Energy 93 (2015) 2191–2198

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Net energy analysis of Bakken crude oil production using a well-level engineering-based model

Adam R. Brandt [a,*], Tim Yeskoo [b], Kourosh Vafi [a]

[a] Department of Energy Resources Engineering, Stanford University, United States
[b] Department of Civil and Environmental Engineering, Stanford University, United States

ARTICLE INFO

Article history:
Received 5 August 2015
Received in revised form
14 October 2015
Accepted 25 October 2015
Available online 19 November 2015

Keywords:
Bakken
Hydraulic fracturing
Tight oil
Energy return on investment (EROI)
Energy returns
Net energy

ABSTRACT

Since 2005, production of oil from the Bakken formation of North Dakota has increased substantially, and the region now supplies about 1.5% of global oil output. This study presents a first engineering-based assessment of the energy intensity of Bakken crude oil production and computes the resulting NER (net energy return) from Bakken hydrocarbon production. The energy required to drill, produce, and process Bakken oil and gas is estimated for over 7000 wells using open-source drilling and production assessment models. The largest energy uses are from drilling and processing of produced fluids (crude/water emulsions and gas). Fluid lifting and injection and embodied energy are also important energy needs. Median energy consumption equals ≈3.4% of net crude and gas energy content, while mean energy consumption equals ≈3.9% of hydrocarbon energy. The median NER is 29.3 MJ/MJ. The interquartile range is 24.3–35.7 MJ/MJ, while the 5%–95% range is 13.3–52.0 MJ/MJ. NERs have declined in recent years, with a decline in median NER of 23% between 2010 and 2014. Results are most sensitive to modeled estimated ultimate recovery, and embodied energy.

1. Introduction

At the end of 2014, the state of North Dakota produced over 1.9×10^5 m^3 (1.2 million bbl) of oil per day [1]. The vast majority of this oil was produced from the Bakken formation. Due to the introduction of horizontal drilling coupled with high-volume hydraulic fracturing, production of oil from the Bakken formation increased rapidly after initial exploratory wells were drilled in 2005. The Bakken formation covers a number of states and provinces, but the core Bakken region lies in north-western North Dakota. The most intensively drilled portion of the Bakken formation is 3000–3400 m (10,000–11,000 ft) deep. Drilling rates were very high until the oil price declines of late 2014: there were over 2500 new Bakken wells drilled in 2014 [2].

Some recent publications have questioned Bakken formation productivity and the ultimately recoverable oil volumes from Bakken wells [3–6]. Because the drilling and hydraulic fracturing of Bakken wells is expensive (8–10 million US dollars per well), some concerns have arisen about the long-term economic and biophysical sustainability of Bakken oil production. These concerns typically center around a number of related concepts: rapid decline rates from Bakken wells, high drilling costs and attendant financial risks of drilling, high embodied energy requirements for drilling, and the role of so-called “sweet spots” in dominating the productivity of these formations. A general theme is that projections of future large output from Bakken and Bakken-like formations are “too good to be true”, supported by ready availability of drilling capital and over-optimistic projections based on extrapolating early drilling productivities to large areas [3–6].

In this study, we examine one aspect of this general question: what is the energetic productivity of producing oil from the Bakken formation? That is, how much energy is produced from a typical Bakken well compared to the amount of energy invested in drilling, producing, and transporting the resulting oil and gas? This study presents a first-of-its kind engineering-based analysis of the energetic productivity of tight oil extraction from the Bakken formation.

The energetic productivity of extractive hydrocarbon industries is generally measured using ERRs (energy return ratios) [7–11]. Generally speaking, ERRs compare the outputs of an energy industry to the energy consumed by that industry. An oilfield or well with a large ERR produces a large amount of energy relative to that consumed in drilling for and producing the oil. The most commonly

* Corresponding author.
E-mail address: abrandt@stanford.edu (A.R. Brandt).

http://dx.doi.org/10.1016/j.energy.2015.10.113

cited ERR is the EROI (energy return on investment) [12], while another common (and closely related) metric is the NER (net energy return) [7]. It should be noted that at least 8 mathematically unique ERRs have been proposed over the last 40 years, and each ERR has somewhat different implications [7].

A recent study of EROI for global oil and gas production suggested that EROI peaked around the turn of the 21st century and has since declined [13]. In that study, financial expenditures were multiplied by the energy intensity of economic activity. A long-term study of energy returns from United States (US) oil extraction estimated direct and indirect energy consumption in the oil industry, finding unambiguous decreases in the energetic returns from producing oil [14]. Similar results had previously been found by Cleveland and others [15,16], relying on reported consumption statistics for the oil and gas industry. A general consensus from these studies is that, in aggregate, conventional oil production has energy return ratios of order 20:1, with some differences depending on the particular ratio definition, underlying dataset, and assessment method. In contrast, a recent study used, for the first time, an engineering-based LCA (life cycle assessment) tool to examine NERs for a suite of forty global oilfields, finding a wide range in energy returns depending on field characteristics. That study found that NERs ranged from 2 MJ (MJ) per MJ to over 100 MJ/MJ [17].

