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Tight Oil Market Dynamics: Benchmarks, Breakeven Points, and Inelasticities

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—*Ronald G. Prinn and John M. Reilly,*
Joint Program Co-Directors



Tight oil market dynamics: Benchmarks, breakeven points, and inelasticities

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ABSTRACT

When comparing oil and gas projects - their relative attractiveness, robustness, and contribution to markets - various dollar per barrel benchmarks are quoted in the literature and in public debates. Among these benchmarks are a variety of breakeven points (also called breakeven costs or breakeven prices), widely used to predict producer responses to market conditions. These analyses have not proved reliable because (1) there has been no broadly accepted agreement on the definitions of breakeven points, (2) there are various breakeven points (and other benchmarks) each of which is applicable only at a certain stage of the development of a resource, and (3) each breakeven point is considerably more dynamic than many observers anticipated, changing over time in response to internal and external drivers. In this paper we propose standardized definitions of each breakeven point, showing which elements of field and well development are included in each. We clarify the purpose of each breakeven point and specify at which stage of the development cycle the use of each becomes appropriate. We discuss in general terms the geological, geographical, product quality, and exchange rate factors that affect breakeven points. We describe other factors that contribute to tight oil market dynamics, including factors that accelerate the growth and retard the decline of production; technological and legal influences on the behavior of market participants; and infrastructure, labor, and financial inelasticities. The role of tight oil in short-term and medium-term oil market stability is discussed. Finally, we explore the implications of a broader, more rigorous, and more consistent application of the breakeven point concept, taking into account the inelasticities that accompany it.

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1. Introduction

From 2011 to mid-2014, Brent crude oil generally traded above \$100 per barrel (1 bbl = 0.159 m³). During that period, U.S. crude oil production increased from about 5.5 million barrels per day (bbl/d) to about 8.9 million bbl/d. Most of the increase was due to the growth in production of tight oil, which is often erroneously termed “shale oil” (as explained in Kleinberg, forthcoming) but is correctly defined by the U.S. Energy Information Administration as oil that is produced from rock formations that have low permeability to fluid flow (EIA, 2016i).

Tensions among oil producers, which originated in the oil price collapse of the mid-1980s, have weakened the ability and willingness of the Organization of Petroleum Exporting Countries (OPEC) to act as an

oil market stabilizer (McNally, 2015). By the third quarter of 2014 it had become apparent that the rate of increase of supply of U.S. tight oil had significantly outstripped the rate of increase of worldwide demand, leading to persistent increases in the amount of oil sent to storage, see Fig. 1. This was an unsustainable situation. In light of the tight oil boom, numerous publications declared America to be the world’s marginal producer (e.g., The Economist, 2014), and when oil production had to decrease, it seemed that burden would fall on the U.S. tight oil industry, whose per barrel costs were far above those of Middle East, and most other, producers.

Many analysts suggested that the oil price needed to maintain the economic viability of the preponderance of U.S. tight oil projects - the breakeven point - was in the range of \$60/bbl to \$90/bbl (e.g., EY, 2014; Wood Mackenzie, 2014c; Bloomberg, 2014). It was further widely believed that once the oil price fell below \$60/bbl, many investments in tight oil projects would end and “since shale-oil [sic] wells are short-lived (output can fall by 60–70% in the first year), any slowdown in investment will quickly translate into falling production” (The Economist, 2014). Thus the \$60–\$90 range for the U.S. tight oil

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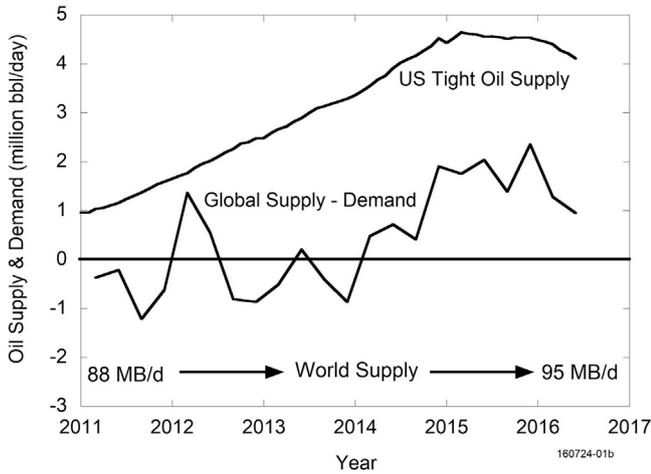


Fig. 1. The growth of United States tight oil production (upper curve) (EIA, 2016i) upset the global balance between supply and demand, leading to persistent additions of stored oil after early 2014 (lower curve) (EIA, 2016g).

breakeven point was thought to act as a shock absorber, with tight oil projects quickly coming onto production as prices increased, and dropping out of production as prices decreased through this range. With tight oil accounting for roughly 4% of global production, and seemingly able to respond to price signals considerably faster than conventional projects, analysts predicted that this new resource could bring welcome stability and price support to oil markets (see e.g. IHS, 2013a; Krane and Agerton, 2015; Ezrati, 2015; The Economist, 2015). There is no documented evidence that the Organization of Petroleum Exporting Countries acted on these assessments, but we can speculate that these considerations might have influenced their decision late in 2014 to preserve their share of the international oil market by increasing oil production. If the conventional wisdom were to hold true, moderate increases of OPEC oil production, accompanied by a moderate oil price decline, would result in prompt declines of tight oil production, thereby preserving both OPEC market share and profits.

In reality, markets did not respond to a modest increase of supply as smoothly as had been predicted. The West Texas Intermediate benchmark oil price fell from \$108/bbl in mid-2014 to \$32/bbl in early 2016, well below tight oil minimum breakeven points calculated by energy economists. Moreover, tight oil production did not start to decline until mid-2015, when it started falling at a moderate rate in the Bakken region, see Fig. 2a, and more rapidly in the Eagle Ford region (EIA, 2016k). Remarkably, oil production from the Permian Basin continued to increase through 2016, see Fig. 2b. As OPEC reported in October 2016, "... the resilience of supply in the lower oil price environment caught the industry by surprise, particularly tight oil in North America." (OPEC, 2016).

The industry was "caught by surprise" in part because the dynamics of breakeven points were not broadly understood. The effects of other market drivers were also incompletely understood, including factors that accelerated the growth and retarded the decline of tight oil production. Technological, legal, infrastructure, labor and financial influences must also be considered. The goal of this paper is to provide a consistent methodological approach to understanding the costs of oil production, and to show, in a systematic way, how those costs change with time and circumstances. We analyze the various breakeven points and other benchmarks, show how they are calculated, and point out how they can sometimes provide misleading signals to analysts and markets. We also explore the difference between the decline rates of a single well and a field, and remark on other inelasticities inherent in the production of crude oil in general and tight oil in particular. Finally we remark on how tight oil influences short-term and medium term market stability.

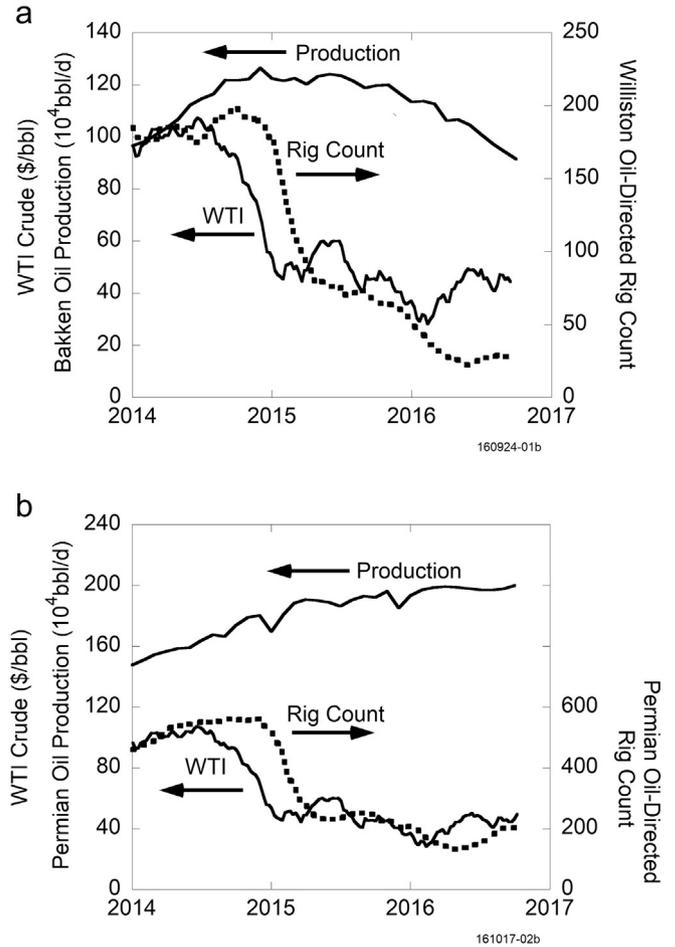


Fig. 2. a. A sharp decline in Williston Basin oil-directed rig count, which is dominated by Bakken field activity (dotted curve) (Baker Hughes, 2016), followed a drop in WTI crude oil price (lower solid curve) (EIA, 2016m) with a lag of less than three months. Bakken oil production (upper solid curve) (EIA, 2016k) started falling in mid-2015. **b.** As in the Williston Basin, the Permian Basin oil-directed rig count (dotted curve) (Baker Hughes, 2016) swiftly followed the decline of WTI crude oil price (lower solid curve) (EIA, 2016m). However, oil production (upper solid curve) continued to increase slowly (EIA, 2016k), defying expectations.

