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Tight Oil Development Economics: 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), which are widely used, and widely misunderstood. Misunderstandings have three origins: (1) There is no broadly accepted agreement on definitions; (2) for any given resource there is no universally applicable benchmark; (3) various breakeven points and other benchmarks are applicable at various times in the development of a resource. In this paper we clarify the purposes of several benchmarks and propose standardized definitions of them. We show how and why breakeven points are partitioned, and when each of the partitioned elements is appropriate to consider. We discuss in general terms the geological, geographical, product quality, and exchange rate factors that affect breakeven points. We show how breakeven points change over time due to endogenous and exogenous factors. We describe some other factors that contribute to tight oil market dynamics. Finally, we explore macroeconomic and policy implications of a broader, more rigorous, and more consistent application of the breakeven point concept, and the understanding of the inelasticities that accompany it.

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1. Introduction

From 2011 to mid-2014, Brent crude oil generally traded above $100/barrel (bbl). 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, 2016d). As a result of this rapid increase in oil production, numerous publications declared America to be a rival to Saudi Arabia as the world’s marginal producer (e.g., The Economist, 2014).

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 Figure 1. This was an unsustainable situation. Oil production had to decrease, and as the newly anointed “marginal producer”, it seemed that burden would fall on the U.S. tight oil industry.

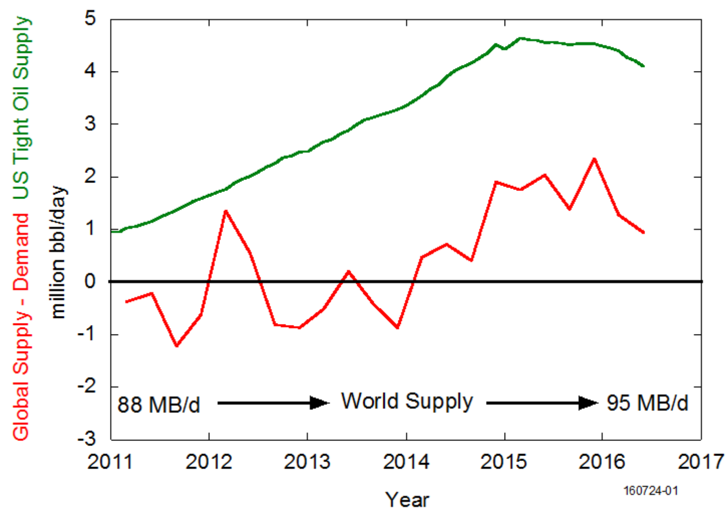

Figure 1. The growth of United States tight oil production (green) (EIA, 2016d) upset the global balance between supply and demand, leading to persistent additions of stored oil after early 2014 (red) (EIA, 2016j).

Many analysts suggested that the oil price needed to maintain the economic viability of the preponderance of U.S. tight oil projects was in the range of $60/bbl to $90/bbl (e.g., EY, 2014; Wood Mackenzie, 2014a; 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 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, Agerton, 2015; Ezrati, 2015; The Economist, 2015). There is no documented evidence that the Organization of Petroleum Exporting

Countries (OPEC) 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.

