Shoal Point, NL Development Scenario from Green Point Formation Shale with Estimated Capital and Operating Expenditures – 153MMbbls EUR

Background

An independent Panel was appointed by the Minister of Natural Resources, Government of Newfoundland and Labrador, in October 2014 to conduct a public review of the socio-economic and environmental implications of hydraulic fracturing in Western Newfoundland.

The Terms of Reference for the Panel were issued by the Minister of Natural Resources, in consultation with the Department of Environment and Conservation and the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB), along with research completed during the Provincial Government's internal review. In terms of the socio-economic component of the Panel's mandate, the following is extracted from the Terms of Reference.

Socio-Economic Impacts

Technology such as hydraulic fracturing has made it possible for many communities to benefit from economic gains due to the production of oil and gas, including employment opportunities, supply and service contracts and local infrastructure development. In addition to recognizing the economic benefits for local communities, care must be taken to minimize disruption during operations and consider social and environmental responsibilities to individuals and communities.

Potential Question:

What is the potential socio-economic impact from unconventional petroleum development involving hydraulic fracturing operations in Western Newfoundland?

The Department of Natural Resources was approached by the panel to assist in developing a potential development scenario of the Green Point Formation. Exploration to date of the Green Point Formation has shown significant net pay thickness, adequate T_{max}, and high total organic carbon. The current scientific and engineering evidence for the Green Point suggests that this formation is a good candidate for stimulation with good quality Type I organic material and a large in-place resource that is presently within the oil window. However, to date the Green Point formation has not been stimulated and has no production history. As such, many assumptions complete with related references, were incorporated into preparing this development scenario. The document provides capital and operating costs based on two scenarios involving flowback and produced water disposal options. Sensitivities can be modelled for various other input parameters.

Limitations

This information is provided for the sole purpose of the independent Panel and the Department of Natural Resources does not represent or guarantee that any information contained in this document is accurate or complete and accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions taken based on this document.

Option 1: Deep Well Injection of Flowback and Produced Water

Assumptions:

1. Estimated Ultimate Recovery – 153 million barrels liquid from EL-1070 [1], and 77 billion cubic feet of Associated Gas
2. All geoscience exploration (seismic, geochemistry and core analysis), pilot drilling activities for resource and productivity estimations were successfully completed. This scenario does not include the cost of these activities.
3. Average initial production per well: 522 bopd. Based on 2014 Bakken region drilling productivity [2]. Decline model based on horizontal wells in the Bakken formation [2b] [Fig. 1]
4. Average drilling and completion cost per producer well: Initial cost of $10M per well, 15% reduction for the first 5 years and then 1% reduction, with drilling efficiencies, for subsequent years. Estimated cost is based on references [3][4] [13] [14]
5. Number of Class II disposal wells for produced water and hydraulic fracture stimulation flow back water: 8 (average disposal capacity of 2500 bbl/d per well). Based on Fortress Environmental Services [5]
6. Average drilling and completion cost per class II disposal well facility : $9.3 M [5]
7. Gas Oil Ratio = 500 scf/bbl. Based on Beggs Standing's Correlation equation Pg. 35 of [6], and DST test for Shoal Point K-39 well [7]
8. Produced Water Oil Ratio: 0.77. Based on oil producing horizontal wells in the Middle Bakken formation completed in 2012-2015 as of August 7^{th}. 2015 [8]
9. Completions estimated to use 4 million US gallons of water per well with 50% water flowback. 5000 US short tons of proppant per well [9][10].
10. Electricity is generated from produced natural gas that will be used to run the production facility
11. Number of producer wells: 420. See figure 1.
12. 7 drilling rigs with capacity of one well per month.
13. Assuming 84 wells drilled per year (5 years to drill all 420 wells)
14. Production years = 20
15. Project scope includes flow line handling of stimulation water, flowback water, produced water, and oil production.
16. Marine dock, oil storage and loading terminal cost based on reported costs for the 2 million Melons Island Oil Terminal (MOTI) facility built in 2009, and the NL Whiffen Head Transshipment Terminal built in 1998.
17. Seawater is used as the main water supply for the project development, and does not require a water purchase cost.