2. Methods

When evaluating the economic viability of a resource or project, one of the most commonly used economic concepts is benchmarking. We discuss how various benchmarks are appropriately used. When comparing projects, companies may wish to prioritize short term cash flow per dollar of investment, reserve additions per dollar, or the robustness of project economics to price declines. In the latter case, the most commonly used measure is the "breakeven point", also called breakeven cost or breakeven price.

The breakeven point is the combination of project costs and market prices for which the net present value of a project is zero (Brealey et al., 2009). In this paper the breakeven concept is analyzed as follows. We start with the definitions of breakeven points; in many publications they are presented without adequate disclosure of what exactly is meant by breakeven. While we realize we cannot promulgate rigorous definitions by fiat, in this paper we offer definitions we believe to be in the mainstream of analyst and corporate practice; the proposed scheme can and should be modified according to individual circumstances. We discuss how breakeven points are partitioned, and when the various breakeven points are appropriately used. We show how breakeven points change with time, due to internal and external drivers.

We discuss other inelasticities that accompany expansions and contractions of output. To address a misconception of fast decline of tight oil

production, we provide a simulation that contrasts individual oil well declines with the collective declines of conventional and tight oil fields. Finally, we assess how a misreading of breakeven points, and lack of insight into the ways in which companies use benchmarks to prioritize investment, may have contributed to the sudden, unexpectedly large change of oil prices in 2014–2016. Although this paper is couched in terms of oil markets, the same principles apply to natural gas resources, and to some extent to other commodities.

3. Results

3.1. Oil market dynamics

Investments in fossil fuel production constitute a multitrillion dollar part of the global economy (IEA, 2014). The largest single segment is occupied by crude oil, which in 2015 provided about one-third of global primary energy use (BP, 2016). Not only is oil consumed at a high rate – roughly a thousand barrels per second – but the demand for it is relatively inelastic (Labandeira et al., 2016). This means demand is relatively insensitive to price. Conversely, a small but persistent imbalance between demand and supply – sometimes as little as 1% of total production – can result in dramatic price changes. Moreover, long lag times inherent in large, risky, capital-intensive exploration and development projects cause substantial, long-lived supply overshoots. Thus the oil price collapse of 2014–2016, when West Texas Intermediate benchmark crude oil prices fell by 70%, was accompanied by substantial increases in production from long lead-time projects in the U.S. Gulf of Mexico (EIA, 2016b) and elsewhere. These were not unprecedented events.

Also contributing to market instability is the complication that a barrel of oil with a relatively high cost of production can enter the market before another barrel that can be produced more cheaply. It is true that the lower the cost of the resource, the more likely it is to be exploited by a producer who holds a range of resources, and lower-cost resources present less risk of loss in the event of a decline of market price. However, dispersal of resources among a wide variety of independent actors, as in the United States, implies that oil and gas resources are not developed in seriatim order of cost. If oil sells for \$100/bbl, the small producer with costs of \$90/bbl will sell as much as possible, regardless of lower-cost resources owned by others. Thus, given a range of producers acting independently of each other, any resource with a marginal cost of production below the prevailing market price can be produced. It was this reality that enabled the creation of the shale gas and tight oil industry in the United States (Wang and Krupnick, 2013). The extensive experimentation that led to the commercialization of Barnett shale gas would never have occurred if left to commercial entities each of which had a wide variety of resources to exploit.

It is in this context that the advent of abundant North American tight oil resources, brought to market by horizontal well construction and massive hydraulic fracturing, was believed to be a market stabilizer (Maugeri, 2013). Unlike deepwater and Arctic projects, for which lead times are typically a decade or more, a tight oil well can be planned, drilled, and completed in months. Furthermore, unlike wells in conventional reservoirs, which decline at around 6% per year (IEA, 2013) and continue producing for decades, tight oil wells typically decline by about 60% in the first year and 25% in the second year of production (IHS, 2013b), see Fig. 3. As a result, nearly half of Lower 48 U.S. oil production in 2015 had originated from wells drilled since the start of 2014 (EIA, 2016d); much of this new production came from tight oil plays. To maintain tight oil production at a constant level, wells must be drilled and completed at a rate beyond that required in conventional fields, a phenomenon colorfully called “The Red Queen Race” (Likvern, 2012). Thus it had been thought that tight oil production would follow the price of oil with a short time lag.

The oil market developments of 2014–2016 in some respects confirmed these views, and in other respects contradicted them. In response to the rapid decline of oil prices after June 2014, U.S. rig counts

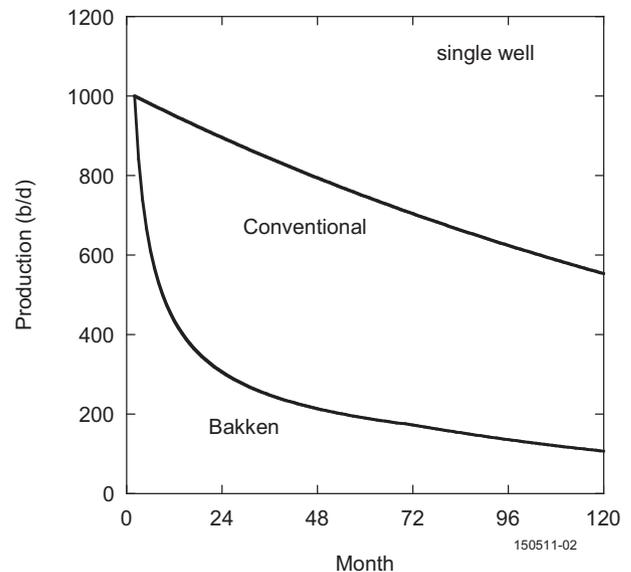


Fig. 3. Type curves for oil production from individual conventional wells with an annual rate of decline of -6% , and from individual tight oil (Bakken) wells (IHS, 2013b).

in tight oil plays declined rapidly, following falling oil prices with a lag of two to three months, as expected for this very nimble industry. Tight oil production peaked in the Eagle Ford play in March 2015 (EIA, 2016k), a lag of nine months, and it peaked in the Bakken play (Fig. 2a) in June 2015, a lag of twelve months. In the Permian Basin, tight oil production continued to increase, as shown in Fig. 2b. Production from these regions was sustained by the relatively slow decline of a substantial number of legacy tight oil wells, by improvements in rig productivity (EIA, 2016k), by reduced costs of oil production (EIA, 2016c), and by a dynamic redefinition of breakeven point. We discuss each of these factors below.

3.2. Cost per unit productive capacity

When companies compare projects to choose those in which they intend to invest, the benchmarks they use depend on their corporate priorities. One is the cost per unit of productive capacity. The cost of productive capacity is of particular interest to oil market forecasters trying to relate changes in capital expenditures to likely levels of future supply. The crude oil market does not care whether the barrels supplied made profits for their producers, only that they are available. Capacity is added both to accommodate increasing demand for petroleum and to compensate for the natural decline of mature fields. Recently an average of 5 million bbl/d of new capacity has been added each year, at a cost of more than \$500 billion: \$100,000 per barrel per day. Therefore it might be expected that a cut back of \$100 billion in capital expenditures would reduce production capacity in the future by 1 million bbl/d. However, these forecasts are complicated by the fact that the impact could be spread over multiple years, e.g. as reductions of 200,000, 300,000, and 500,000 bbl/d over a three year period.

Depending on companies' view of future prices, they might favor one investment over another, even at the expense of damaging the ultimate value of a resource, because they need to meet debt covenants or other factors that are influenced by net operating cash flow. In the market example above, it is quite possible that the projects that are cut are the ones with above average costs of capacity and thus the expected aggregate cutback would be less than 1 million bbl/d.

3.3. Definitions of breakeven points

The breakeven point is seen by some as the most comprehensive assessment of the economic viability of an energy development project.

Breakeven points are also called breakeven costs or breakeven prices. The difference is in the point of view, not in any aspect of the underlying economics. In brief, a hypothetical breakeven project has a net present value of zero. In other words, negative cash flows (capital and operating expenses, taxes, overheads, and so on) are exactly balanced by the discounted positive cash flows (income from sales) expected over the lifetime of the project (Brealey et al., 2009).

Given an expected production schedule, variability of future discounted cash flow due to predicted changes in the price of oil can be built into the breakeven estimates. For tight oil wells, which can be constructed relatively rapidly, and whose production is front loaded, as in Fig. 3, such estimates can be made with some confidence. For projects with long construction schedules and extended production lifetimes, such as those in deepwater offshore, or in the Arctic, risks are commensurately greater. These projects are not sanctioned unless their breakeven points are well below conservative estimates for the future price of oil.

Different assumptions about the discount rate (or required internal rate of return) can have very substantial effects on the breakeven point. Among oil analysts a discount rate of 10% has been widely accepted as a standard, though sometimes 15% is used. Discrepancies also occur because various analysts have used differing slates of costs to include in their breakeven estimates. Because these slates of costs are not standardized nor usually explicitly and fully disclosed, breakeven points published by various analysts, agencies, and oil producers are generally not comparable, and therefore easily misunderstood.