A number of studies have examined the energy intensity of unconventional hydrocarbons, such as the Canadian oil sands [18,19]. More closely related to this work, a number of life LCA (cycle assessment) studies [20,21] and energy intensity studies [22–25] have been performed on fracturing-enabled hydrocarbon extraction from tight ("shale") formations. The results of these studies differ. LCA studies suggest that shale gas energy intensities are similar to those of conventional gas production. Among the energy intensity studies, some suggest that energy returns from shale gas formations are high, while others suggest that shale gas energy returns are more similar to conventional natural gas deposits. For example, Sell et al. find EROI of 70–120 MJ/MJ [23], while Aucott et al. find EROI of 60–110 MJ/MJ [22]. In contrast, Yaritani finds lower energy returns of order 10–20 MJ/MJ [24], approximately in line with conventional oil resources. Waggoner is the first to examine the energy return on investment from tight oil production, examining the Bakken formation. He finds high energy returns when using a "standard" EROI metric (e.g., $\approx$60 MJ/MJ) while also finding significantly lower energy returns ($\approx$10 MJ/MJ) when a broader finance-based metric is used [25].

Determining in detail the reasons for differences between the results of these studies is beyond the scope of the this paper, but common reasons for differences between analysis of complex systems are likely to apply here: differences in system boundaries; differences in definitions of ratios (e.g., which flows are defined as an energy input vs. an energy output); and different methods for accounting for energy uses not directly modeled (i.e., well-known in LCA studies as the "truncation" problem).

In order to improve the understanding of the energy productivity of drilling in the Bakken formation, this paper collects detailed data for 1000s of Bakken wells and models the energy intensity of Bakken crude oil production directly using an engineering-based LCA model called the OPGEE (oil production greenhouse gas emissions estimator) model. Because horizontal drilling and hydraulic fracturing is not modeled directly in prior versions of OPGEE, we augment the OPGEE model with a new drilling and fracturing model, *GHGfrack* [26] to estimate the energy requirements of drilling and fracturing Bakken wells.

This paper proceeds as follows: First we outline data collection and analysis methods. We then discuss the methods of computing ERRs, and discuss the definitions of sensitivity analysis cases. Next, we illustrate the results of the analysis across all years and dynamically over time. Then we discuss the results of the sensitivity analysis as applied to the entire population of Bakken wells. Lastly, we discuss possible extensions of the work and remaining uncertainties.

2. Methods

This section outlines the methods of data collection, data cleaning, and analysis with the OPGEE and GHGfrack models. We then describe computation of ERRs and sensitivity case definitions.

2.1. Data collection

Bakken data were collected from a variety of sources, with an emphasis on public datasets produced by the State of North Dakota. Data from the North Dakota Department of Mineral Resources (hereafter DMR) were collected on a monthly basis for all wells in North Dakota [1,2,27,28]. DMR datasets include large amounts of information, the most important of which include monthly production of all fluids (oil, water, gas); monthly gas flaring rates; well properties (true vertical depth, drilling total depth, casing design, fracturing volumes); and well testing results (initial pressure, flow rates, gas composition). A summary of key data used in this analysis are outlined in Table 1. Numerical distributions of input data are presented in Table 2.

Cleaning and compilation of the data resulted in the removal of some wells from the sample set, resulting in a final dataset of 7271 Bakken wells (see prior work [29] for selection criteria used to define our set of Bakken wells). All time series analyses include wells drilled from 2006 to 2013, inclusive.

Other data were collected from the technical literature, with an emphasis on Society of Petroleum Engineers papers where possible [29]. Information gathered in this manner includes pressure gradients, productivities and production methods, surface processing methods, gas plant activities and processing schemes, and hydraulic fracturing flowback processes.

2.2. Processing and computation of well properties

A number of steps were required to clean and organize well property data before input into the OPGEE and GHGfrack models.

2.2.1. Well geometry and casing characteristics

DMR records contain multiple data points for each well. The top, bottom and diameter of each casing segment are reported, as are the DTD (drilling total depth, or total well length drilled), and in some cases, the TVD (true vertical depth, or deepest point of well). We computed DTD from casing lengths where not reported. We corrected for non-physical reported quantities (i.e., negative

Table 1
Data inputs and sources.

Input	Original unit	Source
Oil EUR	[bbl]	[1,43]
Gas EUR	[MCF]	[1,43]
Water EUR	[bbl]	[1,43]
Well depth (TVD and DTD)	[ft]	[2]
Casing diameter, length, weight	[in, ft, lb]	[2]
Fracturing pressure	[psi]	[28]
Fracturing sand	[lb]	[28]
Fracturing water	[gal]	[28]
Drilling and fracturing energy	[MJ]	[26]
Transport energy	[MJ]	[45]
Embodied energy	[MJ]	[57,58]