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Midstream Master Limited Partnerships

Foreword

This report was prepared by Tom Miesner of Miesner, LLC based on his years of experience in the U.S. Midstream industry, supplemented by several reports downloaded from the National Association of Publicly Traded Limited Partnerships http://www.naptp.org/ and various reports from the U. S. Energy Information Administration and other sources. Those documents are listed in the Bibliography section of this report.

Introduction

The popularity of Master Limited Partnerships (MLPS) grew from tax legislation enacted in the mid 1980's and has grown since that time. According to the National Association of Publicly Traded Limited Partnerships web site there are over 100 MLPs on the market, the majority in industries related to energy and natural resources.

The types of midstream assets in MLPs which are addressed in the report include the following:

- Natural Gas Gathering Lines and Crude Oil Gathering Lines and Trucking
- Natural Gas Treating and Dehydration
- Natural Gas Processing Plants
- Natural Gas Liquids Fractionation Plants
- Natural Gas Compression
- Interstate and Intrastate Natural Gas Pipelines
- Natural Gas Storage
- Crude Oil Trunk or Main Lines
- Crude Oil Storage Terminals

Each of these midstream MLP sectors are addressed in this report sequentially.

Many MLPs participate in more than one of these sectors. Consequently finding "pure sector plays" is difficult. This text deals with the various MLPs on a US wide basis. In most cases the MLPS discussed are very dependent on oil and natural gas production volumes which can vary significantly based on regional drilling and production economics. Consequently, prior to making an investment in a specific MLP, an analysis of the specific regions in which that MLP operates is required.

Natural Gas Gathering Lines, Crude Oil Gathering Lines and Trucking

Gathering lines begin at the production processing pad where well flow lines end and separation equipment separates the production stream from the well into crude oil, the raw natural gas stream[1], water, and various impurities. The gathering lines extend to processing plants or transmission lines in the case of natural gas gathering lines. Depending on the amount of water vapor, carbon dioxide (CO2), and hydrogen sulfide (H2S) contained in the raw natural gas stream, the stream may be dehydrated and treated as it moves along the gathering system before it reaches the natural gas processing plant.

Crude oil in typically not treated and then gathering lines extend from the production processing pad to crude oil main[2] or trunk lines. Gathering lines are normally in the range of 2 to 8 inches in diameter and generally operate at relatively low (less than 150 psi) pressure.

In the case of crude oil, the oil may be collected from the production tank battery by tank trucks and hauled to either gathering lines or gathering stations which feed into main or trunk lines. Many natural gas and crude oil gatherers also have positions in the natural gas treating, transmission, and processing segments as well as crude oil trucking and main line businesses.

Industry/sector drivers.

Throughput on gathering pipelines and on trucks is dependent on regional drilling activity by E&P producers. Discovering how to produce oil and gas from the source rock versus the reservoir rock, has driven a resurgence of natural gas and crude oil production in production areas such as the Bakken, Eagle Ford, Marcellus, Austin Chalk and others. This increased production and the need to move the oil and gas to market is driving construction of new gathering lines.

Revenue drivers

Gathering, including crude oil trucking, is a fee-based activity, as revenue is generated based on a fee per unit (Mcf) of natural gas or barrel (Bbl) of crude oil gathered. Since this activity is volume based, revenue is dependent upon the pace of drilling activity, amount of production, and the amount of competition, within the company's gathering footprint. Gathering companies must be able to convince oil and gas producers and purchasers to utilize their gathering lines rather than lines owned by another party. Once a gathering pipeline is extended into a production area it presents an economic barrier to entry to other gatherers who would have to spend the capital to construct a competing line. The incremental cost of transportation once a line is constructed is relatively low meaning each additional Mcf or Bbl contributes directly to the bottom line.

Crude oil gathering and trucking companies sometime made money in addition to the fees they charge be blending crude oil of various qualities. Crude oil is traditionally priced based on the gravity (density) and sulfur content. Blending various types of crude oil together can result in a crude oil which is higher priced (but not really more valuable) than its constituent parts. Crude

[1] The term raw natural gas stream refers to the gas stream prior to the point is has been processed to extract natural gas liquids including ethane, propane, butane, and heavier hydrocarbons.

[2] In the US, the natural gas industry tends to call the larger, longer distance pipelines transmission lines, while in the crude oil and refined products pipeline industries the lines which provide this same function tend to be called main or trunk lines.

oil blenders collect the upgrade but this is a practice frowned on by the refiners who do not actually reap the value for which they pay.

