Valuation of Non-U.S. Oil and Gas Properties

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Summary

Valuation of non-U.S. concessions, prospects, and producing fields varies greatly from country to country because of differences in fiscal and political regimes and therefore must include quantified adjustments for these differences in the light of comparative modes of sale of other non-U.S. properties. The market for acquisitions and divestitures works by also applying such adjustments to the values derived for U.S. analogs with comparable geological, engineering, and economic risks. This paper discusses the primary types of fiscal regimes found around the world, namely, licenses with royalties and taxes, association agreements, and production-sharing contracts (PSC's). We show that discounted-cash-flow (DCF) models are readily applicable to proved reserves and present a review of a recent market transaction to demonstrate these effects. Political risk in the non-U.S. market is shown to be additive.

Introduction

For most of the 20th Century, non-U.S. oil business was the exclusive domain of industry majors. Over the last few decades, however, numerous small companies and independents have become increasingly global, which, in turn, increases the need to understand the approaches to valuing their non-U.S. properties.

Takings or expropriations are experienced where values may need to be estimated by courts or tribunals. Other instances requiring a valuation include potentially taxable transactions, such as transferring an oil or gas property across country boundaries. Sales transactions frequently take place between apparently willing and knowledgeable buyers and sellers, so the concept of fair market value should apply.

This all sounds familiar to the U.S. oilman, banker, or tax agent. However, can the same approaches to estimates of fair market value be used globally? Are there differences or pitfalls that would be important to consider when appraising non-U.S. properties? This paper shows that a resounding "yes" is the answer to both questions. It also highlights some of our own experiences in the non-U.S. appraisal arena.

U.S. Approaches

Numerous presentations have been made on the merits of conventional approaches, such as the DCF methods and comparable sales with various unit values. In addition, cost methods have seen use, particularly in the downstream sector. This paper examines the ease or difficulty with which these familiar methods can be applied worldwide. A brief review of the most common U.S. method, the DCF approach is presented first, followed by an alternative interpretation of the discount rate applied by the market.

DCF Approach. The DCF method is best applied to producing properties or to properties where the outlook for an income stream in the near future is likely and not speculative. Simplistically, the multistep approach of valuation consists of an annual forecast of oil and gas production volumes times a prediction of prices less an estimate of operating costs. After other, but minor, adjustments, this future cash flow is discounted for both time value of money and the perceived probability of achieving exactly the predicted cash flow. Miller and Vasquez[1] present arguments for their observed 6 to 8% excess of the average market discount rate over the average cost of capital. The excess is sometimes considered equivalent to growth motive, offsetting the "risk" of the oil business. It reflects the desire on the part of owners or management to make a rate of return better than the company's weighted average cost of capital (WACC). Can this 6 to 8% excess be dissected further, and can it be quantified? Most importantly, can such an understanding improve the selection of discount rates to be applied in the valuation of non-U.S. properties?

Key Variables. We examine the oil operating company's perception of the probability that it will actually receive the predicted cash flow when purchasing a producing property. If the company were 100% sure of the cash flow as predicted by the reserve engineer, it might pay close to its cost of capital. Conversely, if an operating company were uncertain, it would pay less and target a higher rate of return.

Prediction of the DCF rate of return is based on four major parameters: production quantities, oil prices, operating costs, and discount rate. Production quantities may vary from the petroleum engineer's predictions, oil prices will fluctuate, and operating costs may likewise turn out differently than forecast. In addition, the discount rate generally used to reflect time value of money—namely, the weighted average cost of capital (WACC) for the E&P industry sector—varies with the country's economy. U.S. appraisal experience and literature provide a framework for estimates of these four parameters.

Quantity, Price, and Operating Cost. The first three parameters have been used for prediction for almost 5 decades and applied in DCF forecasts for valuation of oil and gas properties.

Production Rate. Accuracy has steadily improved for production-quantity predictions. In part, this comes from the availability of reservoir simulation techniques and

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computer access to analog decline data from numerous fields. Still, the predictability of production rates as a function of future market demand is inexact because of the market-demand uncertainties.