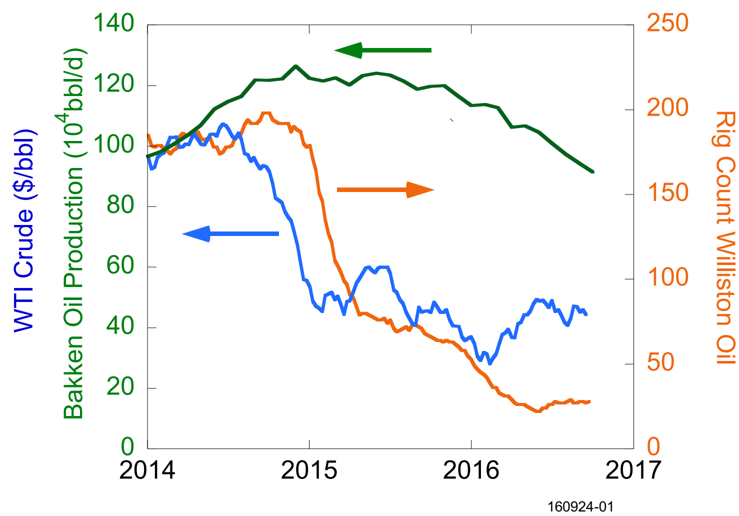

Figure 2a. A sharp decline in Williston Basin oil-directed rig count, which is dominated by Bakken field activity (orange) (Baker Hughes, 2016), followed a drop in WTI crude oil price (blue) (EIA, 2016k) with a lag of less than three months. Bakken oil production (green) (EIA, 2016b) started falling in mid-2015.

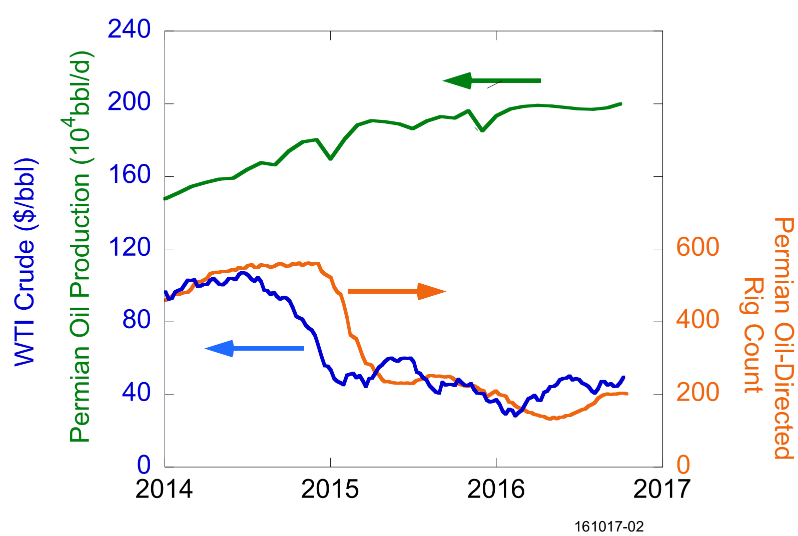

Figure 2b. As in the Williston Basin, the Permian Basin oil-directed rig count (orange) (Baker Hughes, 2016) swiftly followed the decline of WTI crude oil price (blue) (EIA, 2016k). However, oil production (green) has continued to increase (EIA, 2016b), defying expectations.

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. However, tight oil production did not start to decline until mid-2015, when it started falling at a moderate rate in the Bakken region, see Figure 2a, and more rapidly in the Eagle Ford region (EIA, 2016b). Remarkably, oil production from the Permian Basin continued to increase through 2016, see Figure 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. Productivity gains and cost reductions have helped producers maintain output at higher levels than expected and thus delay the slowdown" (OPEC, 2016).

The industry was "caught by surprise" in part because the dynamics of breakeven points were not broadly understood. 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.

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. 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 endogenous and exogenous factors. We discuss other inelasticities that characterize 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 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 price 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, 2016a) 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 amongst a wide variety of independent actors 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 cost of production below the prevailing market price can be produced.

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 Figure 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, 2016g); 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 has 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 rapid decline of oil prices after June 2014, U.S. rig counts 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, 2016b), a lag of nine months, and it peaked in the Bakken play (Figure 2a) in June 2015, a lag of twelve months. In the Permian Basin, tight oil production continued to increase two and a half years after the start of the oil price decline, as shown in Figure 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 2016b), by reduced costs of oil production (EIA, 2016c), and by a dynamic redefinition of breakeven point as discussed below.

When the WTI crude oil price rose from February to May 2016, the Permian Basin rig count followed with a lag of four months but, as of the end of 2016, production trends were unchanged.