Risks

Any reduction in volume results in loss of revenue so the risk of others connecting new producing wells to competing gathering systems or losing connections are key risks. Another risk is the price of crude oil and natural gas as they affect drilling economics. Generally speaking, lower prices mean less drilling and less new volumes. Other risks include rising raw material and labor costs, a material change in regulatory requirements or standards for the system's geographic location, and an overbuild of U.S. energy infrastructure. When crude oil quality deteriorates, Crude oil gatherers who blend crude oil run the risk that crude oil purchasers may "work back through the system" to discover where the quality degradation is occurring. This can result in a blender being forced to stop blending and suffer the loss of revenue from the upgrades.

Natural Gas Treating and Dehydration

Some raw natural gas streams contain contaminants which must be removed prior to delivery to gas transmission lines. Contaminants typically found within the natural gas stream include water vapor, carbon dioxide (CO_2), and hydrogen sulfide (H_2S). In order to comply with downstream pipeline and end-user quality specifications, natural gas may need to be dehydrated (to remove saturated water) and chemically treated to extract contaminants (e.g., CO_2 and H_2S). Natural gas that is saturated with water can form ice that can obstruct parts of a pipeline system. In addition, water can cause pipeline corrosion when combined with CO_2 and H_2S. Natural gas with high levels of CO_2 and H_2S can also harm pipelines and could result in a failure to meet end-user requirements. The amine treating process involves a continuous circulation of amines as the chemical is attracted to CO_2 and H_2S. The impurities are absorbed from the natural gas stream by the amines as they come into contact with each other. The amines are then removed from the natural gas stream, resulting in pipeline quality gas. The amines are then regenerated via a heating process which removes the CO_2 and H_2S.

Industry and sector drivers

Dehydration and treating is fee based and as such depends on the amount of natural gas produced in a production area and the amount of contaminants contained in the raw gas stream. So, like gathering, the ability to produce from the source rather than the reservoir rock is driving increased gas production which, depending on the quality of gas produced may require increased treating. Unlike gathering lines which are buried, treating units are above ground and can be built on skids in a modular fashion so they can be moved from area to area as conditions change which lowers the capital risk.

Revenue drivers

The treating businesses generate 100% fee-based revenue. MLPs typically utilize three types of contracts in the treating business, which includes the following:

- a volumetric fee-based contract based on the amount of gas treated,

- a fixed fee monthly operating fee, or
- a fixed monthly rental fee.

Additional volumes moving on connected gathering lines can drive revenue growth. Likewise a reduction in treated volumes results in less revenue.

Risks

The primary risk for MLPs with treating assets is a declining natural gas volumes resulting in less revenue. As treating rates are not regulated, the economic regulatory risk for treating and dehydration MLPs is limited. Expansion of treating into new fields depends largely on the CO2 and H2S levels contained in the natural gas stream from the particular field. Treating and dehydration rates are not regulated. Therefore, in times of high demand rates can be raised. In times of low demand the opposite is true. Of course producers must be able to get their volumes to the plant so plants already situated in the area present a barrier to entry to new plants. As with the gathering sector, other risks include rising raw material and labor costs. Additionally, a material change in environmental regulatory requirements or standards for the system's geographic location or changes in connecting pipeline quality standards are risks as well.

Compression

As the gas stream moves along the pipeline it loses pressure due to friction between the molecules and between the molecules and the wall. Compressors are placed at the beginning of the line and about every 50 to 100 miles along the line to add pressure back to keep the gas moving along. Some MLPs essentially rent compression capacity either on an unmaintained or on a maintained basis. Compression is often applied in the following locations:

- at the wellhead,
- throughout gathering the systems,
- into and out of processing and storage facilities, and
- along intrastate and interstate pipelines.

Not all compression is leased or rented. Typically pipelines which operate ratably have permanent compression installed along the line which they own themselves. Rented or leased compression tends to be supplied in areas when the compression needs vary – more likely in gathering systems and into and out of processing facilities.

Industry and sector drivers

Compressor needs are driven by the amount of gas which needs to move through the pipeline and the reservoir pressure of the well. The ability to rent or lease compression to meet needs can reduce capital requirements and provide operating flexibility. As more gas wells are drilled in a production area more compression is typically needed. As well production declines compression needs decrease. As such, the amount of gas which needs to move is the largest driver of compression needs.

