able to physically settle commodity positions in local and non-benchmark locations.

Active participation in physical commodities provides visibility into product and market dynamics such as pricing and liquidity, movements and other operational and commercial information critical to effectively price and mitigate risk. Increased interplay between the financial and physical segments of a market for any given commodity increases the commodity’s market liquidity—benefits of this activity include increased commodity price efficiency, greater volumes available for business and greater “degrees of freedom” for market participants when they need to transact. Producers and consumers of commodity products benefit from improved market efficiency via reduced transaction costs and improved price discipline. The functioning of this system—by facilitating investment, managing risk, ensuring employment and serving consumers—works to the great benefit of America’s economy.

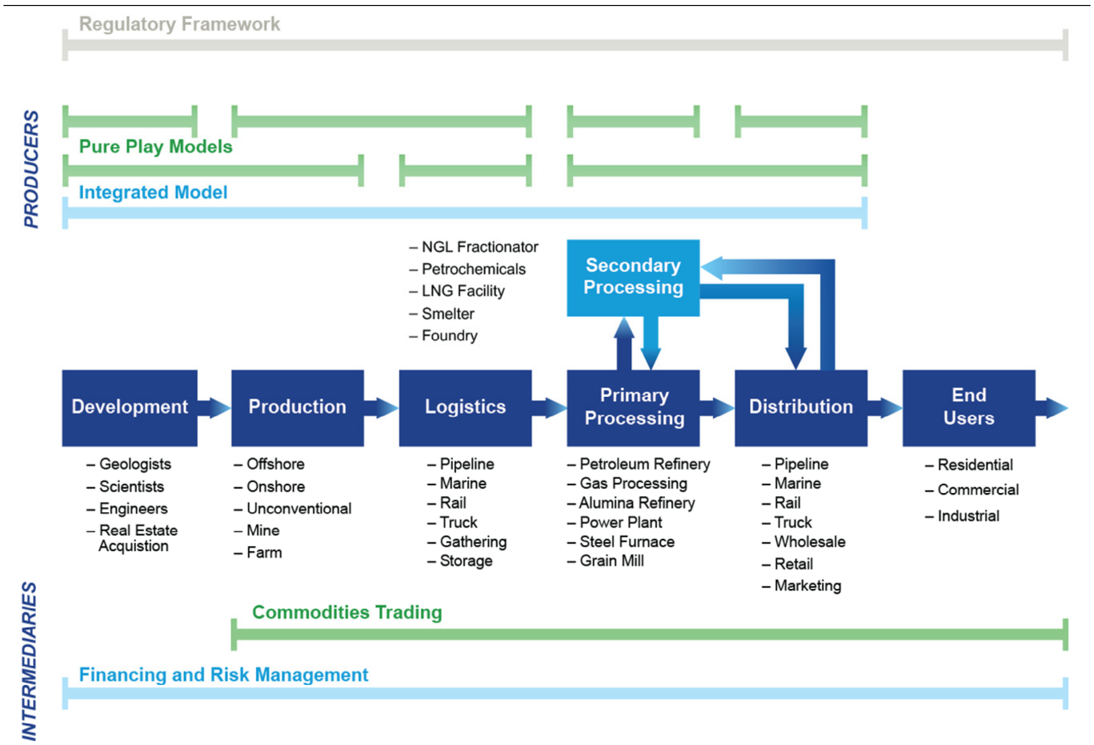
# APPENDIX A: COMMODITY INDUSTRY STRUCTURE

This appendix provides an overview of four commodity industries including structure, commodity trading and examples of risk management. The scale of the industries is highlighted and the different types of players are discussed along with quantification of market share in different supply chain segments.

The industry structures of many commodities value chains are similar despite having vastly different end products and target consumers. For the purposes of this report, we have grouped the supply-side participants involved in the commodities value chain into two groups:

- The **producer** group is responsible for constructing and operating assets involved in producing, processing and distributing the commodities. The producer group can be further defined as integrated, where the producer owns and operates each segment of the value chain, or as pure play where the producer specializes in a specific sector or segment of the value chain.
- The second participant group, the **intermediaries**, is responsible for ensuring that a market framework exists to support growth, trade and a competitively balanced market environment. This group includes but is not limited to financial intermediaries such as banks.

FIGURE 8




Source: IHS Energy
30899-4

This appendix covers four specific commodities chains: crude oil, refined products, natural gas, non-ferrous metals. The discussion includes a physical asset-based description of the commodities value chain and describes the participants as well as how the producing and intermediating groups operate.

## CRUDE OIL

Most consumers interact with petroleum by filling their vehicle with fuel at the local gas station. The relative ease of this activity largely insulates the public from the scale, complexity and resources, both human and financial, required to connect and drive the global crude oil and refined product commodity chain.

Global consumption of liquids[21] currently stands at 91.7 million barrels per day (B/D),[22] of which 85% consists of crude oil and condensate.[23] Crude oil represents the largest global commodity flow, both in terms of consumption and global trade. To put this in financial terms, the market value of the crude commodity chain, at a benchmark price of $100 per barrel, equates to more than USD$2.9 trillion annually. Additionally, the crude oil marketplace features large physical distances between producing, processing and consuming regions. The size of the marketplace, the balance sheet required to finance crude oil transactions, the geographic distance between buyers and sellers and the portability of liquid petroleum have facilitated a global network of producers, consumers, traders and financiers to assist the process of bringing this energy source to the consuming public in a cost efficient manner.

## SIZE OF THE NORTH AMERICAN CRUDE OIL PRODUCTION INDUSTRY

Driven by the U.S., North America is the largest per capita crude oil consuming region in the world with total crude oil demand of 17 million B/D or 22% of the global total. With crude oil production of 9.9 million B/D and growing, North America (the U.S. and Canada together) is the third largest crude oil producing region behind the former USSR and the Middle East, with the U.S. and Canada ranked third and fifth in terms of annual crude oil production. Essentially, all North American production is consumed within the region, the difference between North American production and demand is supplied with imports from all regions of the globe.

Given the role of crude oil in meeting North American energy demand, and the position of the U.S. as the largest importer of crude oil,[24] North America ranks first, and occasionally second, in terms of the number of active drilling and production rigs, number of active wells, miles of gathering pipelines, miles of crude oil trunk pipelines, crude oil storage volume and crude oil importation capacity.

The crude oil production portion of the business is commonly referred to as the "upstream" sector of the crude oil complex and contains several distinct segments:

- **Exploration and Development** involves the acquisitions of land and mineral rights, non-invasive testing to assess the resource potential and the drilling of exploratory wells to confirm the presence of commercial hydrocarbon deposits. Once a resource basin has been characterized as commercially viable, more outside capital, typically supplied by banks, and other resources are allocated to the engineering and constructing of permanent production facilities.

[21] Liquids defined as crude oil, condensate, natural gas liquids (NGL), biofuels, Fischer-Tropsch liquids and processing gains.
[22] IHS CERA Global Liquids & Refined Product Supply & Demand, August 2013.
[23] Referred to as simply crude oil for this report.
[24] China is likely to overtake U.S. as the largest importer of crude oil by the end of the decade.

- **Production** involves the engineering, construction, commissioning and operation of facilities. Depending on the nature of the asset involved and the size of the potential hydrocarbon reservoir, the capital required could range from several million to tens of billions of dollars per project. The operational life of the asset can range from five years for wells with rapid production decline profiles to 30 years or more for large deposits with superior geological conditions. Large upstream projects can involve a multi-billion dollar upfront capital expenditure with financial payback taking place over decades. The inherent price variability of the commodity being produced requires the entities involved in the production to have sophisticated risk management tools and sufficient hedging to protect the investment payback against downside price risk, or to be of super-major scale, or both.

- **Logistics** is the interface segment of the upstream sector also referred to as "midstream", and involves transporting crude oil from the wellhead to demand centers. Gathering systems typically involve either smaller pipelines that aggregate crude oil production into large comingled common streams or tanker trucks that collect fixed volumes of crude oil from individual leases for transport to central collection locations. Long distance transportation systems are used to bridge the geographic distance between producing and consuming regions and can involve pipelines, marine vessels and tankers, as well as rail.

The participants in the upstream sector can be classified into one of the following groups:

- **Global Integrated:** Participates in the full petroleum complex commodities chain (upstream, midstream, and refining or "downstream") and has global operations (e.g. ExxonMobil, Shell, Chevron and BP).

- **Regional Integrated:** Participates in the full petroleum complex commodities chain with focused operations in select regions (e.g. Cenovus, Petrobras, Repsol, Statoil, Sasol and Suncor).

- **Independents:** Large, medium or small based on production and processing capacity and focused on specific sectors of the petroleum complex (production, logistics, refining) (e.g. Apache, ConocoPhillips, Devon, Energy Transfer Partners (ETP), EOG Resources, Marathon Oil, PBF, Phillips 66, Occidental, Carrizo Oil & Gas, Plains All American, Rex Energy, Matador Resources and Valero).

- **National Oil Companies:** Integrated or independent (usually integrated), often with a monopoly position in the home country and may receive and provide substantial direct state support (e.g. PDVSA, PEMEX, Saudi Aramco and Iranian National Oil Company).

Based on 2012 data,[25] North American crude oil production based on these characterization groups was the following:

[25] IHS Energy Insight Herold 2012 Upstream Performance Review (U.S. and Canada).

**TABLE 6**
NORTH AMERICAN CRUDE OIL PRODUCTION MARKET PARTICIPANTS

| | Number of Participants | Typical Production | % of NA Production | Approximate 2012 Production |
|---|---|---|---|---|
| Globally Integrated | < 5 | > 200,000 B/D | 16% | 1.6 Million B/D |
| Regionally Integrated | 10 - 15 | > 100,000 B/D | 15% | 1.5 Miilion B/D |
| Large Independent | 15 - 20 | > 100,000 B/D | 42% | 4.2 Million B/D |
| Medium Independent | 20 - 50 | > 10,000 B/D | 14% | 1.4 Million B/D |
| Small Independent | 100+ | < 10,000 B/D | 13% | 1.3 Million B/D |

Source: IHS Energy Insight Herold 2012 Upstream Performance Review (U.S. and Canada)

Small and medium sized independents number more than 150 companies and account for more than a quarter of North American production. When the large independents are included the share of production rises above two-thirds. Because there are widely divergent sizes between the largest and smallest market participants, their incentives and support requirements differ accordingly. Although not exclusively, the largest and most integrated participants typically have less need for external financing and logistics support.

Smaller participants focused on a specific sector of the industry often do not have the means to build up these internal skills or find it more effective to outsource these skills and thus rely on the participation of intermediaries. These external parties provide key functions such as financing, debt management, price hedging and physical offtake of production, without which the smaller participants would struggle to compete effectively. An example of the role that banks play in supporting small to medium independent producers is provided in the Section II, Case Study on U.S. Natural Gas Production.

Another example of where the banks provided support (in this case debt-financing and the underwriting of a public stock offering) to a medium independent producer is with Mitchell Energy & Development Corporation. The combination of a key technology behind the unconventional oil and gas revolution, slick water hydraulic fracturing, was pioneered by Mitchell Energy & Development Corporation, a medium independent producer who spent decades experimenting prior to realizing commercial scale production using this technique. Along the way, Mitchell Energy was supported by numerous financial and physical intermediaries allowing the company to focus on the Barnett shale development and improving these new production techniques.

Banks play a key role in assisting smaller independent participants to compete by assisting with logistics offtake, marketing and trading services. Bringing crude oil to refineries is a vital link in the oil supply chain. The dominant mode of crude oil transportation in North America is by pipeline and pumping stations, which over a century of experience has proven to be the most energy efficient and cost effective means of moving large volumes of a liquid commodity. Estimates are that over 70% of crude oil production moves by pipeline and that North America contains over 100,000 miles of active crude oil pipelines.[26]

[26] Recent statistics from the U.S. PHMSA and Canada CEPA estimate 210,000 miles of hydrocarbon liquid pipelines in North America used for crude oil, refined products and natural gas liquids.

Similar to the upstream sector, the midstream logistics sector contains both integrated players (owning assets in both production and refining), semi-integrated (owning either production or refining assets) and independent pure midstream participants.

