Research Article

RTA-Assisted Type Well Construction in Montney Tight Gas Reservoir from Western Canada Sedimentary Basin

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Tight gas reservoirs are mainly developed by multistage hydraulic fracturing horizontal wells (MSHFHWs). A type well provides average production profiles based on real well data and can be constructed from multiple wells to investigate the behavior of the reservoir. For unconventional reservoirs, type wells are the key to reserve calculations and medium- and long-term field development planning. Both geological and completion parameters are key factors affecting single well performance of MSHFHWs. Based on the drilling, hydraulic fracturing, and production data for over 1,800 MSHFHWs in the Montney tight gas reservoir in the Groundbirch region of the Western Canada Sedimentary Basin (WCSB), the main hydraulic fracturing factors affecting the production performance of MSHFHWs were investigated. A rate transient analysis- (RTA-) assisted workflow for type well construction is proposed based on existing production data and considering the geological and engineering factors. Based on the field data, the main hydraulic fracturing factors that affect the production performance of the MSHFHWs in Montney are lateral length, proppant tonnage, and the number of stages. Base type wells are predicted from the P50 wells, which are selected from the wells with normalized lateral length and the same fracturing technique and proppant tonnage. The base type well represents the well performance for a specific drilling and completion background. RTA was introduced to scale up the base type well to predict the type well of new completion design. The new workflow predicts both the base type well with a specific drilling and completion background and the upgraded type well, which uses new completion design. It is highly meaningful and provides a valuable reference to practical studies involving type well prediction in unconventional gas reservoirs.

1. Introduction

A tight gas reservoir is a reservoir that cannot be produced at economic natural gas rates unless the well is stimulated by hydraulic fracturing or produced by use of a horizontal wellbore or multilateral wellbores [1]. Generally, a single well has no natural productivity or its natural productivity is lower than the lower limit of industrial gas flow, but industrial natural gas production can be obtained by taking certain economic and technical measures. Tight sandstone gas reservoirs in North America are mainly developed using multistage hydraulic fracturing horizontal wells (MSHFHWs) [2]. Due to the low porosity, low permeability, and lack of a distinct gas reservoir boundary and gas-water contact in tight sandstone gas reservoirs and the fact that reservoir stimulation is needed for effective development, a single well is generally used as the analysis object for this type of gas reservoir [3, 4]. A type well is the key to the reserve calculation of this type of gas reservoir, the creation of a gas-field development plan, and the creation of medium- and long-term development plans [5, 6]. According to the different development stages of tight sandstone gas reservoirs, the prediction of type wells mainly includes three types of methods: analytical methods, numerical simulation methods, and production decline analysis methods [7–11]. In North America, tight gas operators often employ statistical methods, primarily constructing type
wells to prepare their field development plan, especially during the mature development stage [12–14]. These type wells generate a rate-time production profile for a given area with similar geological properties. While type wells are less rigorous than physics-driven models (such as numerical simulation), they can offer sufficient technical accuracy, efficiency, and transparency for much of today’s evaluation and reserve workflows [15]. However, careless and “physics-blind” applications of type wells can damage the interests of companies [16].

Decline curve analysis (DCA) is a widely used well performance evaluation method, and it can be used for type well construction [17, 18]. However, DCA offers limited consideration of the physics of the stimulated reservoir volume (SRV) of horizontal wells, making it difficult to evaluate the completion scenario. A statistically significant well count is required for DCA in a specific area of interest; otherwise, the production forecasts may not be representative [19, 20]. The main assumption inherent in this method is that the performance of the offset wells is representative of the reservoir potential. In many cases, the reservoir properties and completion design are variable from well to well. In these cases, production forecasts using the DCA technique may be unrepresentative of true reservoir potential.

Due to the planar and longitudinal heterogeneities of tight sandstone reservoirs, the production results of single wells vary considerably under different geological conditions. Moreover, drilling and fracturing techniques and parameters are also key factors in the production of single wells using MSHFHWs. Therefore, determining the main geological and engineering parameters that affect the production performance of the MSHFHWs and predicting the type wells based on parameter differences are the keys to ensuring that the predicted type wells are representative and predictive.