In reality, there are various breakeven points for any given project. Each of these breakeven points is valid, but only for a specific purpose, which is sometimes not stated explicitly. Here we present a scheme which does not necessarily follow any one methodology found in analyst, agency or corporate reports. While recognizing that users will want to define breakeven points in ways most useful to them, we propose a model breakeven point scheme that incorporates elements of

diverse breakeven analyses used by analysts and industry participants. We avoid de novo terminology by utilizing terms commonly found in reports of breakeven points - “full cycle”, “half cycle”, and “lifting cost” - and provide explicit definitions of these terms. Table 1 summarizes the definitions, and compares them to related terms: capital expenditures, operating expenditures, finding costs, and development costs.

3.3.1. Lifting cost

Lifting cost is the incremental cost of producing one additional barrel of oil from an existing well in an existing field. This includes lease operating expense, which comprises well site costs such as the cost of operating and maintaining equipment, fuels, labor costs, and the like.

At present, tight oil resources are produced almost entirely by primary recovery: oil is pushed out of the rock formation and into the well by the natural pressure of the overburden, plus the pressure generated by gas expansion during production, a process called solution gas drive. Nearly all conventional reservoirs are produced by secondary recovery, during which either reservoir pressure is maintained by injections of water or gas, or water is pumped into injector wells to push oil into nearby producer wells (Cosse, 1993). Tertiary recovery (also called enhanced oil recovery) methods include the employment of steam, chemicals, or carbon dioxide to mobilize oil. Lifting costs include expenses associated with these methods.

Lifting cost also includes taxes and royalties charged to production at the wellhead, and the expense of disposal of oilfield wastes. When the marginal cost of transporting product to market is included, the breakeven point is conventionally referenced to a pricing hub, e.g. Brent in northwest Europe, or West Texas Intermediate in Cushing, Oklahoma. The wellhead breakeven price is the hub price minus the cost of transporting the oil from well to hub. Lifting costs are similar to variable costs of production, but also include general and administrative expenses, which are corporate overheads. Lifting cost is the appropriate breakeven point to use when the producer acknowledges a field is in decline and is functioning as a “cash cow”, for which little or no further investment is anticipated in the present phase of the business cycle.

3.3.2. Half cycle breakeven

The half cycle breakeven point is the cost of oil production, including lifting cost, the expense of existing well workovers, and of drilling, completing, and stimulating additional wells in a developed field, with the goal of maintaining level production. The cost of financing these activities is included in the half cycle breakeven point.

Half-cycle breakeven costs are often the largest expenses incurred in the development of an oil field. Drilling expenses include the rental of a drilling rig, and ancillary equipment and supplies such as drill bits and drilling fluids. Directional drilling services enable the construction of increasingly popular horizontal wells. Completion expenses include the steel casing used to stabilize the wellbore, and the cement placed between casing and wellbore to assure that hydrocarbons cannot contaminate potable water resources by moving upwards between casing and subsurface rock. Such operations are more efficient and economic when multiple wells are serviced from a single site, a development referred to as “pad drilling”. A review of half-cycle costs can be found in EIA (2016c).

Stimulation was historically a small part of the total cost of well construction. With the advent of massive hydraulic fracturing, it is now roughly half the expense of drilling and completing a shale gas or tight oil well. In modern practice, well stimulation is a choreographed industrial operation involving multiple service providers using a considerable quantity of heavy equipment, along with roughly 30,000 cubic meters of water, 3000 tons of sand, and 300 tons of specialty chemicals per well.

For the purposes of taxation in the United States, the expenses of drilling and completing a well are divided into tangible and intangible drilling costs (IRS, 2016). The exact division between the two is declared by the owner. Generally, the former are permanent fixtures of wells and

Table 1
Components of various breakeven points.

Breakeven Costs				
Full Cycle	Half Cycle	Capital Expense	Finding	Exploration Leasing Reservoir Delineation
			Development	Financing of Field Dev Engineering Regional Pipelines Roads & Infrastructure Financing of Well Dev Well Pad Construction Local Pipelines Well Construction <ul style="list-style-type: none"> • Drill, Case, Cement • Complete Reservoir Mgmt CAPEX <ul style="list-style-type: none"> • Secondary Recovery • Tertiary Recovery Workovers Refracture Decommissioning <ul style="list-style-type: none"> • Plug & Abandon • Site Restoration
	Lifting Cost	Operating Expense	Production	Lease Operating Expense <ul style="list-style-type: none"> • Repair & Maintain • Fuels & Power • Labor Reservoir Mgmt OPEX <ul style="list-style-type: none"> • Secondary Recovery • Tertiary Recovery Royalties & Taxes Transport to Market Water & Waste Disposal General & Administrative

pads, including well heads, casings, pumps, gathering lines, and storage tanks. Intangible drilling costs include items with no salvage value, including wages, fuel, repairs, hauling, and supplies. In North America in 2014, 23% of the average well cost was classified as tangible drilling expense, with the balance classified as intangible drilling expense (Wood Mackenzie, 2015b).

Stopping (“shutting in”) production from a producing oil well is problematic, both technically and economically. However, there is a safer strategy to delay production. After wells are drilled they must be cased and cemented in order to protect potable water resources and to prevent the wellbore from collapsing. Drilling, casing, and cementing usually account for roughly half the expense of a modern horizontal, massively fractured well. Remaining operations required to start the flow of oil, including perforating, stimulating, and installing production tubing and downhole pumps, can be delayed indefinitely at very little cost and with little or no geological risk. Such wells are called “drilled but uncompleted” wells (“DUCs”). This strategy is useful when an oilfield operator is under contractual obligation to continue drilling (to hold a lease or to satisfy a drilling rig rental contract, for example), but wishes to conserve capital and delay production until market conditions are more favorable (EIA, 2016l).

Half cycle breakeven costs include the capital expense of implementing secondary and tertiary recovery methods, where used. These expenses can be significant, particularly for tertiary recovery methods. For example, heavy oil production requires large scale infrastructure to generate steam.

A workover is a procedure in which the subsurface plumbing of a well is repaired or replaced after it has been in service for some time. Refracture is a procedure in which current fractures of a well are enlarged, or new fractures are created. Refracture is most commonly performed several years after the well has been completed and initially stimulated, and is described further in Section 4.3.

The ultimate cost of decommissioning should also be included in the half cycle breakeven point. Decommissioning includes the secure plugging and abandonment (P&A) of the wells, and any necessary or desirable site restoration. P&A expenses are largest in offshore developments; in 2016 the U.S. Bureau of Ocean Energy Management promulgated new rules governing liability (Gladstone et al., 2016). The Texas Railroad Commission requires oil and gas producers to post surety bonds (Texas, 2005), but in many cases liability must be determined through litigation, particularly when an operator has abandoned the well or declared bankruptcy (Oran and Reiner, 2016).

3.3.3. Full cycle breakeven

The full cycle breakeven point encompasses the cost of oil production including all expenses of developing a new field. It is thus the most comprehensive measure of the cost of oil, and is appropriately used when planning a major extension of operations. It includes all the expenses of finding and delineating a resource, including geophysical prospecting, exploratory drilling, and measurements of the size and richness of the resource (“reservoir characterization”). It also includes obtaining rights to resource exploitation, which can be a complicated process where mineral rights are broadly distributed. Above-ground infrastructure such as roads are also included in full-cycle costs. If a common carrier is not available, as with liquefied natural gas projects, it includes takeaway capacity, including the capital expense of providing transportation to a market or to a specified pricing hub. The cost of financing all the above activities is included in the full cycle breakeven point. It might also include property tax on reserves, where levied (see e.g. Texas, 2016). Half cycle expenses, including all costs of maintaining level production, and lifting cost expenses, to actually produce oil and pay taxes and royalties as described above, are subsets of full cycle expenses.

The costs of financing field and well development are included in full cycle and half cycle categories respectively. Remarkably, free cash flow (cash flow less capital expenditures) has been negative for U.S. onshore

producers from the inception of the shale gas and tight oil boom through at least 2016 (Wall Street Journal, 2014; Sandrea, 2014; Domanski et al., 2015; EIA, 2016h). Producers have remained solvent by taking on debt, and by selling assets and equity; it appears some investors view tight oil plays primarily as real estate deals. Negative free cash flow is a characteristic of an industry in the process of building up its stock of productive assets. Indeed, since drilling slowed in Q1 2015, the gap between capital expenditures and operating cash flow has narrowed (EIA, 2016h).

3.3.4. Relationship between fixed and variable costs

Fixed costs do not depend on the level of production, whereas variable costs scale with output. The division between fixed and variable costs in Table 1 depends on the maturity of the asset. Finding costs come closest to being purely fixed costs, because normally geophysical surveys and leasing are completed prior to the drilling of producing wells. Delineation wells, which are generally not significant contributors to production, are part of the fixed costs.

Whether development costs are considered fixed or variable depends on the maturity of the asset. Early in the life of a field, its value is directly proportional to the number of wells drilled; thus these can be considered variable costs. Once drilling ceases, the cost of the wells is sunk, and the only variable cost is the lifting cost, except for general and administrative costs.