Compressor utilization also depends on the producers' views on outsourcing. Many producers choose to outsource their compression requirements, as the purchase of compression units could be a significant capital investment. Operators would be required to modify and replace compressors to retain efficiency, as well, and pipeline pressures change over time. By outsourcing their compression needs, producers are able to deploy their capital on investments related to their primary business (e.g., development of reserves).

Revenue drivers

Compression revenue is driven by the amount of operating horsepower (HP utilization rate) and the rate per HP charged to the customer. Compression MLPs typically generate revenue from a fixed, monthly fee per HP for compression services and may be incentivized to minimize the amount of downtime on the compressor units. These partnerships realize stable, fee-based cash-flow even during periods of limited or disrupted production.

Risks

A decline in natural gas production would negatively affect demand for compression services. In addition, producers' efforts to lower their operating costs in a low natural gas price environment could result in a higher return rate for third-party compressor units. Compression rates are not regulated. Therefore, in times of high demand rates can be raised. In times of low demand the opposite is true. When rentals are on an operated basis, that is the compression provider also operates the compressors, the operator assumes the risks associated with labor and other operating costs.

Natural Gas Processing

As it enters inter and intrastate transmission pipelines, the natural gas stream consists primarily of methane molecules. The raw natural gas stream from the production area, however, normally contains natural gas liquids (NGLs) – ethane, propane, butane, and heavier hydrocarbons which must be removed from the stream in order for the stream to meet pipeline quality specifications. These NGLs are removed from the stream by natural gas processing plants. The NGLs which are removed may be further separated into the constituent molecules, ethane, propane, butane, isobutene, and heavier hydrocarbons at the gas processing plant through a process called fractionation, or they can be shipped on pipeline to a fractionator. The pipelines through which they move are commonly called NGL lines, mix lines, or Y-grade lines.

Industry and sector drivers

NGLs are generally valued relative to the price of liquids – crude oil and refined products – rather than relative to the price of natural gas. Consequently, when the spread between natural gas and crude oil is wide, significant economics exist to extract the liquids. So, producing "wet gas" results in more value than producing "dry gas". Accordingly, natural gas producers attempt to find and produce NGL rich, rather than NGL lean, gas. The current significant spread between the price of natural gas and crude oil means there are significant economics to extract the greatest percentage of NGL in the stream possible. Increasing natural gas production is driving the need for new gas processing plants as well as expansions to existing natural gas processing plants.

Revenue Drivers

Natural gas processors normally generate earnings under the three following basic types of processing arrangements:

- Keep whole – The processor processes the natural gas, sells the NGL, and keeps the full proceeds from the sale of the NGLs. Removing the NLGs reduces the BTU content of the stream, so the processor "keeps the producer whole" by giving the producers additional natural gas volumes such that the total BTUs returned to the producer in the dry natural gas are equal to the total BTUs contained in the wet gas stream prior to processing.
- Percentage of proceeds/index/liquids – Natural gas is processed for the producers. The gas processor sells the resulting pipeline quality gas and the NGLs and pays the producer an agreed upon percentage of the proceeds (PIOP) based on an index price. In the case of percentage of proceeds contracts, both the producer and processor benefit from higher natural gas and NGL prices. A percentage-of-liquids (POL) contract is a type of POP contract where the processor receives a percentage of the NGLs only with the natural gas producer receiving back the gas and part of the NGLs.
- Fee-based – A fixed fee is charged for the volume of natural gas that flows through the processing plant. Consequently, Revenue is directly dependent and proportional to the volumes processed, independent of the price of the gas of the NGLs.

Each of these contracting formats has its own risks and benefits.

Risks

The amount of volumes which are processed is a key determiner of natural gas processing profitability. Volume reductions, regardless of the cause are a key risk. Volumes reductions can result as a consequence of lower natural gas pricing which reduce the incentive to produce. It can also result from natural volume declines in mature producing areas. Each of the type of processing contracts has its own risks. The fixed fee contract has the lowest risk but also has the lowest upside. POP contracts are next in line in terms of risk. As revenue depends on commodity pricing, when natural gas, and/or NGL pricing declines the processor receives less revenue. Natural gas processing rates are not regulated. Therefore, in times of high demand rates can be raised. In times of low demand the opposite is true. Finally, keep whole risk comes when natural gas prices increase faster than NGL prices.

