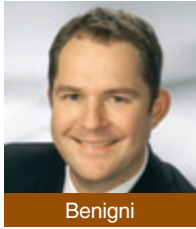


The Complex World of Oil Markets and Trading

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Oil trading is a broad term, incorporating the exchange of physical oil cargoes and trading of paper instruments, which does not necessarily result in physical delivery of oil. It is a complex mechanism composed of several markets—spot, over-the-counter, and futures markets.

In the 1960s and partly in the 1970s, oil trading was mostly limited to direct deals between producers and consumers, whereas the price of oil was fixed by the producer. Following the first oil shock in 1973, refiners were eager to get oil from a wider variety of sources. This initiated spot oil trading, also called physical markets. The oversupplied market in the early 1980s led to more competition and more barrels in the spot market, which eliminated the price control by the producer and gave more power to consumers. The emergence of spot markets also attracted a large number of intermediary parties—trading companies and, recently, hedge funds—which increased liquidity in the market.

Due to a large number of different grades based on quality and location, which are sold and bought in the spot market, it is difficult to determine the absolute price of each single grade. Therefore, the market chose several grades and endowed them with a benchmark status. The rest of the grades are priced at a differential (premium or discount) to one of those markers. Currently, there are several important crude-oil markers: West Texas Intermediate (WTI) in the US; Brent, Forties, Oseberg, and Ekofisk in Europe; and Dubai and Oman in the Middle East. These grades have to fulfill a number of requirements for a benchmark, such as sufficient production volumes, a stable market, representative quality, and absence of resale restrictions. Benchmarks are also indicators for interregional crude movements, called arbitrage.

Although active spot trading increases competition in the market, it leads unavoidably to more-volatile pricing and growing risk for all participating parties—especially for those at the start and the end of the supply chain. In addition, there are significant time gaps

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between the deal conclusion, loading date, and delivery date. This led to the emergence of hedging techniques, helping to protect physical barrels from price volatility. By fixing a certain price level, it is possible to secure more-stable cash flows. This is done by using derivatives. A derivative is a traded paper instrument, and its value depends on the underlying commodity. Typical examples of derivatives are forward contracts, swaps, and futures.

There are two different types of paper markets—over-the-counter markets and futures exchanges. Over-the-counter markets are “organized” around a limited number of participants, normally large players such as oil majors. Although generally flexible, these markets have developed a number of standardized contracts—i.e., forward contracts (where physical delivery of the oil is required) and swaps (where only cash is exchanged). The over-the-counter market, similar to the spot market, is rather opaque, which means that the scale of real trading activity remains unknown. The obscured trading activity resulted in a need for price discovery and the services of price-reporting agencies, which assess prices of different grades after collecting trading information from the market.

Unlike over-the-counter contracts, futures contracts are standardized and can neither be changed nor adapted by market participants. There are two major futures exchanges—the New York Mercantile Exchange (Nymex) and the InterContinental Exchange (ICE) in London—with two major crude-oil futures contracts, ICE Brent and Nymex light, sweet crude (called Nymex WTI). While the former is cash settled at the expiration, the latter is physically deliverable. Due to high liquidity and the large number of participants, futures markets are considered price setters, while over-the-counter and spot markets are seen as price takers.

Public exchanges are the most active and liquid oil markets, with trading volumes of more than 500 million B/D. (Compare this with the actual oil-production level of about 84 million B/D). Due to lower market barriers, public exchanges are attractive for a large number of participants. These exchanges are an ideal market for financial institutions such as banks and hedge funds, which can profit from price volatility (speculative trading) while avoiding physical delivery.

Oil trading remains a turbulent segment, with few novelties emerging on the horizon. Recently, an important new exchange appeared—the Dubai Mercantile Exchange, inaugurating the Omani futures contract. At the same time, ICE launched the new Middle Eastern Sour Crude Oil futures contract. They are both competing for the status of the new benchmark in the Middle East. At the same time, several benchmarks are struggling with different problems—mostly inadequate production volumes, illiquid markets, and unstable quality, which resulted in a number of improvements to the trading mechanism.