3.3.5. Fiscal breakeven

Full cycle breakeven costs, and all its components, are essentially technical and economic in nature, and as such are controlled by corporate decision-making, geological and geographic factors, market forces, and rates of taxation. Fiscal breakeven is of a completely different nature. It is the price of oil required to finance national expenditures, for those nations which depend heavily on oil receipts to fund government operations (Clayton and Levi, 2015; IMF, 2016). It includes full-cycle, half-cycle, or lifting cost expenses, depending on the state of the indigenous industry. Moreover, it depends directly on certain components of the technical breakeven costs, such as leases, royalties, and taxes. Where government is a major shareowner in oil companies, as is often the case in countries heavily dependent on resources, fiscal breakeven also depends on corporate dividends and similar payouts.

Although not generally expressed in this manner, individual corporations also have fiscal breakevens, which relate to the expectations of their investors. For those corporations financed predominantly by equity, fiscal breakeven includes revenues required to meet expected corporate dividends. Corporations like to show steady or rising dividends over time, which are put under pressure when income falls as a result of unexpected costs, or falling commodity prices. Recently, corporations have increased their debt load in order to pay dividends (Bloomberg, 2016).

3.3.6. Externalities breakeven

In some cases, breakeven costs might be considered to include additional aspects of production activities, such as social cost of carbon (EPA, 2016), direct and indirect costs of accidents, environmental impacts, and societal impacts (Greenstone and Looney, 2012; Jackson et al., 2014; HEI, 2015).

3.4. Geological, geographical, quality, taxation and exchange rate influences on breakeven points

3.4.1. Geological factors

Every oil field has a range of distinct breakeven points. A primary cause of breakeven point variation is geological. Conventional oil plays are defined by traps: the subsurface structural or stratigraphic geometries of oil or gas reservoirs in which the placement of fluids is driven by their buoyancy (USGS, 2016). Small traps are clearly harder to find,

and are less productive when found. Large traps can be delineated and produced at exceptionally low cost - as low as a few dollars per barrel of oil produced.

Unlike conventional reservoirs found in traps, “shales” (more properly referred to as organic-rich mudstones (Kleinberg, forthcoming)) are continuous: “large volumes of rock pervasively charged with oil and gas” (USGS, 2016). Although these plays may be hundreds of kilometers in extent, the richest rock bodies, and those most susceptible to hydraulic fracturing, can be quite localized (Gulen et al., 2015; Ikonnikova et al., 2015). Thus there are considerable variations in breakeven points between and within sub-plays (North Dakota Department of Mineral Resources, 2015; Wood Mackenzie, 2015a).

3.4.2. Geographical factors

Equally important are geographical factors. The local availability of oil field infrastructure has a major influence on breakeven points. Much of the field and well development inherent in resource exploitation is performed by a network of contractors who provide materials and perform services essential to every aspect of this process. Local availability of - and the presence of competitive markets for - exploration expertise and instrumentation; drilling rigs, equipment and services; and completion and stimulation services, have a major influence on oil field development costs. Operators engaged in onshore exploratory drilling in advanced industrialized nations in Europe are dismayed to learn they are in “frontier areas” with respect to oil field services, where costs can be double or triple those prevailing in Texas or Oklahoma. This is true even when those nations, such as the United Kingdom, have well established offshore exploration and production industries with globally competitive economic structures.

All else being equal, well construction costs in ultra-deepwater (greater than 1500 m water depth) are an order of magnitude greater than on land. Therefore only very productive reservoirs can be exploited, and there must be a strong expectation that future oil prices will be high enough to warrant investment. Arctic regions can also be economically challenging, even though in various parts of the Arctic very significant amounts of oil have been produced.

Nonetheless, the petroleum industry is remarkably adaptable, and operates efficiently in many improbably remote locations. Economy of scale is key, and once sufficient activity develops in a geographical locale, no matter how remote or uninhabitable, cost reduction will follow. Thus the lowest-cost places in the world to work are many areas in the United States and Canada, the nations surrounding the Arabian Gulf, and infrastructure-rich parts of Russia, all of which have long histories of intensive oil and gas development. For example, in mid-2014, at a recent peak of oil prices, there were 1850 land rigs in the United States and only 100 in all of Europe. This is one of the reasons why exploitation of shale gas resources developed so much more rapidly in the United States than anywhere else.

One of the greatest hurdles to working in remote areas is the cost of transporting product to markets (“takeaway”). This is particularly true for natural gas, for which practical transport is limited to large-diameter high-pressure pipelines, or liquefied natural gas ships and associated export and import facilities. Both approaches are costly (Shaw and Kleinberg, forthcoming). Thus, for example, plans for exploitation of natural gas on the North Slope of Alaska have been repeatedly frustrated by the cost of moving gas to markets. Oil transportation is generally cheaper and easier because of its much higher energy density under ambient conditions of temperature and pressure.

Finally, country risk can be a decisive factor in the decision whether or not to develop a resource. There are a wide variety of risk factors, including the extent and stability of environmental regulations; labor availability, regulations, and militancy; disputed land claims; political and legal instability; and insecurity arising from crime, conflict, or terrorism (Jackson et al., 2016). Arguably, tight oil fields are less subject to political risk such as expropriation because the payback time of an individual well is short, and field production can only be maintained by

continuous drilling of wells requiring technically sophisticated horizontal well construction and high volume multistage fracturing.

3.4.3. Quality factors and price hub locations

The market price of a barrel of crude oil depends on its value to refiners. Generally speaking, “light” (low mass density) oils comprising low molecular weight hydrocarbons are more valuable than “heavy” (high mass density) oils with high contents of nitrogen-, sulfur-, and oxygen-bearing compounds.

The location of the hub at which oil is priced can also be an important factor. As mentioned above, oil is normally relatively inexpensive to ship long distances via pipeline or tanker (Shaw and Kleinberg, forthcoming). However, when the rate of oil production temporarily exceeds available transport capacity, significant price differentials between hubs can develop. Historically, prices of Brent Crude, traded in northwestern Europe, and West Texas Intermediate (WTI), traded in Cushing, Oklahoma, have been within a few percent of each other. However, between 2011 and 2014, when U.S. tight oil production increased so rapidly that pipeline capacity was exceeded and railroads were brought into service to move crude oil (EIA, 2016o), the Brent price exceeded WTI by as much as 20% (EIA, 2013).

When quality and hub location factors combine, price differences can be especially large. For example, in December 2013, WTI sold for \$98/bbl in Cushing, while Western Canadian Select, which is both heavy and transportation constrained, sold for \$59/bbl in Hardisty, Alberta (Alberta, 2016).

In many plays, substantial quantities of associated gas are produced with oil. In such circumstances, the heating value of the combined production can be referenced to barrels of oil equivalent (boe), which is defined in terms of the higher heating value (HHV) of the oil and gas products upon combustion: 1 boe = 5.8 million Btu = 6.1 GJ (IRS, 2005). However, the barrel of oil equivalent is not a valid means of estimating the economic value of production, as the relative prices of gas and oil often do not scale with their heating values. Associated gas rich in methane and natural gas liquids - ethane, propane, normal butane, isobutane, and natural gasoline - can be more accurately assessed in terms of the individual product streams, which have species-specific values to the refining and petrochemical industries (Brazier, 2016; EIA, 2016e).

3.4.4. Taxation

The kinds and amounts of taxes imposed on the petroleum industry by governments are driven by two conflicting desires: first to maximize tax receipts, and second to encourage economic development associated directly and indirectly with hydrocarbon production. Generally speaking, the easier it is to find oil, and the cheaper it is to extract, the larger the tax (Brackett, 2014). Practices vary widely among countries (EY, 2015) and from state to state within the United States (EIA, 2015c). In the U.S., oil and gas production is encouraged by special tax preferences, the three most important of which were worth about \$5 billion in net tax reductions to the industry in 2017 (Metcalf, 2018).

3.4.5. Exchange rate factors

Breakeven points are conventionally stated in U.S. dollars per barrel of oil. While oil is traded internationally in dollar-denominated contracts, in some cases breakeven points are more appropriately stated in terms of national currencies. For example, the Russian oilfield service sector is large and well-developed, and prices its services in Russian rubles. From mid-2014 to early 2016, when the ruble fell in value relative to the dollar in synchrony with the decline in the international price of oil, Russian oil companies came under less financial pressure than did Western oil companies (Financial Times, 2016; IHS, 2016). In essence, technical breakeven points in ruble terms remained mostly unchanged. However, Russia's dollar-denominated balance of trade with other countries suffered as a result of the dollar-denominated oil price decline.

3.5. How breakeven points change with time

Despite the lack of transparency of many breakeven point estimates, the mid-2014 consensus range of \$60/bbl to \$90/bbl for full cycle breakeven in tight oil plays, appears to have been broadly accurate. Once oil prices fell through this range, in the second half of 2014, rig counts in the major tight oil basins collapsed, as illustrated by Fig. 2a and b. More than 100 North American exploration and production companies, and a similar number of oilfield service companies, filed for bankruptcy between January 2015 and mid-2016 (Haynes and Boone, 2016a; Haynes and Boone, 2016b). Even the strongest of the U.S. independent tight oil producers reported negative operating and net incomes throughout this period.