Natural Gas Liquids Fractionation

After the NGLs are separated from the natural gas stream they must be separated into their constituent parts such as ethane, propane, butane, iso-butane, and heavier hydrocarbons. This process is generally called fractionation and is accomplished by fractionators. Fractionation use difference in pressure and temperature to, one at a time, reduce one type of molecule to a liquids when the others remain in gaseous form in a tower. The liquid is withdrawn from the bottom of the tower and the components still in gaseous form are withdrawn from the top of the tower. The various components are used as chemical feedstocks, fuel, and blending components in the fuel market. Ethane for example can be cracked to produce ethylene, which can be directly polymerized to produce polyethylene, the world's most widely used plastic. Other feedstocks such as heavy naphta and vacuum gas oils which are produced by refineries which can also be cracked to produce ethylene compete with ethane. Propane can be cracked to produce propylene or it can be used for fuel such as home heating in areas not served by natural gas. The most familiar use is as a fuel for home grilling. Butane is used to produce butylene, and is also used extensively in refineries for fuel blending. As such, any fractionation contracts which are based on selling the constituent NGLs is very sensitive to the strength of the chemical market and fuels markets which in turn depend to a large extent on the state of the economy.

The largest amount of NGL fractionation in the world is located on the US Gulf Coast in or near Mount Beliveu, Texas. Consequently, a number of mixed NGL lines or Y grade lines terminate on the Gulf Coast.

Revenue Drivers

As with natural gas processing plants, the key drivers of profitability for fractionators are rates and volumes. While there may be other forms of contracts, fractionation is typically charge on a fixed fee per unit plus some sort of escalator, the PPI, for example, annually. This means that once negotiated the price or rate risk is small. Volumes depend on the amount of gas being produced in an area, and the NGL content of the production stream. As the natural gas production profile in the US evolves with shale and other unconventional gas production a key question is whether new NGL pipelines will be built to existing Fractionation plant or whether new fractionation plants will be built near the production field.

Risks

The primary risk for fractionators is declines in volumes which are processed through the plant. Volume reductions can be caused be several factors including a reduction in the price of ethane either because of reductions in ethylene production or reductions in the price of other ethylene feedstocks such as heavy naphtha and vacuum gas oils. When the price of ethane falls, leaving a larger proportion of the ethane in the methane stream may be profitable which means the ethane is not withdraw to NGLs and consequently the total NGL stream available for fractionation decreases. Fractionation rates are not regulated. Therefore, in times of high demand rates can be raised. In times of low demand the opposite is true.

Natural Gas Transmission Pipelines

Interstate natural gas pipelines economic and shipper matters in the US are regulated by the Federal Energy Regulatory Commission (FERC). Intrastate natural pipelines are regulated by state and local agencies depending on the particular laws and regulations of the state. Inter and intra state natural gas pipelines both receive natural gas from gathering systems gas processing plants, and other pipelines, and deliver it to the end user – primarily large industrial users, power plants, and local distribution companies. Along the way, the pipelines may deliver volumes to or receive volumes from storage and other natural gas transmission pipelines. The interconnections between pipelines are referred to as interchange facilities or hubs. Interchange facilities generally consist of two or three pipeline connecting to each other whereas hubs normally consist of many pipelines which interconnect to each other. Since the physical molecules can move between many pipelines at hubs, hubs function as market clearing centers and natural gas contracts are priced against individual hubs, for example the Henry hub in Henry Louisiana.

Industry and sector drivers

Natural transmission pipelines contract with shippers to move natural gas from point to point for the shipper. For this transportation service, they charge various rates which are published in a document called a tariff. There are a variety of tariff types. Two of the primary types of tariffs are firm and interruptible. These mean exactly what the term implies. When a shipper contracts for firm transportation, the shipper promises to deliver and receive a fixed amount of gas and the pipeline company promises to have enough capacity to move that amount of gas. The shipper pays regardless of whether or not they actually move the gas. In the case of interruptible rates (which are nearly always lower than firm rates) the shipper promises to move the gas if there is space on the pipeline. The shipper is not obligated to ship the gas however and the pipeline can refuse shipment when they do not have sufficient available capacity. Since natural gas is highly compressible it is possible to receive more volumes into the pipeline than are delivered out. This is called packing the line. It is also possible to deliver more from the line than is received into it which is called unpacking the line. Neither of these phenomena can continue long term but “parking” excess gas short term by packing the line and “loaning” gas short term by unpacking the line over the short term is a valuable service to the shippers and the transmission pipelines often charge for parking or loaning gas. There are a variety of other types of rates as well.