Based on 2011 and 2012 data, major North American crude oil pipeline market participants were the following:

**TABLE 7**
NORTH AMERICAN CRUDE OIL PIPELINE MARKET PARTICIPANTS

| | Participant Group | Miles of Crude Oil Pipeline | % of Total (Estimate) |
|---|---|---|---|
| Enbridge | Midstream Independent | ~ 8,000 | 7.3% |
| Enterprise Product Partners | Midstream Independent | ~ 5,250 | 4.8% |
| Energy Transfer Partners | Midstream Independent | ~ 5,000 | 4.5% |
| ExxonMobil | Global Integrated | ~ 5,000 | 4.5% |
| Kinder Morgan | Midstream Integrated | ~ 1,000 | 0.9% |
| Phillips 66 | Large Downstream Independent | ~ 6,000 | 5.5% |
| Plains All American | Midstream Independent | ~ 14,000 | 12.7% |
| Shell | Global Integrated | ~ 1,000 | 0.9% |
| Spectra | Midstream Independent | ~ 2,000 | 1.8% |
| TransCanada | Midstream Independent | ~ 3,000 | 2.7% |
| Total | | 49,250 | 45.7% |

Source: Various Public Company Data (10-K, Investor Presentations)

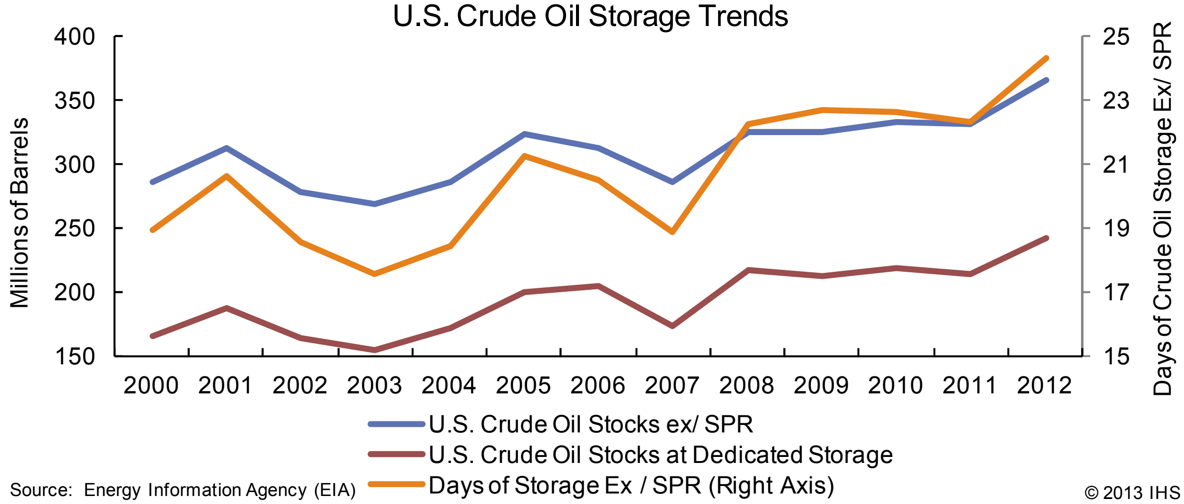
The economics of the crude oil midstream sector are based on long term, fixed-fee throughput tolls (or tariffs), which are used to fund the construction of these pipelines. Long distance crude transmission pipeline and smaller regional gathering systems can require investments ranging from several hundred million to several billion dollars. To recoup the investment and to service borrowed capital, pipeline operators charge a throughput fee to potential shippers. Prior to committing capital to a large transmission pipeline, operators require producer or third party commitments to ship a fixed volume of crude oil for a given duration at a negotiated rate. These upfront committed contracts are often negotiated on a "take-or-pay" basis, meaning that the committed shipper is required to pay the throughput fee regardless of whether the shipper (producer) has crude oil barrels to meet this volume commitment.

This financial structure provides another example of intermediaries playing a key role in supporting independent producers. Smaller production participants may not have enough production volume or financial capital to reserve pipeline capacity on a long term take-or-pay basis. By structuring a long term offtake agreement, which aggregates the production of multiple small participants with a merchant or trading customer, the bank facilitates for small producers a cost effective offtake for expected production, enabling small producers to focus solely on production without being exposed to the risk of long term logistics commitments. The alternative would be to arrange a contractual offtake agreement with a larger integrated competitor in the same market, which could use its logistics position to apply pricing pressure to smaller participants, reducing competition.

The physical storage of crude oil is another component of the midstream crude oil logistics sector and serves as the balancing mechanism between supply and demand, smoothing out short term price fluctuations. For the U.S., the available working storage capacity for crude oil is 1.2 billion barrels distributed across storage at petroleum refineries (10%), dedicated storage facilities (30%) and at the U.S. strategic petroleum reserves (60%).[27]

Interestingly, as the number of participants in the midstream crude oil storage segment has shifted toward a higher concentration of independent players, the working inventory of the U.S. crude oil system has increased by 28% since 2000, excluding the Strategic Petroleum Reserve (SPR). This increased dedicated (non-refinery) shell capacity is indicative not only of growth in U.S. crude oil production, but also of the diversification of the dedicated storage business. As with upstream production, the financing and leasing of storage capacity by producers, refiners and merchants is dependent on support from both financial partners and logistics intermediaries.

Figure 9
U.S. Crude Oil Storage Trends




Source: Energy Information Agency (EIA)

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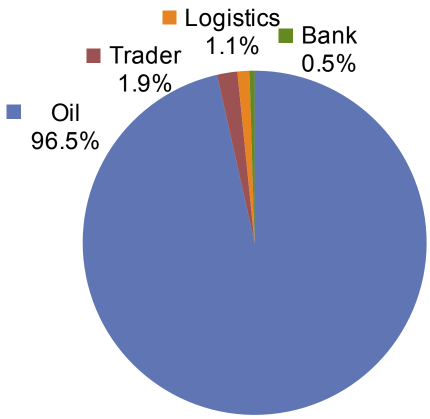
Recent developments in the midstream logistics space toward both the larger role of independent pure play participants and overall storage capacity growth is typified at Cushing, Oklahoma. As both the physical settling location for the NYMEX crude oil contract and the largest non-SPR storage hub in the U.S.,[28] the dynamics of Cushing serve as an instructive proxy for the midstream industry. At present there are 12 active operators (who own and lease storage capacity) in Cushing of which only two are integrated in some fashion to either upstream production or downstream refining assets. The remaining 10 are pure play independent storage operators who have, over the past eight years, doubled the capacity of the Cushing storage hub, largely in response to storage capacity demand from producers, refiners and merchants, and facilitated by the financial support of well capitalized banking entities. A similar summary of Cushing ownership before 2000 would show fewer participants and the majority of physical storage capacity owned by regional and globally integrated oil companies.

[27] Data only available for U.S. crude oil storage operations, provided by EIA.
[28] The Cushing storage terminal hub contains 65 million barrels of working capacity or 5% of the U.S. non-refinery dedicated storage capacity.

The physical buying, selling and marketing of crude oil involves many parties and multiple transactions from the point of production to the point of consumption. There is no public data available summarizing the physical global or U.S. trade of crude oil, the number of physical barrels bought, sold, marketed or transacted. What is publically available is the U.S. EIA[29] crude oil import data. The EIA maintains records that provide details for every cargo of crude oil imported into the U.S., including country of origin, cargo size, crude oil bulk quality and the importer of record. Since more than half of U.S. crude oil demand is supplied with imports,[30] analyzing this data provides a useful proxy for the individual companies and types of participants involved in the physical purchase and trade of crude oil. We include below a summary of the data for 2008-2012.

Figure 10
U.S. Crude Oil Importers 2008-2012 Average




| | |
|---|---|
| Oil[1] | 8,920 |
| Trading | 177 |
| Logistics[2] | 105 |
| Bank | 44 |
| Total | 9,245 KB/D |

Source: Energy Information Agency (EIA)

1 - Oil companies includes petrochemical companies
2 - Logistics includes end users, blenders, utility companies



From the EIA data, it is evident that the physical purchase and importation of crude oil is largely transacted by oil companies,[31] with other market participants handling only 3.5% of importation volumes. These other market participants include large trading houses, dedicated logistics and midstream pure players and banks.

## REFINED PRODUCTS

A similarity that crude oil shares with other natural resource-based commodities is that, in its natural state, it has very little use or value to the general public.[32] Crude oil must be refined into useable products for its value to be realized. In facilitating the logistical flow of crude oil, the physical barrel may change hands several times, but in the end there is only one true crude oil consumer: petroleum refineries.

[29] Energy Information Agency, the statistical and data analysis arm of the Department of Energy (DOE).
[30] Statement excludes Canada crude oil imports and is for the time period from 2008-2012.
[31] Oil companies are defined as entities that either physically produce crude oil or own refining assets.
[32] The only current direct use for as-produced crude oil is direct burning which is practiced in small volumes and not environmentally permissible in large portions of the world.

## SIZE OF THE NORTH AMERICAN REFINING INDUSTRY

As the largest consuming region of crude oil, North America also contains the largest and most sophisticated refining system in the world. Sophistication refers to a refinery's ability to convert the full crude oil barrel into "light" petroleum products (gasoline, jet fuel and diesel), the interconnectivity with the petrochemicals value chain and a refinery's ability to process heavy, sour or acidic crude oils. A total of 63 different entities are involved in the ownership of North America's refining system, consisting of 152 individual refineries with a crude oil processing capacity of 20 million B/D.

The crude oil refining and subsequent refined product marketing portion of the business is commonly referred to as the "downstream" sector of the petroleum complex and contains several distinct segments:

- **Refining** involves the physical processing of crude oil into many petroleum derived products. Refineries resemble small industrial cities and often entail 20-30 separate manufacturing processes, each with a different function. These individual process units can be classified into one of three groups: physical separation, conversion and treating. Physical separation, usually through boiling, splits the crude oil barrel into narrow fractions for further processing. Conversion units focus on rearranging less desirable molecular compounds into those more in demand and with higher value. In the treating units, impurities such as sulfur, nitrogen, and metals are removed. The end result of this intricate manufacturing process is the transformation of crude oil into usable refined products.

- **Specialty operations** can be thought of as a subset of the basic refinery process. The majority of production from a refinery is transportation fuels (gasoline, jet fuel, diesel and marine bunker fuels); many refineries produce only these transportation fuels. A smaller subset of refineries also produce a diverse array of useful products that include naphtha, lubricating oils, waxes, transformer and refrigeration fluids, petrochemical feedstocks and inputs into the fertilizer production complex.

- **Marketing and distribution** is the logistics function of the downstream sector and involves the transportation and sales of refined product from the refinery through regional distribution terminals down to local retail stations. Several of the assets and participants involved in this segment are closely affiliated with the upstream crude oil logistics sector.

Additionally, refiners are large customers of utilities both in the form of electricity and heat (typically steam) and are often co-located with large power facilities that supply the energy needs of the refinery and export surplus power onto the electricity grid.

In recent history, 2013 marks the first time a larger percentage (59%) of North American refining capacity is owned and operated by independent players rather than integrated oil companies. This is partially a function of the de-integration of Marathon and ConocoPhillips. The distinction between large (>1,000,000 B/D), medium (>250,000 B/D), and small independents (<250,000 B/D) is based on crude distillation capacity. The ownership breakdown of the North America refining system is the following:

**TABLE 8**
NORTH AMERICAN REFINING MARKET PARTICIPANTS

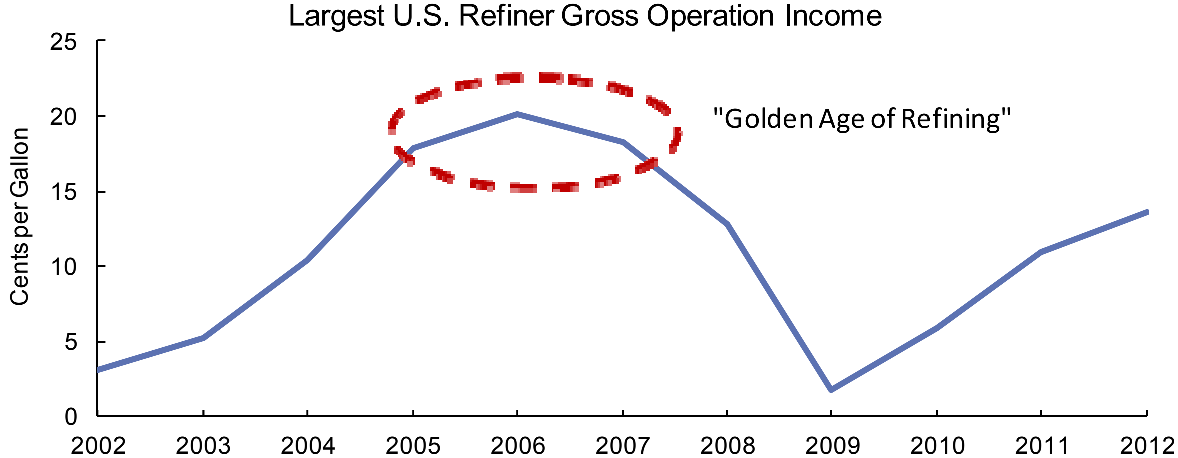
| Ownership Entity | # of Refineries | % of Refining Capacity | Crude Oil Capacity (B/D) |
|---|---|---|---|
| Global Integrated | 25 | 26.0 | 5,180,373 |
| Regional Integrated | 12.5 | 7.6 | 1,514,263 |
| Large Independent | 31 | 28.2 | 5,618,712 |
| Medium Independent | 21 | 17.6 | 3,506,714 |
| Small Independent | 57 | 12.8 | 2,550,337 |
| National Oil Companies | 5.5 | 7.8 | 1,554,112 |
| Total | 152 | 100 | 19,924,510 |

Source: IHS Energy Insight

At its core, refining is an energy and capital intensive manufacturing business where crude oil is the raw material and petroleum products are the finished goods. In the public discourse, petroleum refining is frequently characterized by two ideas, "refining is a high-margin business" and "since no new refineries have been built since the 1970s, the nation must be short of refining capacity." These two reasons are often cited as the driver of high pump prices.[33]

Refineries have historically been a relatively low margin and high volume manufacturing enterprise. At a crack spread[34] of $10 per barrel, roughly half of this difference goes toward covering operating costs with the residual for investor return and taxes. The resulting operating margin of $5 per barrel (12 cents per gallon), reflects a single digit fraction of the price paid for finished refined products.

Figure 11
Largest U.S. Refiner Gross Operation Income




Source: Valero 10-K Report © 2013 IHS

[33] Committee on Government Reform Subcommittee on Energy and Resources, "Petroleum Refineries: Will Record Profits Spur Investment in New Capacity", October 2005.
[34] The difference between the price of crude oil feedstock and finished refined products, typically gasoline and diesel.

Although no new refineries have been constructed in several decades, existing refineries have expended vast sums of capital to grow capacity, to add new processing units and to continually replace and upgrade existing equipment. As a rule of thumb, refineries typically allocate 2-3% of the replacement cost of the refinery in sustaining capital and facilities refurbishment annually.

The magnitude of the capital necessary to support ongoing operations becomes evident when considering the replacement cost of the North American refining system. The conservative estimate to replace the 20 million B/D of high complexity refining capacity would likely exceed $500 billion. With moderate demand growth and relatively geographically diverse locations, North American refiners have not needed new refining sites to satisfy domestic demand. North America's refineries produce an output of 18.2 million B/D for North American refined product demand of 16.8 million B/D. Indeed, in 2011 the U.S. became a net exporter of petroleum products. Large multi-billion dollar investments are hard to justify in a regional market that is already over-supplied.