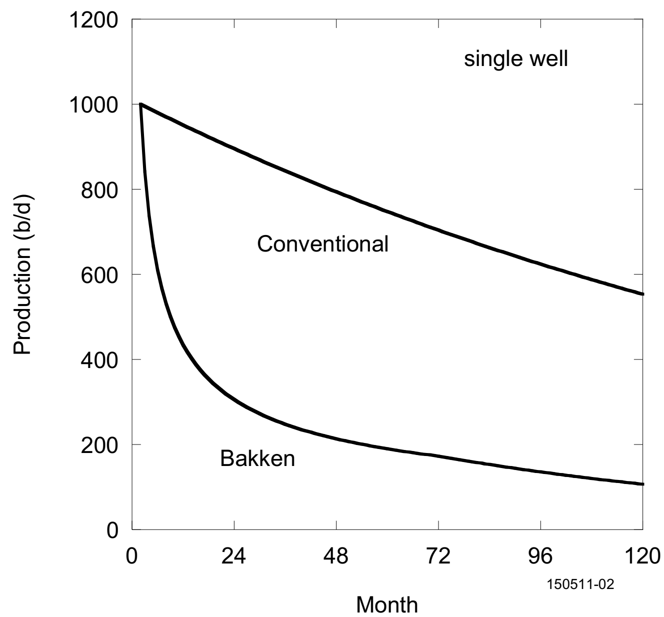

Figure 3. Decline curves for oil production from individual conventional wells and from individual tight oil (Bakken) wells (IHS, 2013b).

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.

A second complicating factor is the time variation of productive capacity. For example a project that costs \$10 billion and produces at a plateau rate of 200,000 bbl/d has a cost of capacity of \$50,000 per bbl/d. By contrast, a well in that field that costs \$10 million and produces at 1,000 bbl/d in its first year could be said to have a cost of capacity of \$10,000 per 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). Breakeven means that the profit is zero, though it does include corporate overheads. Profits are made when the oil price is above the breakeven point, or when expenses and overheads are lower than anticipated. Other circumstances under which projects make money are discussed in section 3.5.3 below.

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 Figure 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. 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 incongruent, and therefore easily misunderstood.

In reality, there is a range of breakeven points for any given project. Each of these various breakeven points is valid, but only for a specific purpose, which again is not usually stated explicitly. Here we present a scheme which does not necessarily follow any one methodology found in analyst, agency or corporate reports, but which we believe approximates a middle-of-the-road synthesis. We avoid *de novo* terminology by utilizing terms found in some reports of breakeven points, but we attempt here to provide explicit, exact 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. Lifting cost also includes taxes and royalties charged to production at the wellhead, and the marginal cost of transporting product to market. 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.

<table>
<tr><td rowspan="21">Full Cycle</td><td rowspan="8"></td><td rowspan="9"></td><td rowspan="13">Capital Expense</td><td rowspan="3">Finding</td><td>Exploration</td></tr>
<tr><td>Leasing</td></tr>
<tr><td>Reservoir Delineation</td></tr>
<tr><td rowspan="10">Development</td><td>Engineering</td></tr>
<tr><td>Gathering Pipelines</td></tr>
<tr><td>Roads & Other Infrastructure</td></tr>
<tr><td>Cost of Financing Field Development</td></tr>
<tr><td>Decommissioning</td></tr>
<tr><td rowspan="13">Half Cycle</td><td>Cost of Financing Well Development</td></tr>
<tr><td rowspan="3">DUC</td><td>Well Pad Construction</td></tr>
<tr><td>Well Construction</td></tr>
<tr><td>Drilling, Casing, Cementing</td></tr>
<tr><td>F</td><td>Completion</td></tr>
<tr><td rowspan="8">Lifting Cost</td><td rowspan="8">Operating Expense</td><td rowspan="8">Production</td><td>Lease Operating Expense</td></tr>
<tr><td>Repairs & Maintenance</td></tr>
<tr><td>Fuels and Electric Power</td></tr>
<tr><td>Labor</td></tr>
<tr><td>Royalties & Taxes</td></tr>
<tr><td>Transport to Market</td></tr>
<tr><td>Water & Waste Disposal</td></tr>
<tr><td>General & Administrative</td></tr>
</table>