Revenue drivers

The revenue drivers for natural gas transmission lines are volumes and rates. Volumes move under contracts of varying lengths with some contracts providing for firm, and others interruptible, service. Many new pipelines are backed by long-term contracts providing for firm service. Natural gas transmission pipelines are highly capital intensive and the incremental cost to transport is usually relatively low. Consequently, a relatively small reduction in volumes can have a significant impact on the bottom line. Many natural gas pipe rates are established using a “Cost of Service” (COS) approach. COS rates provide for a return on the invested capital plus recovery of operating expenses. The COS process is regulated by the FERC. In some cases the markets served are deemed competitive and the FERC approves the pipeline to charge market based rates. Pipelines are also allowed to discount rates from the maximum established rates and may do so to attract business. The FERC also normally approves rates which are negotiated at arm’s length between a shipper and the pipeline company.

Most natural gas transportation service agreements are structured to allow the pipeline operator to retain a small portion of the gas shipped to use as fuel. Depending on the particulars of the contract, pipeline operators may be able to generate incremental earnings if they can use less fuel than they are allowed to retain. On the supply side, the current boom in shale and other nonconventional natural gas production is providing an opportunity for construction of new lines and increasing the capacity of existing lines. On the demand side, the growing natural gas power generation industry is providing opportunities for construction of new delivery lines to power generation facilities.

Risks

Revenue risks center around reductions in volumes and rates. Volume risks can be either wide spread such a slowdown in national economic activity, or regional such as a regional slowdown. Additionally, volume reductions can occur because volumes move from one source to another or from one pipeline to another. Over the past 30 or so years the FERC has worked to increase competition in the natural gas transportation market which has driven an increased number of interconnects and has provided shippers more flexibility which in turn has required the natural gas transmission business to become more market focused. FERC regulates natural gas rates as well and, while the FERC traditionally does not require pipeline companies to lower rates, raising rates can be difficult as it involves a public filing process which provides shippers the right to protest rate hikes. Additional risks include rising raw material and labor costs, an overbuild of U.S. energy infrastructure and a decline in commodity prices (resulting in a decline in drilling activity).

Natural Gas Storage

Natural gas storage assets (depleted reservoirs, caverns, aquifers, and above ground LNG storage are regulated by the FERC. Natural gas production is relatively constant over the day and over the year, but natural gas usage varies seasonally and during the day making both short and long term storage critical. It acts as the balancing mechanism or buffer to balance supply and demand. Customers for natural gas storage include financial institutions, producers, marketers, utilities, pipelines, and municipalities.

Industry and sector drivers

Natural gas volumes are produced relatively constantly over the year, but the consumption of natural gas varies significantly from season to season, within a season, or even within a day, depending on weather conditions. This variability is what drives the natural gas storage industry. Natural gas is stored in depleted natural gas production reservoirs, caverns, aquifers, and above ground steel storage (in a liquefied state). Storage characteristics determine the rate at which natural gas can be injected into or withdrawn from storage. Generally speaking storage used to meet inter-seasonal storage requirements can be filled and emptied slowly. Storage used to meet intra-day variability must be able to deliver the volumes needed at the rate they are required. For example, in the winter natural gas demand ramps up quickly in the morning as people wake and prepare for work. In the summer, intra-day demand generally peaks in the afternoon as electrical generation plants come on line to meet peak air conditioner power needs.

Revenue drivers

Natural gas storage is almost exclusively a fee based business. The amount of storage dedicated or committed to a particular customer, the amount of storage used by each customer, the amount injected and withdrawn, and the fee charged for each of these activities are the key determiners of the amount of revenue earned by natural gas storage facility owners. Construction and operations of natural gas fired electrical electricity plants is driving the construction of "high deliverability" natural gas storage caverns. Some natural gas storage is owned by natural gas transmission operators and required for the orderly operation of the natural gas pipeline. As such, storage used for the operations of the pipeline does not carry an additional charge. But, transmission companies, in the desire to generate more revenue are actively seeking ways to charge for short term storage. The advent of park and loan charges discussed earlier is an example of charging for short term storage. Some rates are "market based" providing pricing flexibility to the owners and some is regulated by the FERC or state and local regulators.

Risks

The primary risks for natural gas storage operators has to do with loss of volumes, reduction in rates, and more ratable fill and withdrawal rates. These risks are driven by natural gas demand and natural gas prices which impact drilling and production rates. The demand for intraday gas storage by natural gas generation plants is driving development of additional storage which could result in an over-build of domestic natural gas storage. A high interest rate environment increases the carrying cost for natural gas storage so rising interest rates could make natural gas storage more costing in terms of inventory carrying costs. Market based rates are not regulated. Therefore, in times of high demand rates can be raised. In times of low demand the opposite is true.