As the North American refining system has become more independent and less vertically integrated, an additional challenge has emerged for many of the smaller participants in the industry—the funding of working capital. Working capital for refineries is primarily the purchase of feedstocks and funding operations until the raw materials can be processed, sold and revenue collected. The credit and financing challenge of buying feedstocks for smaller refiners is high compared to other commodities manufacturing businesses. Consider the example of a very large crude carrier (VLCC), laden with 2,000,000 barrels of crude oil, or the feedstock for a 200,000 B/D refinery for 10 days. The working capital for this cargo exceeds $200 million in today's prices. The typical supply chain from crude oil purchase through refinery delivery, processing and product sales can take 1-2 months.

While the refining business is relatively continuous with ongoing product revenue offsetting crude purchases, there is a significant sustained working capital requirement. Smaller participants with smaller balance sheets are taking significant risk with each cargo of crude oil purchased. Market conditions often change and the value of the products sold can be less than the cost of the feedstock purchased. Although market fluctuations generally "even out" over time, a given price movement can have a sharp effect on small company financial performance or even viability. A critical factor in ensuring that small participants can compete in the refining sector is partnerships with external banks that can provide working capital for ongoing operations and manage the risk of short term price fluctuations. The working capital funding challenge for independent refiners is illustrated in the transactional value of the refining asset itself. Consider the recent example of the sale of the Texas City Refinery from BP (a global integrated) to Marathon Petroleum (a large independent refinery): the transactional value of the refinery asset was reported at $598 million, with the transactional value of the onsite inventory listed at $1.2 billion.

This high perpetual capital reinvestment, both in the facility and in working capital, and the historic low margins for the core business provide a role for banks in financing ongoing operations and providing non-core refining services such as feedstock supply and product offtake. The economic challenges faced by the U.S. refining industry and the valuable services that banks can provide in reducing overhead costs and improving capital efficiency has been demonstrated over the past three years in the U.S. East Coast market and elsewhere.[35] This value to independent refining companies is illustrated in the following statement, "We have agreements with [a major financial intermediary] for the supply of crude oil that will support the operations of the Big Spring refinery, the Krotz Springs

[35] Similar arrangements are in place for small independent refineries in Louisiana, Texas, Minnesota and California.

refinery and the California refineries. These agreements substantially reduce our need to issue letters of credit to support crude oil purchases. In addition, the structure allows us to acquire crude oil without the constraints of a maximum facility size during periods of high crude oil prices."[36]

Similar to crude oil production, the majority of the three primary transportation fuels moves from the refinery to large demand centers via pipeline. There is an estimated 105,000 miles of refined product pipeline in North America connecting the major refining centers to regions of high population density.[37] The largest of these systems is the Colonial Pipeline System, running from the Houston, Texas area to New York Harbor. This system, together with Kinder Morgan's Plantation pipeline, has the capacity to transport 3 million B/D of gasoline, jet and diesel from the Gulf Coast to the U.S. Southeast and Mid-Atlantic regions, almost 20% of North American refined product demand.[38] Provided below are the main participants in the refined product trunk line[39] transportation sector of the industry:

**TABLE 9**
NORTH AMERICAN REFINED PRODUCT PIPELINE MARKET PARTICIPANTS

| | Participant Group | Miles of Crude Oil Pipeline | % of Total (Estimate) |
|---|---|---|---|
| Buckeye Partners | Midstream Independent | ~ 6,000 | 6.5% |
| Colonial Pipeline | Midstream Independent | ~ 5,500 | 5.2% |
| Energy Transfer Partners | Midstream Independent | ~ 2,500 | 2.4% |
| Enterprise Product Partners | Midstream Independent | ~ 4,800 | 4.6% |
| Explorer Pipeline | Midstream Independent | ~ 1,900 | 1.8% |
| ExxonMobil | Global Integrated | ~ 2,000 | 1.9% |
| Kinder Morgan | Midstream Integrated | ~ 8,000 | 7.6% |
| Magellan Product Partners | Midstream Independent | ~ 9,600 | 9.1% |
| Marathon Petroleum | Large Downstream Independent | ~ 7,900 | 7.5% |
| NuStar | Midstream Independent | ~ 3,800 | 3.6% |
| Phillips 66 | Large Downstream Independent | ~ 4,000 | 3.8% |
| Total | | 56,000 | 54.1% |

Source: Various Public Company Data (10-K, Investor Presentations)

The refinery output not transported in North America's trunk line system is distributed via tanker truck, rail and marine tanker. The use of tanker truck and rail is particularly prevalent for the smaller volume specialty products that rely solely on physical transactions as a means of price discovery. From the major refined product supply trunk lines, fuels are moved through connected storage terminals to wholesale blending and terminal facilities. At these facilities, the fungible fuel products provided by the refinery are blended with additives and renewable blend components (such as ethanol and biodiesel) to form the finished transportation fuel.[40] Once blended into finished

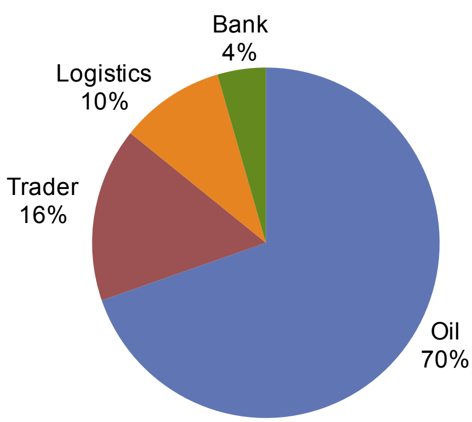
[36] Alon USA Energy 2012 Annual Report.
[37] With the U.S. containing 95,000 miles.
[38] Ownership of Plantation Pipeline split 52.2% Kinder Morgan and 48.8% ExxonMobil.
[39] Trunk line refers to the major interstate pipeline systems and are differentiated from the intrastate and local distribution pipeline systems.
[40] Some refineries perform the onsite blending of additives and biofuels inside the refinery with sales from the refinery directly to distributors; these are commonly referred to as "rack sales".

transportation fuel, the distribution system becomes even more fragmented as dealer tanker trucks and “jobbers” (independent middleman businesses) fulfill the final “last mile” of the distribution system, which involves delivering product direct to retail stations and large industrial customers. The level of integration of refiners in the distribution sector varies by operating entity, from having no presence in the distribution and marketing space to being fully downstream integrated and owning the main refined product trunk line, wholesale blending operation, delivery tanker trucks and the branded retail outlets.

As with the different sectors of the full petroleum complex, there is no standard downstream business model. Instead different operating entities have different intermediation needs from financing, logistics and trading entities. For the pure independent refiner whose sole focus is on refinery operations there is a role for external intermediaries to help facilitate crude purchasing, crude financing, product offtake and product distribution to independent wholesale operators. These intermediaries need a strong balance sheet to provide the credit worthiness to fund ongoing operations and a detailed knowledge of the physical marketplace to facilitate the trading of the refined product.

Similar to crude oil, there is no publically available data concerning refined product transaction volumes, the buyers and sellers in the market and the involvement of marketers and other intermediaries. However, the U.S. EIA import statistics can again be used as a proxy to analyze the participation of individual entities and of participant groups.

Figure 12
U.S. Refined Product Importers 2006-2012 Average




| | |
|---|---|
| Oil[1] | 1,868 |
| Trading | 434 |
| Logistics[2] | 261 |
| Bank | 120 |
| Total | 2,683 KB/D |

Source: Energy Information Agency (EIA)

1 - Oil companies includes petrochemical companies
2 - Logistics includes end users, blenders, utility companies



The market participation of refined product imports (by importer of record) has higher diversification than crude oil with oil companies handling 70% of refined product imports. This higher degree of diversity is a reflection of the segmentation of refined product output and the business decision of many downstream oil companies to exit the wholesale and retail market segments.

To successfully participate and provide these services, these external participants, such as the banks, must have a deep commercial knowledge of local and regional flows, players and facilities. Petroleum markets are quite dynamic and changes can and do occur rapidly. Some changes are foreseeable, such as when local fuel specifications become more region specific or the added complexity of biofuels blending and compliance. Other changes, such as a refinery outage or a storm that delays a ship's arrival, are unpredictable and require tactical knowledge of the crude oil and refined products supply chain. The role of banks is discussed more in Section III.

## NATURAL GAS

The North American natural gas commodity sector has experienced profound structural changes in the past 30 years, with the advent of the modern competitive trading structure occurring in 1992 with FERC Order 636. Pre-1990s, the natural gas industry was heavily regulated. There existed large structurally integrated companies that took part in production, ownership of transportation pipelines and end use distribution. The interstate pipeline companies were charged with purchasing gas from producers at regulated prices and reselling gas to local distribution companies (LDCs), again at regulated prices. This regulated system left limited room for competition from smaller players across the value chain, but functioned reasonably well so long as natural gas was in surplus owing to price controls that had retarded investment, as it was until the severe winters of the late 1970s. When shortages arose, however, this regulated system adjusted only slowly to shifts in market conditions. Large dislocations occurred between natural gas prices in the unregulated intrastate marketplace, and the regulated prices for gas dedicated to interstate pipelines—with resulting shortages of gas in the interstate market.

The deregulation of the natural gas industry beginning in the 1980s paved the way for more competition and choice across the value chain and enabled both producers and consumers to respond in a more timely manner to shifts in market conditions. Deregulation of wellhead prices,[41] unbundling of the pipeline sale and transport functions and the flexibility of end users to purchase natural gas directly from producers, LDC or marketing entities allowed pricing signals to flow through to both producers and end users, allocating supply and demand in a more efficient manner through both producer drilling responses and consumer energy choices.[42] These measures also introduced a new breed of marketing entities as facilitators of natural gas movement from producers to end users. By providing bundled or unbundled services to any two parties within the value chain, marketers play a valuable role in facilitating the transactions that bridge the geographic and chronological gap between production and consumption. Significant regulatory oversight in the transportation and distribution of natural gas still exists to ensure competitive natural gas markets.

In the early 2000s, U.S. natural gas production had stagnated and began to decline, and liquefied natural gas imports were thought to be necessary to supplement U.S. supplies of natural gas for households, electricity generation and large industrial operations. The result was a construction wave of import facilities by the mid-2000s on the Atlantic and Gulf Coast to receive LNG imports. Between 2000 and 2003, an economic downturn temporarily slowed the increase in gas prices. Between 2004 and 2008, prices rose on strong demand, rising construction costs and stagnant production (to over

[41] Post deregulation, natural gas prices became a function of market fundamentals (supply and demand) rather than a pre-set regulated price.
[42] Bundling refers to the legacy where long distance interstate transmission pipelines took physical ownership of the natural gas being transported. As this system was deregulated, pipeline operators moved to a system of charging throughput volumes on natural gas movements through their pipeline assets.

$8.00/MMBtu from $5.00/MMBtu). By 2008, due to higher prices and conventional wisdom of declining supply, the U.S. had constructed 12 LNG import facilities with a total regasification capacity of 19 Bcf per day, or about one-third of U.S. natural gas demand. It was widely assumed that the Caribbean, North Africa, the Middle East and West Africa would be major suppliers of the U.S. natural gas imports. But just as the last domestic natural gas import terminal was being completed, an upsurge in unconventional gas production, principally shale, reshaped the energy landscape and marginalized the long term need for LNG imports, re-orienting the market towards a position of supply strength.

The revolution in shale production was primarily driven by independent players, both large and small, with financial assistance from banks with strong balance sheets. The capital and price risk management provided by banks has been a key driver of the unconventional gas revolution. The full impact of the shale revolution is only now taking shape, North American dry gas production increased from 69 Bcf per day in 2007 to 79 Bcf per day in 2012, a 13.4% increase in five years.[43] Correspondingly, a slow demand recovery due to the 2008-2009 recession is leading to slower gas-directed drilling activity in light of excess supply. Supply and demand will likely rebalance in the next few years due to structural increases in demand growth expected to cause upward pressure on natural gas prices.

North American natural gas consumption is primarily determined by the residential, commercial, industrial and electric sectors with the potential of an increasing contribution from the transportation sector in the form of natural gas vehicles (NGVs), specifically heavy-duty trucking. Residential and commercial consumption has been largely flat for the past decade averaging 14 Bcf per day and 9.2 Bcf per day, respectively, between 2007 and 2012. Industrial demand was structurally weakened by the economic recession of 2008-2009, averaging 17 Bcf per day. Demand has stabilized and is beginning to recover. Electric consumption witnessed a 25% increase (the largest growth of all sectors) from about 20 Bcf per day in 2007 to about 26 Bcf per day in 2012. Electric consumption continues to maintain the largest share of natural gas demand and is expected to maintain a large position in the future. To put these numbers in financial terms, total North American natural gas market value equals USD$128.2 billion annually.

