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FRACTURE FLOODING™

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Presentation Outline

1. Introduction
2. Description of Fracture Flooding^{tm}
3. Sequential Fracture Flooding^{tm}
   US 9,976,400
4. Continuous Fracture Flooding^{tm}
   US 10,024,124; US 10,215,005
5. Intermittent Fracture Flooding^{tm}
   US 10,287,863: 10,400,562
6. Conclusions

1. Introduction

Presently, production of tight oil using multi-fractured wells is not economical because of:

- High capital costs
- Low oil prices
- Rapid well production decline rates
- Low oil recovery factors
- Environmental issues related to high oil high Reid vapour pressure (shipping) and flaring

Introduction……

What is needed is a Process with:

- Low capital costs- no new wells (at 8-million USD each)
- Continuous and higher oil rates
- > 20% OOIP recovery factors
- Solutions to flaring and oil Reid vapor pressure (safety)
- Broad applicability

Introduction……

The upside of Primary oil production (solution gas flooding):

- Initial high oil rates at low operating cost, which pays for the well capital cost

The downside of Primary oil recovery:

- Increases the viscosity of the remaining oil which inhibits flow
- Creates 3-phases which inhibits flow (relative permeability effect)
- Reduces reservoir pressure, the flow-driving energy

The obvious next step is Secondary Oil Recovery

The SOLUTION is to apply secondary oil recovery
to the 100,000 existing wells
using liquid or gas flooding

The BARRIER to secondary oil recovery is low INJECTIVITY

The INJECTIVITY PROBLEM

Secondary oil recovery processes require injection of a fluid into the reservoir.
For a given rock, Injectivity is proportional to –

- Differential pressure (Injectant-Reservoir)
  Limited by rock fracture pressure

- Rock permeability
  A "Given", varies between 0.5 mD in Canada to 0.01 mD or less

- Viscosity and phase type of the injectant
  Liquid versus gas

- Rock surface area available
  Inject by a vertical well, horizontal well, other?

2. Fracture Flooding^{tm}

Fracture Flooding greatly reduces the injectivity barrier to flooding tight rock

Fracture Flooding^{tm} uses the fractures themselves as injection and production conduits

This greatly increases fluid injectivity into the tight rock matrix

For example, with a 4.5-inch horizontal well 9000 feet long, with 50 fractures 35 feet high and 1000 feet wide, the fractures increase the exposed rock face by **2000-fold** compared with an un-fractured horizontal well.

How Fracture Flooding^{tm} works

Fluids are selectivity injected into Alternate
fractures and

Oil is simultaneously and continuously produced
from the other fractures, all via
The existing wellbore

(Surface area 2000 x horizontal well)

WHY HIGH SWEEP EFFICIENCY?

- The Fracture Flooding Process uses a PLANAR surface rather than a line source

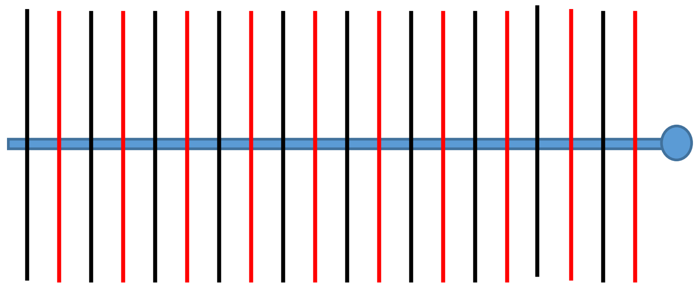
- High rock surface area ensures <u>low linear velocity,</u> which improves sweep efficiency by reducing viscous fingering

- Fluid-oil viscosity contrast is low with water. Injected gas does not have to be miscible in the oil

- We could alternate water and gas, enrich the gas or add chemicals to the water

We can selectively inject and produce from fractures from the same existing wellbore

Red = Injection fractures
Black = Production fractures

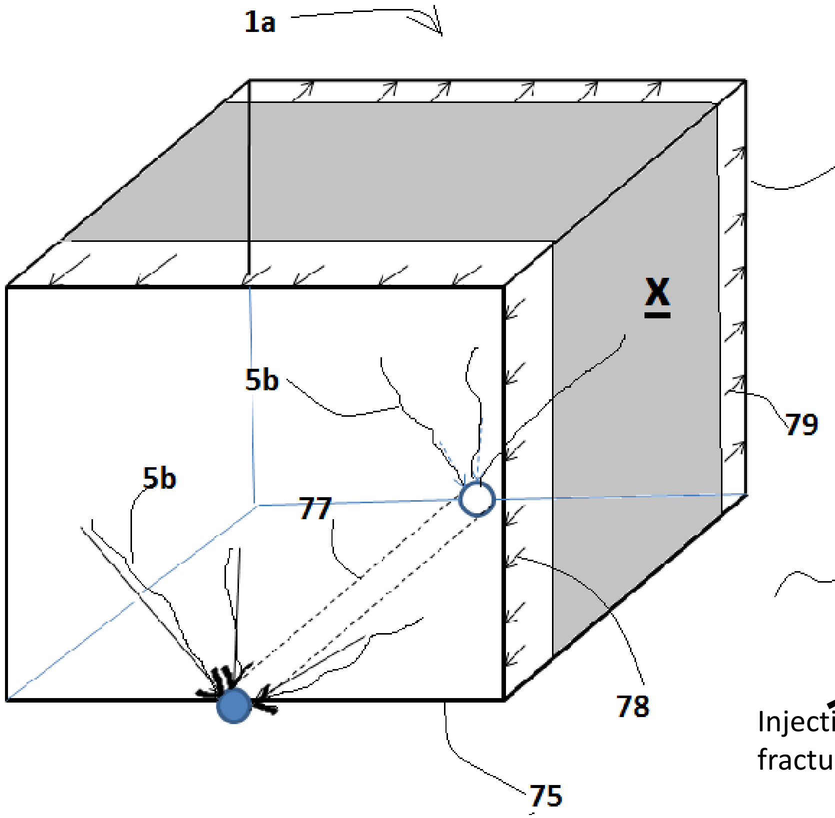


4.5-inch horizontal well

……………… Sequentially, Continuously or Intermittently

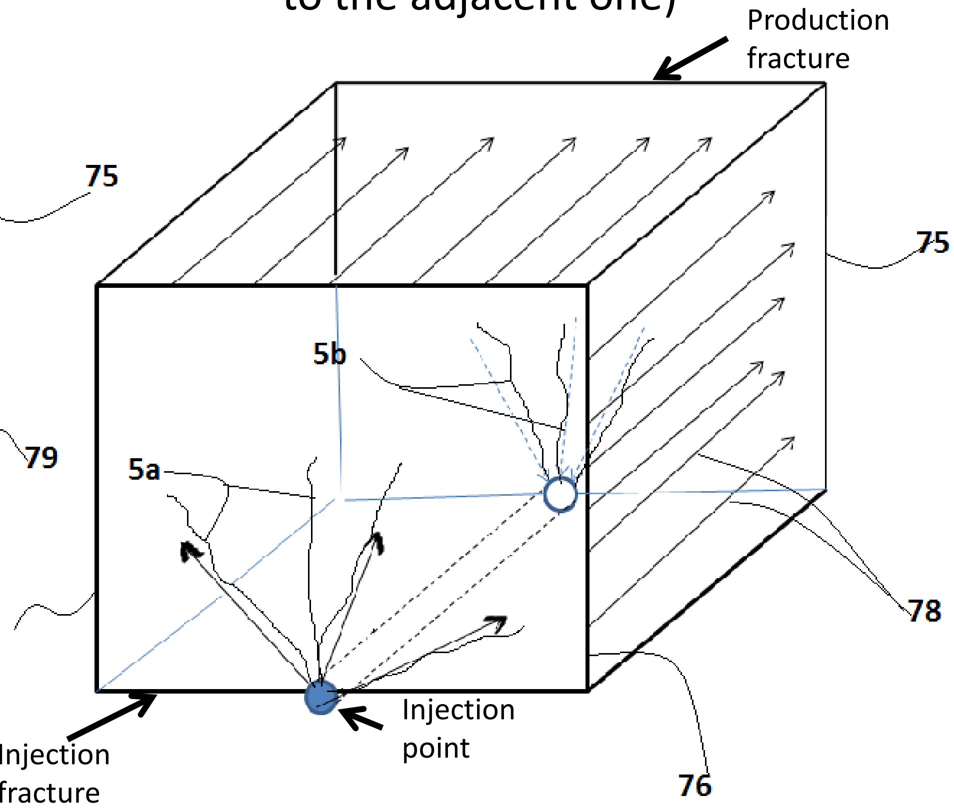
Consider fluid flow in the rock matrix:

Primary production produces from near the fracture only



Produce oil only from near the fractures
<10% recovery

Fracture-Flooding[tm]
(Sweeping from one fracture to the adjacent one)



Produce oil from the entire shale matrix:
Increased recovery

Inexpensive test of Fracture Flooding^{tm} concept

2. Sequential block flooding

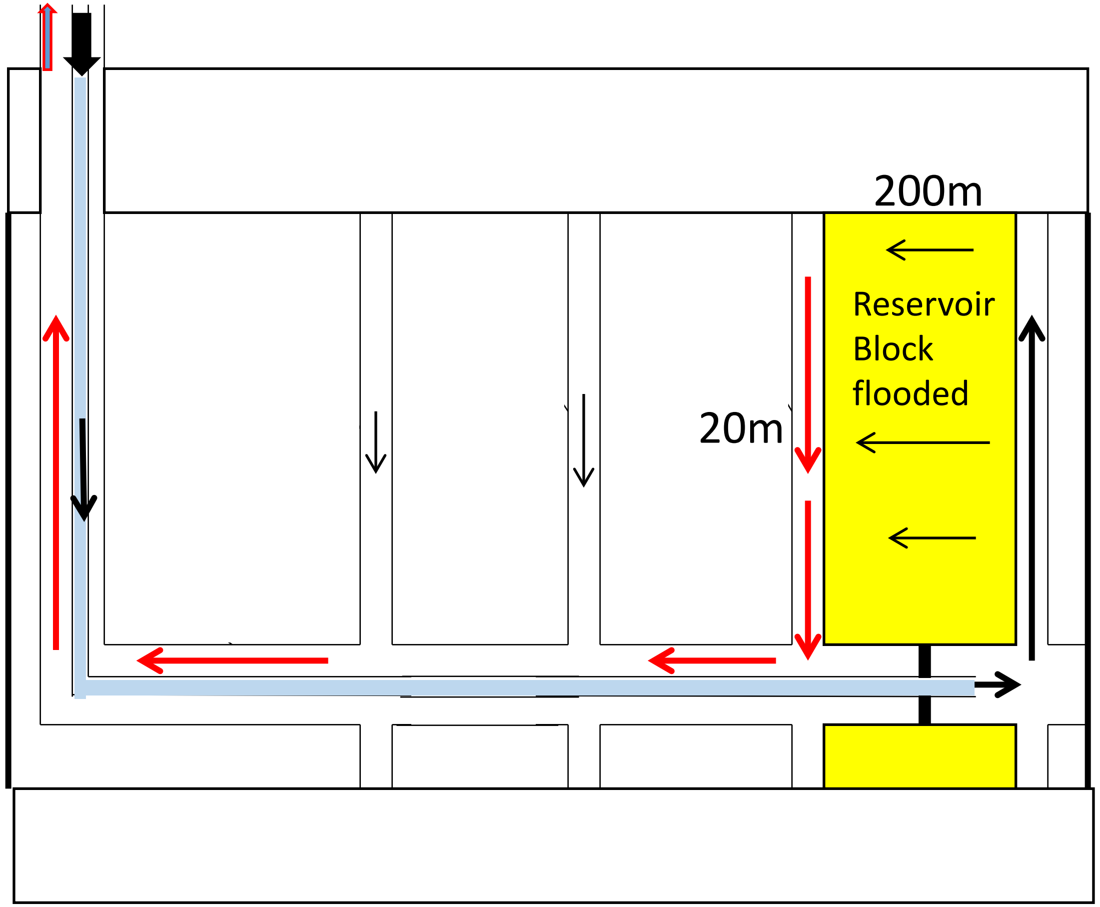
Just place a long tubing with a packer into the multi-fractured well