Commodity Price. Forecasting of oil and gas prices has been the subject of both joking and serious literature. Changes appear unavoidable, and predictions are mostly in error. The Soc. of Petroleum Evaluation Engineers' (SPEE) annual consensus surveys of price forecasts dating back to 1983 show little improvement in the industry's ability to predict oil prices. The price parameter is probably the one input in the DCF equation with the highest perceived uncertainty. Again, marketplace buyers and sellers attempt to guard against the lack of predictability by increasing their targeted rate of return.

Operating Cost. While forecasts have also improved here, this is an area where progress is being impeded by the oil industry itself. Detailed costs of operations are not reported to any regulatory agency, as is the case with production quantities. Therefore, only a few computer databases exist, and these are mostly private. Better information on historic operating costs would form a natural base for forecasting but is considered confidential business information.

Additional uncertainties are introduced by the general economy, including labor costs, power costs, chemicals, and other such factors. Government influences must also be considered because of likely tightening of environmental regulations, which invariably increases operating costs. Buyers and sellers in the marketplace are therefore at their own risk and must guard against surprises by targeting a slightly higher rate of return.

Time Value of Money. The parameter applied to discount back future income to its present value is the discount rate. The discount rate selected by numerous authors is the WACC for the specific industry. The WACC changes with the economy. Generally, it is high in times of inflation and low in times of a flat economy. The excess of 6 to 8% in market discount rate over WACC (as found in market transactions) appears to float on top of the WACC; at least, this is what has occurred over the last few decades. This lends credence to the concept of an intended markup to hedge against the perceived uncertainties in quantity, price, and cost, the primary components of the cash flow.

Cost of Capital. Cost-of-capital rates vary but can be generalized for particular industries. This is the case with the oil industry, where the cost of capital as surveyed by the SPEE averaged 10.2% in 1996. This number is weighted for average debt portion in the oil industry at 30%. The percentage of capital that is debt is found, on average, to be higher for E&P companies (approximately 40%) and lower for integrated oil companies (approximately 20%), the opposite of what would be anticipated. Bankers are expected to lend more funds to integrated companies because of their greater distribution of risk. This opportunity for low-cost debt capital appears to have been tempered by a recent debt aversion on the part of the integrated oil companies. In view of the drastic oil-price drop during 1998, this policy may have been wise.

Quantification. Here, we attempt to quantify the market's historical approach to guard against the lack of predictability of cash flow. Whether consciously derived or empirically experienced, the excess relates closely to the premium added to derive a targeted rate of return. Until the 1998 oil-price drop, U.S. property exchanges traded at a net present value based on a discount rate of approximately 18% on a before-income-tax (BFIT) basis. This was during the 1990's when the WACC was steady at approximately 10 to 11% for the oil industry (also BFIT). The difference is approximately 7% and falls within the range found by Miller and Vasquez.[1]

Westin and Copeland,[2] among others, used a building-block approach to describe the observed discount rate. The general approach of adding mutually independent risk components appears to have been accepted. These authors suggested that the nominal rate of return, i_R, is made up of four components.

$$i_R=(i_{rE}+I_E+P_{lE}+P_{rE}), \quad \text{(1)}$$

where i_{rE}=expected real interest rate, I_E=expected inflation, P_{lE}=expected liquidity premium, and P_{rE}=expected risk premium. i_{rE} and P_{lE} are well-known components of the WACC. The inflation component usually is handled in the reserve estimate and financial forecast by including an inflation factor for oil and gas prices as well as for operating costs. It is the remaining "risk premium" that needs further examination.

The market for oil and gas properties has been seen to impose a markup of approximately 7% as a risk premium to reach its targeted rate of return. We attempt to divide this 7% spread further among the perceived quantity, price, and cost uncertainties.

A Different Approach to Risk Premium

A review of the last 2 decades shows that the market discount rate has been varying as a direct function of the WACC for the oil sector. For example, in the early to mid-1980's when inflation rates were high, the cost of capital was in the 15% range. Producing properties sold at discount rates of approximately 22 to 23%, again a markup or premium of about 7%.

It is apparent that, in general, the oil sector requires a reasonable reward or profit corresponding to about 7% for taking the risk of putting its capital to work. The same 7% markup for risk has also been experienced in other extractive industries of high-unit-value commodities, such as copper. Interviews with financial executives have revealed that these industries target their internal rate of return at the same general level—namely, 17 to 18%. They discount at even higher rates for more risky properties, such as nonproducing reserves, and at lower discount rates for less risky producing reserves, thereby buying at higher purchase prices.