Rate transient analysis (RTA) enables explicit consideration of completions and reservoir properties which enables identification of uplift opportunities and completion optimization [21, 22]. The improved mechanistic integrity of the RTA workflow also reduces reliance on offset well count and well performance. RTA integrates reservoir and stimulation properties into DCA [23–25]. This improved mechanistic integrity reduced uncertainty, enables completion scenario evaluation, and reduces reliance on offset well performance.

The Triassic Montney tight gas reservoir is a major unconventional gas reservoir spanning 130,000 km² in the Western Canada Sedimentary Basin (WCSB) [26]. The Groundbirch region is one of the most productive unconventional gas reservoirs, with over 1,800 horizontal wells producing from the Montney tight sandstone.

In this study, based on drilling, fracturing, and production data for more than 1,800 MSHFHWs in the Montney tight sandstone gas reservoir in the Groundbirch area of the WCSB, the main fracturing completion parameters affecting the production performance of the MSHFHWs were determined, and a set of RTA-assisted type well construction methods based on the existing production data and the geological and engineering factors was proposed. The results of this study provide an important reference for the exploration and development of similar types of gas reservoirs.

2. Methodology

2.1. Decline Curve Analysis Methods of Tight Gas Reservoirs. DCA has been widely used in the production forecast of unconventional reservoirs, and it is a fast method by matching production rate-time history data. Many DCA models have been designed for unconventional gas reservoirs. However, DCA models require a long production history to get a reliable result [27].

The gas production pattern of the MSHFHWs in tight sandstone gas reservoirs is characterized by a rapid decline in the early stage and a gradual flattening in the late stage. The production time is about 20–25 years, the natural gas production of a single well in the first 5 years accounts for 50–60% of the total production, and this period is the critical period for tight gas well production.

Tight sandstone gas reservoirs have low permeabilities, and their decline pattern is different from that of conventional oil and gas reservoirs. At present, methods such as the Arps decline, the power law exponential decline, the Duong decline, and the two-segment decline are mainly used to fit and predict the productivity of tight sandstone gas reservoirs.

2.1.1. Arps Decline Model. The classical decline model was originally proposed by Arps [28]. The model consists of three preconditions: the bottom hole pressure is constant, the skin coefficient is constant, and the bottom hole flow state is boundary dominated flow. The hyperbolic decline in the Arps decline model is

\[ q(t) = q_i (1 + bD_i t)^{-1/b}, \]  

where \( t \) is the time, \( q \) is the production rate at time \( t \), \( q_i \) is the initial production rate, \( b \) is the decline index, and \( D_i \) is the nominal initial decline rate. When \( b = 1 \), Equation (1) becomes a harmonic decline:

\[ q(t) = q_i (1 + D_i t)^{-1}. \]  

When \( b = 0 \), Equation (1) becomes an exponential decline:

\[ q(t) = q_i e^{-D_i t}. \]  

In the Arps decline model, when \( b > 1 \), the estimated ultimate recovery (EUR) will approach infinity, which is inconsistent with the actual production [29]. In order to solve the problem, the Arps decline model can be separated into two segments; that is, in the early stage of production, the hyperbolic decline model is used, that is, Equation (1), and in the later stage of production, when the decline rate drops to a certain value, the exponential decline model is used, that is, Equation (3); the determination of the conversion point can be realized by a computer program.
2.1.2. Modified Hyperbolic Decline Model. Robertson [30] proposed a modified hyperbolic decline model, that is,

\[ q = q_i \left(1 - \beta \right)^{N} e^{-\beta t} \]  \hspace{1cm} (4)

where \(a\), \(\beta\), and \(N\) are all positive numbers. When \(\beta\) approaches 1, it is a hyperbolic decline, and when \(\beta\) approaches infinity, it is an exponential decline.