Crude Oil Pipelines

Crude oil pipelines transport crude oil from producing regions to refineries. Along the route they may connect to crude oil market centers (such as Cushing, Oklahoma) or other pipelines. Development of shale and other nonconventional oil production as well as Canadian oil and tar sands is driving construction of crude oil main or trunk lines in North America. These nonconventional production plays – Eagle Ford Shale, Bakken Shale, Austin Chalk, Alberta Basin, Niobrara Shale, and Barnett Shale Combo and so forth – have quickly becoming familiar to the oil industry. North American crude oil production has increased significantly over the past couple of years and is forecast to continue growing into the near term. This growing production of crude oil is driving construction of new crude oil transportation pipelines, expansions and reversals of existing lines (Seaway for example), and conversion of existing lines to crude oil (for example Long Horn).

Revenue drivers

The revenue drivers for crude oil trunk or main lines are volumes and rates. Typically crude oil does not move on existing crude oil pipelines under a transportation services agreement. Rather, each month crude oil shippers "nominate" the amount of volumes they want to move. Pipeline companies develop schedules to determine if they have sufficient capacity to move the nominated volumes. If pipeline capacity is insufficient they pipeline company "prorates" the amount each shipper can move – normally based on the shipper's 12 month rolling average. Before agreeing to construct new crude oil pipelines the pipeline company may require prospective shippers to sign a long-term contract guaranteeing the volumes as a way to reduce the risk of building the new pipeline. Crude oil pipelines are highly capital intensive and the incremental cost to transport is usually relatively low. Consequently, a relatively small reduction in volumes can have a significant impact on the bottom line.

Rates for existing movements on many crude oil pipelines are "indexed" (that is raised or lowered) annually based on a factor established by the FERC. New rates can be established based on a "Cost of Service" (COS) approach. COS rates provide for a return on the invested capital plus recovery of operating expenses. The COS process is regulated by the FERC. In some cases the markets served are deemed competitive and the FERC approves the pipeline to charge market based rates. Pipelines are also allowed to discount rates from the maximum established rates and may do so to attract business. The FERC also normally approves rates which are negotiated at arm's length between a shipper and the pipeline company.

Risks

Revenue risks center around reductions in volumes and rates. Volume risks can be either wide spread such a slowdown in national economic activity, or regional such as a regional slowdown. Additionally, volume reductions can occur because volumes move from one source to another or from one pipeline to another. Additional risks include rising raw material and labor costs, an overbuild of U.S. energy infrastructure and a decline in commodity prices (resulting in a decline in drilling activity).

Crude Oil Storage Terminals

Crude oil storage is required for pipeline operations reasons, to balance supply and demand, and to store crude oil in hopes of receiving a higher price in the future. Both storage used as operating storage, and crude oil stored in hopes of purchasing at one price and selling it at a higher price, may be owned by crude oil pipeline companies or other entities. In the case of either ownership, the rates are not generally regulated. Increasing crude oil pipeline movements do require more operating tankage but changing supply patterns and the desire by some customers to store crude oil in hope of higher prices is the main factor driving crude oil tank and terminal construction. One of the major storage locations is Cushing, OK.

Industry and sector drivers

Crude oil volumes are produced relatively constantly over the year, but the consumption of crude oil based on varying refined products demand varies somewhat from season to season. The price of crude oil can vary significantly over time and between regions. This variability in demand and the changing crude oil prices or differentials are what drive the crude oil storage and crude oil terminaling industry.

Revenue drivers

Crude oil storage is a fee based business. The amount of storage dedicated or committed to a particular customer, the amount of storage used by each customer, the amount delivered into and withdrawn from storage, and the fee charged for each of these activities are the key determiners of the amount of revenue earned by crude oil storage operators. Over the past 10 to 20 years significantly more crude oil storage tanks have been constructed than are required by pipeline operations. These tanks are leased by crude oil marketers or traders as they attempt to capture market pricing swings. That is they attempt to purchase crude oil when prices reach a low and sell as the prices recover.

Risks

Crude oil storage rates are not regulated. Therefore in times of high demand rates can be raised. In times of low demand the opposite is true. The cost of operational storage is normally included in the price of transportation rates which are regulated so are not normally a factor in crude oil storage revenue. The primary risks are volume fluctuations and market swings (or lack thereof). During times of crude oil pricing volatility, traders lease or rent tankage in an attempt to capture the price swings. When the crude oil market is stable, the value of crude oil storage to capture pricing swings is considerably diminished making the rental and lease markets soft.

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