Item	Cost (CAD$)
Drill and Complete 420 directional Wells	$3,115,250,250.0
Drill and Complete 8 Class II disposal wells	$74,400,000.0
Central Processing Facilities and Main Gathering Lines x8	$80,000,000.0
Central Storage and Loading Facilities x8	$120,000,000.0
Total Wells and Central Facilities Cost	**$3,389,650,250.0**
Field Oil and Gas Gathering Lines - 30 well pad sites	$30,000,000.0
Field Oil and Gas Treatment Facilities - 30 well pad sites	$30,000,000.0
Main Processed Gas Line x8	$80,000,000.0
Install 8 x 3.5 MW Gas to Electric Turbines	$40,000,000.0
Electricity Distribution	$40,000,000.0
Marine Dock - 1 Million Barrels Storage Loading Terminal	$150,000,000.0
Total Capital Expenditure	**$3,759,650,250.0**

Field Oil Operating Costs Variable $/bbl	$0.6
Field Oil Operating Costs Fixed $/bbl	$0.4
Storage and Loading Facilities Operating Cost $/bbl	$1.0
Total Operating Cost 153 Million Barrels of Oil	**$306,000,000.0**
Well Operating Cost Fixed $/month	$2,000.0
Well Abandonment cost $/Well	$100,000.0
Total Well Operating Cost for 420 Wells for 20 Years	**$219,620,000.0**
Field Gas Operating Costs Fixed $/mcf	$0.3
Field Gas Operating Costs Variable $/mcf	$0.5
Total Operating Cost 77 BCF Gas	**$61,200,000.0**
Hydraulic fracture stimulation water transportation cost $/bbl	$0.5
Flowback & Produced water transportation to injection site cost $/bbl	$0.6
Flowback & Produced water Deep-Well Injection cost $/bbl	$0.5
Total Water Handling Cost for 183 Million Barrels of Flowback and Produced water	**$293,366,346.6**
Electricity Generation and Transmission Operating Cost for 20 years	$25,000,000.0
Total Operating Expenditure	**$905,186,346.6**

Grand Total Project Cost	**$4,664,836,596.6**

Option 2: Offsite Flowback and Produced Water Treatment

Assumptions:

1. Estimated Ultimate Recovery – 153 million barrels liquid from EL-1070 [1], and 77 billion cubic feet of Associated Gas
2. All geoscience exploration (seismic, geochemistry and core analysis), pilot drilling activities for resource and productivity estimations were successfully completed. This scenario does not include the cost of these activities.
3. Average initial production per well: 522 bopd. Based on 2014 Bakken region drilling productivity [2]. Decline model based on horizontal wells in the Bakken formation [2b] [Fig. 1]
4. Average drilling and completion cost per producer well: Initial cost of $10M per well, 15% reduction for the first 5 years and then 1% reduction, with drilling efficiencies, for subsequent years. Estimated cost is based on references [3][4] [13] [14]
5. Number of Class II disposal wells for produced water and hydraulic fracture stimulation flow back water: 2 (average disposal capacity of 2500 bbl/d per well). Based on Fortress Environmental Services [5]
6. Produced Water Oil Ratio: 0.77. Based on oil producing horizontal wells in the Middle Bakken formation completed in 2012-2015 as of August 7th. 2015 [8]
7. Completions estimated to use 4 million US gallons of water per well with 50% water flowback. 5000 US short tons of proppant per well [9][10].
8. Costs of Flowback and Produced water transportation and treatment are based on [10] [11][12]
9. Electricity is generated from produced natural gas that will be used to run the production facility
10. 420 producer wells. 7 drilling rigs with capacity of one well per month. 84 wells drilled per year (5 years to drill all 420 wells)
11. Production years = 20
12. Project scope includes flow line handling of stimulation water, flowback water, produced water, and oil production.
13. Marine dock, oil storage and loading terminal cost based on reported costs for the 2 million Melons Island Oil Terminal (MOTI) facility built in 2009, and the NL Whiffen Head Transshipment Terminal built in 1998.
14. Seawater is used as the main water supply for the project development, and does not require a water purchase cost.