However, one of the pitfalls of inadequate understanding of breakeven points is a failure to realize that they change with time. For example, in Andrews, Martin, Howard, and Midland counties, in the Permian Basin of Texas, breakeven points declined from \$76/bbl in June 2014 (Wood Mackenzie, 2014b) to \$37/bbl in August 2016 (Wood Mackenzie, 2016c), behavior that was typical of U.S. tight oil plays (IHS, 2017). We identify two kinds of changes. *Internally-driven* changes reflect steady microeconomic improvements in infrastructure and efficiency. *Externally-driven* changes occur in response to changing macroeconomic conditions. In the dynamic U.S. oil and gas industry, and particularly in the tight oil sector in which production technology is evolving rapidly, internally and externally driven changes can significantly alter production economics on a time scale of 1–2 years.

3.5.1. Internally-driven changes

Table 2 outlines some of the internal drivers of breakeven point change. Changes can be early or late in the development cycle, and can increase or decrease costs. Often, breakeven points are high or increasing early in development, as oil producers compete for resources such as leases, personnel, and infrastructure. Later in the development cycle, debottlenecking and increased competition among service providers causes costs to fall. Thus well drilling and completion costs in five U.S. shale gas and tight oil plays rose from 2010 to 2012 and fell from 2012 to 2015 (EIA, 2016c), during a period in which oil prices were stable.

Decreasing costs can be accompanied by increasing production. From late 2012 to the third quarter of 2014, internally-driven improvements led to a doubling of new well oil productivity per rig in the Bakken tight oil play, see Fig. 4. This was partly due to wells being drilled and completed more quickly, and partly due to increases in the initial production per well (EIA, 2016a). Throughout this period, West Texas Intermediate crude traded in a narrow range around \$100/bbl (EIA, 2016m).

Taxes and other aspects of “government take” can be important exceptions to the pattern of costs falling over time. Governments seek

Table 2

Internally-driven factors which change breakeven points, early and late in the development cycle. Factors which increase costs are shown in bold font, and factors which decrease costs are shown in italic font.

Stage in Development Cycle	
Early	Late
Exploration & delineation	<i>De-risked geology</i>
Well construction surprises	<i>Efficient well construction</i>
Competition for leases	<i>Consolidation of leases</i>
Supply chain bottlenecks	<i>Supply chain optimization</i>
Infrastructure bottlenecks	<i>Infrastructure buildout</i>
Service cost increases	<i>Service cost discounts</i>
Equipment shortages	<i>Increased competition</i>
Personnel shortages	
<i>Tax Decreases</i>	Tax Increases

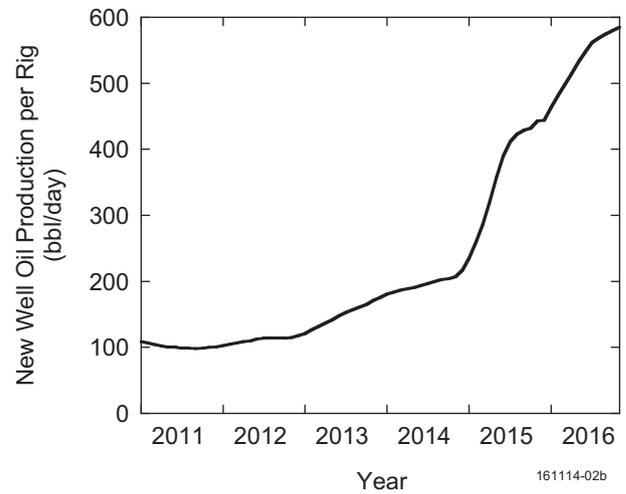


Fig. 4. Productivity of drilling rigs directed to Bakken tight oil. Internally-driven changes occur throughout the period shown. Externally-driven changes are driven by rapid declines in the price of oil, e.g. mid-2014 through 2016. The vertical axis represents the amount of new production an average rig, operating for one month, contributes to the oil supply (EIA, 2016k).

to maximize their share of oil industry revenues, and while some countries have fixed rates of taxation, others change their tax rates at will, increasing taxes to just short of the point at which local oil exploration and production is discouraged and moves elsewhere. At the inception of activity, when risks are high and sunk costs are low, or when oil prices are low, governments encourage activity with low tax rates. After reserves have been booked and expensive infrastructure built, or when oil prices increase, tax rates can increase.

3.5.2. Externally-driven changes

Breakeven points change as a result of changes in the price of oil. While the price of oil depends on the cost of its production, the opposite is also true: the cost of oil production depends on capital, labor, and material inputs, the prices of which are affected by the state of the oil market. When the price of oil is high relative to long term trends, as it was in 2011–2014, the goals of producers are rapid growth of reserves and production: they are incentivized to find, delineate, and develop new fields, with all the attendant inefficiencies. Service providers offer new, more expensive technology directed to those objectives. Cost control is a secondary consideration. Service company profitability increases.

These trends are also dependent on the rate of change of the oil price. Rapid expansion of the industry creates bottlenecks in equipment, supplies, labor, and infrastructure. The oil industry faced such stresses from the early 1970s to the early 1980s, when the price of oil quadrupled in inflation-adjusted dollars. Discovery of rich new plays sets off a similar gold-rush mentality, as illustrated by the advent of tight oil production in 2009–2014.

When oil prices decline, all these trends are reversed. Exploration, the growth engine of the industry, slows to a crawl. Determination of the areal and vertical extent of the reservoir, and measurements of the spatial variation of its richness (asset delineation or “de-risking”) is no longer prioritized. The industry tends to focus on familiar resources and geographical areas known to contain substantial recoverable reserves (with a few notable exceptions, such as the Alpine High field (Apache, 2016)), and within those areas, the best drilling locations (“sweet spots”), a process known as asset high grading. This leads to a greater responsiveness to price changes (Smith and Lee, 2017). Moreover, a large reduction in the number of drilling rigs results in survival of the most modern and efficient rigs, manned by the most experienced and successful drilling crews. This might be termed operational high grading. Thus over the period 2004 to 2015, the IHS Upstream Capital

Cost Index (IHS, 2015a) tended to increase *after* increases in the price of Brent crude, and tended to decrease *after* decreases in the crude price.

As illustrated in Fig. 4, rig productivity can increase rapidly due to externally-driven factors. After having doubled during times of relatively constant oil prices, Bakken rig productivity increased by another factor of three while oil prices declined precipitously from the third quarter of 2014 through 2016. During this period, normal process improvements were amplified by asset high grading and operational high grading.

In addition to internally-driven cost reductions due to normal improvements in efficiency, and externally-driven market-related cost reductions due to asset high grading, steep declines in activity enable operators to drive down costs while the supply of services exceeds the demand for them. Service providers respond by laying off personnel and by warehousing (“stacking”) or destroying or cannibalizing (“writing off”) equipment, but these cost-control measures, which are costly in themselves, usually do not keep pace with the rapid declines in business activity, such as occurred in 2014–2016.

The Permian Basin provides another dramatic example of how rapidly price structures can change. Following the national trend, the Permian Basin oil-directed rig count fell by more than 75%, from a peak of about 560 rigs in November 2014 to a trough of about 130 rigs in April of 2016 (Baker Hughes, 2016), see Fig. 2b. Much of this decline was due to retirement of almost all of the 200 vertical and directional rigs, which were primarily exploiting the conventional subplays of the basin, but even the horizontal rig fleet declined by almost two-thirds. Nonetheless, tight oil production continued to increase through 2016 (EIA, 2016k). While oil prices were relatively stable between 2012 and late 2014, internally-driven improvements doubled rig productivity. Falling oil prices after late 2014 triggered externally-driven improvements, which increased rig productivity by a further factor of 2.7 (EIA, 2016k), while well costs declined by 35% and production costs declined by 25% (Pioneer Natural Resources, 2016).

Governments can change tax structures and rates in response to market conditions. When oil prices are rising, governments can increase tax rates without driving producers out of business or to other countries. When oil prices fall, governments are forced to make tax concessions to maintain the viability of their petroleum industry (Wood Mackenzie, 2017).

3.5.3. Change in type of breakeven point

Just as importantly, the relevant type of breakeven point changes with time. Once finding costs are sunk, the full cycle breakeven oil price is no longer relevant in assessing project economics going forward. Similarly, once drilling concludes, the cost of well construction becomes irrelevant. Thus there is a natural progression of a project from full cycle economics through half cycle economics to lifting cost economics.

The relevance of the various breakeven points also changes due to external drivers:

- During periods of rising oil prices, when producers move into new plays, full cycle breakeven is relevant to planners and investors.
- In stable markets, when activity is focused on in-fill drilling and modest step outs in de-risked plays where infrastructure is in place, half cycle breakeven economics is most relevant.
- When markets are in free fall and oil companies are focused on survival, the viability of existing assets is measured against lifting costs.
- When prices rebound, some operators will have accumulated substantial acreages of derisked prospects, with plenty of undrilled sites in their inventories. They will be able to continue with favorable half-cycle economics for some time. However, as their sweet spots are depleted, as is already occurring in the Barnett shale, and they have to move to fresh prospects, they will be forced to return to full cycle economics.