Seshadri and Mattar [31] proposed another form of modified hyperbolic decline model, that is,

\[ q(t) = \begin{cases} q_i (q + bD_i t)^{-1/b} & (D < D^*), \\ q_i e^{-D_i t} & (D \geq D^*). \end{cases} \]  \hspace{1cm} (5)

Seshadri’s model gives a decline rate \(D^*\) in advance. When the actual decline rate reaches \(D^*\), the decline curve changes from hyperbolic decline to exponential decline, where \(q_i\) is the initial production and \(D_i\) and \(D_s\) are the decline rate. However, the selection of \(D^*\) is entirely based on experience, without any physical model basis [32].

2.1.3. Power Law Exponential Decline Model. Based on the Arps decline model, Ilk et al. [33] proposed a power law exponential decline model to calculate production in 2008. The equation of this model is as follows:

\[ q(t) = q_i e^{-D_{no} t + D_i t}, \]  \hspace{1cm} (6)

where \(D_{no}\) and \(D_i\) represent the decline constants for infinite time and starting time, respectively, \(\bar{n}\) is the time index, \(q_i\) is the initial rate (at \(t = 0\)), and \(D_i\) is the initial decline rate, where the parameter \(D_i\) is defined as follows:

\[ D_i = \frac{D_s}{\bar{n}}. \]  \hspace{1cm} (7)

2.1.4. Stretched Exponential Decline Model. For those oilfields with abundant production data, the stretched exponential decline model can be used, which can avoid many defects of the Arps decline model (for example, when \(b > 1\), it does not conform to the actual production); Valkó and Lee [34, 35] proposed that the production rate satisfies the stretched exponential decline, that is,

\[ \frac{\partial q}{\partial t} = -n \left(\frac{t}{\tau}\right)^n q, \]  \hspace{1cm} (8)

\[ q = q_i e^{-D \tau t}, \]

where \(\tau\) is the characteristic time constant and \(n\) is the exponent. To obtain the relevant parameters of the stretched exponential decline model, it is necessary to solve the following nonlinear equation:

\[ \Gamma(1/n) - \Gamma(1/n, (24/r)^n) \Gamma(1/1) - \Gamma(1/1, (36/\tau)^n) = r_{31}, \]  \hspace{1cm} (9)

where \(r_{31}\) and \(r_{31}\) represent the ratio of the cumulative production in the second year and third year to the cumulative production in the first year. The gamma equation is defined as follows:

\[ \Gamma(t) = \int_0^\infty x^{r-1} e^{-x} dx, \Gamma(s, x) = \int_x^\infty t^{r-1} e^{-t} dt. \]  \hspace{1cm} (10)

2.1.5. Duong Decline Model. According to the observation of the production of tight gas reservoirs and shale gas reservoirs, Duong [36] proposed that on the logarithmic coordinate axis, the relationship between \(q/G_p\) and \(t\) is a straight line (where \(G_p\) is the cumulative gas production), which can be expressed as

\[ \frac{q}{G_p} = a t^{-m}. \]  \hspace{1cm} (11)

\(q\) and \(G_p\) can be expressed as

\[ q = q_i t^{-m} e^{a t^{-m} (t^{-m} - 1)}, \]

\[ G_p = \frac{q_i}{a} e^{a t^{-m} (t^{-m} - 1)}, \]  \hspace{1cm} (12)

where \(a\) and \(m\) refer to the intercept and slope in logarithmic coordinates, respectively.

2.2. Determination of the Economic Limit Production of a Single Well. The main principle for determining the economic limit production of a single well is that the unit sales revenue should be greater than or equal to the operational cost of a single well. The equation can be described as follows.

\[ q_{limit} = \frac{OPEX_{well}}{(\text{Price} - \text{Cost})/T_{day}}, \]  \hspace{1cm} (13)

where \(q_{limit}\) is the economic limit production of a single well, \(OPEX_{well}\) is the operation cost of a single wellhead, Price is long-term gas price, Cost is the unit operating cost, and \(T_{day}\) is the number of production days per year.