Table 1. Components of various breakeven points. DUC represents the cost of wells that are drilled, cased, and cemented, but not completed. F Represents the cost of fracturing or refracturing a well.

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. The disposal costs of oilfield wastes, and the present value of the ultimate cost of abandonment, during which wellbores are plugged and any required surface remediation undertaken, should also be included. Completion expenses include the steel casing used to stabilize the wellbore, and the cement placed between casing and wellbore to assure hydraulic isolation of geologic formations. A recent 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 20,000 cubic meters of water, 2000 tons of sand, and an average of 200 tons of specialty chemicals per well. Such operations are more efficient and economic when multiple wells are serviced from a single site, a development referred to as “pad drilling”.

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 are declared by the owner. Generally, the former are permanent fixtures of wells and 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.

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 and 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, 2016m).

3.3.3. Full Cycle Breakeven

Full cycle breakeven 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 reservoir characterization. It also includes obtaining rights to resource exploitation, which can be a complicated process where mineral rights are broadly distributed, and all above-ground infrastructure, such as roads. It includes takeaway capacity, including the capital expense of providing transportation to a specified pricing hub – which might be on another continent. 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 included.

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 the first quarter of 2016 (Wall Street Journal, 2014; Sandrea, I, 2014; Domanski et al., 2015; EIA, 2016i). Producers have remained solvent by taking on debt, and by selling assets and equity. 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 and has narrowed (EIA, 2016i).

3.3.4. 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). 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 unexpectedly rising costs, or falling commodity prices. Recently, corporations have increased their debt load in order to pay dividends (Bloomberg, 2016).

3.3.5. 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, 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 produced barrel of oil.

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 zones, and the zones 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, 2015).

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. Clients engaged in exploratory drilling on land in advanced industrialized nations in Europe are dismayed to learn they are "frontier areas" with respect to oil field services, where costs can be double or triple those common 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 reason (of several) 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.

3.4.3. Quality Factors and Pricing 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 the 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 the available transport capacity, significant price differences 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, 2016n), the Brent price exceeded WTI by as much as 20% (EAI, 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, economics 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). Tight oil, which often co-produces associated gas rich in natural gas liquids (ethane, propane, n-butane, i-butane, and natural gasoline) can be more accurately assessed in terms of the individual product streams, which have species-specific values to the petrochemical industry beyond their values as fuels (EIA, 2016e).

3.4.4. 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. When the ruble falls in value relative to the dollar in synchrony with the decline in the international price of oil, Russian oil companies come under less financial pressure than do Western oil companies (Financial Times, 2016; IHS, 2016). In essence, technical breakeven points in ruble terms remain mostly unchanged. However, Russia's dollar-denominated balance of trade with other countries suffered as a result of the dollar-denominated oil price decline of 2014-2016.

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 Figures 2a and 2b. 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 & Boone, 2016a; Haynes & 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 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, 2016a). We identify two kinds of changes. *Endogenous* changes reflect steady improvements in infrastructure and efficiency. *Exogenous* changes occur in response to changing economic conditions. In the dynamic U.S. oil and gas industry, and particularly in the tight oil sector in which production technology is evolving rapidly, endogenous and exogenous changes can significantly alter production economics on a time scale of 1-2 years.

3.5.1 Endogenous Changes

Table 2 outlines some of the endogenous reasons breakeven points 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).

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

Table 2. Endogenous factors which change breakeven points, early and late in the development cycle. Yellow boxes represent high or increasing cost factors, blue boxes represent decreasing cost factors.