When flooding of the first block is complete, move the packer along to the next block

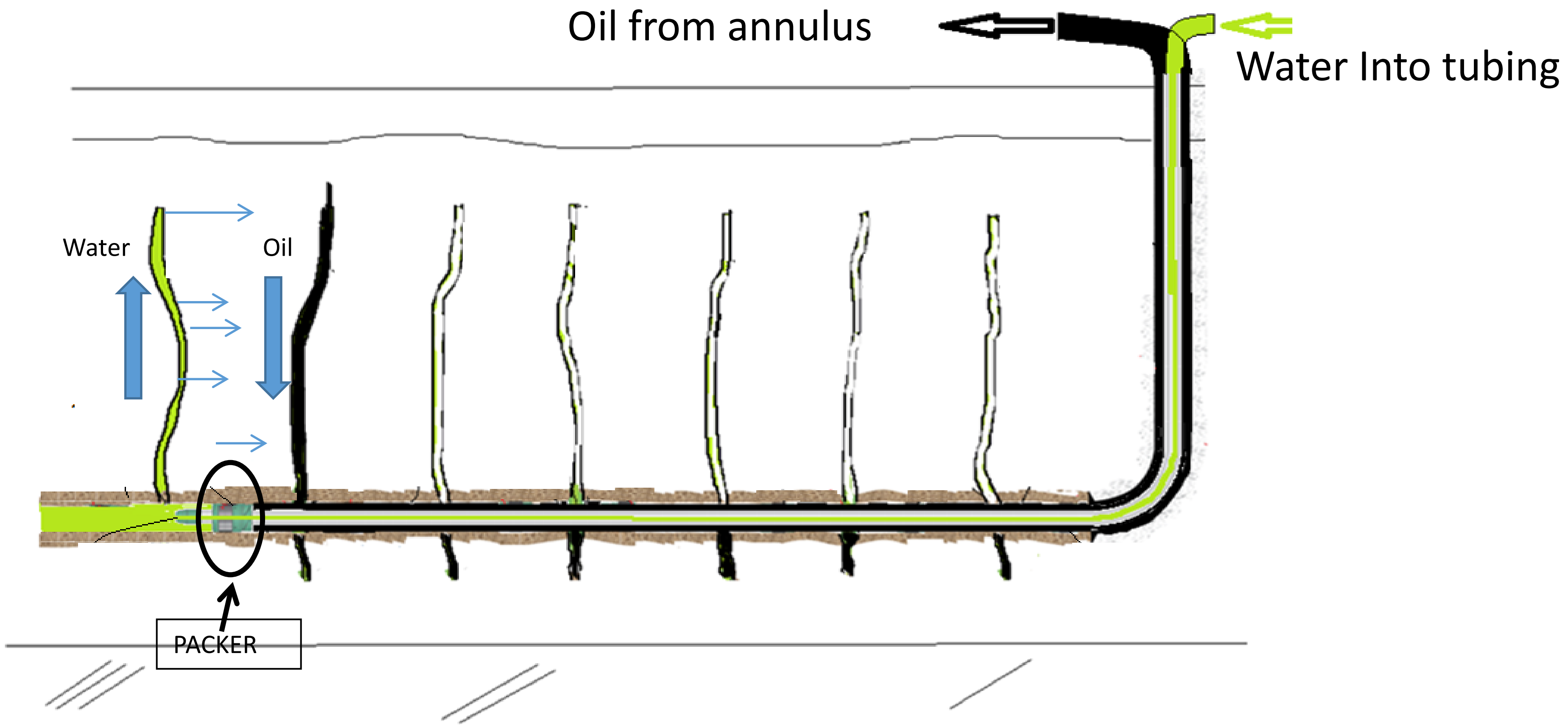
Sequential Fracture Flooding^{tm} may be conducted at low capital cost by running a coiled tubing to the toe of the horizontal well with an inflatable packer placed between the last two fractures, as illustrated in the following Figure. Fluid injected into the tubing enters the furthest fracture and sweeps oil from the matrix to the adjacent fracture in the direction of the heel, where reservoir fluids drain into the well annulus for conveyance to the surface. Once the injectant breaks-through, the packer is moved one fracture closer to the heel and the next block of matrix is flooded. This process is continued until the entire fractured zone is flooded. The block of rock matrix being flooded benefits from the injection pressure, while the other fractures towards the heel nevertheless produce primary oil into the annulus. Since only part of the fractured zone is being flooded at one time, the oil rates are substantially lower than for Continuous Fracture Flooding^{tm}, but the ultimate oil recovery factor is the same.

Single well with sequential movement of packers

Inject in tubing and produce from annulus



Single well with sequential movement of packer
Stage 1. Initial injection at the toe



Single well with sequential movement of packer
Stage 2

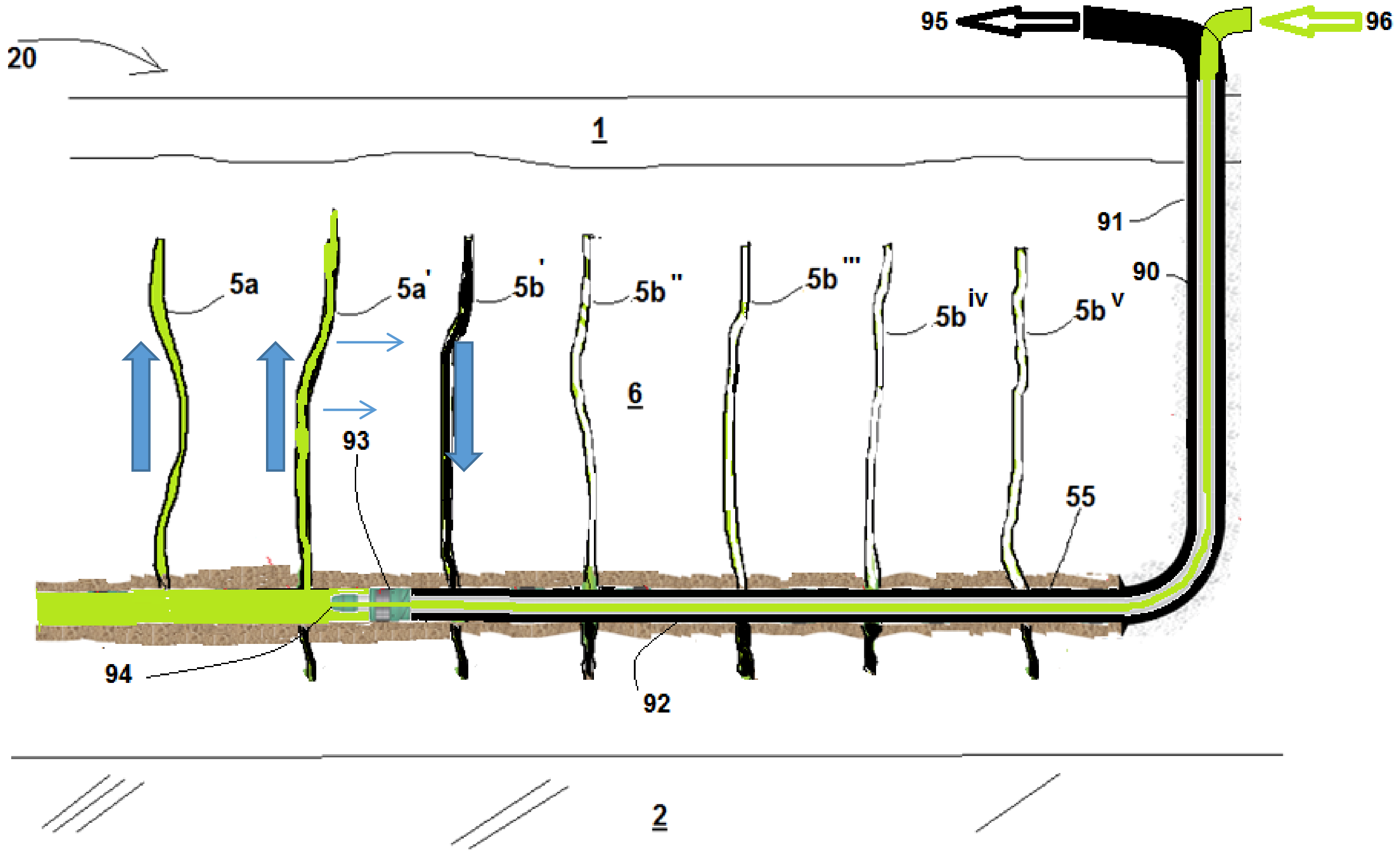


FIG. 4B

3. Continuous Fracture Flooding^{tm} using dual-channel tubing or pipe

Simultaneous complete zone flooding

Rather than flood a single block at a time, the entire well/fracture zone can be flooded simultaneously

re-enter
your existing multi-fractured well
with our Dual-Channel Pipe completion

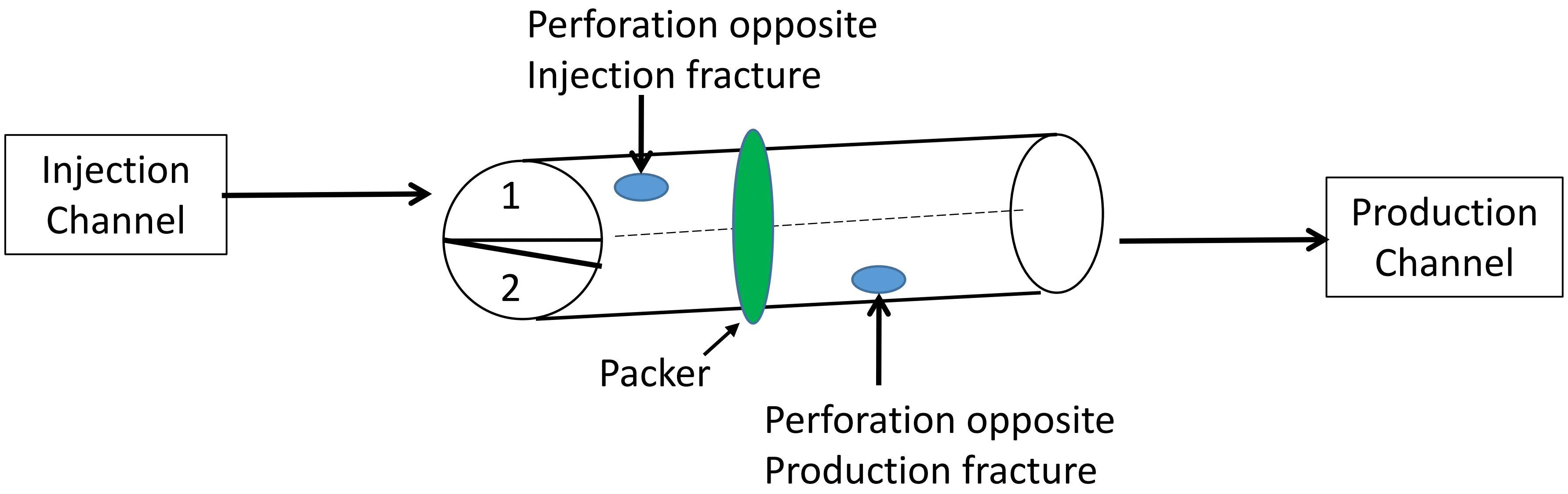
Process Description

In **Continuous Fracture Flooding**tm, alternate fractures serve as injection or production fractures, and flooding is conducted from the wellbore, into the Injection Fractures, through the matrix, into the production fractures and back into the wellbore through the Production Fractures for production to the surface. This is illustrated in the next Figures. The operation is conducted with our Dual-Channel Pipe completions that has separate injection and production flow channels within a pipe that is inserted into the wellbore. The pipe has a packer between each fracture, which controls access to each fracture.