We attempt to analyze the 7% that the oil sector apparently wants to realize beyond the cost of its capital. First, we discuss the underlying cost of capital.

Risk Components and Their Justification. In our opinion, the risks associated with oil and gas production can be summarized further as follows. The risks relate to the expectation of the predicted cash flow. Cash flow (BFIT net revenue) is predominantly the produced net quantity of oil or gas multiplied by the market prices of the commodity less the operating cost. Local taxes play less of a role. Therefore, three risk categories are inherent in oil and gas production: production-rate (quantity) risk, commodity-price risk, and operating-cost risk.

These various subcategories of risk are broadly quantified. Market-price risk weighs heavily and makes up approximately 3% of the total. Operating-cost and production-rate risks are approximately 2% each. Can this rough division be proved? Market examples help support the numbers presented.

Operating Cost. This example demonstrates the 2% adjustment for operating-cost risk. Investors often are given the choice between purchasing full working interest in a particular property or a royalty interest in a producing property. A full working interest indicates that the investor will be responsible for all costs and will share in the net revenue interest from the production. In contrast, a royalty interest conveys the right to receive oil or cash from the production without being responsible for any operating cost. Therefore, royalty interests usually sell at a 16% discount rate or expected rate of return, while total working interests sell at 18% discount rates as discussed previously. This 2% difference represents the market's operating-cost risk adjustment. When there is no operating-cost risk, the market values a producing property at a higher value that corresponds to a 2% reduction in the discount rate.

Production Rate. Production-rate risk can be quantified by comparing the oil industry with another extractive industry where the rate of production of the commodity is rarely a factor, for instance, the aggregate industry. Only sand and gravel price and cost of production and transportation are major risks, not reserves or short-term rates of production. Aggregate-industry operators usually experience a discount rate of approximately 16% for discounting the net cash flows associated with an operating mine or quarry. Production-rate risk is the difference between these two numbers—namely, 2%.

Price Risk. Finally, the remaining 3% excess may be attributed to price risk. This is further proved by looking at the oil and gas derivatives market. A knowledgeable investor with experience in the derivative markets can eliminate nearly all price risks associated with oil and gas investments by locking into a definitive price for the commodity well into the future. This has a profound effect on the valuation of oil and gas properties. The cumulative effect of efficient use of derivatives to hedge against price fluctuations increases the value. The increase corresponds to approximately 3% of discount rate (when applied to future net cash flow), lending further evidence to the previous discussion.

Summation of the three major risk factors and their corresponding effect on discounted present value yields a total of a 7% adjustment, which is equal to the difference between cost of capital and market price.

Non-U.S. Application

The DCF approach is already finding wide application in the non-U.S. market for oil and gas exchanges. As is the case in the U.S. market, confidence in the valuation is greatest when the property consists of proved, producing reserves. In further parallel, selection of a discount rate creates the greatest problems in a valuation.

Discount-Rate Adjustment. The discount rate to be applied to the cash flow forecast to arrive at a fair market value of the property must be determined. With time and development of a non-U.S. database of comparable property transactions, the market discount rates can be back-calculated. A few parts of the world are partially covered (e.g., the commercial vendor Wood Mackenzie's covers asset deals in the U.K. North Sea). Unfortunately, details of reserve estimates and cash-flow forecasts frequently are missing. A researcher has to ensure comparability and make adjustments on the basis of secondary information, such as total reserves, current production rates, physical conditions of the production facility, and fiscal regime.

Discount Rate After Income Tax (AFIT) vs. BFIT. As data from comparable sales become available, discount rates will be easier to determine. In the meantime, attempts can be made to construct discount rates "from the bottom up." Starting with the U.S. WACC, BFIT is first adjusted to AFIT. This adjustment is necessary because taxes are nearly always different in the host country. Therefore, non-U.S. DCF appraisals must be calculated on an AFIT basis. This downward adjustment is on the order of 2%, which yielded an AFIT WACC of 9% during most of the 1990's.

Adjustment of WACC. Next, an adjustment must be made for any observed or perceived changes in WACC imposed by working in the host country. Such factors as currency-exchange risk, repatriation limitations, and central-bank delays all increase the WACC. The increase may seem difficult to quantify; however, effects convertible into simple time delays can be calculated as an additional interest cost. An example is the delay in receiving payment in hard currency through a central-bank system in a developing country. This extra step can easily take 3 months, which translates into an increase in WACC of 2 to 3%.