2.3. Type Well Construction Workflow

2.3.1. Sensitivity Analysis of Geological and Engineering Parameters. The performance of MSHFHWs of tight gas reservoirs varies considerably under different geological conditions and different drilling and fracturing techniques and design. Therefore, determining the main geological and engineering parameters that affect the production performance of the MSHFHWs and predicting the type wells based on parameter differences are the keys to ensuring that the predicted type wells are representative and predictive.
2.3.2. Production Well Screening. The following principles were used to screen out the wells with similar geological conditions, the same development layer, and similar completion parameters from the existing production wells.

(a) The well is located at the same layer and had similar reservoir conditions
(b) The completion technique and design are similar
(c) The actual amount of proppant injected is more than 90% of the designed amount
(d) The production data is continuous, and the production does not fluctuate substantially

2.3.3. Calculation of the Single-Well EUR. Decline curve analysis is used to calculate the single-well EUR. Multiple decline models should be adopted to compare the difference and determine the decline model with the best fit. The time, lateral length, and peak production of the selected production wells were normalized. Based on the normalization, EUR of the unit lateral length is estimated for each well.

2.3.4. Selection of Typical Well. Plot the EUR probability distribution using the estimated EUR of the unit lateral length. Select the well with P50 EUR as the typical well.

2.3.5. Type Well Construction for Future Planned Wells with New Completion Design. Conduct rate transient analysis (RTA) on the P50 typical well. Based on RTA, the lateral length and fracturing parameters (i.e., number of fracturing stages, stage spacing, and proppant tonnage) can be adjusted to the designed drilling and completion parameters to obtain the type well under the designed lateral length and fracturing parameters.

3. Case Study of Montney Tight Gas Reservoir

3.1. Overview of the Studied Reservoir

3.1.1. Tectonic and Sedimentary Background. The WCSB is an asymmetric graben developed between the stable intracontinental platform of the North American Craton and the Rocky Mountain Fold and Thrust Belt [37]. It is mainly located in the province of Alberta, is adjacent to the Rocky Mountains, and partially extends into neighboring provinces, i.e., extending eastward into Saskatchewan and Manitoba and westward and northward into British Columbia.

The Lower Triassic tight sandstone gas reservoirs in the Montney Formation in the WCSB have a wide distribution range and an area of about 130,000 km². The structure is a simple northeast-southwest tilted monocline. The formation thickness is 0–350 m, and it gradually decreases from west to east before pinching out (Figure 1) [26]. The depositional environment is diverse and ranges from the distal deposition of the shallow shelf (including turbidite channels and turbidite fan complexes) to shoreline deposition, with a large set of well-developed shale, siltstone, and fine sandstone. The provenance direction is NE, and the deposition center migrated from NE to SW. From top to bottom, it is subdivided into three subunits: the Upper Montney, Middle Montney, and Lower Montney units.

3.1.2. Basic Gas Reservoir Parameters. The main target layer in the Montney Formation in the Groundbirch area is the Upper Montney Formation. The entire formation is composed of offshore sediment deposited under the normal wave base of a passive continental margin. The sand body is stacked in the horizontal direction and is partially superimposed in the vertical direction, and it is a thick, massive tight sandstone unit. The tight sandstone reservoirs in the Upper Montney Formation are vertically divided into 7 layers, AA and A to F (Figure 2), with burial depth of 2,200 m to 3,500 m, a total thickness of 150 m to 200 m, a reservoir thickness of 120 m to 180 m, a porosity of 3%–6%, a gas saturation of 58%–84%, a permeability of 0.00006–0.001 mD, TOC (total organic carbon) contents of 1%–4%, and Ro (thermal maturity) values of 1.2%–1.8%.
The Montney Formation in the Groundbirch area is a system with a normal temperature gradient and an abnormally high pressure. The formation temperature is 70–110°C, the temperature gradient is 3.3°C/100 m, the reservoir pressure is 27–46 MPa, and the pressure coefficient is 1.3–1.5. The fluid is 89%–95% methane, has a low CO₂ content (less than 0.5%), and does not contain sulfur. The condensate to gas ratio is 0.5–30 g/m³, with an average of 6.34 g/m³.