The injected flooding fluid may be associated gas, natural gas, CO_2, miscible hydrocarbons, immiscible gas, water or mixtures, and the fluid can be changed during the life of the flood.

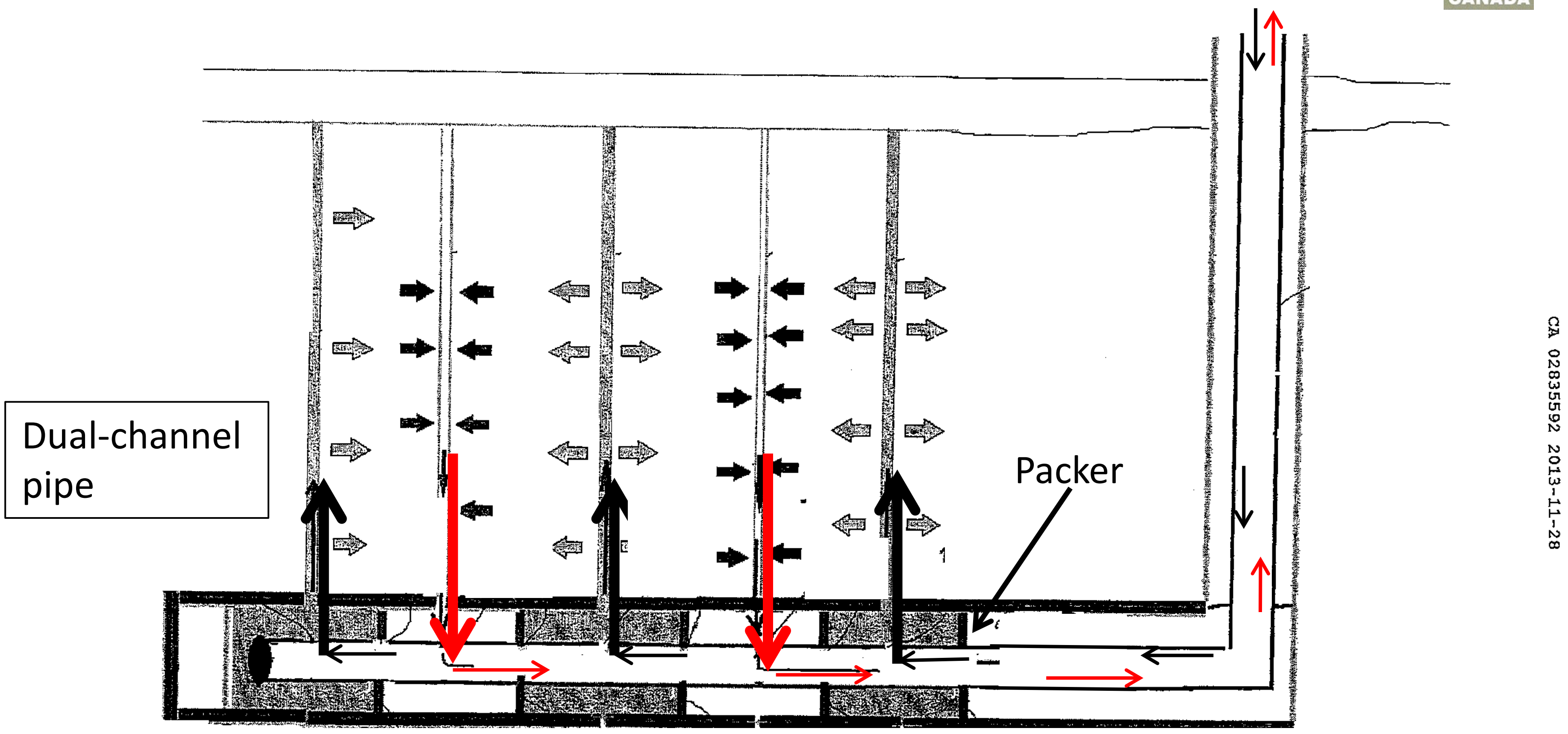
The entire fractured region is flooded simultaneously.

Single segmented Pipe: Dual-Channel Pipe



A packer is placed between the perforations

Lined and cemented hole

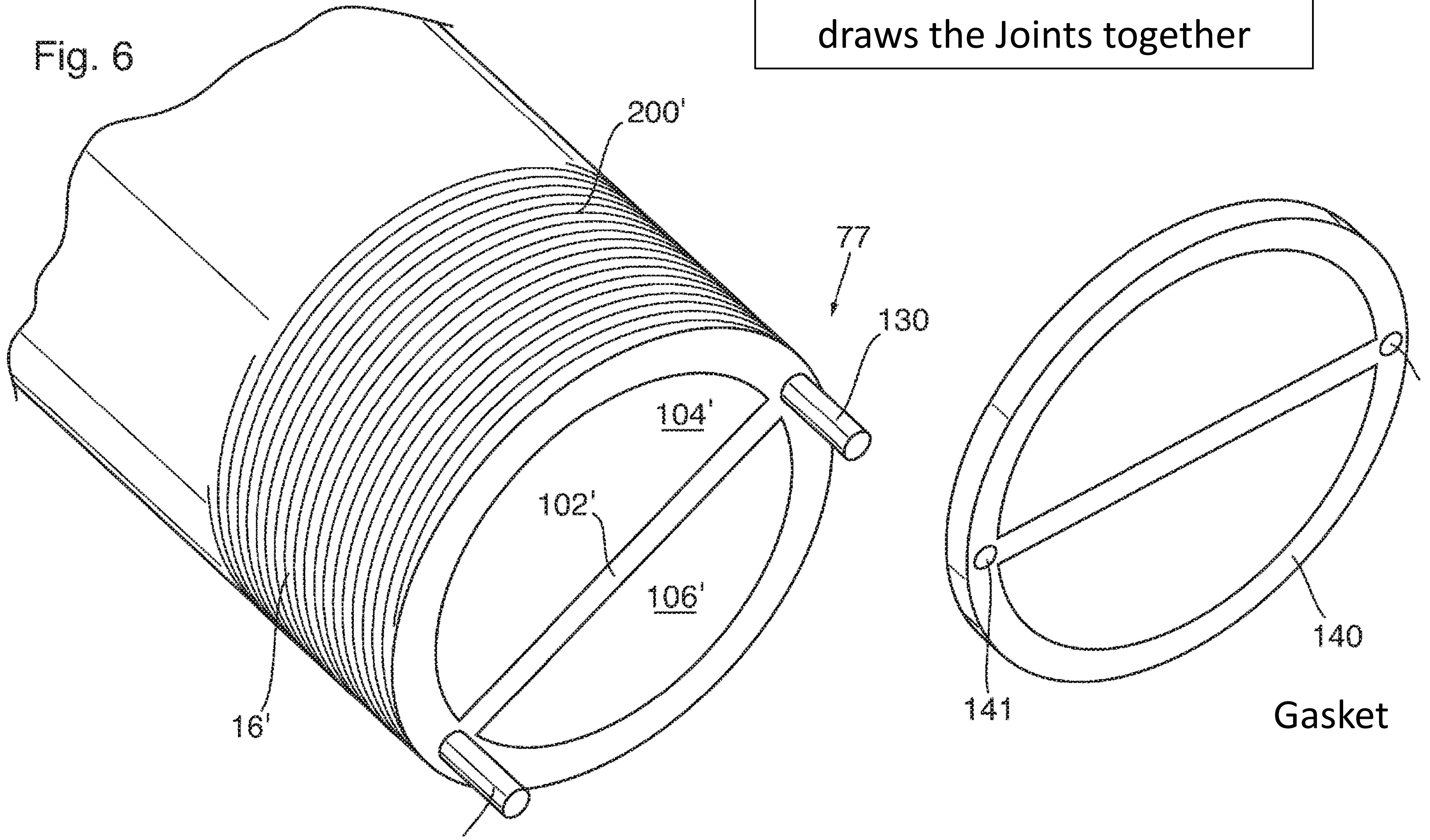


Simultaneously Fracture Flood and produce the <u>entire</u> fractured zone

Union of Segmented Dual-Channel Pipe Joints

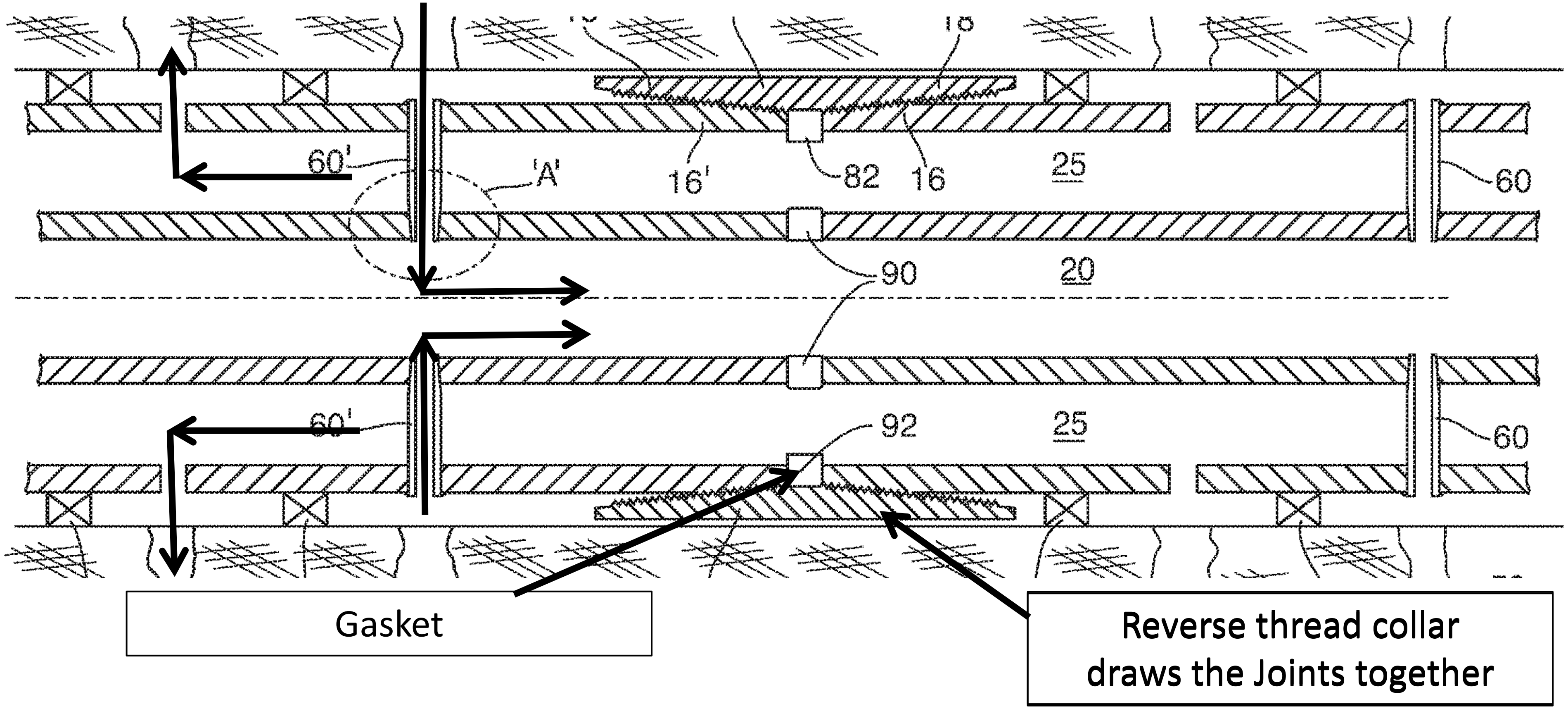
A Reverse Thread collar
draws the Joints together