The tiered nature of breakeven points is important because the tiers are relatively far apart. In mid-2014, full cycle breakeven points for U.S.

tight oil produced by massive hydraulic fracturing were generally in the range of \$60–\$90/bbl. Given that the excess of oil supply over demand was in the range of 1–2%, and that “rapidly responding” tight oil constituted about 4% of the world oil market, one might have expected that the price of oil was unlikely to fall below about \$60/bbl. However, half cycle breakeven points were in the range of \$50–\$70/bbl, and lifting costs were below \$20/bbl. When oil prices declined, not only did these brackets move to lower cost ranges due to internal and external drivers (compare e.g. Wood Mackenzie, 2014a, 2015a, 2016b; Goldman Sachs, 2017), but there was a large-scale transition from greenfield full cycle economics, to the half cycle economics of drilling to maintain level production, and eventually, after the second half of 2015, to production from existing wells. Anticipated profits vanished, and the capital expenses accounted for in full-cycle economics became sunk costs reflected in falling share prices, debt restructuring, asset sales, or bankruptcy.

4. Other factors affecting tight oil market dynamics

The conventional definition of price elasticity of supply is the ratio of the percentage change of quantity supplied to the percentage change in price. When this ratio is less than unity, the market is said to be inelastic (Mankiw, 2011). The supply of oil is inelastic in the short term. This inelasticity arises from many sources, each of which has its own characteristics.

4.1. Rate of growth of tight oil production

Part of the conventional wisdom surrounding tight oil production is that it is very responsive to changes in markets. This certainly seemed true from 2009 to 2014, when tight oil production grew from 700,000 bbl/d to 4,200,000 bbl/d (EIA, 2015b). During the latter part of this period (following recovery from the recession of 2008), rates of growth of U.S. oil production were the largest in more than 100 years, mostly attributable to tight oil (EIA, 2015a).

However, these dramatic growth rates do not imply tight oil is cheaper or easier to produce than conventional oil. In fact, tight oil wells are more expensive and more complex to construct than most conventional oil wells, requiring specialized equipment, such as bottom hole assemblies capable of horizontal drilling and fleets of truck-mounted high-pressure high-volume pumps. However, exactly the same drilling rigs and hydraulic fracturing equipment are used to exploit shale gas and tight oil, and large quantities of this equipment had been brought into service during the shale gas boom that started in 2004. That boom terminated abruptly at the end of 2008, when gas prices fell from \$6–\$14 per million British thermal units (1 MMBtu = 1.055 GJ) to \$2–\$4/MMBtu, causing the number of U.S. gas-directed drilling rigs to fall from 1600 to 700. Thus tight oil drilling programs could ramp up rapidly when the West Texas Intermediate benchmark oil price doubled in 2009, as shown in Fig. 5. The rapid increase of tight oil production, rather than being a property intrinsic to tight oil, was the product of the accidental, rapid crossing of oil and gas prices, and the fact that shale gas and tight oil drilling and stimulation equipment is interchangeable.

Note however that despite the redirection of drilling rigs from shale gas to tight oil, U.S. natural gas production did not decrease. One reason was continued improvement in well recovery rates in the Marcellus dry gas play. Another was the rapidly increasing production of natural gas associated with tight oil, mostly from the Bakken, Eagle Ford, and unconventional Permian plays, which grew from essentially zero in 2009 to 13% of total U.S. gas production by mid-2015 (IHS, 2015b).

Once drilling and stimulation infrastructure are generally available, onshore production of oil can respond rapidly to price signals. The average lag between investment and production for tight oil wells is about one year, coincident with the shortest lags associated with all oil wells drilled in 14,000 oilfields between 1970 and 2015 (Bornstein et al., 2017). The entire Bornstein data set is broadly distributed, the longest

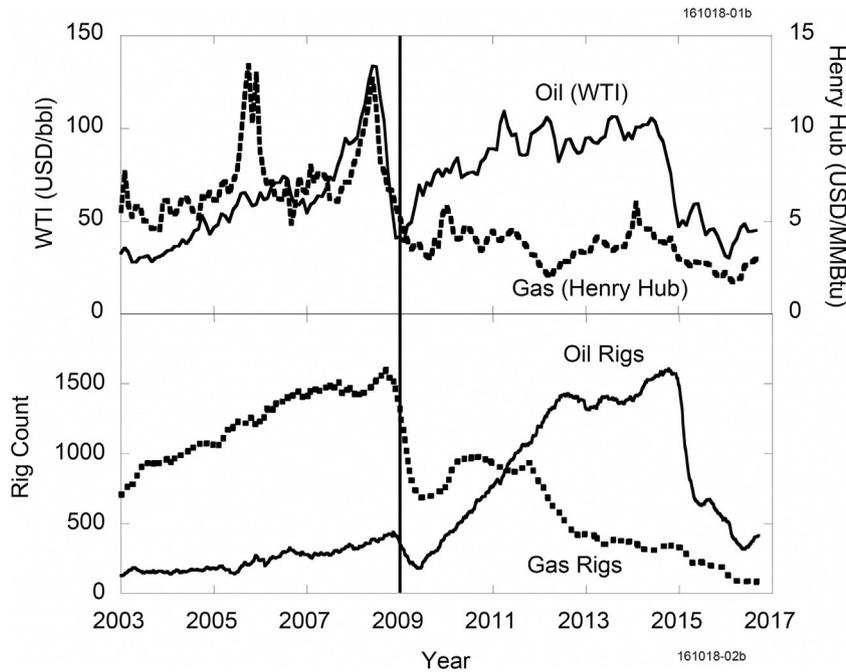


Fig. 5. Horizontal drilling rigs (bottom) (Baker Hughes, 2016) and hydraulic fracturing equipment moved from gas plays (dotted curve) to oil plays (solid curve) after oil and gas prices diverged (top) (EIA, 2016m, 2016n).

lags presumably associated with wells drilled in deepwater or frontier regions.

4.2. Rate of decline of tight oil production

When oil prices fell, the decrease of tight oil production proved slower than some expected. In the two years following the completion of a well, tight oil production from that well declines quickly, in contrast to conventional oil wells under secondary recovery. Thereafter, the decline of tight oil wells roughly parallels that of conventional wells, see Fig. 3. However, there are important differences between the production rate of individual wells and that of a field of such wells. The rate of decline of production for a field comprising numerous wells drilled at various times is not necessarily the same as the rate of decline of an individual well in that field, even if all wells have exactly the same production parameters.

To illustrate this principle, we compare a simplified model of a conventional oil field with a comparable model tight oil field. We model the conventional oil field development as a series of 48 wells, completed at the rate of one per month. Each well has an initial (maximum) production of 1000 bbl/d, performance which is above average but not unknown in U.S. onshore fields. Following standard oilfield practice (Cosse, 1993), the field is assumed to be put on secondary recovery immediately after production starts, thereby maintaining reservoir pressure.

We model tight oil field development using assumptions similar to those used for the model conventional field: 48 wells, completed at the rate of one per month, with initial production of 1000 bbl/d, again above average but not exceptional (Sandrea, 2012; EIA, 2016a). Because tight oil fields cannot normally be put on secondary recovery (Kleinberg, 2014), individual wells decline rapidly in the first several years, typical of primary recovery.

For an ensemble of wells completed at times t_k , with k ranging from 1 to N , where N is the total number of wells completed, the rate of oil production from the field at any time t is given by

$$Q(t) = \sum_{k=1}^N q_k(t-t_k) \quad (1)$$

where $q_k(t-t_k)$ is rate of production from a single well k at the time t subsequent to the completion of that well at time t_k . Since wells do not produce prior to being completed, $q_k = 0$ for all $t < t_k$. Eq. (1) allows each well to have a unique decline curve q_k . In our models we assume all conventional wells have a common decline curve, q_c , and all tight oil wells have a different common decline curve, q_t .

In a *conventional oil field* under secondary recovery, rates of decline are roughly uniform over much of the life of each well:

$$\frac{1}{q_c} \frac{dq_c}{dt} = -\alpha_y \quad (2)$$

where α_y is the annual rate of decline, which we shall assume to be $\alpha_y = 0.06/\text{yr}$. This corresponds to an annual rate of decline of 6%, a value that is justified below. The monthly rate of decline is $\alpha_m = \alpha_y/12$. This simple differential equation is integrated to find the conventional oil well decline curve when the field is on secondary recovery; IP is the initial production rate of an individual well:

$$q_c = IP \cdot \exp(-\alpha_y t) \quad [t] = \text{years} \quad (3a)$$

$$q_c = IP \cdot \exp(-\alpha_m t) \quad [t] = \text{months} \quad (3b)$$

For the model of a *tight oil field*, we assume that all wells have a common decline curve q_t , given by a Bakken average type curve (IHS, 2013b) normalized to an initial production rate of 1000 bbl/d, see Fig. 3.

After the cessation of completions in month 48, the conventional oil field declines at an annual rate of 6%; a sum of exponentials decays at the same rate as the individual exponential functions of the argument of the summation. With this knowledge, we selected the individual well decline rate, $\alpha_y = 0.06/\text{yr}$, based on a global average of conventional oil field decline rates (IEA, 2013).