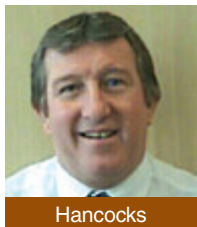
Oil trading mechanisms will still have scope to develop and expand, as the dislocation of supply (producing areas) and demand (refineries and consuming areas) remains. Oil trading is expected to increase significantly in the future. **TWA**

In this issue, we introduce some fundamental concepts in oil trading to allow us to further explore this industry sector in future articles. We also look into operating expenditure modeling issues, which tend to be overlooked at project appraisal stages.

Kristine Petrosyan, Deputy Editor-in-Chief, TWA, Editor, Economist's Corner

Issues With Opex Forecasting in Economic Evaluation

Terry Hancocks



Hancocks

Historically robust demand and hydrocarbon prices in the past have conditioned the industry to regard operating expenditure (opex) as a minor element compared with capital expenditure (capex).

The industry's downstream sector, which has had more traditional competition, has been assessed on world-league tables of refinery performance. Downstream has used whole-of-life costing for many years, which includes both capex and opex. In contrast, the upstream sector has tended to focus on capital costs, making rigorous assessments of them, for example, when delivering a facility with which to exploit a hydrocarbon reservoir. As a result, the scope, dimensions, and impacts of the potential risks during a venture's production phase often have been grossly understated and poorly defined. Failure to achieve expected financial performance has been an inevitable consequence. This experience, together with the continually changing global business environment faced by operating and service companies, is now resulting in changing attitudes toward managing opex and business strategies for maximizing economic returns on developing, developed, and mature fields.

Diminishing business performance and high costs have been linked to numerous causes, including excessive levels of plant unavailability because of lack of fit-for-purpose equipment to meet process demands; a poor initial capex/opex balance, resulting in operating-cost levels that erode margins; operations personnel who lack certain competencies; regulatory and fiscal regime changes; currency movements; and changes in market demand.

To understand and mitigate the risks of the operational phase, it is essential to model the key assets linked to business results. Through modeling, one can examine major opex issues such as

- Effect of capex on opex
- Effect of engineering change on asset status and performance
- Forecast of expenditures

A key enabler of this whole-life solution is the implementation of activity-based costing (ABC). Historically, operating costs have been very difficult to model. ABC provides a framework that allows costs

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to be tied directly to assets. The principle of ABC is that all costs can be described by the activities performed on a company's assets and the resources these activities consume. In detail:

- An asset can be anything that has value to the company. (This means functional assets such as pipelines or separators.)
- Activity describes the tasks that take place on the asset—for example, inspection and maintenance.
- Resource describes everything needed to undertake an activity (i.e., manpower, equipment, materials, and services).

Through this concept, because costs are now applied to the physical asset, it becomes much easier to analyze the impact of a change on that asset—for example, the addition of a compressor.

The creation of a model consists of a number of stages, including building an asset register, defining activities/resources on assets, and applying tariffs. This approach can be used at all stages of the life cycle, and it can be simplified by discriminating between greenfield (new project) and brownfield (ongoing project) phases.

In the case of a greenfield, the asset register is based on equipment lists derived from basis-of-design information. For activities during the early phases of a project, it is important to model multiple scenarios rapidly and understand quickly the impact of capex decisions on opex.

Not all costs can be represented by the activity/resource relationship; some need to be allocated to the asset through tariffing. A typical example is tariffs associated with access to a multiuser pipeline. The key to this process is to achieve a fair and equitable distribution of costs—for example, by allocating regional pigging costs to the total length of pipeline traversed in each asset.

The main advantages of this approach are an interaction between capex and opex; the facilitation of capital-phase decision analysis, such as equipment type, training, sparing, and manning; the ability to rank opportunities on a more rigorous net-present-value basis; and enhanced visibility of the annual budget requirements with the ability to assess the impact of different options.

Life-cycle costing has been around for many years but has not been used widely in the upstream sector for activity/asset-based planning and asset business planning. The processes used to develop the latter are the real key to achieving business success because they

- Systematically address the primary business attributes: assets, activities, and resources
- Identify the key risks that may threaten the business
- Help to identify options for managing those risks successfully.

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