Fig. 6



Gasket

Concentric Pipe Union with Gasket and Reverse Thread Collar



Threaded Unions and Flow for Concentric Pipe

See US Patent 10,215,005 for other designs

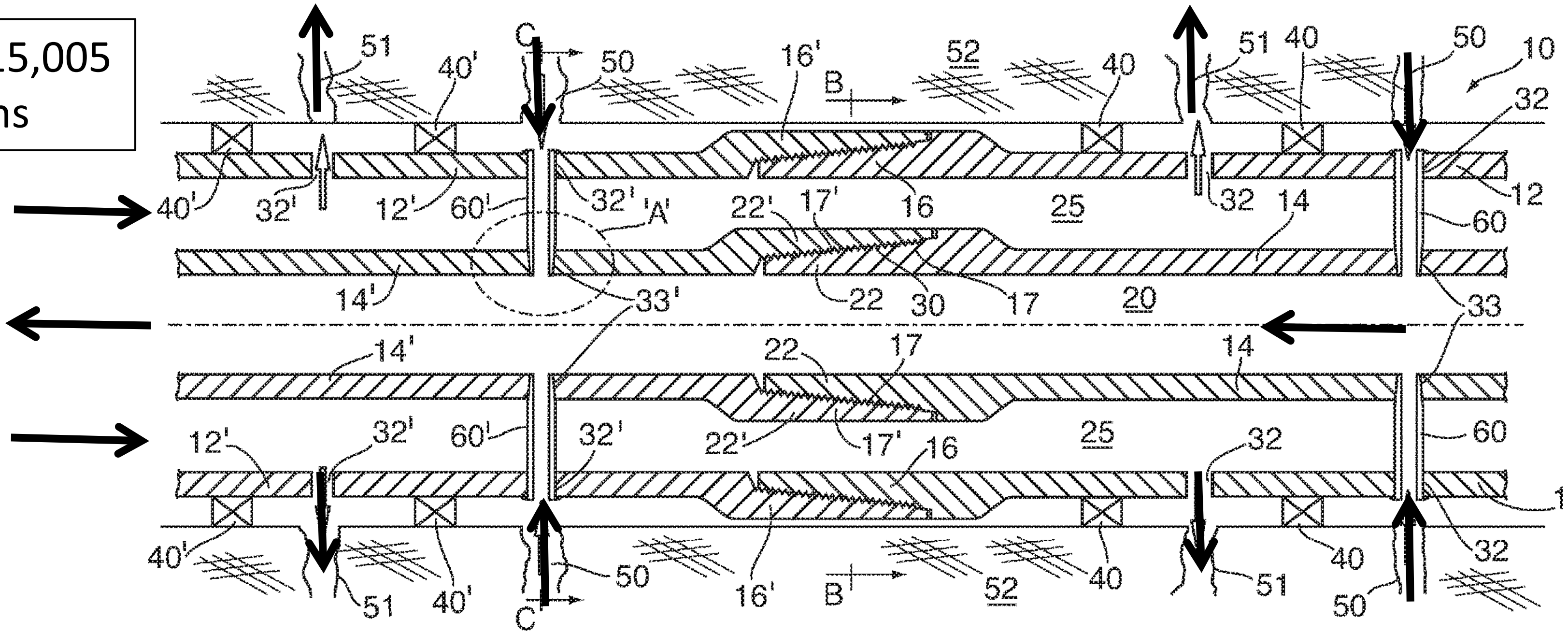


Fig. 1A

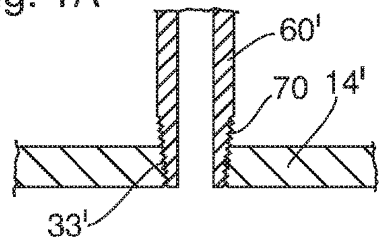


Fig. 1B

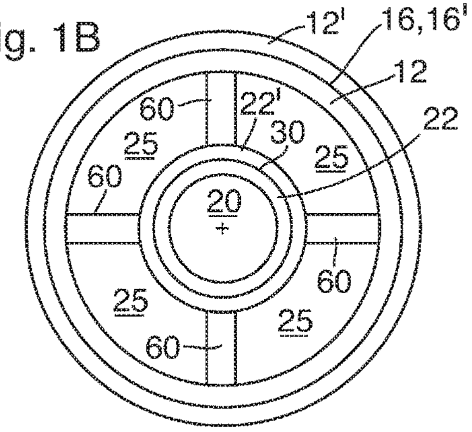
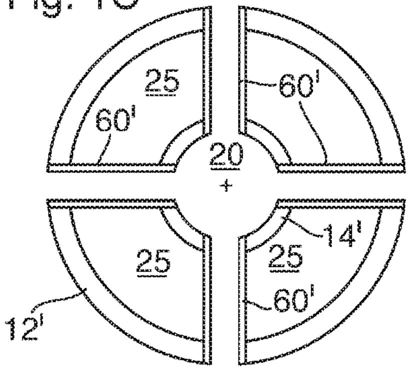


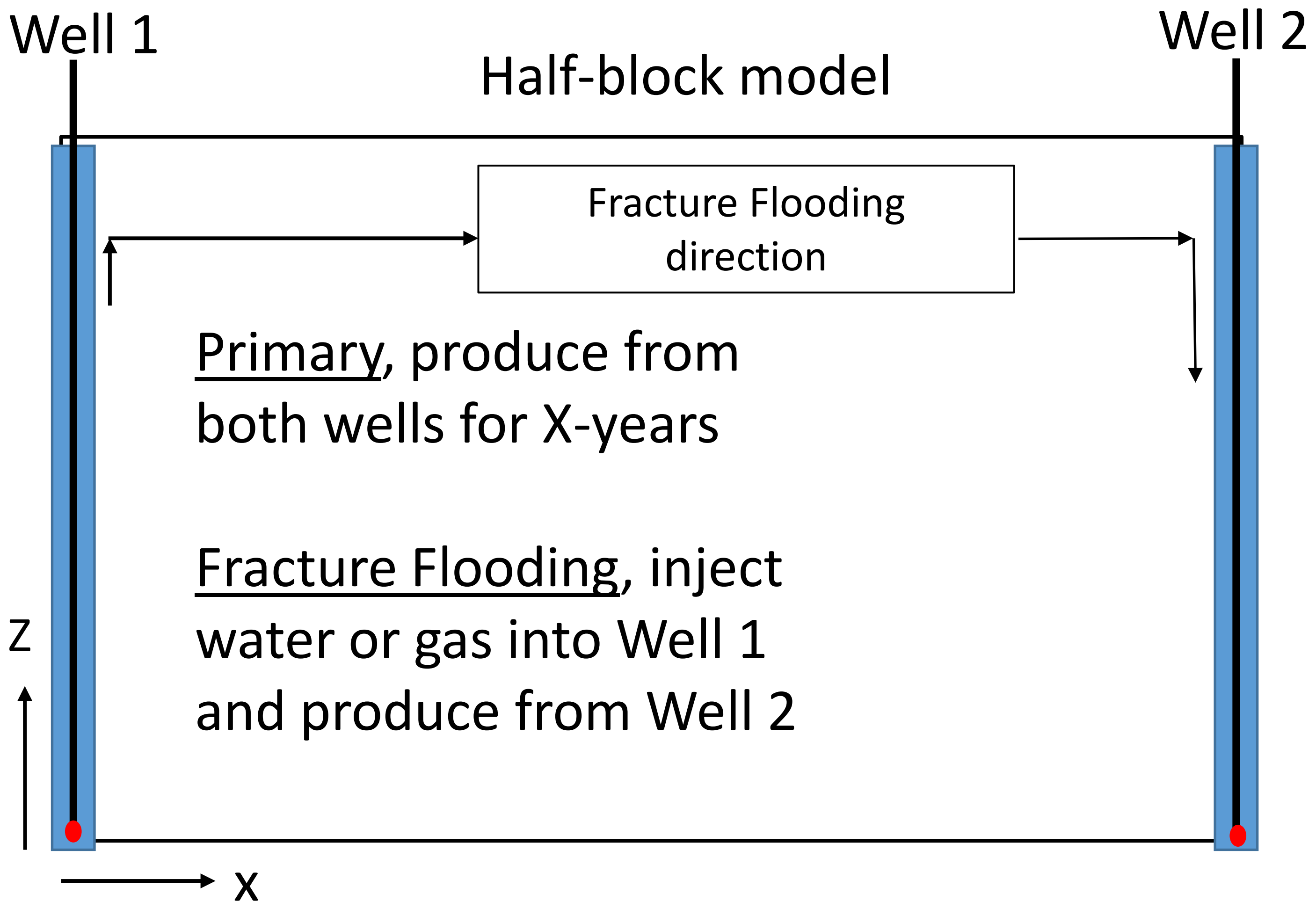
Fig. 1C



Canadian Bakken Numerical Simulation Parameters

Software	CMG STARS^{tm}
Model dimensions, meters	200 x 100 x 20
Oil Saturation, %	50
Water saturation, %	50
Porosity, %	10
Temperature, ºC	72
Initial pressure, kPa	16,000
Maximum injection pressure, kPa	23,000
Permeability, mD	0.5-0.001