3.2. Completion Parameter Sensitivity

3.2.1. History of the MSHFHW Development. In order to determine the main engineering parameters affecting the MSHFHWs, the development history of the fracturing completion technique for the MSHFHWs in this area was analyzed based on the fracturing completion parameters of more than 1,800 horizontal wells in the Montney Formation in the Groundbirch area of the WCSB.

Since 2007, with the continuous progress of horizontal well drilling and the use of the multistage hydraulic fracturing technique, the drilling and completion parameters in the Groundbirch area have been continuously optimized [38, 39]. The average lateral length increased from 1,252 m in 2007 to 3,114 m in 2021, and the average number of fracturing stages increased from 5 stages in 2007 to 56 stages in 2021 (Figure 3). The average amount of injected proppant per meter (proppant tonnage) increased from 0.41 t/m in 2007 to 1.18 t/m in 2021, and the average liquid volume per meter increased from 0.41 m³/m in 2007 to 4.98 m³/m in 2021 (Figure 4). Fracturing methods in Montney wells include plug and perf (PnP), plug and perf with ball, ball and seat, and single-entry pinpoint [40].
The development of the MSHFHWs in the Groundbirch area can be divided into 4 stages.

Stage 1: before 2011, the lateral length was less than 2000 m, and the average initial production (IP30: average daily gas production in the first month) of a single well was $1.0 \times 10^5 \text{ m}^3/\text{d}$

Stage 2: from 2012 to 2016, the lateral length exceeded 2,000 m, and the average initial production of a single well was $1.1 \times 10^5 \text{ m}^3/\text{d}$

Stage 3: in 2017, the lateral length continued to increase past 2,000 m, and the average initial production of a single well was $2.8 \times 10^5 \text{ m}^3/\text{d}$

Stage 4: from 2018 to 2021, the lateral length exceeded 3,000 m, the average initial production of a single well was $4.2 \times 10^5 \text{ m}^3/\text{d}$, and the maximum production was $5.4 \times 10^5 \text{ m}^3/\text{d}$

The average initial production of a single well in a typical gas field in the Groundbirch area increased from $9.2 \times 10^4 \text{ m}^3/\text{d}$ before 2011 to $4.1 \times 10^5 \text{ m}^3/\text{d}$ in 2021.

### 3.2.2. Correlation Analysis of the Completion Parameters and Production of MSHFHWs

In order to eliminate the impact of reservoir differences on the production performance as much as possible, 35 wells with similar geological conditions in the upper layer system in the S block that were completed using the plug and perf (PnP) fracturing method were selected for the correlation analysis of the completion parameters and production.

For the PnP fracturing method, the correlations of 4 single well production datasets, the initial production of a single well (average daily gas production in the first month), the average daily gas production in the first year, the average daily gas production per meter lateral length in the first year, and the average daily gas production per stage in the first year with completion parameters (i.e., lateral length, number of stages, stage spacing, total proppant tonnage, total fluid volume, and proppant tonnage per meter) were analyzed (Table 1). Each number in Table 1 indicates the correlation coefficient between two parameters. The color in Table 1 represents the value of the correlation coefficient. For example, green means negative correlation, red means positive correlation, and the darker the color, the stronger the correlation.

The correlation analysis revealed the following facts.