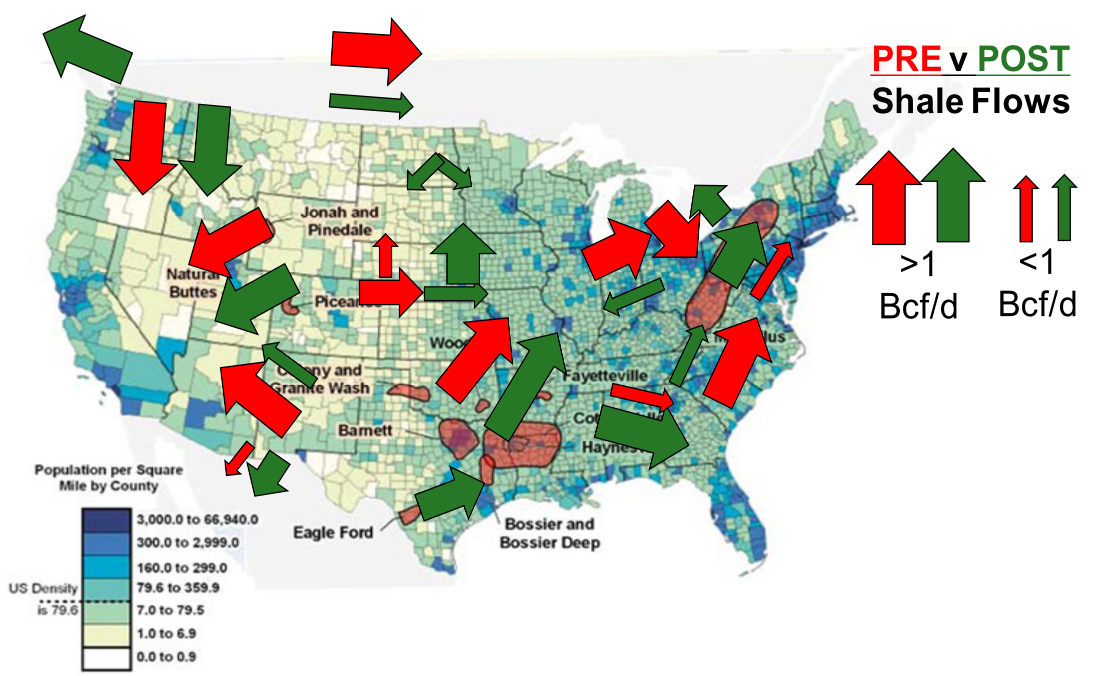
## NATURAL GAS FLOW PATTERNS SHIFT

The substantial growth of shale gas over the past few years, including the Marcellus[44] in the Northeast is causing a shift in gas flow across North America (see the following figure). Marcellus production will increase by at least 1.2 Bcf per day to nearly 12 Bcf per day by the end of 1Q2014. Marcellus will displace another 400 million cubic feet (MMcf) per day of supply previously moving to the Northeast. From November 2013 to March 2014, 2.6 Bcf per day of additional interstate pipeline infrastructure and 1.2 Bcf per day of gas processing capacity are expected to come online.[45] The projected increase in infrastructure will connect Marcellus supply to existing regional pipelines but will require large capital investment. Banks play a crucial role in helping smaller players to be competitive by providing them with cost effective access to capital, risk management and intermediation services. The Marcellus continues to gain market share in an area of highly concentrated gas consumption replacing supply historically served by the Gulf Coast, as well as

[43] IHS CERA Aug 2013 "Moving Sideways", EIA.
[44] Marcellus is the natural gas rich geological formation running under Western Pennsylvania.
[45] IHS CERA "New Infrastructure Continues to Unleash New Production in the Marcellus" Aug 2013.

eastern and western Canada. The excess supply coming out of the Marcellus has exerted downward pressure on prices and, as a result, drilling activity. It has also dampened gas volumes going from the Rockies to the east and from Texas to the north, thereby also reducing the transportation costs of natural gas to these large consuming regions. The landscape of North American natural gas movements will continue to evolve as new shale plays are discovered and older plays decline. Access to capital, risk management and intermediation services will be critical in allowing market participants to develop new resources and continuously modify the infrastructure required to connect new supply to consumers.

FIGURE 13




Source: IHS CERA and U.S. Census Bureau, *Census 2000.*
00112-13

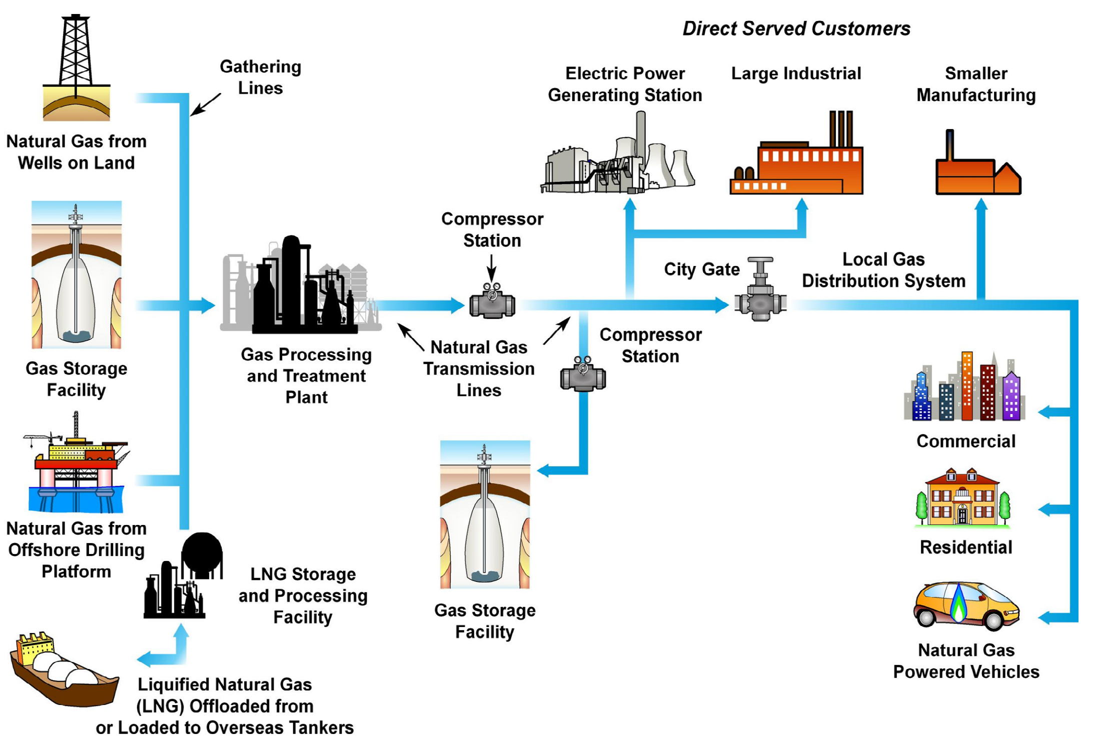
## NATURAL GAS SUPPLY CHAIN

The process of getting natural gas out of the ground to its end use is complex and involves players in both the natural gas physical and financial markets.

The natural gas exploration, development and production portion of the business is analogous to the upstream sector of the crude oil complex described above.

The natural gas midstream logistics segment in the natural gas complex involves transporting produced natural gas from the well head to demand center distributors or LDCs.[46] This transportation function can involve smaller gathering systems and larger long distance transportation networks commonly called transmission lines. The gathering systems typically involve pipelines which aggregate natural gas from individual wells or groups of wells and transport them to either gas processing plants where the separation of natural gas liquids (NGLs) occurs or to treatment plants, which remove impurities such as $H_2S$ and $CO_2$ in the case of lean gas. Dry gas then goes through pipelines to LDCs, large utilities or large industrial sites which in turn distribute gas to end users (commercial, residential, industrial or transportation (NGVs). Many larger end users such as power generation facilities or industrial facilities are directly connected to the high-pressure pipeline grid as well. Volumes of natural gas are stored underground, in depleted reservoirs, in salt caverns or aquifers, to moderate supply and demand imbalances and seasonal swings. The figure below provides a representation of the natural gas value chain.

## FIGURE 14




Source: IHS Energy Insight
30899-3

[46] LDCs or Local Distribution Companies are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. There are two basic types of natural gas utilities: those owned by investors, and public gas systems owned by local governments.

There are over 6,300 natural gas producers in North America. The participants in the upstream sector can be classified into one of the following groups (value represents percent of North American natural gas total production):

- Global Integrated (9.8%) such as ExxonMobil, Shell, BP and Chevron
- Regional Integrated (5.1%) such as BHP, Cenovus, Suncor and Husky
- Large Independents (53.1%) such as Apache, EnCana, Chesapeake Energy, Anadarko Petroleum, Devon Energy and ConocoPhillips
- Medium Independents (22.7%) such as Southwestern Energy, Cabot Oil & Gas, QEP Resources and EP Energy
- Small Independents (9.3%)

**TABLE 10**
NORTH AMERICAN NATURAL GAS PRODUCTION MARKET PARTICIPANTS

| | Number of Participants | Typical Production | % of NA Production | Approximate 2012 Production |
|---|---|---|---|---|
| Globally Integrated | < 5 | > 2 Bcf/d | 10% | 7.8 Bcf/d |
| Regionally Integrated | 10 - 15 | > 0.5 Bcf/d | 5% | 4.1 Bcf/d |
| Large Independent | 15 - 20 | > 1 Bcf/d | 53% | 42.1 Bcf/d |
| Medium Independent | 20 - 50 | > 0.5 Bcf/d | 23% | 18.0 Bcf/d |
| Small Independent | 100+ | < 0.5 Bcf/d | 9% | 7.4 Bcf/d |

Source: IHS Herold

Similar to the upstream sector, the gas processing and gas treatment logistics sector (midstream) including pipelines and storage facilities contains both integrated players (owning assets across the value chain), semi-integrated (owning assets in production, gas processing or distribution) and independent pure midstream players.[47]

- There were over 500 active natural gas processing plants in 2012. Operating natural gas processing facilities had a total capacity of 66 Bcf of wet gas.[48]
- There are over 160 pipeline companies with over 300,000 miles of pipe, approximately half of which constitute interstate pipelines. Current pipeline capacity is about 148 Bcf per day from the producing to the consuming regions.

[47] See naturalgas.org for more details.
[48] Wet gas, as opposed to dry gas, is any gas with liquids content too high to be accepted into the interstate pipeline grid. Natural gas liquids (NGLs) such as ethane, propane and butane are extracted from wet gas.

- There are 132 natural gas storage operators in North America. They control over 400 underground storage facilities. These facilities have a working storage capacity of about 4500 Bcf of natural gas, roughly 60 days of North American demand and an average daily availability of 85 Bcf per day.[49]

- There are over 1,200 natural gas LDCs in North America with ownership of over 1.2 million miles of distribution pipe. A few markets have multiple competing LDCs, bringing choice and price restraint to the consuming public in those areas. In addition, certain states are working to provide more natural gas distribution choices to their consumers.

- The trading and marketing of natural gas is an important component of the midstream sector. Marketers undertake a multitude of transactions to ensure the delivery of natural gas in a timely manner to the end user. The marketing of natural gas is a diverse and transparent commodity market where companies enter and exit from the industry frequently. Since 2000, there have been 260 companies involved in the marketing of natural gas and they moved about 80% of all natural gas supplied and consumed in North America.

## COMMODITY TRADE

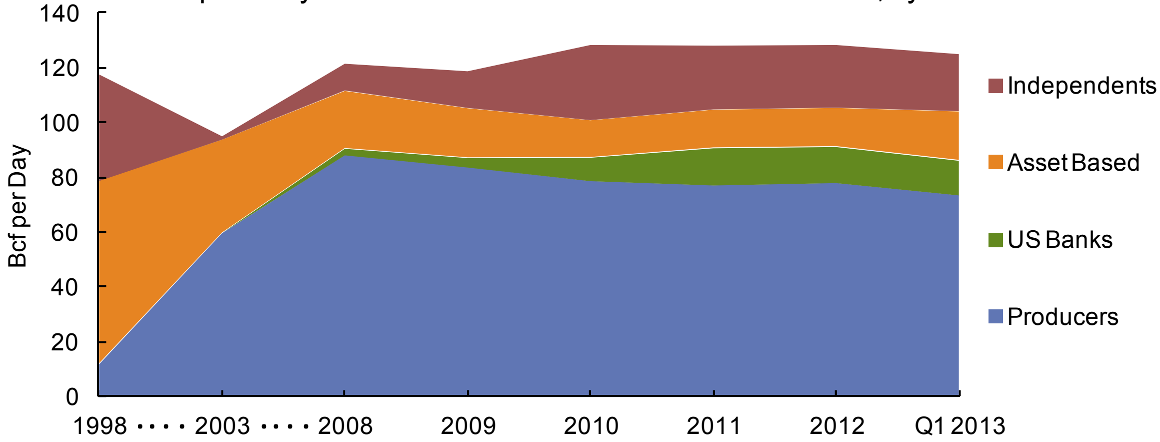
Since the separation of interstate natural gas pipelines from the buying and selling of commodity gas by FERC[50] Order 636 in 1992, both physical and financial trading of gas in an open and competitive marketplace have been necessary in order for buyers and sellers to come together in the U.S. and Canadian natural gas markets. In the U.S., natural gas is traded on both a physical and financial basis, with daily physical trading prices quoted by Platts[51] at 51 distinct pipeline zones on the high-pressure gas transmission system, and at an additional 28 market area locations on large utility systems or at major interstate pipeline interconnects (hubs). Other publications, including Energy Intelligence and SNL, provide survey-based quotes at additional locations. Financially, the benchmark futures contract is traded on the New York Mercantile Exchange (NYMEX) for delivery at the Henry Hub in Louisiana,[52] and basis futures products are also offered on the NYMEX at approximately 40 additional locations in the U.S. gas grid, corresponding to the more heavily traded physical locations in the North American grid.

Trading in this combination of daily and monthly physical markets, as well as financial futures markets, defines the value of natural gas throughout the North American grid. It also serves to reveal areas of shortage or constraint in the gas delivery system, and directs both upstream and midstream (pipes and storage) investments most efficiently to meet the needs of U.S. natural gas consumers.

Financial institutions are relatively new to the physical trading sector of the natural gas business in the U.S. Only in 2011 did U.S. banks emerge as the third most active sector involved in the physical trading of natural gas, far behind producers and other independent players (see following figure).

[49] Outflow capacity.
[50] Federal Energy Regulatory Commission, primary responsibility is the regulation of interstate energy movements.
[51] Platts along with Argus Media and OPIS are the main price reporting agencies, they confidentially collect and report transparent pricing on non-exchange traded commodities.
[52] Henry Hub is a pipeline juncture that serves as the physical delivery point for the NYMEX contract.