Numerical Simulation Model

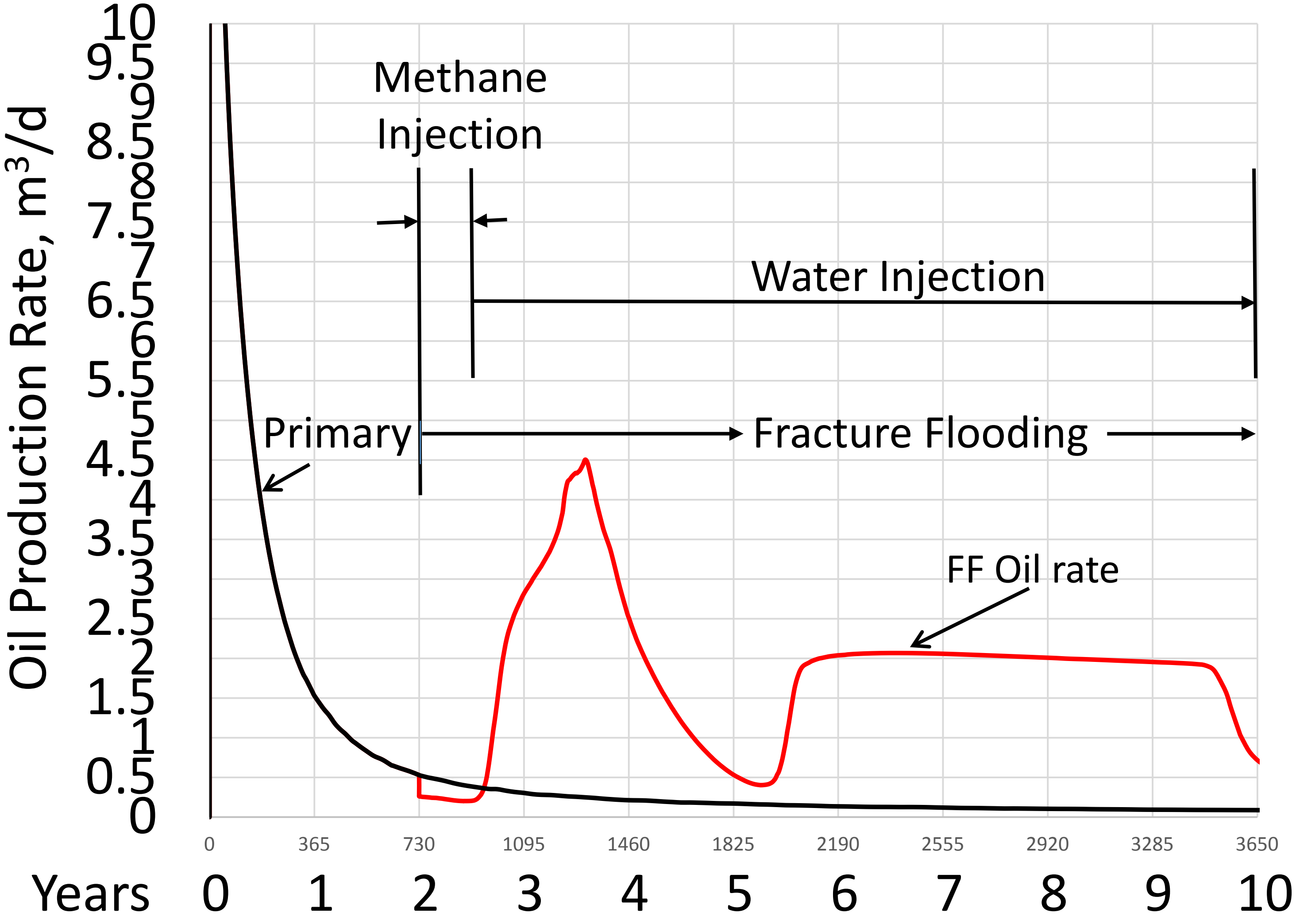


Simulation Results: Canadian Bakken

Two approaches were simulated: injection of gas, then water and only water injection. Fluid injection was commenced after 2-years of "flush" oil production, when the well capital costs have been recovered and the oil rate is low. Starting injection at the outset is detrimental because only half the fractures are producing during this high-flow period. Between years 3 and 10, the water flooding oil rate is **332-times** as high as for primary recovery and the 10-year oil recovery factor is 37.7%, while the 30-year recovery is 44.6%.
Using a permeability of only 0.05 mD gives a lower Recovery Factor. For the tighter rock, injection of gas is more beneficial than water because of higher injectivity, giving recovery of 24.6%.

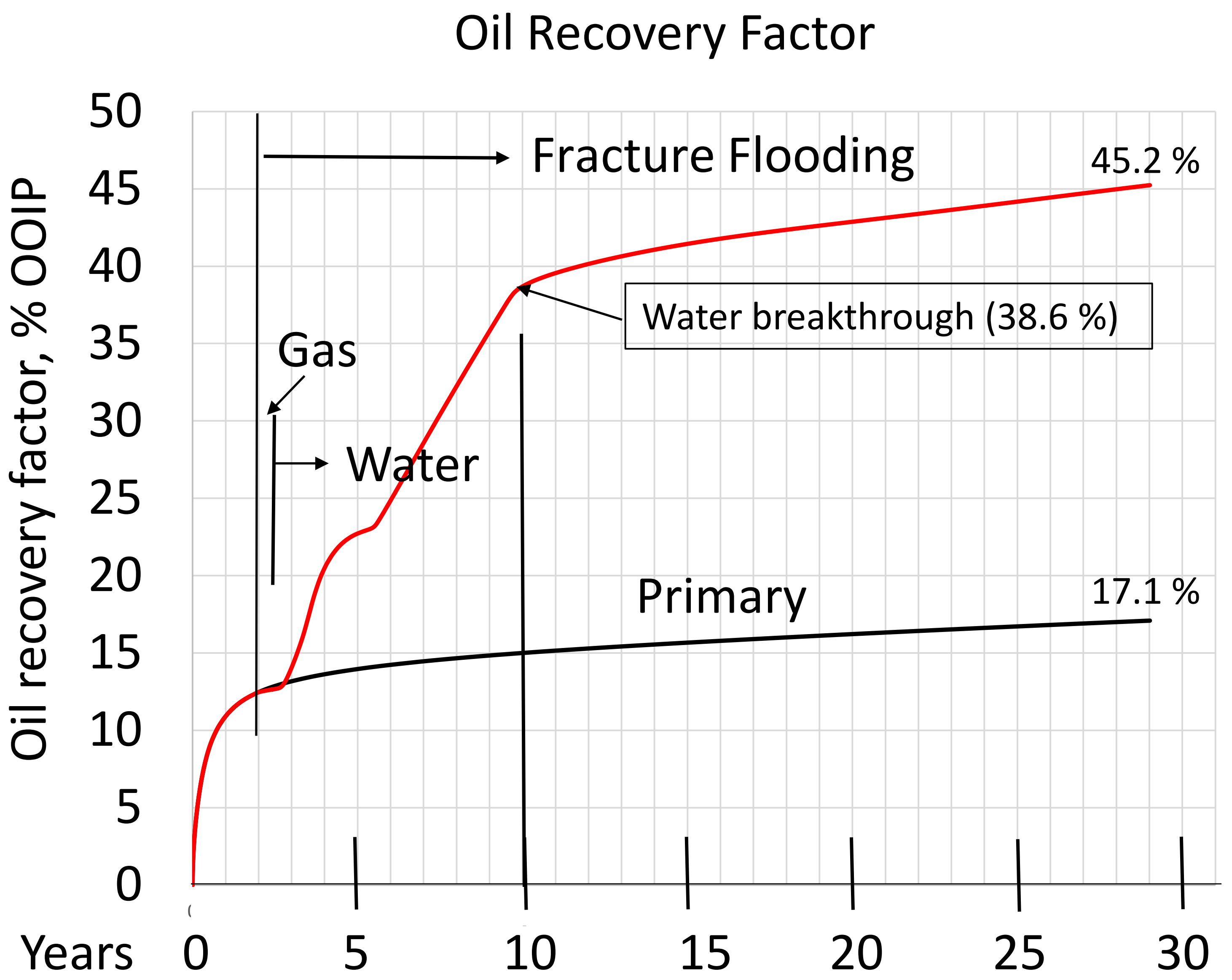
Canadian Bakken, Kh=0.5 mD, Gas then Water

Oil Production Rate

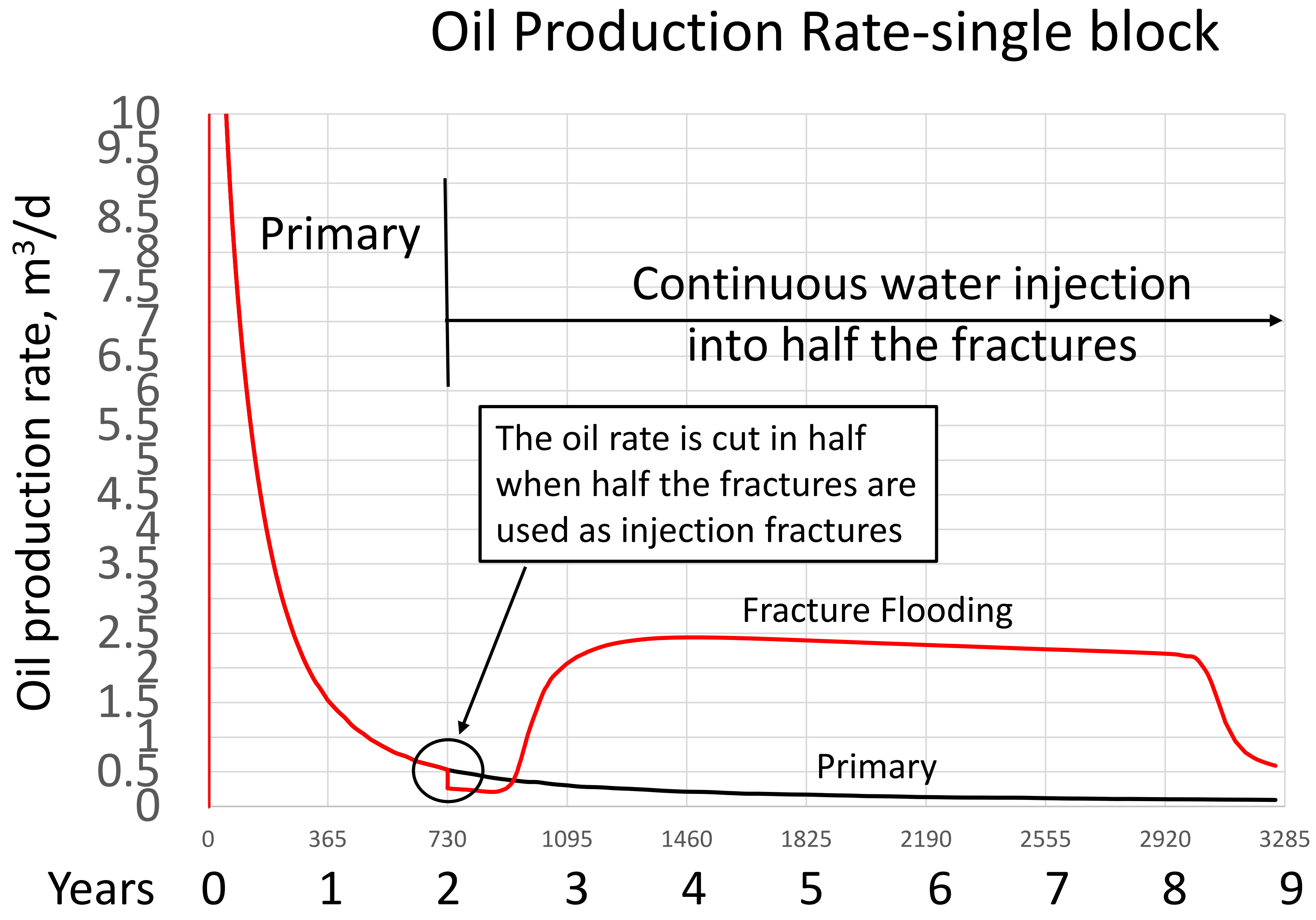


From the start of year 3 to the end of year 10,
the average oil rate is
332 times greater with Fracture Flooding^{tm}
compared with Primary production