The results of the two models are shown in Fig. 6. During months 1 to 48, while wells are being completed, the production from both fields increases with time. Because the conventional wells decline rather slowly, the ramp up of production during the development phase is nearly linear. The much more rapid initial decline of production of the

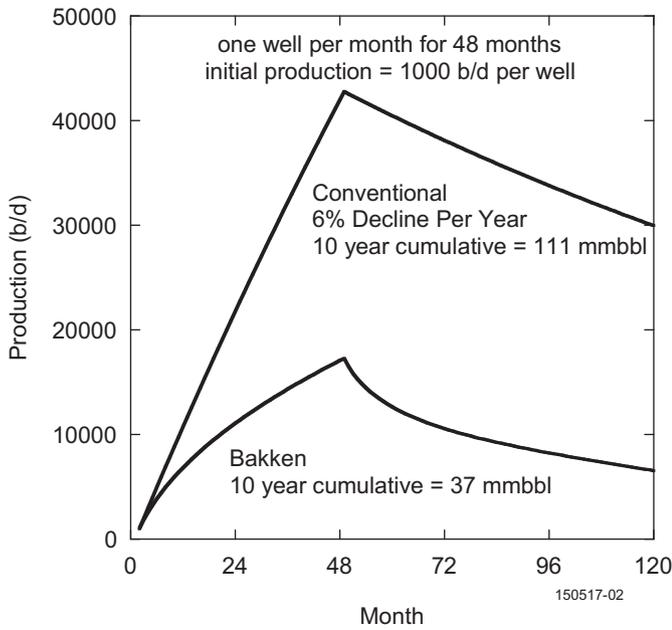


Fig. 6. Modeled field-level production in conventional and tight oil (Bakken) fields, during and after 48 month drilling and completion campaigns, using the individual well decline curves shown in Fig. 3.

tight oil wells leads to a distinctly sublinear ramp up of production. This is the origin of the “Red Queen Race” (Likvern, 2012).

After the cessation of completions in month 48, the conventional oil field declines at an annual rate of 6%, the global average of conventional oil field decline rates. Unlike the conventional oil field, the tight oil field does not decline at a time-invariant rate following the cessation of drilling, as shown in Fig. 6. Table 3 provides a summary of annual production decline rates of the model conventional and tight oil wells and fields. Although tight oil fields experience a substantial decline in production in the first two years after cessation of drilling, as the most recently-drilled wells decline, a larger number of slowly-declining legacy wells supports substantial continued production. Thus tight oil fields with large legacy inventories of wells will produce substantial quantities of oil for many years after completions have ceased. Note that Table 3 is only illustrative: tight oil field decline rates depend on details of the development schedule. If completion activity has increased immediately prior to cessation, a large proportion of wells in the field are relatively new, leading to faster initial decline of field-level production once drilling and completion comes to an end. On the other hand, if completion activity has slowed in the year or two before terminating, production after termination will decline more slowly than suggested by Fig. 6 and Table 3.

Table 3

Percentage annual decline of conventional oil well and field under secondary recovery, and tight oil well and field under primary recovery. The field level declines follow the termination of the drilling and completion program. The tight oil results are model-dependent, as explained in the text.

Year	Conventional oil (secondary recovery)		Tight oil (primary recovery)	
	Well	Field	Well	Field
1	6%	6%	60%	28%
2	6	6	27	16
3	6	6	18	12
4	6	6	13	11
5	6	6	11	11

4.3. Refracturing

It is generally agreed among oilfield service companies that hydraulic fracturing is an imperfect method for connecting gas or oil in low permeability formations to the wellbore; according to production logs, 30–40% of fractures do not produce fluids (Jacobs, 2015; Hunter et al., 2015). Either of two types of refracturing are used to overcome this problem. In the “reconnect” procedure, fractures that are poor conduits for fluid flow can be reopened, whereas in the “restimulate” procedure, new fractures are created (Hunter et al., 2015). Refractures cost between about 20% and 40% of the cost of a new well (Lindsay et al., 2016), so it would seem the economic case for these techniques would be compelling. Nonetheless, experience has shown that a rigorous screening process maximizes the chance of success (Hunter et al., 2015), and only a few percent of shale gas and tight oil wells drilled in the last ten years have been refractured using chemical diversion, the most cost-effective technique (Lindsay et al., 2016). Lack of predictability is the main barrier to widespread implementation (Wood Mackenzie, 2016a).

4.4. Infrastructure, labor and financial inelasticities

Following an industry collapse, as occurred in 2014–2016, the rate at which tight oil production can ramp up once drilling resumes depends on how equipment was taken out of service during the period of low activity. If equipment is written off, it is destroyed or cannibalized. However, when equipment is stacked, as is the practice of some large service providers (Schlumberger, 2015; Seeking Alpha, 2016), it is assumed to retain value as a productive asset and is warehoused accordingly.

A second factor is labor availability. Labor required in the tight oil sector, along with associated equipment, made a smooth transition from gas drilling to oil drilling in 2009. Following massive layoffs from the petroleum industry in 2015 and 2016, skilled labor may not be as abundant in the future as it has been in recent years. The duration of training varies with the degree of skill and specialization required, and can exceed a year to gain proficiency in some job categories.

Financial markets also introduce inelasticity. The ready availability of capital played an important role in the initial growth of the US tight oil industry, with many producers, year after year, operating at negative free cash flow (cash flow after capital investments) (Sandrea, 2014; EIA, 2014, 2015d; Domanski et al., 2015). It remains to be seen whether debt and equity financing is as available in the future.

5. Oil market stability

5.1. Short term market stability

5.1.1. Spare capacity

Although it has been stated that US tight oil can challenge Saudi Arabia as the world’s marginal producer (e.g. The Economist, 2014), this assertion is open to question. Spare capacity is the most important characteristic of a swing producer. Spare capacity is defined as production that can be brought on line within 30 days and sustained for at least 90 days (EIA, 2016f; Munro, 2014). While there is no doubt Saudi Aramco can increase production this rapidly, the US tight oil industry cannot. In addition, unlike OPEC members, who can in theory increase or reduce their oil production in concert, the hundreds of U.S. producers cannot and will not coordinate their activities.

5.1.2. Inventories

Inventories of crude oil and petroleum products are also drivers of short term market stability. As of the first quarter of 2017, US commercial crude oil and product inventories amounted to 1.34 billion barrels, with an additional 0.69 billion barrels of crude oil in the U.S. Strategic Petroleum Reserve (SPR) (EIA, 2017a). Altogether this amounts to

about 100 days of U.S. consumption. If needed, the SPR can be drawn down at a maximum rate of 4.4 million barrels per day for 90 days, after which the maximum rate decreases (Carr, 2017). Thus SPR meets the definition of spare capacity.

5.2. Medium term market stability

Although tight oil resources do not constitute spare capacity in the strict sense of that term, it is useful to consider a second type of spare capacity: a medium-term spare capacity, which can be brought on line in a few months. Given the special circumstances explained in Section 4.1, the U.S. tight oil industry sustained production rate increases of 1 million barrels per day per year from January 2011 until January 2015, see Fig. 1. Other factors also suggest that U.S. tight oil production can contribute to medium term price stability.

5.2.1. Drilled but uncompleted wells

Drilled but uncompleted wells (“DUCs”) have become a resource capable of providing medium-term market stability. The use of the “drilled-but-uncompleted” terminology is widespread but imprecise; such wells should be called “drilled and partially completed”. Completion of oil and gas wells includes lining the well with steel pipe, cementing the pipe in place, perforating the pipe to either start hydrocarbon production or to create fracture initiation points, stimulating the well (most often by fracturing), and installing other equipment (such as pumps) to bring liquids to the surface. A DUC has been drilled, cased, and cemented, but perforation and stimulation have not yet been performed. The cased and cemented well is stable, and production can be delayed indefinitely without risk. Once the well is perforated and stimulated, reservoir equilibrium is disturbed and stopping the flow of fluids can have unintended consequences that can negatively affect future production.

There are several reasons why more wells are drilled than are completed (Nasta, 2016). First, delays in scheduling and mobilizing fleets of high-value hydraulic fracture equipment are normal. Second, some drilling rigs are leased on long term contracts, which are uneconomical to cancel prior to the completion of a drilling campaign. Third, some leases require a certain level of drilling activity, or the lease is forfeit. Fourth, a lag in the availability of pipeline capacity affects the rate at which gas wells, or oil wells that produce substantial amounts of associated gas, can be put on line. Fifth, after the fall in the price of oil started in mid-2014, fracturing was delayed in the expectation that oil left in the ground would be worth more in the future.

Some of the reasons for delaying well completion are illustrated by Fig. 7. When prices decline (July 2014–January 2015; September 2015–January 2016), the inventory of DUCs grows, as operators keep oil in the ground in expectation of higher prices in the future. DUC inventory also grows when activity is strong (January 2014–July 2014; January 2017–April 2017) due to infrastructure and service bottlenecks.

5.2.2. Leases held by production

Markets can also be stabilized by the availability of undrilled well locations, where the resource has been de-risked and leases have been secured. The desire of oil and gas producers to have a substantial inventory of locations ready to be drilled in response to market signals can conflict with the land- or resource-owner's desire to realize royalty income as quickly as possible. These interests are balanced by lease contracts, which typically provide that a lease granted to an oil or gas driller is cancelled unless royalties are derived from it within a specified period, often three years. The lease remains in force for as long as the stream of royalty revenue continues (Smith, 2014; Herrnstadt et al., 2017).