Figure 15
Top 20 Physical Trader in the U.S. Natural Gas Market, by Sector




Source: Energy Intelligence Group

© 2013 IHS

The figure above illustrates the physical volumes traded by the top 20 natural gas trading organizations, as reported by the Energy Intelligence Group, for the full years 1998, 2003, and 2008-2012. Data for 2013 is for the first quarter. Each organization is classified into one of four categories, with the 2013 first quarter companies as follows:

- Producers (10 producers in 2013)
- Financial institutions, including large banks (JP Morgan, Goldman Sachs, and Citigroup)
- Asset-based traders, largely utilities and/or pipeline companies, some of which have traded well beyond their asset footprint but for which trading is secondary to asset operations (Tenaska, Sequent, ONEOK and CenterPoint)
- Independent traders and marketing service providers, which may hold assets but emphasize trading and marketing services in the U.S. market, with U.S. asset holdings designed to support trading (Macquarie, EDF Trading and Castleton)

The volume traded during these periods by these entities collectively has averaged approximately twice total end user demand in the U.S. over the years sampled. With other trading organizations added, each gas molecule in the U.S. market is physically traded on average more than twice from the point of entry into the high-pressure pipeline grid to the point of consumption.

Banks hold a relatively small but important niche in this overall competitive business, representing approximately 10.4% of traded volumes among the top 20 traders over the first quarters of the past three years. By contrast, the producers have maintained a share of approximately 60.2% of overall traded volumes, while the asset-backed and independent traders together account for approximately 29.4%.

Banks participation in this sector increased somewhat in 2003 as a result of the Federal Reserve's 2003 determination that physical trading is an activity "complementary" to financial activity. However, a more significant driver was the exit of major independent and asset-backed participants from the business after the crises in energy wholesale markets (both natural gas and power). The banks essentially emerged into a void left as others exited.

This shift in market share is evident in the above graphic. In 1998, producers were largely outsourcing the physical trading function to asset-backed and independent entities, which combined to claim over 89% of trading volumes among the top 20 firms. By 2003, utilities and pipeline (asset-backed) companies were exiting the trading business, while the independent entities including Enron, Dynegy and Aquila had largely disappeared. Into that void stepped first the producers with the majors providing a full range of products and services, as they and the banks do today. The producers' share has remained relatively steady in the 59-65% range since 2010, with their share having peaked at 74% in 2009.

The banks offer an important alternative to many customers as major, independent providers of the full range of services in the marketplace. Small producers often depend on larger producers in the same area to market their gas, (the more active producer-marketers including BP, Shell and Chevron, many of which market more than they produce). Given large producers' strong market position, without the banks there would be very few other firms to offer small producers and end users marketing and other services that would be competitive with those provided by large producers. In fact, only one U.S.-based firm aside from the banks is in the top 25 physical marketers without also having a large direct stake in the physical natural gas value chain; i.e., is not a producer, utility or pipeline company. International firms are aggressively competing to provide independent marketing services, but the U.S. banks are by far the largest U.S.-based non-producer providers of marketing services in the natural gas industry.

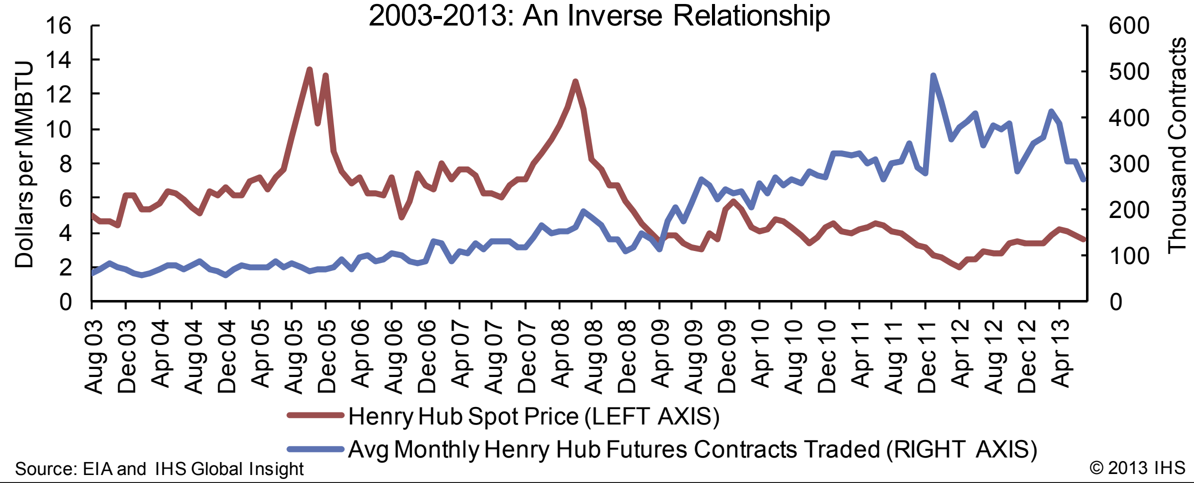
## THE FINANCIAL MARKETS FOR NATURAL GAS

Natural gas is well established in the financial markets in the U.S. The benchmark Henry Hub futures contract, which began trading in April 1990, is the most liquid natural gas contract and the third largest physical commodity futures contract in the world by volume.[53] The daily trading volume of the Henry Hub contract has averaged nearly 340,000 contracts so far this year, below the 2012 average but a high level by historic standards (see following figure).[54]

Over the years, some have argued that futures trading has increased volatility and overall price levels for both oil and natural gas. However, the experience of recent years shows that this is not the case: traded futures volumes have increased significantly while the overall price level and volatility has declined substantially. The decline in overall price level has been more a function of North America supply and demand fundamentals than futures contract liquidity.

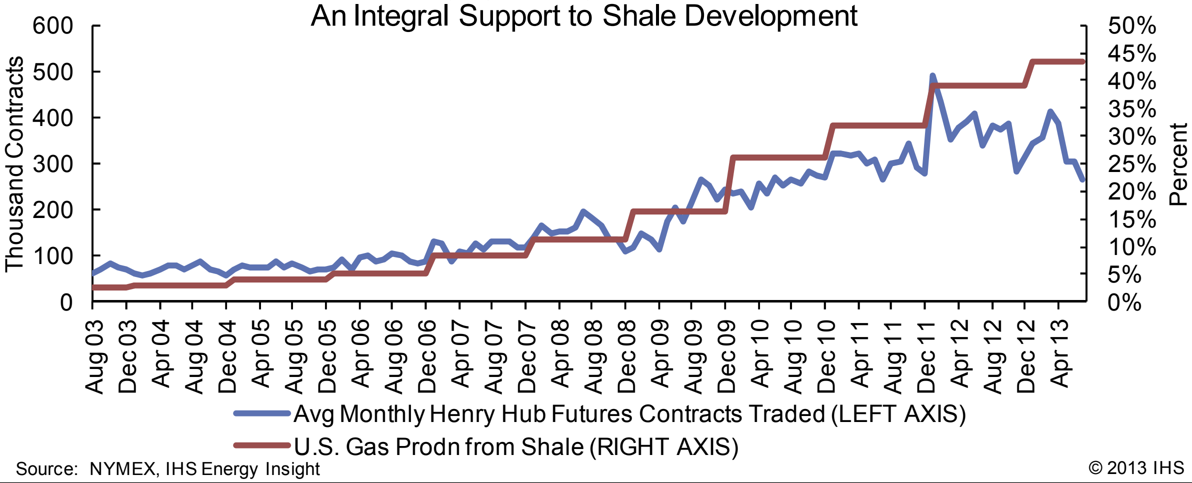
[53] The CME Group.
[54] IHS Global Insight.

Figure 16
Henry Hub Spot Prices and Futures Trading Volumes
2003-2013: An Inverse Relationship




This important point bears repeating: trading in and of itself has had no discernible impact on price. Rather, the strong increase in total NYMEX volume and especially the volume of long-dated trades occurred for a fundamental reason—it enabled investment in physical natural gas production even as prices fell, as shale producers (commonly through their bank intermediates) used futures as an effective risk management tool. Shale production differs from previous conventional gas production in that large acreage positions are accumulated, with many drill sites that may take several years to drill. As such, these are longer-lived assets than many earlier conventional plays, and often require billions of dollars in investment over a multi-year period. Hedging provides a means of ensuring a forward price, limiting price risk associated with these investments and increasing the ability to use debt to finance these investments. The relationship between the increase in shale production and the Henry Hub futures volume is illustrated below:

Figure 17
Hedging Through the NYMEX
An Integral Support to Shale Development



The percentage of U.S. production coming from shale gas is an IHS Energy Insight estimate on an annual basis, so each year is shown above at a flat level. Also, clearly many factors contribute to an increase in trading volume of this magnitude. Nevertheless, the simple correlation coefficient (R^2) for this relationship is 91%, a strong and stable association. The banks' ongoing participation in this market is driving liquidity and helping to support important risk management services to producers, without which they would not be investing in incremental production as confidently. This ability to hedge ultimately reduces energy costs for American consumers. If producers did not have access to long-dated contracts, their investments in new production would likely diminish with a corresponding rise in consumer prices and greater volatility. An efficient natural gas futures market and access to effective intermediation services are key factors in the rapid development and monetization of the North America's shale resources. Other shale rich countries with large resource potential (e.g. China, Argentina and Poland) that do not have the same market structure and intermediary presence are struggling to replicate North America's success.

Away from the Henry Hub, in forward basis trading at the major producing and consuming hubs, banks are even more critical providers of risk management and liquidity in the forward markets. While exchanges offer forward future contracts at many locations (more than 40) in the gas grid, the liquidity of these contracts is quite limited, and therefore so is their usefulness to market participants. To illustrate the lack of liquidity on the public exchanges for contracts other than the Henry Hub (in the basis markets), there are 59 contracts (either futures or options) at locations other than the Henry Hub offered by the CME Group. On August 22, 2013, a total of only 422 trades occurred among all 59 locations—in contrast to the over 300,000 contracts traded on an average day at the Henry Hub. In addition, even these 422 trades occurred at only two of the 59 locations (the Permian and Dominion South Point contracts); the other 57 locations registered no trades.[55] Open interest totaled 466,351 contracts at all 59 basis locations, for an average of less than 8,000 open interest contracts per location (the most open interest was at SoCalGas), in comparison to the more than 1.3 million open interest contracts at the Henry Hub the same day.

This is a single day sample and is not atypical. For example, for all of 2013 to date for 35 locations away from the Henry Hub[55] average trading volume was only 15 contracts per day, and on 94% of days no trades at all occurred at a given location. This lack of liquidity illustrates that producers and consumers clearly may not rely on the financial exchanges to be able to execute their hedging and risk management needs at locations away from the Henry Hub.

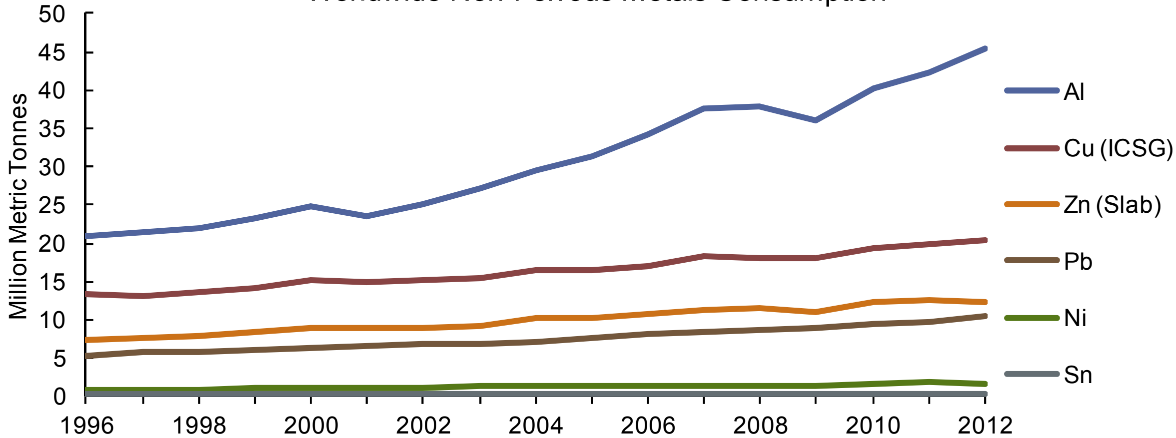
The banks' willingness to quote forward prices and hedge for producers and consumers at these locations is a critical service with no effective financial alternative currently available in the market. In addition, the banks' ability to provide this service requires physical participation in the marketplace at these locations day-to-day in order to provide the information necessary to make competitive price assessments. Additionally, banks participation in physical natural gas in these same regions enables them to manage their risk profile efficiently through increased market understanding. Without physical participation, banks' financial natural gas positions in these regions would carry higher uncertainty and associated risk. The end result would be that banks would either exit the business of providing financial risk management services (hedges), or materially increase the cost of providing these services. Both results would have an adverse effect on producers and consumers risk management strategies.

[55] The CME Group.

## NON-FERROUS METALS

Non-ferrous metals trading is centered in six major commodities: aluminum, copper, zinc, nickel, lead and tin. Aluminum is the largest of the non-ferrous metals markets, evidenced by trading volume on the London Metal Exchange (LME) and global consumption figures. By tonnage consumed, it is about 80% the size of the rest of the non-ferrous metal industry combined and the fastest growing.

Figure 18
Worldwide Non-Ferrous Metals Consumption




Source: IHS Supply Chain © 2013 IHS

Global aluminum demand has been growing at about 6% per year since the demand contraction during the recession of 2008-2009. Today, greater quantities of aluminum are consumed in countries such as China, Brazil and India, with China at 40% of the total demand and a high growth rate. Over the last 40 years, the United States has dropped from around 35% of the market to only about 10%. Aluminum has three principal end markets: transportation equipment, packaging and construction. The largest end use for aluminum is typically transportation or automobile manufacturing. The next largest use is for the packaging of beverage cans, although usages can vary across different regions.