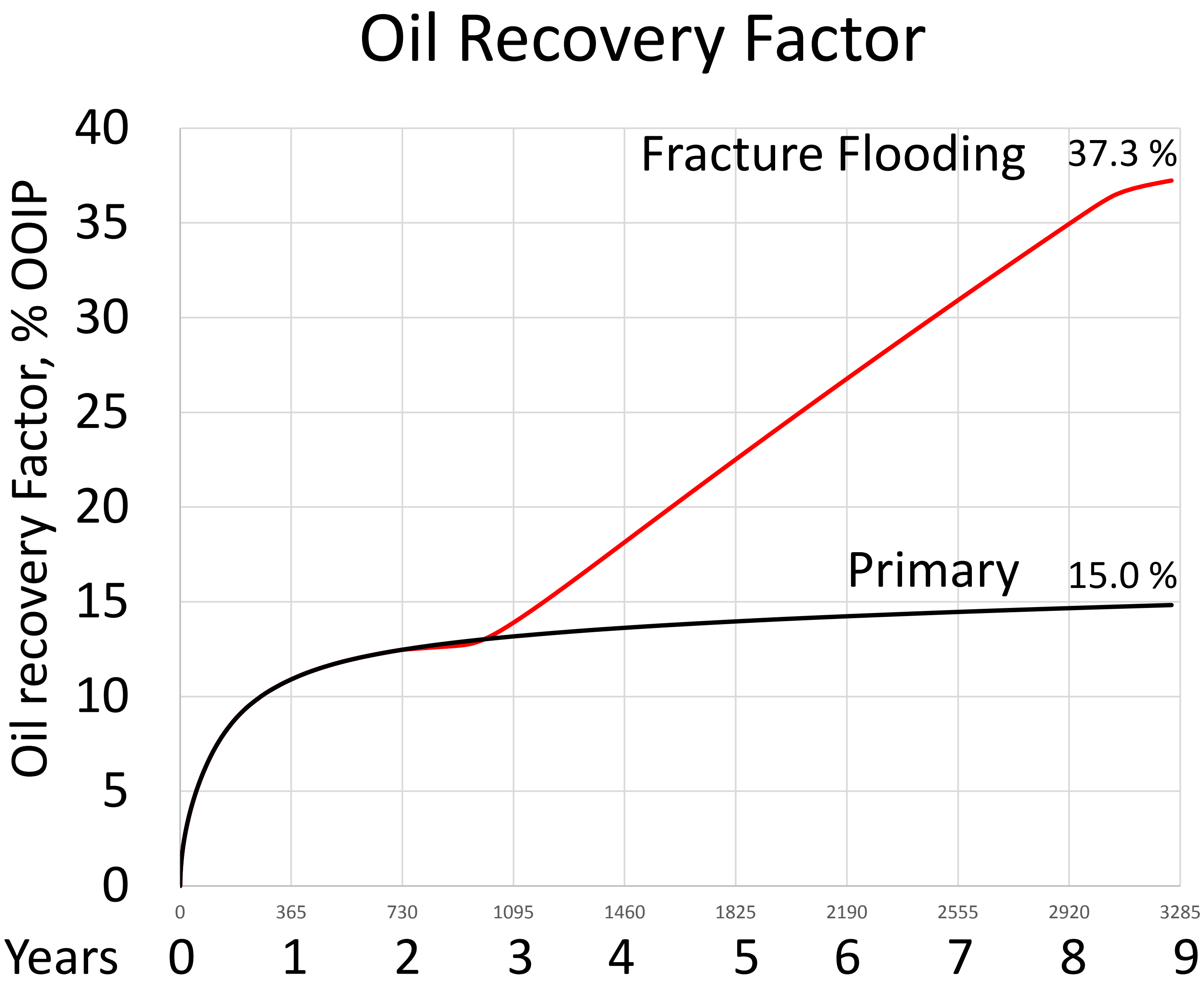
Canadian Bakken, Kh=0.5 mD, Gas then Water



Canadian Bakken, Kh=0.5 mD, Water Only



Canadian Bakken, Kh=0.5 mD, Water Only



Calculating oil rate in the model

The projected oil rate for a full well with X fractures is:

(Oil rate from the model) x (X-1) x (2)

Example-
With 21 fractures and an oil rate of 1-m^3/d in the model,
the full well oil rate is : 1 x 20 x 2 x 6.29 = 251.6 bbl/d

Fracture Flooding^{tm} Canadian Bakken

Oil Recovery Factors

Gas injection rate 1000 m^3/d/fracture

Process	Kh = 0.5 mD	Kh= 0.5 mD	Kh = 0.05 mD
Duration	*30-YEARS*	*(9 or 10) YEARS*	*30-YEARS*
Primary	17.2	15.0 (10)	13.5
Gas 5- months then Water	45.2	38.3 (10)	20.3
Water Only	44.6	37.3 (9)	19.2
Gas Only	44.7	32.2 (9)	23.6

4. INTERMITTENT FRACTURE FLOODING FOR LINED WELLBORES USING A SLIDING SLEEVE COMPLETION

Intermittent Fluid Injection

Fractures are designated alternately as

Injection Fractures or **Production Fractures**

INTERMITTENT FRACTURE FLOODING

Requires a single pipe with appropriate perforations and packers

1. Place the pipe with packers inside the liner so that odd-numbered fractures (Production fractures) are isolated and the even-numbered fractures (Injection fractures) can access the inside of the pipe.

2. Inject water or gas into the pipe for 4-months to pressurize the reservoir.

3. Shift the position of the pipe so that the Injection fractures are isolated and the Production fractures can access the inside of the pipe for production to the surface.

4. Repeat as needed

5. For cycles after the first cycle, before injecting fluid, briefly produce from the Injection Fractures to flush oil from the wellbore

Intermittent Fracture Floodingtm may be conducted In any well that has a cemented liner. The process can be applied to partially de-pressured older wells, reviving them. Again, alternate fractures are labeled Injection Fractures and Production Fractures. The first Figure below shows the first stage where the Production Fractures are isolated by sliding the pipe to the appropriate position and the flooding fluid is injected into the pipe, enters the Injection Fractures only and pressurizes the rock matrix. The next Figure shows the second stage where, after a few weeks or months, when pressurization is complete, the pipe is moved to block the Injection fractures and open the Production fractures to flow into the pipe. After the first iteration, prior to re-starting injection, the Injection Fractures are briefly produced to the surface in order to sweep oil from the wellbore, thereby preventing a change in the fluid injectivity caused by a decrease in relative permeability. Our simulations indicated favorable injection periods of 4-months for injection and two-years for production.

Intermittent Fracture Flooding-Slideable sleeve

Fig. 3

Injection cycle

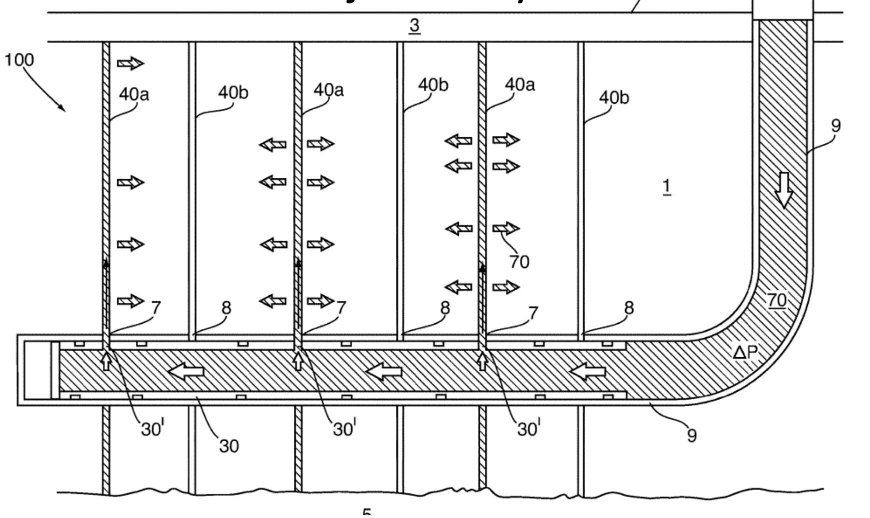
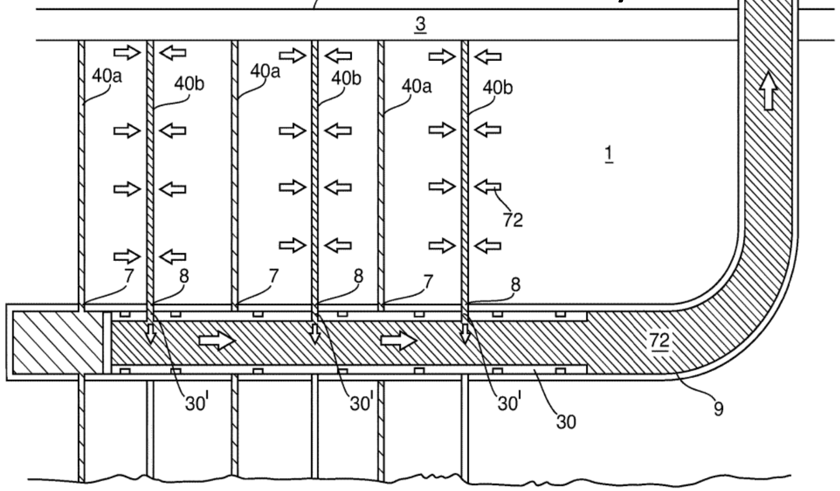