Item	Cost (CAD$)
Drill and Complete 420 directional Wells	$3,115,250,250.0
Drill and Complete 2 Emergency Class II disposal wells	$18,600,000.0
Central Processing Facilities and Main Gathering Lines x8	$80,000,000.0
Central Storage and Loading Facilities x8	$120,000,000.0
Total Wells and Central Facilities Cost	**$3,333,850,250.0**
Field Oil and Gas Gathering Lines - 30 well pad sites	$30,000,000.0
Field Oil and Gas Treatment Facilities - 30 well pad sites	$30,000,000.0
Main Processed Gas Line x8	$80,000,000.0
Install 8 x 3.5 MW Gas to Electric Turbines	$40,000,000.0
Electricity Distribution	$40,000,000.0
Marine Dock - 1 Million Barrels Storage Loading Terminal	$150,000,000.0
Total Capital Expenditure	**$3,703,850,250.0**

Field Oil Operating Costs Variable $/bbl	$0.6
Field Oil Operating Costs Fixed $/bbl	$0.4
Storage and Loading Facilities Operating Cost $/bbl	$1.0
Total Operating Cost 153 Million Barrels of Oil	**$306,000,000.0**
Well Operating Cost Fixed $/month	$2,000.0
Well Abandonment cost $/Well	$100,000.0
Total Well Operating Cost for 420 Wells for 20 Years	**$219,020,000.0**
Field Gas Operating Costs Fixed $/mcf	$0.3
Field Gas Operating Costs Variable $/mcf	$0.5
Total Operating Cost 77 BCF Gas	**$61,200,000.0**
Hydraulic fracture stimulation water transportation cost $/bbl	$0.5
Flowback & Produced Water transportation cost $/bbl	$25.0
Flowback & Produced water Treatment cost $/bbl	$3.0
Total Water Handling Cost for 183 Million Barrels of Flowback and Produced water	**$5,225,588,048.9**
Electricity Generation and Transmission Operating Cost for 20 years	$25,000,000.0
Total Operating Expenditure	**$5,836,808,048.9**
Grand Total Project Cost	**$9,540,658,298.9**