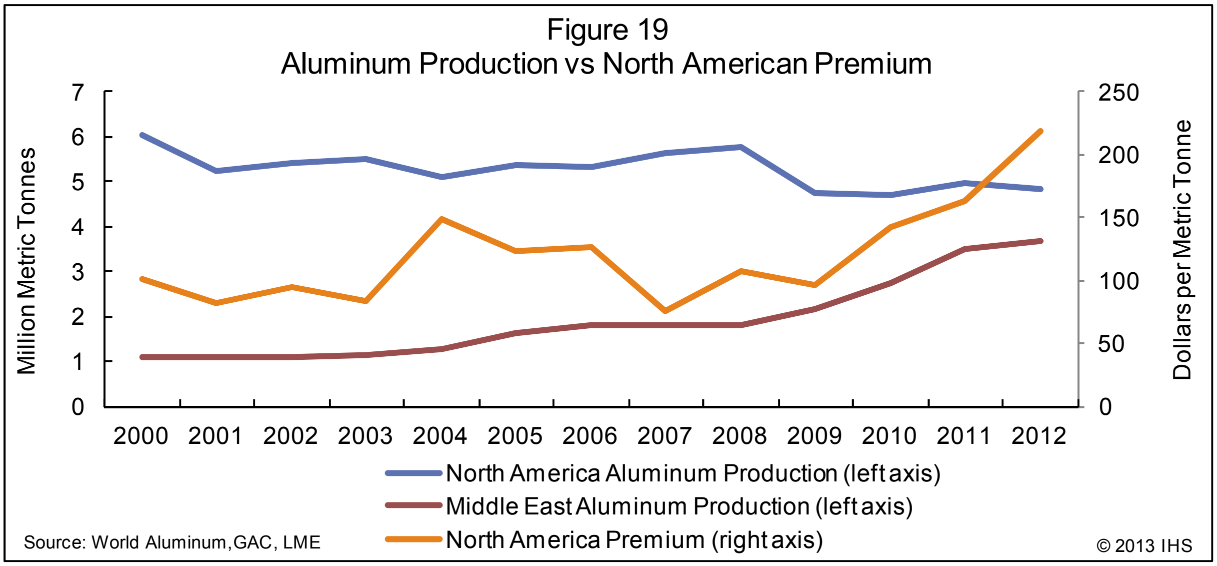
## PHYSICAL INDUSTRY

Aluminum is produced through the processing of bauxite ore which is obtained by mining. It takes about four tonnes of bauxite to produce one tonne of aluminum. Aluminum oxide (alumina) is refined from the bauxite ore as an intermediate processing step. Primary aluminum is produced by an alumina smelter through an electrolysis process that has a high consumption of electricity. The finished high purity aluminum is usually formed into bars or ingots for storage, transport and sale.

The aluminum industry has changed significantly over the last 40 years. In the 1970s, the major producers were highly vertically integrated in mining, refining, smelting and fabricated aluminum production with most of the primary aluminum production in major developed countries. Prices were driven by producers through changes in capacity utilization or inventory accumulation. This began to change near the end of the 1970s as the first aluminum contract was introduced on the LME in 1978. The establishment of an exchange-based pricing mechanism shifted pricing power from the integrated producers to the transparency of the exchange.

The geographic distribution of bauxite mining and aluminum production has shifted significantly over the years. The four largest countries producing bauxite are now Australia, Brazil, China and Indonesia accounting for over 70% of the market. A similar pattern is found in the alumina refining industry with China, the largest producer, along with Australia, Brazil and India having a combined share of over 70% of the market. Primary aluminum production costs are mainly influenced by energy costs for electricity consumed in the electrolysis process. Energy costs are typically one-third of the manufacturing cost of aluminum, including the cost of the bauxite raw material. Therefore, aluminum production has moved to areas with lower energy costs such as China, Russia, the Middle East and Canada. Over the past 10 years, China has emerged as the dominant player with around 40% of the market. The United States has dropped from producing over 30% of the total aluminum in the 1970s to less than 5% today, driven by the higher costs of electricity and labor, which together make up about 50% of the cost structure of producing aluminum. The high proportion of electricity in the cost of producing finished aluminum sets it apart from the other non-ferrous metals. Access to cheap energy, rather than proximity to demand centers, is often the driving factor for sources of production and supply. In the past 20 years, the market dynamics of production, trade and incremental supply have shifted as new smelters were constructed in response to the development of new low cost energy supplies. This can be seen in the construction of new smelters in inland China with access to large supplies of coal fired electricity and in the Middle East where aluminum is often viewed as a portfolio diversification strategy to the regions large hydrocarbon endowment. This shift in production capacity has altered the supply dynamics for several of the larger consuming regions including North America.

Ten years ago the marginal supply of aluminum into the U.S. was from smelters in Quebec taking advantage of the region’s large hydroelectric capacity. Since 2000, global demand has increased by 80%; during this period Canadian aluminum output has increased by only 20%, limited by the availability of new suitable hydroelectric locations. Over the same time frame, the energy-rich Middle East has increased aluminum output by over 300%, shifting a potential source of incremental supply to the opposite side of the Atlantic. This shift in supply has lengthened the supply chain to meet the last tonne of demand for U.S. aluminum consumers. On a macro level, this shift is beneficial to consumers due to the downward pressure on the price of aluminum (on a real basis) with marginal production replaced by more cost efficient modern capacity. However, the secondary effect is to widen the spread between the global benchmark aluminum price (the LME price) and the actual price for delivery in a given region (the regional premium). In simplified terms, the regional North American aluminum premium is now structurally higher versus the LME benchmark as the marginal supply chain has been extended from Quebec to the Middle East. The following figure illustrates the growth of new production from the Middle East and the North American premium as discussed above.




The global aluminum production industry is much less concentrated today than in the past. In the 1970s, the six majors had over 70% of the output. Today, this has been reduced to less than 40%. The pattern is similar for the bauxite mining and alumina industries. Many producers are not fully integrated in upstream and downstream operations as was more prevalent in the past.

Aluminum is transported in the form of bars or ingots by ship on waterborne routes or by rail and truck within land-only accessible regions. Aluminum is relatively easy and inexpensive to store and there are significant inventories stored in warehouses. Some warehouses are LME bonded, which means that the aluminum stored there must meet LME standards and be an LME approved brand.

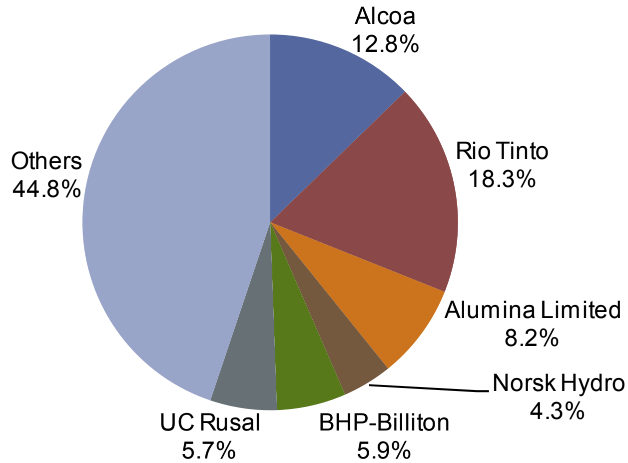
**Players**

The aluminum industry is made up of mining companies, bauxite refiners that produce alumina and aluminum smelters that produce primary aluminum. Some companies are vertically integrated in some or all of these functions. Companies downstream of these entities can produce many forms of aluminum products such as sheet, tubing, pipe, plate and beverage can stock. These functions can also be vertically integrated. Some of the major bauxite and alumina producers are:

- Alcoa (AWAC)[56]
- Rio Tinto Alcan
- Alumina Ltd. (AWAC)[56]
- Norsk Hydro
- BHP Billiton-bauxite
- UC Rusal
- Chinalco/Chalco
- Chiping/Xinfa-alumina

[56] Alcoa Worldwide Alumina and Chemicals is a joint venture between Alumina Ltd. (40%) and Alcoa (60%), the joint venture is involved in the mining of bauxite and alumina refining.

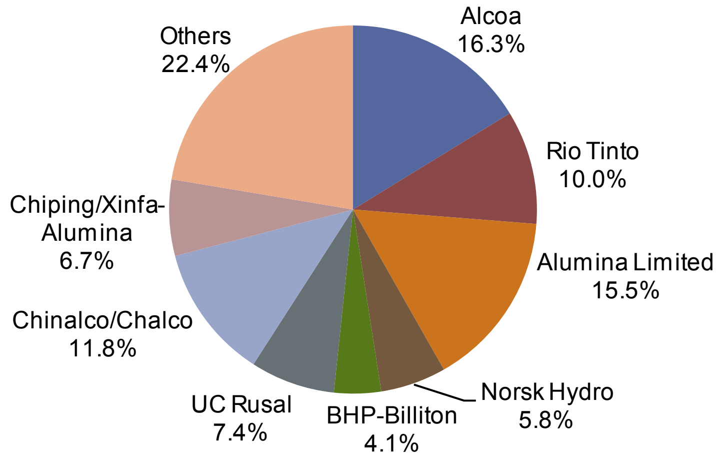
Figure 20
Bauxite Production Participants (2012)




Source: World-Aluminum website and individual company 10-K statements



Figure 21
Alumina Production Participants (2012)



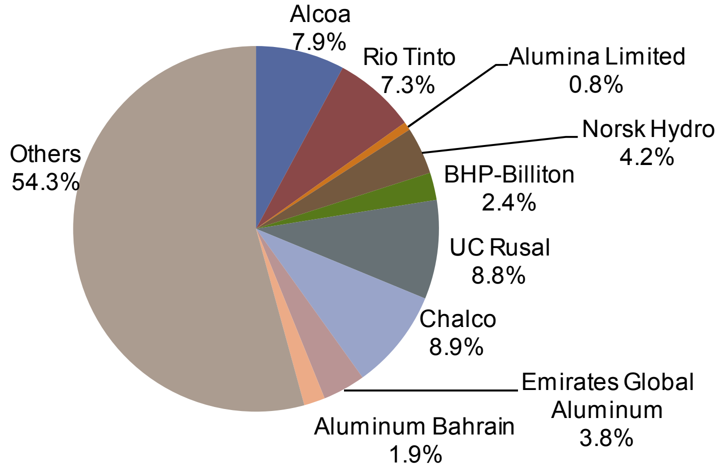

Source: World-Aluminum website and individual company 10-K statements



The production of aluminum is less concentrated, although major Chinese producers account for significant share when taken together. Major aluminum producers include the following:

- Alcoa
- Rio Tinto Alcan
- UC Rusal
- Norsk Hydro
- Chalco
- BHP Billiton
- Emirates Global Aluminum
- Aluminum Bahrain

Figure 22
Aluminum Production Participants (2012)




Source: World-Aluminum website and individual company 10-K statements



In each of the three figures above, a few companies have notable market share but clearly none have an overly dominant global position.

Other participants in the market are commodity trading firms and banking entities that take physical ownership of primary aluminum. The ownership of LME warehouses typically falls under one of three participant groups including banks, large trading firms, and independent storage operators. The largest owners of LME bonded warehouses include the following:

- J.P. Morgan
- Goldman Sachs
- Barclays
- Glencore Xstrata
- C. Steinweg
- CWT Commodities
- Trafigura
- Noble Trading

Consumers of aluminum are involved in the packaging, automotive and construction industries. Typical consumers of aluminum are as follows:

- Automobile manufacturers: aluminum content per car has doubled over the last 20 years
- Airplane manufacturers
- Beverage can makers: cans today contain mostly recycled aluminum
- Other food containers
- Structural building products, cladding, windows and door frames

## COMMODITY TRADE

Aluminum is freely traded on commodities markets such as the LME and the Shanghai Metal Exchange Market (SHFE). The LME is the major price setting market. Financial contracts on the exchanges allow all those along the metal supply chain, as well as investors, to hedge against or take on price risk. An exchange contract is standardized with the obligation to buy or sell a standard quantity of a specified asset (metal) on a set date at a fixed price, agreed upon today. The standard quantity of aluminum contracts on the LME is 25 metric tons.

The LME differs slightly from the other major commodities exchanges in several important ways. The settlement of traded contracts is not done on a cash basis as on the NYMEX, but in the form of a physical commodity receipt, represented by the establishment and transfer of ownership warrants. The LME contract is not structured to represent delivery of aluminum at a single fixed location (e.g. “FOB” or Freight on Board for a specific location), such as Cushing, Oklahoma, for U.S. light sweet crude and Erath, Louisiana, for Henry Hub natural gas. Instead, when purchasing aluminum on the LME the physical location of the aluminum can come from any one of the hundreds of LME bonded warehouses located around the globe. On the LME exchange, the operating practice leaves flexibility to the discretion of the seller on setting locational basis.[57] As such, taking physical delivery of the aluminum being purchased on the exchange involves either additional costs such as transportation, intermediate storage and handling, financing and insurance or a secondary market transaction to trade delivery locations.

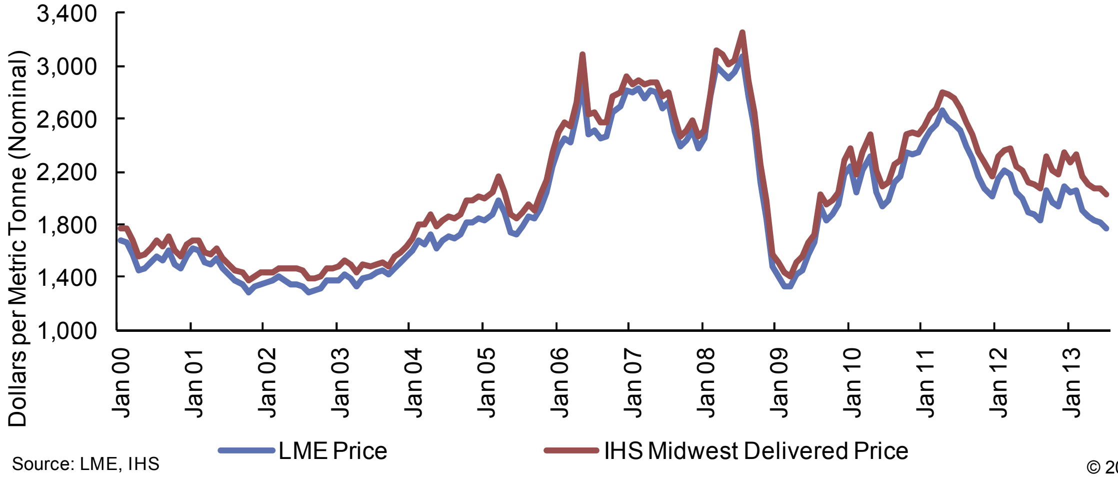
These incremental costs are reflected in the regional delivered price of the aluminum purchased. The difference between the LME benchmark cash price and the regional delivered price is known as the regional premium.[58] The key point is that the LME benchmark cash price is a reflection of global supply, demand, production costs and other macro fundamentals, while the premium reflects regional imbalances in production, demand, inventory and transportation costs. For example, from 2009 through 2012 the global surplus in primary aluminum exceeded 6 million metric tonnes providing downward pressure on the LME benchmark cash price, while the U.S. market was in supply and demand deficit by more than 11 million metric tonnes, helping drive the U.S. Midwest premium to levels last observed in the 1990s.