Decreasing costs can be accompanied by increasing production. From late 2012 to the third quarter of 2014, endogenous improvements led to a doubling of new well oil productivity per rig in the Bakken tight oil play, see Figure 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, 2016h]. Throughout this period, West Texas Intermediate crude traded in a narrow range around $100/bbl (EIA, 2016k).

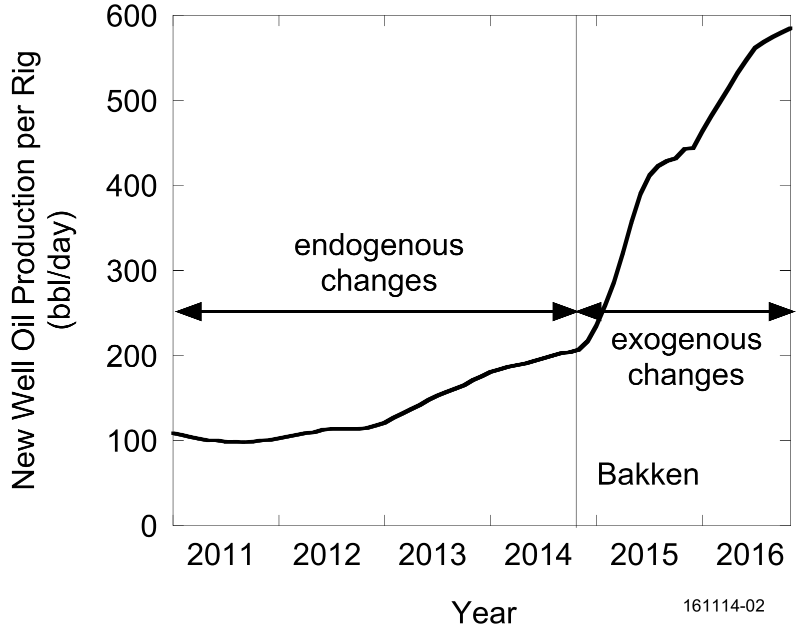

Figure 4. Productivity of drilling rigs directed to Bakken tight oil. Endogenous changes occur during periods of relatively stable oil prices, e.g. 2011 to mid-2014. Exogenous changes are driven by rapid declines in the price of oil, e.g. mid-2014 through 2016. The source of the data and the precise definition of the vertical axis are found in (EIA, 2016b).

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

Breakeven points change exogenously as a result of changes in the price of oil. While the price of oil depends on the cost its production, the opposite is also true: the cost of oil depends on capital, labor, and material inputs, the prices of which are affected by the state of the oil market. When oil prices are high, 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. The expansion of the industry creates bottlenecks. Cost control is a secondary consideration. Service company profitability increases.

When oil prices decline, all these trends are reversed. Exploration, the growth engine of the industry, slows to a crawl. Asset delineation ("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, see e.g. Apache, 2016), and within those areas, the best drilling locations ("sweet spots"), a process known as asset high grading. Moreover, a large reduction in the number of drilling rigs results in the 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 Figure 4, rig productivity can increase rapidly due to exogenous 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.

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 Figure 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, 2016b). While oil prices were relatively stable between 2012 and late 2014, endogenous improvements doubled rig productivity. Falling oil prices after late 2014 triggered exogenous improvements, which increased rig productivity by a further factor of 2.7 (EIA, 2016b), while well costs declined by 35% and production costs declined by 25% (Pioneer Natural Resources, 2016).

3.5.3 Change in Type of Breakeven Point

Just as importantly, the relevant type of breakeven point changes with time. In normal circumstances, the discounted cash flow of a project will exceed the sum of investments made in it before the productive assets have outlived their usefulness. Thereafter, the full cycle breakeven oil price is no longer relevant in assessing project economics. 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, the 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.