Fig. 4

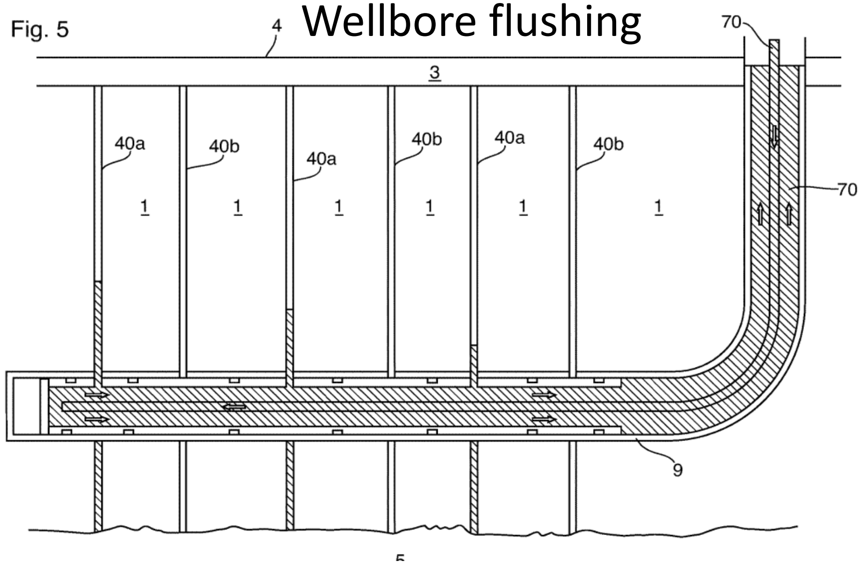
Production cycle



Sliding Sleeve

Fig. 5

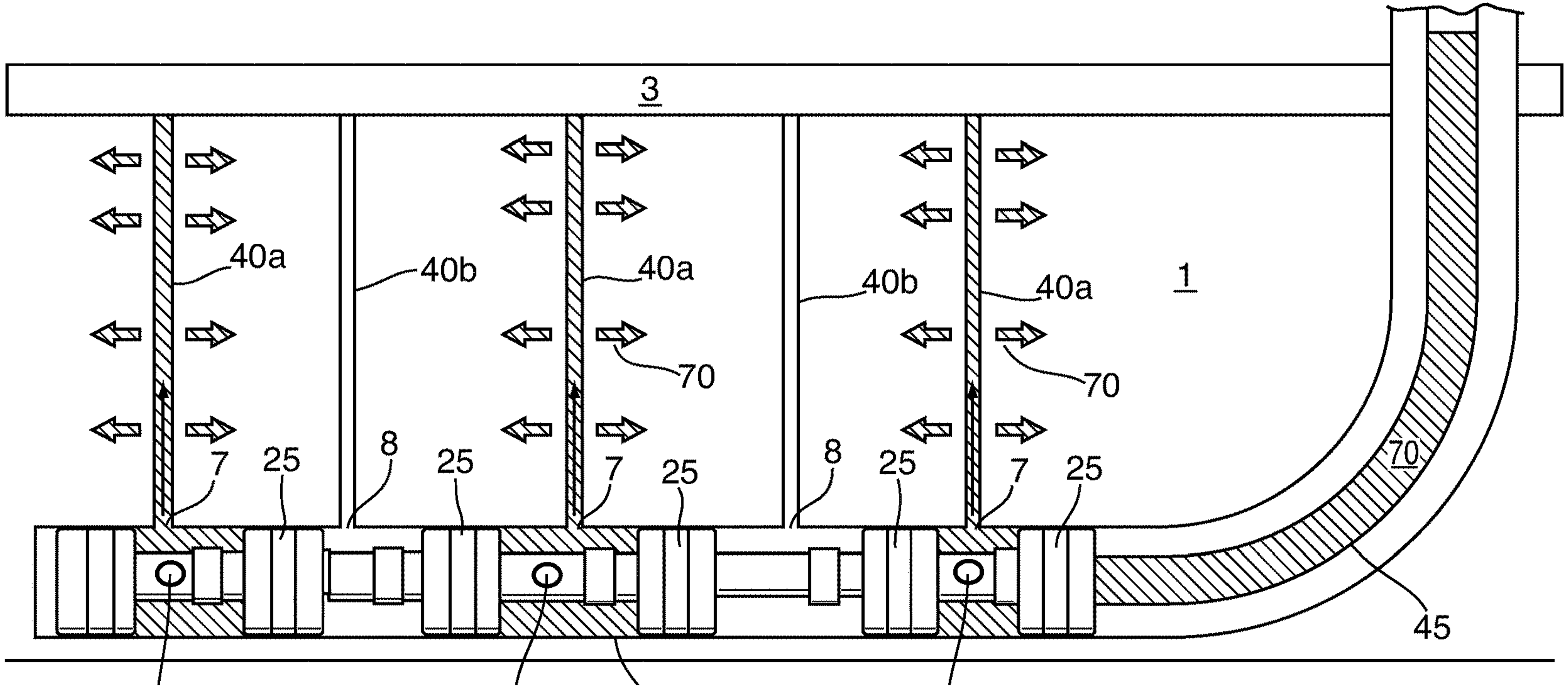
Wellbore flushing



Removal of wellbore oil after the Production Cycle

Before the Injection Cycle starts (Fig. 3), it is desirable to have the wellbore already filled with Injection fluid so that oil is not pushed into the Injection Fractures because this would inhibit injectivity of the Injection fluid. Flushing is accomplished by briefly producing from the injection fractures to flush out the wellbore oil left over from the previous Production Cycle. Optionally, Injection fluid can be circulated using coiled tubing as shown in Fig 5 in order to flush out the wellbore oil.

Intermittent Fracture Flooding-Inflatable Packers

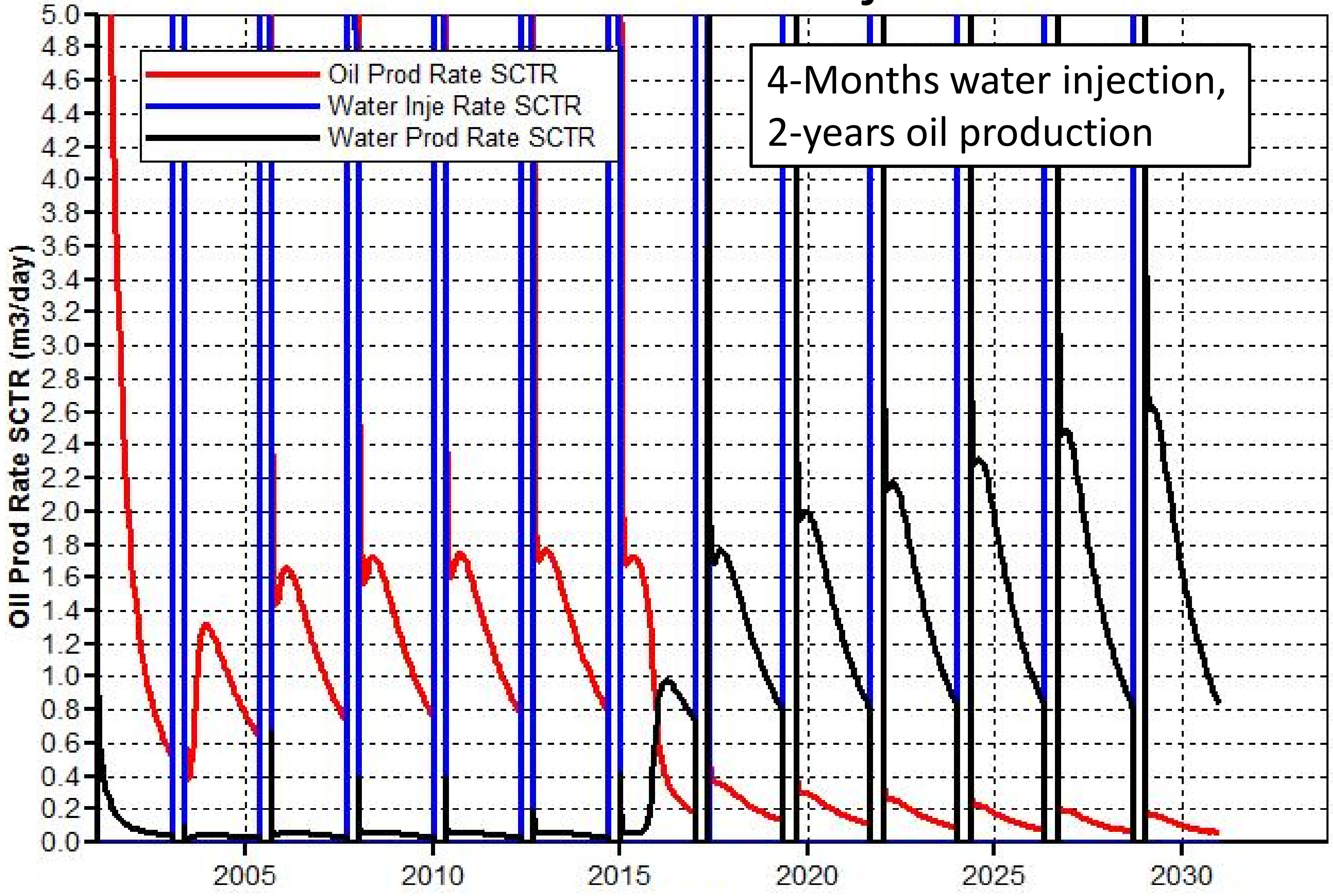


OPERATIONAL SEQUENCE: Position pipe with packers as shown.
Inject fluid 4-months, deflate packers, move the assembly, inflate packers, produce oil 2-years, deflate packers, move the assembly, inflate packers. Repeat.

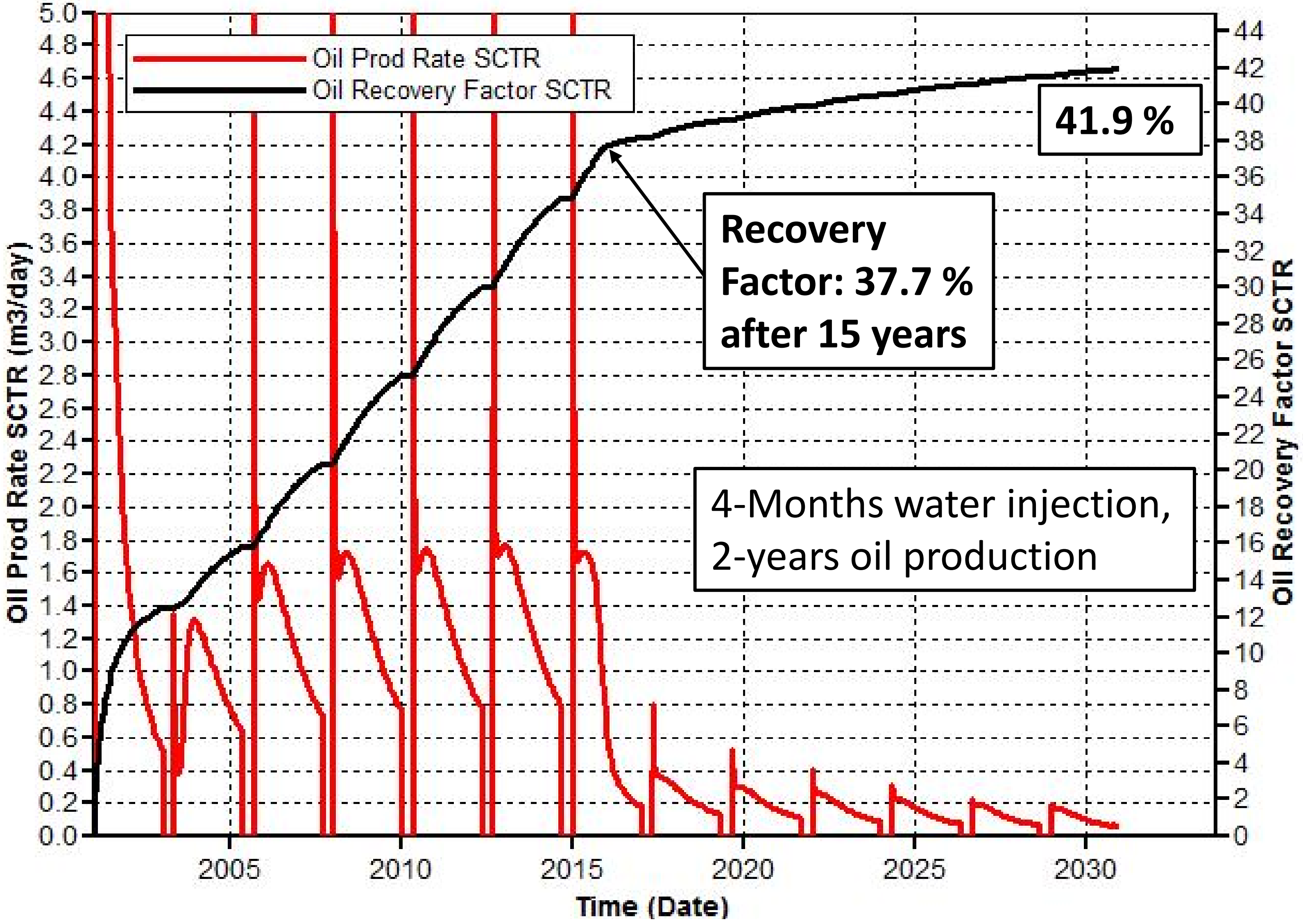
Simulation Results

The following two Figures show the numerical simulation results for **Intermittent Fracture Flooding^{tm}**.
In the first Figure, the blue lines show the water injection for 4-months. The oil rate over increments of 2-years is shown in red, while produced water is in black. High oil rates are sustained over the first 6-cycles, until water breakthrough at year 15. The second Figure shows that the Oil Recovery Factor is 37.7 % at that time. Thirty-year oil recovery is 41.9%.