Most commodity markets work this way, establishing a central price and then assessing premiums or discounts to that reference price to account for quality differentials, transport costs and other individualized differences. For example, with crude oil, the NYMEX traded contract is backed by light sweet crude oil located in storage tankage at Cushing, Oklahoma. But there are no physical refineries located in Cushing, Oklahoma. The delivered cost to individual end user refineries will reflect the Cushing, Oklahoma spot price, plus the cost to move those crude oil barrels from the storage hub to individual refineries (including pipeline tariffs, insurance, additional intermediate storage and handling costs by third party intermediaries). Furthermore, things such as logistics bottlenecks, marine shipping costs, infrastructure disruptions, security premiums and geographic distance are all influencing factors in determining the price spread (or premium) between the commodities exchange benchmark price and the physical commodity delivered cost to end users.

[57] Metals Trading Handbook, p. 19-20.
[58] There are four major regional premiums, North America (U.S. Midwest), Europe (Rotterdam), SE Asia (Johor, Malaysia and Singapore) and NE Asia (Shanghai and Japan).

While the regional premiums for aluminum have increased, the absolute price of aluminum, both on an LME basis and at the delivery points commonly transacted by real world buyers and sellers, has declined since 2008 consistent with supply and demand fundamentals. The Midwest delivery price, used by key U.S. manufacturers, and the LME price is shown in the figure below.

Figure 23
Aluminum Prices




Source: LME, IHS

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## FINANCING ALUMINUM INVENTORIES

Aluminum production moves from producer to customer through long term contractual arrangements and sport transactions. The LME inventories and associated warehouses are generally viewed as the buyer of last resort by market participants. Over the past few years, aluminum inventories have increased markedly due to the convergence of four factors.

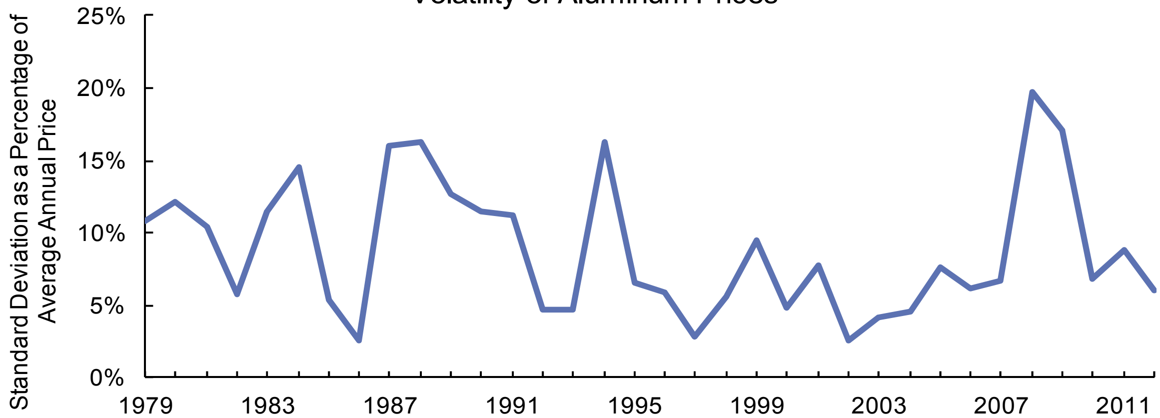
- An overcapacity of production following a cyclical drop in demand, as occurred during the 2008-2009 timeframe, punctuated by upheaval in the end use market which saw the bankruptcies of GM (a major consumer), the City of Detroit (a major hub), and Ormet (a producer) in the past five years;
- Strong contango market structure where future prices on exchanges are higher than current prices;
- Low interest rates; and
- Low storage costs—aluminum is relatively inexpensive to store compared to most commodities.

Given these four factors, market participants have been able to purchase production, finance its storage at low rates in anticipation of future demand and hedge the price risk in the future, thereby creating an “inventory arbitrage” where the risk is low and the return is known.

At a macro level, these banking and large trading entities are providing a service to producers by enabling production facilities to continue operating despite a significant slackening in demand, thus avoiding expensive shutdown and restart costs. Without this activity, production would be lower and additional capacity would be shuttered. When global economic activity increases, demand for aluminum will recover and interest rates will increase. These inventories will already be sitting in warehouses in usable form, benefiting consumers by tempering price increases. The incentives and benefits associated with providing financial inventory support are discussed in greater detail in Section II, Case Study: Non-Ferrous Market Support via Metals Inventory.

With the exception of the 2008-2009 financial crisis, when most markets were volatile, aluminum price volatility has been markedly lower since the banks entered the market in the early 1990s. The following figure illustrates the lower price volatility in the aluminum market in the time period after bank involvement in the market.

Figure 24
Volatility of Aluminum Prices




Source: London Metal Exchange (LME)

# APPENDIX B: HEDGING MECHANICS IN THE PHYSICAL MARKETS

Hedging encompasses a wide range of possible financial instruments, physical tactics and overall strategies. The concept of hedging is relatively simple; however, the implementation of even a basic hedging strategy becomes complex as physical cargoes and financial instruments flow over the hedging period. We provide examples of hedging below to illustrate business purpose, tactics and limitations. While these examples are for crude oil and refined products, they are equally applicable to other commodities.

## CRUDE OIL AND REFINED OIL PRODUCTS

While futures exchanges are necessary tools for commodity risk management, there are two reasons why end users prefer banks to manage their oil price risk rather than rely on exchanges: (1) the exchanges offer an important but limited range of products that typically do not precisely match the actual risk the users face; and (2) end users frequently do not have the credit capacity necessary to access the exchange-based products and the margining procedures on which the clearing houses depend.

## CONTRACTS OFFERED BY REGULATED EXCHANGES

The CME/NYMEX lists a very wide range of crude oil and refined oil product contracts. However, except for in the major benchmark grades, the liquidity available in these contracts is inadequate for all but the very smallest of users. This manifests itself in some cases in wide bid-offer spreads and, in other cases, in no volume being transacted for several days and contracts that report very low levels of open interest. So, although an apparently wide range of oil contracts is listed by regulated exchanges, end users seek market makers off exchange or OTC products to find counterparties who will take the other side of their deals. Most OTC contracts are settled outside the exchange and while there is a desire by some to move these deals onto the exchange and settle through the clearing house mechanism, the liquidity in all but the traditional benchmark contracts is quite low, therefore of limited use for physical users. Illiquidity may also present challenges for customers hoping to achieve hedge accounting standards.

## BASIS RISK

The nature and size of a basis risk is often misunderstood and under-appreciated. Using a fruit analogy, it is not simply that end users are forced to hedge the price risk of physical oranges with an exchange traded contract in apples. It may be that the end user has to hedge the basket price of oranges, lemons, and grapefruit for delivery in California tomorrow with a futures contract in apples for delivery in the Gulf Coast in two months' time. In other words, there is product, location and timing basis risk.[59]

Banks make markets to manage basis risk, but these risks do not disappear and still need to be managed. Exchange-based tools do not exist for the banks to manage basis risk. If they did, end users would be able to use them themselves and would not need the banks. Instead the banks manage the risk by taking physical delivery of the product and arranging blending, storage and transportation to minimize and dissipate the different types of basis risk.

[59] The difference between movements in the price of the underlying commodity and movements in the reference price of the hedge.

It is instructive to compare the list of crude oils and refined products provided by a Price Reporting Agency (PRAs), such as Platts, with the list of exchange traded contracts provided by CME/NYMEX. The Platts list of products is considerably more extensive and even so is nowhere near an exhaustive list of the crude oils and refined products that are actually traded in the market.[60]

## U.S. REFINER HEDGE EXAMPLE

A U.S. Gulf Coast refiner needs to secure a supply of crude oil feedstock for its refinery and enters into a spot contract with a West African producer. The refiner commits to buy a typical sized 1 million barrel cargo of Nigerian Bonny Light crude oil[61] with a scheduled loading date of January 15-17.

It will take approximately 15 days to ship the crude oil across the Atlantic and a further 15 days for the refiner to process the crude oil and sell the refined products. In addition, there is a multi-day period between when the crude contract is signed and the crude is loaded onto a ship in Africa.

As an ongoing business, the refinery seeks to achieve a positive net cash cost margin and sell the refined products at a price that at least covers the crude purchase price, trans-Atlantic freight cost, and refinery operating cost. The refinery is willing to take some margin risk but wants to hedge a portion of the crude and refined product price risk over the delivery and processing time. Rapid price movements of either crude or products during this 30-day period can adversely affect the refining margin. To secure its refining margin both the crude oil price and the refined product prices need to be fixed at the current positive market margin. Writing contracts at a fixed absolute price in physical contracts is atypical in the oil market. So the refiner seeks a hedge to manage risk.

This somewhat simplified example illustrates the risks that a refiner faces, which cannot be managed using regulated exchanges, and which requires the risk management services offered by banks.

### <u>Hedging a Crude Oil Purchase</u>

**First Risk (Price Risk)**

Physical crude oil is sold at a formula price that references a specific crude oil grade. It is extremely unusual to buy crude at a fixed price of $X/bbl. Instead, the contract prices the crude based on a formula that establishes the price at or near the loading date of the cargo in question, which is typically 15-45 days after the contract execution. This is referred to as the “floating price” since is moves with the market. In the case of Bonny Light, the crude oil price formula is expressed as the market price as quoted by a PRA, such as Platts, on a five day average after the bill of lading (B/L) date (the day the ship is loaded). The B/L is the document that is used to establish the applicable price for invoicing and taxation purposes for a crude oil producer.

The refiner, as mentioned above, wants to fix the price at which it buys the crude oil as a key component of its effort to lock in a refining margin. To protect the crude-side of the margin, on the day that that the physical crude contract is signed (15-45 days in advance of the scheduled loading date), the refiner will need to buy a crude oil hedge instrument at a fixed price. For illustrative purposes we will assume that the physical January 15-17, cargo purchase contract is agreed to on December 15. To complete the crude oil hedge, the refiner will then sell that same hedge instrument over the five days after the B/L date of the cargo, to offset the financial exposure represented by the

[60] Platts PRA provides crude oil price assessments for over 110 grades of crude oil versus the three grades covered by the commodities exchanges.
[61] The cost of the cargo is $100 million at a crude price of $100 per barrel.

physical five days purchase (the floating physical contract formula price). Using the financial instrument in combination with the physical contract, the refiner has effectively established a fixed crude oil price for the loading date 30 days hence from the contract execution, no matter how world crude oil prices change.

Now, let's examine the financial instruments involved. There is no regulated futures exchange contract in Bonny Light crude oil. There are only three benchmark grades of crude oil that have futures contracts with reasonable liquidity: WTI (U.S. Light Sweet crude oil), Brent and Oman. The benchmark grade that shows the closest correlation with Bonny Light is Brent. Both CME/NYMEX and the Intercontinental Exchange (ICE) list Brent contracts, but liquidity is considerably better on the ICE contract. In our example, the refiner hedges the crude cargo purchase by buying 1,000 ICE Brent futures contracts at a fixed price of $110/bbl, for example, on December 15.

**Second Risk (Timing Risk)**

The refiner now faces a timing basis risk exposure. To complete the hedge of the physical purchase the 1,000 lots of ICE Brent futures need to be sold on the five days after the B/L date. The B/L date of a cargo scheduled to load January 15-17 can vary, but is likely to be on or about January 18. So, the refiner will need to sell 200 lots of ICE Brent contract on each of the five days of January 19-23, i.e. the five days after the B/L date (ignoring weekends for simplicity's sake.)

Now let's consider the actual futures contract used to conduct this hedge. The ICE quotes contracts for each month. The ICE Brent contract expires on or about 15th of the month prior to the contract month. So on January 19-23, the "near month" ICE Brent contract will be the March contract. In order to fix the price of a physical *January* 15-17 delivery cargo purchase contract, the refiner will have to buy the futures *March* Brent contracts, because by the date the ship loads, the January and February futures contracts available at contract execution will have expired.

The real issue is that by purchasing the March ICE contracts when the physical contract was signed in mid-December, the refiner has taken on a timing basis risk. If the market "timing structure" shifts between December 15 when the hedge is purchased and January 19-23 when the hedge is sold, the refiner could lose the effectiveness of the hedge. Timing structure is the degree to which future prices vary from current "near month" and in this case, if the market shifts into steeper backwardation, the refinery will pay a higher price for the physical oil than the price at which it will be able to sell (i.e. cash settle) its March Brent contract hedges.

Fortunately, there is an OTC market in which this timing basis risk can be hedged. This is the dated-to-paper contract-for-difference (CFD) swap market (an OTC product). This is an actively traded market but participation is not widespread and is generally restricted to large oil companies, trading houses and banks. In the oil market, the term CFD is reserved for the particular swap in the differential between the price of Dated Brent and the price of the 25-Day BFOE forward Brent contract. Dated Brent refers to cargoes of Brent loading in the next rolling 10-25 days from the date of publication of the price. The term 25-Day BFOE refers to cargoes loading from 25 days forward from the date of publication of the price to about six months forward, quoted in monthly contracts.