This logic applies as much to service providers as to operators. When demand for services is in free fall, the prices asked are based on the alternative of stacking equipment and laying off workers. Service provider breakeven points change from full cycle to just operating expenses when service capacity is static or declining: when no more rigs, hydraulic fracturing spreads or other resources need to be built.

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 was 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 endogenous and exogenous drivers (compare e.g Wood Mackenzie, 2014c; Wood Mackenzie, 2015; Wood Mackenzie, 2016b; EOG, 2016), but there was a large-scale transition from greenfield full cycle projects, 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, or bankruptcy.

3.6. Other Factors Affecting Tight Oil Market Dynamics

3.6.1 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, 2015a). 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, 2015b).

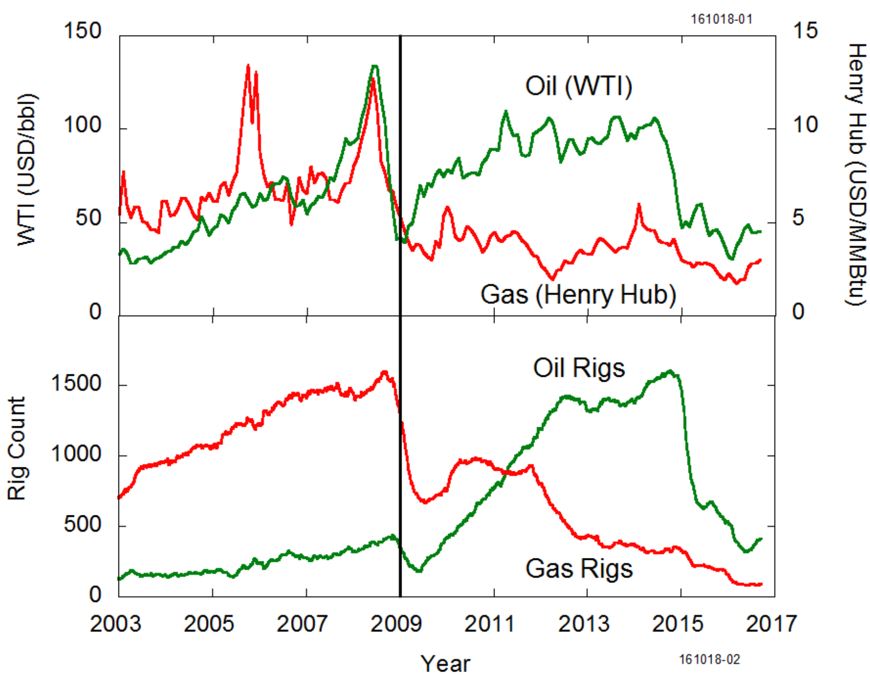

Figure 5. Horizontal drilling rigs (bottom) (Baker Hughes, 2016) and hydraulic fracturing equipment moved from gas plays (red) to oil plays (green) after oil and gas prices diverged (top) (EIA, 2016k; EIA, 2016l).

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/MMBtu 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 Figure 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).

3.6.2. 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 Figure 3. However, there are important differences between the production rate of individual wells and that of a field of such wells.

For the purposes of constructing simple models of field-wide behavior, we compare a model conventional oil field with a comparable model tight oil field, and assume a drilling campaign for each in which one well is completed every month for 48 months. Details of the calculation may be found in the Appendix.

The results of the two models are shown in Figure 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 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 (IEA, 2013). 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 Figure 6. Table 3 provides a summary of annual production decline rates of 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 Figure 6 and Table 3.