The effect of other factors may be determined by obtaining quotes from the derivatives market. The additional cost to hedge against currency-exchange risk is an example. This adjustment can run into several percentage points, depending on the fiscal stability of the host country and the quantity of oil subject to sale to the local market.

Excess for International Business. Once the WACC has been adjusted, the markup for "being in the oil business" must be adjusted over that historically experienced in the U.S. oil market. The three overweighing factors would be expected to be the same as for U.S. properties—namely, production quantities, prices, and costs. Each of these needs examination. In addition, country risk (sometimes called political risk) must be added.

Production Quantities and Ownership. In U.S. cases, the net revenue interest is readily introduced into reserve forecasts from a legally described working interest less royalties to the mineral-estate owners. In addition, the underlying lease form has been tested in court numerous times. There is, therefore, little risk associated with title to the production.

In contrast, the various forms of international petroleum contracts between oil companies and the host-country agency introduce numerous variations and questions of title. In some cases of PSC's, title to the oil is obtained only on export from the host country. Many variations exist. Therefore, while engineers may predict reservoir performance with normal accuracy, the production is now subject to numerous splits, each of which involves legal interpretation. Title to the oil frequently is not even held by the

TABLE 1—COMPARATIVE OIL TITLE RISK

Contract Type	Country	Title Risk
License with royalty	U.S.Gulf of Mexico	Base case
	U.K. North Sea	Less risky
	New Zealand	Less risky
	Turkey	More risky
	Canada	Comparable
Association contract	Colombia	Very risky
PSC	Indonesia	Very risky
	Kazakhstan	Very risky
	Côte d'Ivoire	Comparable

international oil company. **Table 1** shows the sensitivity to petroleum contract type for a number of countries by comparison with the ownership standards for the U.S. Gulf of Mexico (base case).

Marketability. Geographical limitations may severely influence the marketability of the oil and gas and bring further doubts about production quantities. Instead of the 2% increase in the targeted rate of return, we have seen the premium go as high as 5% for reasons of oil ownership. We have seen an extra 5% added to the benchmark rate of return east of the Caspian Sea because of uncertainties about oil-export opportunities.

Oil and Gas Prices. Many countries allow export of the non-U.S. oil company's production share at world oil prices or at a basket of prices. In such cases, the perceived uncertainty of oil-price forecast is identical to that for U.S. sale of oil. Therefore, the cost of derivatives is the same and a markup of 3% for the targeted rate of return seems reasonable. In contrast, some countries impose a domestic market obligation (DMO) on part of the oil. If the DMO price can be varied at the discretion of the host government, the perceived price risk is higher and an upward adjustment would be made.

The perceived uncertainty of commodity price forecasts is higher for natural gas because most countries have no gas-pricing model in their petroleum contracts. Therefore, a substantial increase in the targeted rate of return and thus in the applicable discount rate for valuation is indicated.

Costs. Perceived operating-cost uncertainty is higher in non-U.S. areas than in the U.S. The major cost factors are the same (e.g., labor, power, and expendables). Absolute costs generally are higher and vary substantially with the global location and environment. Predicted costs are already included in the financial forecast. The sensitivity to fluctuations is important and appears to be greatest for labor-cost predictions.

Addition of Political Risk Perception. In contrast to U.S. appraisals, a discount for political, or country, risk must be included in non-U.S. valuations. Gebelein *et al.*[3] summarize the components of political risk as follows.

1. Civil-disorder losses.
2. External-war losses.
3. Sudden expropriation.
4. Creeping expropriation.
5. Taxation changes.
6. Domestic price controls.
7. Production restrictions.
8. Oil-export restrictions.
9. Restrictions on remittances.

Ref. 3 provides detailed definitions of these risks. So that the adjustment for political risk is not doubled, some of these components must be eliminated because they were already considered in the quantity, price, and cost adjustments discussed previously. One is taxation changes, the risk of which (in our opinion) is equally threatening in the U.S. arena as in the non-U.S. arena. Adjustments should be made only in extreme cases of uncertainty, such as currently found in the Russian Federation. Another is domestic price control, which already will have been adjusted under price adjustments. Production restrictions have been adjusted under quantity risks, and any uncertainty with regard to restrictions on remittances would have been included in the previously mentioned cost-of-capital adjustment to that of the host country.