The 25-day BFOE forward contract shows a close correlation with the ICE Brent futures contract because the latter is cash-settled by reference to the 25-day BFOE market. There is usually an exchange-for-physical (EFP) differential between the two of about $0.10-0.25/bbl. Nevertheless, the CFD is the best hedging instrument available to manage the price difference between Dated Brent and futures Brent. When the EFP differential gets too wide, the banks are active traders in the arbitrage between the forward and futures contracts helping maintain this spread at reasonably small levels. They do this by buying and selling 25-Day BFOE physical cargoes which are traded in lots of 600,000 barrels and which expire early in the contract month, and selling or buying the futures contract, which is traded in lots of 1,000 barrels, which expires midway through the month before the month of loading. This is a common example of convergence between physical and financial commodity instruments possible only with physical market participation.

Using the tight physical to financial tie in the Dated Brent market, the refiner can hedge timing risk by buying the CFD week represented by the January 19-23 date range at a fixed price of, say, $0.50/bbl, in this example. To achieve this, the refiner will cash settle by selling at the actual average price differential between Dated Brent and March delivery 25-Day BFOE Brent over the 5 days of January 19-23. By adding these two hedging steps (CFD and March Brent) together, the refiner has now effectively fixed the price of the cargo at $110+0.50=$110.50/bbl.

**Third Risk (Quality Basis Risk)**

The refiner has one additional basis risk to consider the difference in the price of physical Bonny Light crude oil and the price of Dated Brent crude oil, which has been used to hedge its physical Bonny light price risk. If the price of Bonny Light rises relative to that of Dated Brent between December 15, when the hedge is opened, and January 19-23, when the hedge is closed, the hedge will be less effective and the refinery will pay a higher price for the physical oil than the price at which it is able to sell (i.e. cash settle) its combined CFD/March Brent futures contract hedges.

There is no active market, regulated or OTC, in which the Bonny Light/Dated Brent price differential can be hedged. The refinery may be willing to retain this risk. Ideally, the physical contract pricing terms could be changed, but this simply transfers the risk to the producer, who is generally unwilling to take the risk and in our case, the formula is an official government formula applied to all producers equally. However, with intimate market knowledge and crude valuation theory, banks and others can manage this price differential risk by trading in physical Bonny Light and/or in the refined products that can be produced from it.

The market drivers for changes in Bonny Light/Dated Brent price differential are mostly related to the value of the products produced from the two different crude qualities. This is referred to as the Gross Product Worth (GPW). For example, the GPW of Bonny Light is calculated by summing the prices of each of the products that can be produced from Bonny Light multiplied by the quantity of that product.

$GPW_{\text{Bonny Light}}$ = (Quantity of Product 1 x Price of Product 1) + (Quantity of Product 2 x Price of Product 2) + (Quantity of Product 3 x Price of Product 3), etc.

This market price differential will necessarily have more basis risk but can still be useful, particularly when considering crude oils with large quality (and price) differences, like the heavy sour crude grades often processed by U.S. refiners in the Gulf Coast refining system. In the absence of an exchange or OTC traded contract for this quality basis risk, the refiner may use a bank market maker to fix the Bonny Light/Dated Brent price differential. It may manage to fix this differential at an attractive level on December 15, at +$1/bbl, for example. This protects the refiner against a widening of the differential between December 15 when the physical purchase decision was made and January 19-23 when the price formula under the physical contract is calculated by reference to Platts.

The analysis above of the refiner's attempts to "lock in" the refining margin has focused on hedging the price that the refiner must pay to buy the Bonny Light crude oil feedstock. By a combination of hedging with futures, buying CFD in the OTC market and using a market maker to handle quality basis risk, the refiner has more or less managed to fix the purchase price of its Bonny Light feedstock at $110 + 0.50 + 1/bbl = $111.50/bbl.

**Hedging a Refined Product Sale**

But the refiner must also protect the sales price of the refined products that will be produced from the refinery one month later (allowing for shipping time and time to transit the refinery) to secure its margin (and profit). The formula price under which the refiner sells its physical products will depend on the refinery's logistics and whether the refiner sells into the seagoing or barge market or into, as an example, the Colonial Pipeline.

The futures exchanges offer a range of U.S. product contracts, many of which are illiquid and show a wide bid-offer spread and a large EFP differential. The prices of many more products are published by PRAs and in the case of refined products in the U.S., the dominant PRAs to which physical contract price formula refer are Argus Media and Platts.

**Crack Spreads**

In our example, the refiner could try to hedge the product pricing by using a standard contract like a crack spread. These crack spread contracts are generic and do not reflect the GPW of any particular refinery. Crack spreads are generally expressed as a ratio, such as A:B, A:B:C or A:B:C:D where:

- A represents the number of barrels of crude oil purchased
- B represents the number of barrels of gasoline sold
- C represents the number of barrels of ultra low sulfur diesel (ULSD) sold
- D represents the number of barrels of fuel oil sold

The most widely used cracked spreads are the:

- 3:2:1. This means that for every 3 barrels of crude purchased, 2 barrels of gasoline and 1 barrel of ULSD are sold
- 5:3:2. This means that for every 5 barrels of crude purchased, 3 barrels of gasoline and 2 barrel of ULSD are sold
- 2:1:1. This means that for every 2 barrels of crude purchased, 1 barrel of gasoline and 1 barrel of ULSD is sold

These exchange traded crack spreads are not only illiquid, they constitute a very poor reflection of the actual price risk faced by an individual refiner. Banks offer more highly tailored crack spreads. For example, a refinery that processes a very heavy grade of crude oil and which has some upgrading capability may seek something more like a 6:3:2:1 crack spread (where the "1" adds residual fuel oil product). The more highly tailored a crack spread the less easy it is to trade. Banks overcome this challenge by unbundling the components of the crack and hedging them separately both on exchange and off exchange using physical refined product contracts.

**Hedging Summary**

Our example refiner has managed through combining a number of exchange trades, OTC contracts and bank help to provide a reasonable refining margin hedge on a single cargo of crude oil. Without these instruments the refiner's operating profit is largely unknown and uncontrollable for an extended period of time. In this example, we have broken down the major contracts and steps involved but in practice, a small or medium sized refiner does not have the capability to complete and manage these transactions and will engage a bank to advise with this hedge and perform the services above described.

**Financing the Hedger**

This brings us to the other role of the banks in the oil market, financing the operations of small producers and refiners. A producer requires payment for crude oil on or about 30 days after the B/L date. The refiner may not be paid for the products for a further 10-30 days after that, depending on how and when the products are delivered. Small refiners often bridge that financing gap using a bank that may require taking physical delivery of the products to sell on its own account in order to safeguard itself against default by the refiner. Without the credit security of taking title to the physical products, lending to a cash-strapped refinery can be a risky proposition for a bank. Without physical security the bank would otherwise have to charge a high rate of interest to assume that type of risk.

The role of the banks in financing hedges is paramount. If the refiner we have used in our Bonny Light example uses a futures exchange to carry out its hedges, it has to have ready access to substantial amounts of cash to meet its margin calls. As discussed above, this particular refiner would probably have to use the ICE Brent contract to hedge its physical crude price risk. Since it is based in the U.S., the best available futures contracts to hedge its products sales price would be CME/NYMEX. Hence, it has to find two sets of initial and variation margins to hedge its long position on ICE and its short position on CME/NYMEX.

If it tried to reduce its margin exposure by placing all its hedges, both long and short, on CME/NYMEX, it would first have to bear the low liquidity cost of the CME/NYMEX Brent contract; but secondly, it would still have to bear full margin payments for the period of time when the long crude oil hedges are closed (January 19-23) and the time when the short refined product hedges are closed perhaps 10-15 days later, depending on the precise sales price formula under its physical product sales contracts.

Banks are able to take a comprehensive approach to the margining of producers' and refiners' hedges. A clearing house backing an exchange sees only the long or short positions held by the hedger on its exchange. It does not see the physical underlying contract that is being hedged. It assesses the riskiness of a long or short position without the context of the physical offset that significantly reduces the hedger's overall risk. But a bank doing the same business OTC with the refiner can not only see the hedges, but the existence and pricing of the underlying crude and products being hedged, and has more accurate parameters to feed into its risk assessment calculation. This reduces the margining required from the refiner and may eliminate it altogether if the hedger uses the same bank for both the financing and related hedging.

# APPENDIX C: BIOGRAPHIES

This IHS report draws on the multidisciplinary expertise of IHS Inc.

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## APPENDIX D: GLOSSARY

**Arbitrage:** The practice of taking advantage of a price difference between two or more markets—striking a combination of matching deals that capitalize upon a price imbalance, the profit being the difference between the market prices. An arbitrage transaction offers the possibility of virtually risk-free profit. For instance, an arbitrage is present when there is the opportunity to instantaneously buy low and sell high (across two markets).

**B/D:** Standard daily measurement of oil. Barrels per day. One barrel equals 42 U.S. gallons.

**BCF/D:** Standard volumetric measurement unit for natural gas. Billion cubic feet of gas per day.

**BFOE:** North Sea Crude oil contract. Stands for Brent, Forties, Oseberg and Ekofisk crude oil grades.

**Backwardation:** A situation where the price of a commodity for delivery in the future is lower than the price for immediate delivery. Opposite of contango.

**Basis Risk:** The difference between movements in the price of the underlying commodity and movements in the reference price of the hedge.

**Benchmark Prices:** An objective and transparent reference price for a commodity (e.g. WTI crude oil), which includes specification of product grade and point of delivery.

**Cpg:** U.S. cents per gallon.

**Clearing House:** An institution that provides settlement services for financial and commodities derivatives and securities transactions. These transactions may be executed on a futures exchange or securities exchange, as well as off-exchange in the OTC market. A clearing house stands between two clearing firms (also known as member firms or clearing participants) and its purpose is to reduce the risk of one (or more) clearing firm failing to honor its trade settlement obligations. A clearing house reduces the settlement risks by netting offsetting transactions between multiple counterparties, by requiring collateral deposits (also called "margin deposits"), by providing independent valuation of trades and collateral, by monitoring the credit worthiness of the clearing firms, and in many cases, by providing a guarantee fund that can be used to cover losses that exceed a defaulting clearing firm's collateral on deposit.

**Contango:** A situation where the price of a commodity for delivery in the future is higher than the price for immediate delivery. Opposite of backwardation.

**Credit Extension:** To lend money (either by extending cash funds or by waiving a need to remit cash funds) on the basis of the strength or quality of the risk of a counterparty, the value of expected associated future cash flows, or the value of an underlying asset posted as collateral to secure the transaction.

**Flat Price Risk:** Risk posed by changes in underlying commodity price.

**Forward Spread:** Price difference between spot price and next month forward price. Typically defined as Month 1 vs. Month 2 on futures commodity exchange. A positive forward spread occurs in a backwardated market and negative spread in contango market.

**Futures Contract:** A standardized contract, offered by an exchange or clearing house with a standard set of terms and conditions, to buy or sell a predetermined volume of an asset (often a commodity) at a predetermined price and location, on some established date in the future.

**Futures Market:** The market for a good expressed in terms of future delivery. Exchanges such as the Chicago Board of Trade (CBOT) act as a platform of standardized contracts for future delivery of commodities.

**Hedge:** A transaction that insulates the party from risk of a movement in an asset's price, by offering an offsetting risk of price movement in the opposite direction for the same good. The counterparty might be an exchange or clearing house in the case of standard exchange traded hedge products, or a bank in the case of a tailored OTC market solution.

**kWh:** Standard measurement of electric power. Kilowatt-hour.

**Long Position:** A financial position with the expectation that the underlying asset will rise in value.

**MMBTU:** Standard heat content measurement unit for natural gas. Million British Thermal Units.

**Market Liquidity:** The presence of a sufficient volume of open buyers and sellers to enable willing counterparties to trade with minimal price disturbance. This results in relatively efficient markets as measured by the difference in open bids and offers for a given product (bids-ask spreads). Market liquidity is often measured in average daily trading volume.

**Market (Price) Discipline:** Buyers and sellers in a market are said to be constrained by market discipline in setting prices because they have strong incentives to maximize profit and avoid bankruptcy. This means, in order to meet economic necessity, buyers must avoid prices that will drive them into bankruptcy and sellers must find prices that will maximize profit (or suffer the same fate).

**Over-the-Counter Contract:** A contract, typically offered privately by a bank or trader, to buy or sell a predetermined volume of an asset (often a commodity) that has the potential to be tailored in terms of product, grade, volume, price, tenor and point of delivery.

**Play:** A group of fields and or potential fields that have similar geologic characteristics. Exploration methodology and production is generally similar and shared.

**Price Convergence:** When two prices for a product, most often in two different forms or locations, move closer together over time. Generally refers to convergence between a futures price and underlying cash price for a commodity.

**Public Exchanges:** Public exchanges are trading venues open to all interested parties (many sellers and many buyers) that use a common technology platform and that are usually run by third parties. Public exchanges support trading activities in a wide range of commodities.

**Short Position:** A financial position with the expectation that the underlying asset will decline in value.

**Spot Market:** The market for a good with immediate delivery. Also referred to as the cash market.

**Standardized Contract:** The commercial terms that govern OTC contracts and futures contracts tend to be standardized. For example, most OTC swaps are executed under common ISDA (International Swap Dealers Association) contract. Similarly, futures contracts, even on different exchanges, tend to be governed by a standardized set of commercial terms.

**Volumetric Production Payment (VPP):** An extension of credit where resource producers agree to deliver a certain amount of production over a set period of time (e.g. forward sale of production), ranging from 5-15 years. Banks pay a fixed price, as a lump-sum cash payment in advance. The seller is responsible for delivering gas up to the agreed upon amount and the operating cost to produce gas. The collateral to this transaction is the physical delivery of future production.