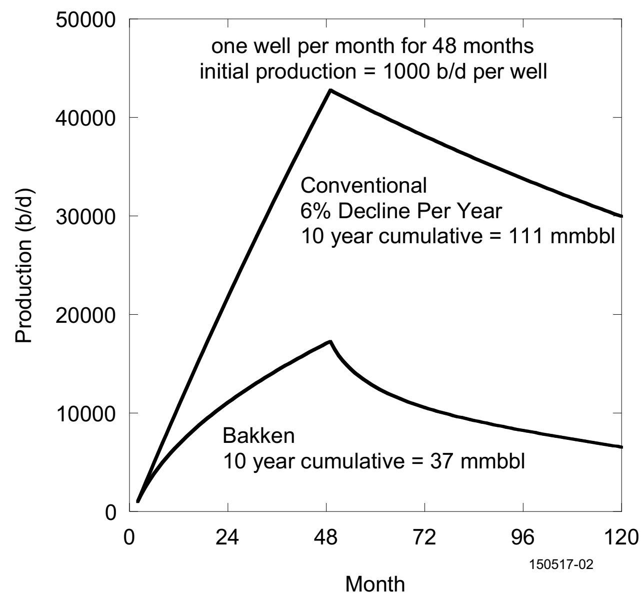

Figure 6. Modeled field-level production in conventional and tight oil (Bakken) fields, during and after 48 month drilling and completion campaigns, using the individual well decline curves shown in Figure 3.

	Conventional Oil (Secondary Recovery)		Tight Oil (Primary Recovery)	
Year	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

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.

3.6.3 Infrastructure. Financial, and Labor Inelasticities

The rate at which U.S. production can ramp up once tight oil drilling resumes depends on how equipment was taken out of service during periods 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.

Financial and labor markets also introduce inelasticity. The ready availability of capital played an important role in the 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, I., 2014; EIA, 2014; EIA, 2015c; Domanski et al., 2015). It remains to be seen whether debt and equity financing is as available in the future. 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, or may not be available at the same cost.

3.6.4 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.

Despite these important inelasticities, and despite lacking any coordination amongst 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 2016, may provide a restraint on the expectations of market participants who seek to raise prices by cutting production.

4. Conclusions

In projections of the reaction of oil markets to increased oil production, many analysts underestimated the dynamic nature of tight oil economics. In this paper we have shown that benchmark and breakeven points are only useful to the extent their calculation is transparent. 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. However, 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 endogenous and exogenous drivers discussed in this paper, but there was a large-scale transition from full cycle projects, to the half cycle economics of drilling to maintain level production, and eventually, after the second half of 2015, to allowing production to fall by producing almost entirely from pre-existing wells, the production from which falls rather slowly after the first two years or so.

Frequently, breakeven point data are presented by analysts, or in corporate presentations to investors, without adequate disclosure of what exactly is meant by breakeven. 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.

In this paper we propose a consistent treatment of the breakeven points – full cycle, half cycle, and lifting cost – and explain endogenous and exogenous changes in breakeven point economics. In a rapidly evolving industry such as tight oil production, this analysis is likely to be uncertain. 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, oilfield and takeaway infrastructure, capital markets, and labor factors. 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 endogenous and exogenous factors should be taken into account. Energy analysts, in both the private and government sectors, can improve forecasts by incorporating into their economic models realistic ranges of breakeven points, and models of how they change under various conditions.

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Appendix: Calculation of Field Level Decline Curves

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. This distinction is particularly important in the case of tight oil fields, in which individual wells decline very rapidly in the first few years of production, and more slowly during the balance of their productive lives.

To illustrate this principle, we compare a model 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, R., 2012; EIA, 2016h). 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, oil production from the field at any time t is given by

$$Q(t) = \sum_{k=1}^{N} q_k(t - t_k) \qquad \text{(A.1)}$$

where $q_k(t-t_k)$ is the 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 $t < t_k$. Eqn. (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:

$$\frac{1}{q_c}\frac{dq_c}{dt} = -\alpha_y \qquad \text{(A.2)}$$

where α_y is the annual rate of decline, which we shall assume to be $\alpha_y = 0.06$/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:

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

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

For the model *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 Figure 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, α_y = 0.06/yr, based on a global average of conventional oil field decline rates (IEA, 2013).