Political Risk Components. The remaining five components are genuine contributors to the perception of political risk over and above quantity, price, and cost risks. Gebelein *et al.*[3] proposed a qualitative approach to compare various countries and opportunities, and Stauffer[4] proposed a quantitative approach. He related the discount rate to be applied to a "certain" expected cash flow (that includes all geological risk and any business risk except specifically nationalization) to the discount rate to be used when nationalization is included. He found that the adjusted discount rate, R', equals the basic discount rate, r, plus the annual probability, p, of uncompensated expropriation plus a small correction.

$$R'=(r+p)/(1-p)=r+p+p(r+p). \quad \ldots\ldots(2)$$

Stauffer's approach appears to support our proposal that the discount rate may be built up by addition of individual components. It also places a maximum limit on the adjustment, which would be less in cases of partial expropriation or disruptions of the type listed by Gebelein *et al.*[3] None of these authors attempted a full calculation of percent to add.

Approach to Quantification. Proehl[5] suggested a quantification approach and illustrated his results with early 20th Century cases from Chile and Iran. His probabilities are ominously high but perhaps justifiably so in view of Chile's copper policy and Iran's nationalization of oil and other political unrest. For Chile, Proehl's calculated annual probability of government or popular action against foreign investments increased from 23% to 62% from 1910 to 1980. It is reasonable to expect that the perceived risk of the market is in the same range for countries of high political risk. Unfortunately, no information is provided about the current perception of political risk in the two case countries.

Following Stauffer,[4] the annual probability is additive to the certain discount rate as discussed previously. This permits us to build up the discount rate to be applied to the expected cash flow for non-U.S. valuation purposes.

Comparison With Actual Sale

A check of the applicability of the proposed building-block approach was made. A recent transaction in Côte d'Ivoire fulfills all requirements for the definition of fair market value. The transaction was the sale of an undivided 10% working interest in the Panther/Lion offshore oil- and gasfield complex. The underlying asset value of the working interest is represented almost entirely by proved, producing reserves,

TABLE 2—PRODUCTION FORECAST FOR THE LION/PANTHER OIL AND GAS FIELDS (JANUARY 1998)

Year Ending	Gas (Bcf)	Oil (million bbl)
1998	35.6	13.7
1999	28.4	11.1
2000	31.0	8.9
2001	24.5	6.4
2002	22.3	1.9
2003	18.0	
2004	18.0	
2005	18.0	
2006	18.0	
2007	18.0	
2008	18.0	
2009	18.0	
2010	16.6	
2011	13.3	
2012	10.8	
2013	7.9	
2014	5.4	
2015	2.9	
2016	2.2	
2017	1.4	
2018	1.1	
2019	0.4	
2020	0.3	

TABLE 3—CÔTE D'IVOIRE PRODUCTION-SHARING-CONTRACT INPUT PARAMETERS

Capital costs			
Abandonment cost (Year 21), estimated U.S. million dollars			15
Production facilities, estimated U.S. million dollars			343
Economic assumptions (early 1998)			
Oil price, U.S. $/bbl			16
Oil-price escalation, %/yr			3.25
Gas price, U.S. $/Mcf			1.50
Gas-price escalation, %/yr			3.25
Operating costs, U.S. $/bbl oil equivalent			3.70
Inflation rate, %/yr			3.25
Income tax rate, %			35
Libor rate, %			5.75
Contract terms			
Petroci-carried interest, %			0
Cost recovery (oil and gas), %			63
Contractor's profit oil share			
Oil (BOPD)	Gas (Mcf/D)	Oil (%)	Gas (%)
0 to 20,000	0 to 70,000	40	40
>20,000	>70,000	30	30

which have been estimated by independent engineers and certified by another group of independent consultants.

The sale was made by Petroci, the state-owned oil company, to United Meridian (now Ocean Energy) for cash or cash equivalent in an arm's-length transaction after exposure to the market. The transaction price was U.S. $20.5 million. We obtained total reserves from press releases, and the production forecasts shown in **Table 2** are from publicly available contracts for gas sales to the only market, the electric power plants at Abidjan.