Leases must encompass the entire subsurface volume drained by wells drilled on them. Since shale gas and tight oil wells have horizontal legs ranging from one to two miles in length, with perpendicular fractures hundreds of feet in length, leases are now commonly one to two square miles in area. Each lease may include property from several

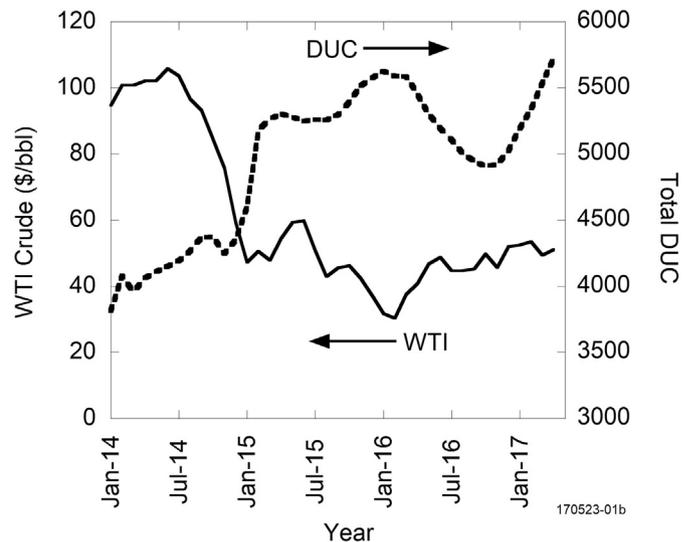


Fig. 7. U.S. tight oil and shale gas drilled but uncompleted wells (EIA, 2017b) (dotted curve, right axis) and West Texas Intermediate crude oil price (EIA, 2017c) (solid curve, left axis) from January 2014 to April 2017.

resource owners (“unitization”), with royalties pooled and divided equitably.

In order to maintain maximum operational flexibility, an oil or gas producer may drill, complete, and put on production only a single well in a lease that might be fully developed by six or more wells. That well might remain on production for many years, albeit at low levels. Such leases are held by production, and allow a producer to retain a large inventory of ready-to-be-drilled well locations (Smith, 2014; Herrnstadt et al., 2017).

5.2.3. U.S. tight oil as a price maker

Given the factors promoting medium term price stability, despite important inelasticities, and despite lacking any coordination among suppliers, U.S. tight oil has the potential to impose some discipline on crude oil pricing. The threat of significant new quantities of product entering the market when the price of oil exceeds the lower bound of tight oil full cycle breakeven, about \$50–\$60/bbl in 2017, may provide a restraint on the expectations of market participants who seek to raise prices by cutting production.

The effectiveness of U.S. tight oil to be a price stabilizer was tested in early 2017. In November 2016, in an effort to increase the price of crude oil, ten OPEC and eleven non-OPEC nations agreed to cut oil production by 1.81 million barrels per day. By April 2017, this group had reduced production by 1.73 million barrels per day relative to October 2016, substantially achieving their objective. However, this effort was partially undercut by the U.S. tight oil industry, which between December 2016 and May 2017 increased production capacity by more than 300,000 barrels per day (EIA, 2017b).

The ability of the U.S. tight oil industry to be a price maker is in marked contrast to industry segments which exploit deepwater, arctic, and other challenging resources. Adding significant capacity in those sectors can take years, and they are thus price takers. The same is true of tight oil resources outside the U.S., as those resources are undeveloped and therefore lack the ability to increase production at a rate that would be significant in world oil markets.

The longer term outlook is less certain. From 2011 to 2015, 1 million barrels a day of production was added each year, a rate of increase almost unprecedented in the history of the industry. However, the U.S. Energy Information Administration Annual Energy Outlook 2016 (AEO2016) reference case predicts a much slower growth rate of about 120,000 b/d per year between 2020 and 2030. Production is expected to increase faster in the High Oil Price case, but then cannot be

sustained after 2025. Only in the High Oil and Gas Resource and Technology case do the rate increases of 2011–2015 continue past 2020 (EIA, 2016j).

6. Discussion

Given knowledge of a range of breakeven points for a relatively high-cost resource, a lower-cost competitor with ample spare capacity might be tempted to increase production to the extent that the price of the resource falls below the breakeven point range of its higher-cost rival. To be successful, this strategy requires an understanding of the tiered nature of breakeven points. Frequently, breakeven point data are presented by analysts, or in corporate presentations to investors, without adequate disclosure of what exactly is meant by breakeven. In this paper we have shown that benchmark and breakeven points are only useful to the extent their calculation is transparent.

In projections of the reaction of oil production to changes in the price of oil, many analysts underestimated the dynamic nature of tight oil economics. In mid-2014, full cycle breakeven points for U.S. tight oil produced by horizontal well construction and massive hydraulic fracturing were generally in the range of \$60–\$90/bbl, giving rise to expectations that the price of oil was unlikely to fall below about \$60/bbl. Half cycle breakeven points were in the range of \$50–\$70/bbl, and lifting costs were below \$15/bbl. When oil prices declined, not only did these brackets move to lower cost ranges due to internal and external drivers discussed in this paper, but there was a large-scale transition of breakeven points. Oil production promptly shifted from full cycle projects to the half cycle economics of drilling to maintain level production. After the second half of 2015, drilling was no longer adequate to maintain level production, but oil production continued from pre-existing wells, the rate of production from which falls rather slowly after the first two years or so.

In this paper we propose a consistent treatment of breakeven points - full cycle, half cycle, and lifting cost - and explain internally-driven and externally-driven changes in breakeven point economics. In a rapidly evolving industry such as tight oil production this analysis is itself subject to change. Nonetheless, it is important for a variety of reasons:

- The various levies imposed by governments, including leases and royalties, are calculated to maximize payments while allowing oil producers to retain sufficient profit to make resource development attractive. A better understanding of breakeven points by governments would facilitate this process.
- Asset valuation depends critically on estimates of future costs. Because stable tight oil production requires the continuous drilling and completion of wells, the economics of a long-lived play requires understanding how half cycle breakeven points change over time. Similarly, the economics of growing oil volumes requires analysis of full cycle breakeven points. In both cases, secular changes due to internal and external drivers should be taken into account.
- Energy analysts, in both private and government sectors, can improve forecasts by incorporating into their economic models realistic ranges of breakeven points, and models of how these change under various conditions.

Inelasticity in the response of oil production to market signals is a further complication, the understanding of which requires close examination of individual well decline curves and their implications at play level. The interaction between productive capacity and technical features of oilfield practice, such as drilled but uncompleted wells and refractured wells, must also be considered, as does oilfield and takeaway infrastructure, capital markets, and labor factors.

7. Conclusions

Breakeven points are among the most useful measures of the economic viability of a hydrocarbon development project. They are particularly useful in assessing the robustness of the project with respect to a decline in the price of the produced commodity: if future market prices are projected to be comfortably above the breakeven cost of a project, the investment is likely to be a profitable one.

This work explores the following characteristics of breakeven point analysis:

- The breakeven point is most useful when its calculation is transparent. We argue that the purveyors of breakeven point data have a responsibility to carefully define the elements that go into their calculations.
- While recognizing that various users will want to define breakeven points in ways most useful to them, we propose a model breakeven point scheme that incorporates many elements of these calculations, and which approximates consensus schemes used by analysts and industry participants.
- We define and explain each major category of expense in our slate of breakeven costs.
- We divide our slate of costs into three major categories: full cycle, half cycle, and lifting cost. These terms are common in the breakeven analyses found in the work of analysts, agencies, and oil producers; we provide precise definitions of them.
- We show how breakeven costs change due to internally-driven factors. These are microeconomic factors which represent normal improvements in operational efficiency. Efficiency improves over time in every new play exploited by the petroleum industry, as geological knowledge and infrastructure maturity progress. Because tight oil production technology has developed rapidly in this decade, internally-driven improvements have been very pronounced.
- Externally-driven factors, driven by the macroeconomic environment - principally the price of oil - also have a strong effect on breakeven point dynamics because, counterintuitively, changes in the market price of oil lead the cost of producing oil.
- Not only do individual costs change due to macroeconomic factors, but the breakeven point structure itself changes. As prices fall, full cycle economics gives way to half cycle economics, and eventually to lifting cost economics. In rising markets, the reverse is true.

We have discussed other factors affecting oil market stability:

- The surprising speed with which U.S. tight oil production increased after 2010 is explained, in part, by the timely availability of specialized oilfield equipment built between 2004 and 2009 to exploit shale gas.
- The unexpectedly slow decline of U.S. tight oil supplies during the oil price declines of 2014–2015 is shown to be due to the relatively slow decline of production from legacy tight oil wells, when considered on a field-average basis.
- Infrastructure, labor, and financial inelasticities also affect oil market dynamics.
- U.S. tight oil production does not ramp up or down quickly enough to significantly affect short term oil market stability. However, it does have the potential to stabilize oil markets in the medium term. Thus unlike deepwater, heavy, or arctic oil resources, which are price takers, U.S. tight oil is likely to function as a price maker in the medium term.

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