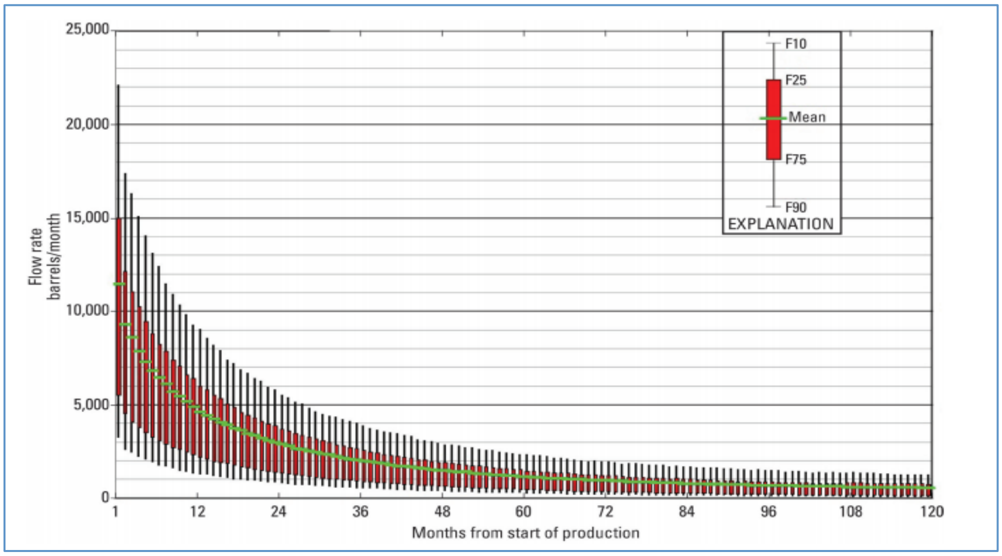
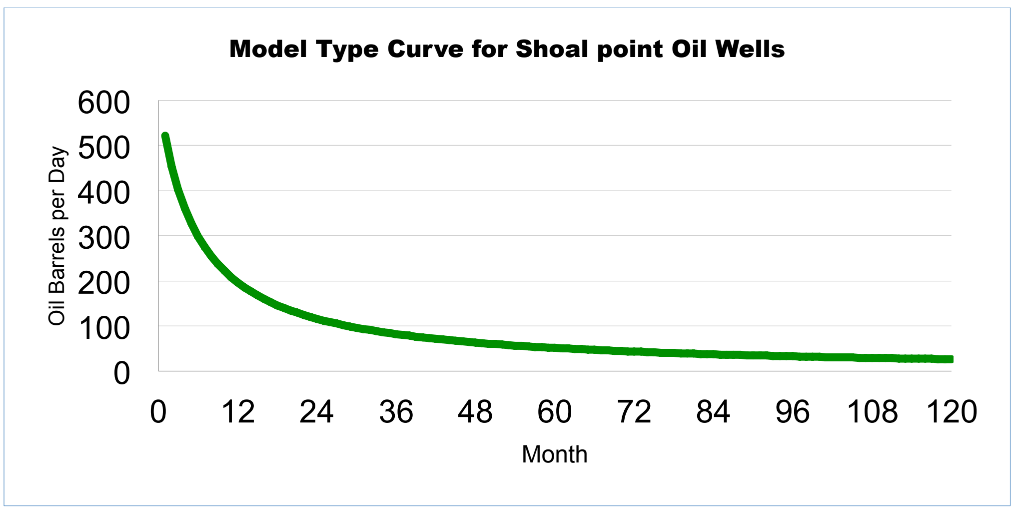
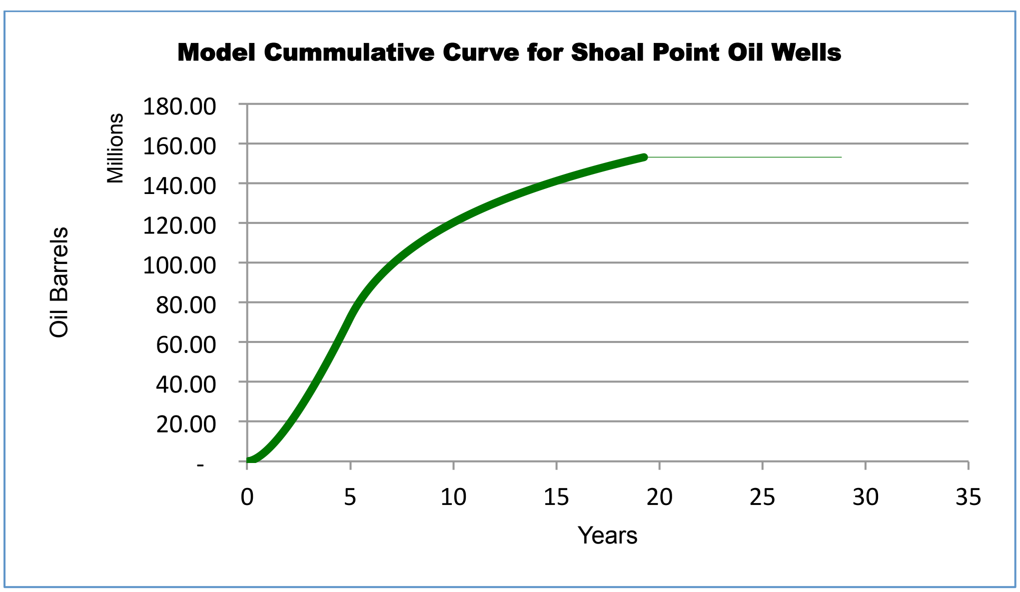


Figure 1: Ten-year Type curve for all horizontal wells in the Bakken Formation [2b]





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