Commodity prices were obtained from both buyers and sellers of the gas. Transportation costs from the offshore-field facilities along the coast to the market were backcalculated at U.S. $0.20/Mcf. Early 1998 oil-price perceptions were adopted as having influenced buyer and seller.

PSC Model. The current PSC model for Côte d'Ivoire in Excel spreadsheet format was adapted from U. of Tulsa course material.[6] The model allows input of all fiscal terms, such as cost recovery and profit oil splits as well as a 20-year production forecast. The model also has input ability for detailed well- and facility-development costs. **Table 3** summarizes the input parameters as of the date of the transaction.

Discount Rate Based on Building-Block Approach. The first adjustment is made for the WACC for the selected country, namely Côte d'Ivoire. The country has free exchange of hard currency because its national currency, the CFA (Cefa), is tied to the French franc. No adjustment is necessary, so an AFIT WACC of 9% is selected. Adjustments are added to this for quantity-, price-, and cost-risk perceptions. The quantities to be produced by the reservoir were predicted by U.S. engineering companies, while the rates are locked in by the gas market during the economically important near-term period. Therefore, the U.S. equivalent 2% level is chosen.

Price risk is also identical because the oil is sold at world oil prices, there is no subsidized DMO, and gas prices are locked in by a take-or-pay contract. The U.S. 3% level is chosen. Predictions of costs are riskier because of distances to supply yards and international service centers. In addition, the inflation rate for labor in Côte d'Ivoire is uncertain. An educated guess puts this percentage at double the U.S. number for 4%. The total before considering political risk is 18%.

Political Risk. The political risk with Proehl's[5] approach resulted in a 15% probability of major disruption. Admittedly, the period of analysis is only half the time used in Proehl's Iran and Chile cases. In the Côte d'Ivoire case, the period ranges from the end of the French colonial epoch in 1960 to the recent political change following the death of long-term ruler Felix Houphouet-Boigny. During his rule, the country invited international investments, participated positively in multilateral financing projects, and upheld agreements with international oil companies.

Recent Events. In some cases, the "stability" was too great. When oil prices hit bottom in 1986, Phillips Petroleum was considering converting from temporary to permanent production facilities at the Espoir oil field offshore Côte d'Ivoire. With the new, low oil prices, Phillips' original cost-recovery percentage of 50% was too low to allow investment in the new facilities. The government ignored requests for renegotiations, and Phillips chose to cut the production pipes below the seafloor and leave. Were it not for that uncompromising attitude to foreign investment in 1987, the country would rate an even lower political risk. A trend in the right direction for foreign investors was the 1998 renegotiation of the cost-recovery percentage for the Lion/Panther fields. Originally 40%, it was increased to 63%.

Result of the Building-Block Approach. By adding the estimated 15% to the previously calculated 18%, we arrive at a minimum of 33% for the discount rate to be applied. The recent sale to Ocean Energy involved a 10% working interest, which calculates to a predicted value of U.S. $18 million. The actual transaction price was U.S. $20.5 million. What are possible reasons for the difference?

Reconciliation. A careful study of the model revealed a number of factors that singly or in combination might substantiate the difference. We used a U.S. \$16/bbl oil price with a 3.25% escalation for the market in early 1998. The buyer may have used a different oil-price scenario. In addition, uncertainties in remaining cost recovery may play a role. Finally, the transaction took place at the very peak of production, so sensitivity to the near-term reserve estimate was high.

A reverse calculation based on the market value of U.S. \$20.5 million yielded a discount rate of approximately 25%. This might indicate that the buyer placed the discount for political risk at a substantially lower number (10% or less). It also might indicate that the buyer perceived additional value in the property because Ocean Energy was the operator and already had a large working interest in the property.

Conclusions

Approaches to estimation of fair market value known from the U.S. arena are applicable to non-U.S. properties. For proved, producing reserves, the DCF approach may be applied after considering the host country influence on the excess components related to quantity, price, and cost perceptions. A political-risk component must also be added, but its determination is highly subjective. **JPT**

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SI Metric Conversion Factors

$$\text{bbl} \times 1.589\,873 \quad \text{E}{-01} = \text{m}^3$$
$$\text{ft}^3 \times 2.831\,685 \quad \text{E}{-02} = \text{m}^3$$

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