Canadian Bakken, Kh=0.5 mD
Intermittent Water Injection



Canadian Bakken, Kh=0.5 mD
Intermittent Water Injection



Modelling oil recovery in the U.S. Bakken

Compared with the Canadian Bakken, the U.S. Bakken is deeper. Consequently, it has half the porosity, 50-times lower permeability and 1.6 times the temperature.

In the simulation, water injectivity was very low, so the focus was on gas injection (methane). Methane injection was started after 5-years of primary production (simulation started at 2001) since the process benefits from low reservoir pressure.

The oil recovery Factor peaked at 30% for the U.S Bakken. Figures are shown for Intermittent Fracture Flooding^{tm}. The delay to the oil rate peak depended on the gas injection rate and the maximum allowed injection pressure. These data need to be validated in a field test.

US Bakken Numerical Simulation Parameters

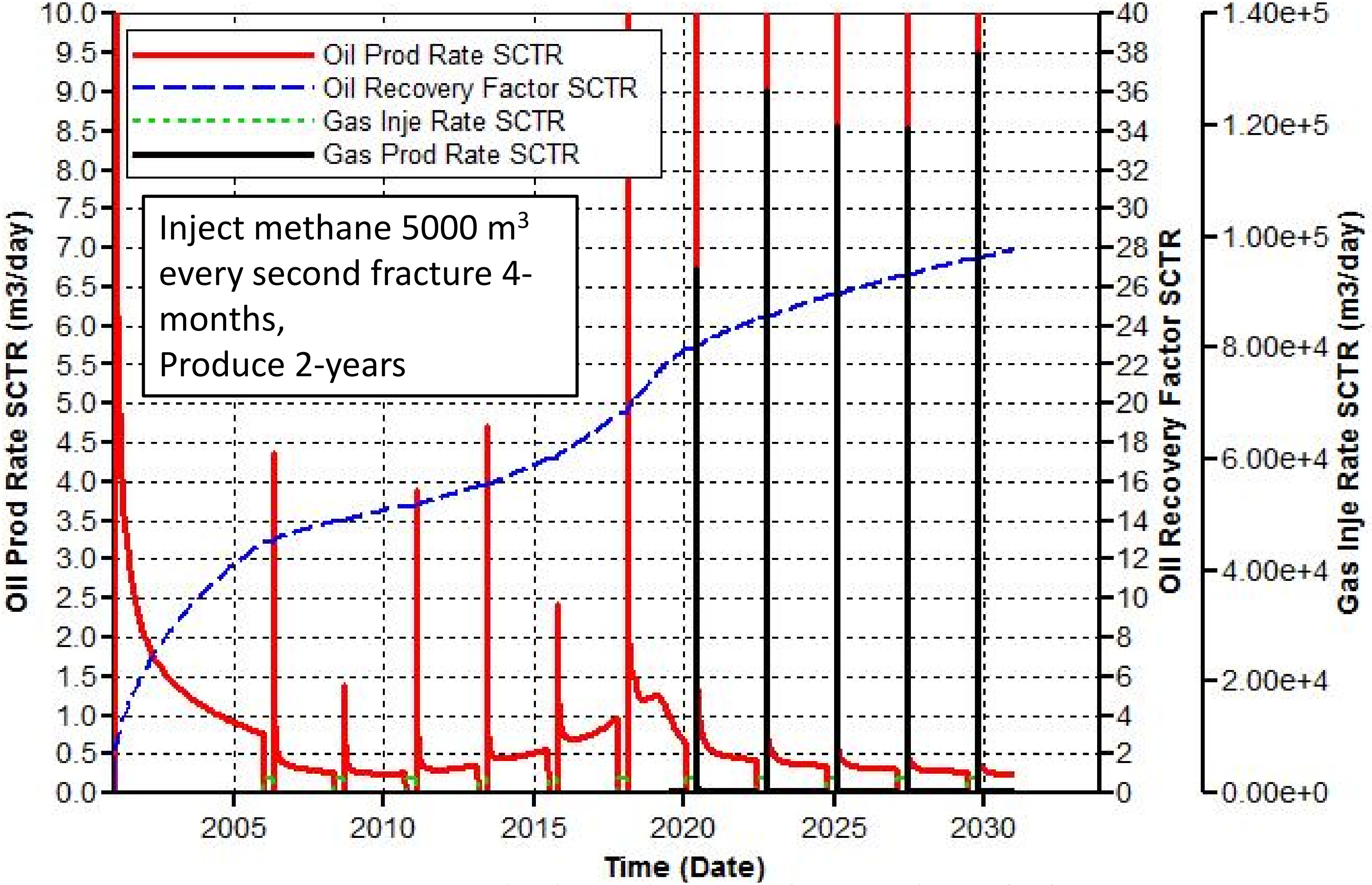
Software	CMG STARS^{tm}
Model dimensions, meters	200 x 200 x 26
Oil Saturation, %	50
Water saturation, %	50
Porosity, %	5
Temperature, ºC	115.5
Initial pressure, kPa	37,922 (5500 psi)
Maximum injection pressure, kPa	Variable
Permeability, mD	0.01

US Bakken, Kh=0.01 mD
Methane Fracture Flooding[tm]

Year of gas injection start	Gas amount m^3 to half the fractures, m^3/d	Max. injection Pressure K kPa	30-year oil Recovery Factor	Years of peak oil rate delay
0 (primary)	0	NA	19.4	NA
3	2000	74.7	29.3	7.8
6	5000	80	30.5	4.6
6	5000	60	28.9	7.3
6	5000	45	27.9	14.8

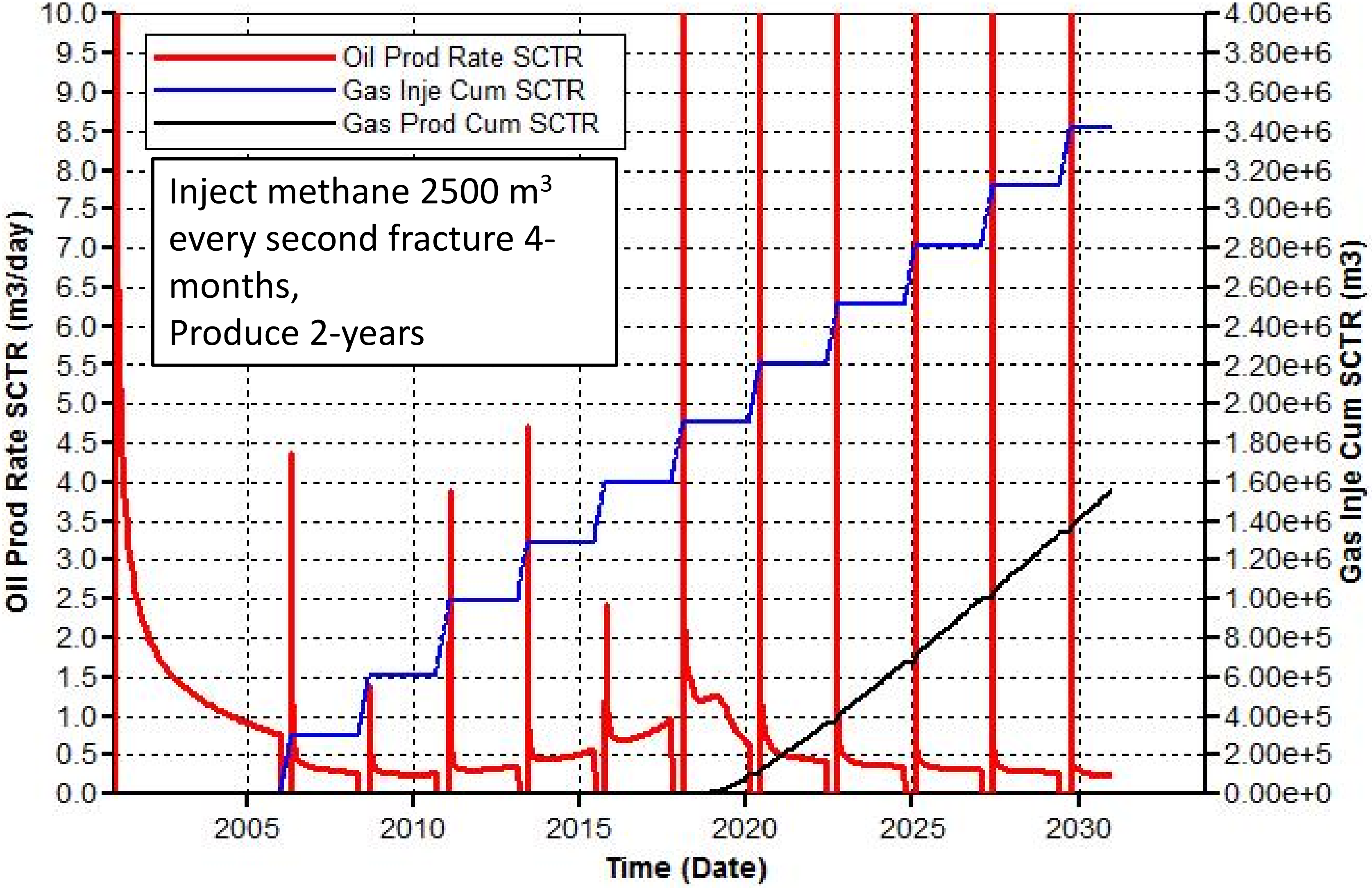
US Bakken, Intermittent Fracture Flooding[tm]

Oil Rate, Gas Rate, oil Recovery Factor



US Bakken, Intermittent Fracture Flooding

Oil Rate and Cum Gas Rate



Years 0 4 9 14 19 24 29

Reid vapour pressure of 40 ºAPI Tight Oil

The high Reid vapor pressure (RVP)can lead to catastrophic explosions as shown in the Lac Megantic and other disasters

RVP can be reduced by warming the produced oil ahead of the separator. The associated gas becomes enriched in heavier hydrocarbons, which makes it a potential miscible solvent for gas Fracture Flooding

Even without that step, continuous cycling of produced gas into the reservoir will lead to “multiple-contact miscibility”, which would have a dramatic effect on the oil rate and recovery factor.

Flared gas conversion to Fuels

Our Sister company, Canada Chemical Corporation (www.canchem.ca) has an advanced economical GTL process that produces a mixture of naphtha, Jet fuel and diesel as well as water and power. These products are vey clean-burning, reducing vehicle tail pipe emissions of CO by 38%, hydrocarbons and particulates by 30%. The Reactor tail gas could be recycled to the reservoir.

Applicable Formations for Fracture Flooding™

Bakken

Eagle Ford

Three Forks

Shaunovan

Viking

Montney

Cardium

Any tight rock or shale

Any Consolidated Rock

Will replace all water flooding methods

World light tight oil reserves

Reserve data from the October, 2015 US Energy Information Administration Report are provided below.

IOR Canada holds 5-US Issued patents on Fracture Flooding and 8-Canadian patents.

OPPORTUNITIES TO APPLY FRACTURE FLOODING^{tm}

COUNTRY	Billions bbls
USA	78.2
Russia	74.0
China	32.2
Argentina	27.0
Libya	26.1
UAE	22.6
Chad	16.2
Australia	15.6
Venezuela	13.4
Mexico	13.1
Kazakhstan	10.6
Canada **Oct. 2015**	8.8 WORLD TOTAL: 418.9 Billion bbls **US Energy Information Administration**

Conclusion

Fracture Flooding^{tm} is a promising low-capital process for achieving higher and sustained oil production from a consolidated rock reservoir.