1. The initial production of a single well exhibited a good positive correlation with the lateral length and the total proppant tonnage, with correlation coefficients of 0.46 and 0.43, respectively

2. The average daily gas production in the first year was positively correlated with the lateral length, the number of stages, the total proppant tonnage, and the total fluid volume. Among them, the correlation with the total proppant tonnage was the highest, with a correlation coefficient of 0.66

3. The average daily gas production per meter lateral length in the first year had a good positive correlation with the proppant tonnage per meter, with a correlation coefficient of 0.55

4. The average daily gas production per stage in the first year and the proppant tonnage per stage showed a good positive correlation, with a correlation coefficient of 0.55

In summary, the daily gas production of a single well had a good positive correlation with the lateral length and the total proppant tonnage, providing an important basis for the normalization of the lateral length and the proppant tonnage. The annual average daily gas production had a good positive correlation with the proppant tonnage per meter lateral length. After removing the data for the cases when the amount of proppant placed did not meet the design requirements, the correlation coefficient increased from 0.55 to 0.73, laying the basis for the calculation of type wells for different proppant tonnage. The positive correlation
between the average daily gas production per meter lateral length of a single well in the first year and the proppant tonnage per meter lateral length indicates that when the proppant tonnage per meter was increased by 50% and 2 times, the average daily gas productions per meter lateral length of a single well in the first year increased by 67% and 2.7 times, respectively (Figure 5). Therefore, the lateral length of the horizontal well was used as the basis for production normalization, and the proppant tonnage per meter was used as the key parameter affecting the production of the MSHFWs in the study area.

### 3.3. Type Well Construction

#### 3.3.1. Type Well Selection

(1) Sensitivity Analysis. Based on the sensitivity analysis of the MSHFW production and completion parameters, the

| Daily gas production in different stages (m³/d) | Lateral length (m) | Number of stages | Stage Spacing (m) | Total proppant tonnage (t) | Proppant tonnage per stage (t) | Total liquid volume (m³) | Proppant tonnage per meter (t) |
|------------------------------------------------|-------------------|------------------|------------------|---------------------------|-------------------------------|--------------------------|-------------------------------|
| Initial production (average daily production in the first month) | 0.46              | 0.29             | 0.18             | 0.43                      | 0.14                          | 0.32                     | -0.03                         |
| Average daily gas production in the first year | 0.56              | 0.60             | -0.22            | 0.66                      | 0.01                          | 0.64                     | 0.18                          |
| Average daily gas production per meter lateral length in the first year | -0.05             | 0.09             | -0.25            | 0.29                      | 0.35                          | 0.28                     | 0.55                          |
| Average daily gas production per stage in the first year | -0.03             | -0.14            | 0.20             | 0.15                      | 0.55                          | 0.11                     | 0.37                          |

**Table 1: Correlation between the production and completion parameters for PnP in the upper layer in the S block.**

| Average Gas Rate in first 12 months per meter lateral length (10³ m³/d) | Proppant tonnage per meter lateral length (t/m) |
|------------------------------------------------------------------------|-----------------------------------------------|
| 1.0                                                                    | 0.0                                           |
| 2.0                                                                    | 0.2                                           |
| 3.0                                                                    | 0.4                                           |
| 4.0                                                                    | 0.6                                           |
| 5.0                                                                    | 0.8                                           |
| 6.0                                                                    | 1.0                                           |
| 7.0                                                                    | 1.2                                           |

**Figure 5: Correlation between production and proppant per meter in the upper layer in the S block.**
lateral length and the proppant tonnage were used as the sensitive parameters for the studied area; the lateral length was used as the normalization benchmark, and the proppant tonnage was used as the main reference for the type well adjustment.

(2) Production Well Screening. The following principles are used to screen out the wells with similar geological conditions, the same development layer series, and similar completion parameters from the existing production wells.

(a) The well is located at the same layer and has similar reservoir conditions
(b) The completion method is PnP fracturing method, the cluster spacing is 50 m, and proppant tonnage is 0.6 t/m
(c) The actual amount of proppant injected is more than 90% of the designed amount
(d) The production data is continuous, and the production does not fluctuate substantially

(3) Selection of Typical Well. The time, lateral length, and peak production of the selected production wells were normalized. Based on the normalization, EUR of the unit lateral length was estimated for each well. The EUR probability distribution using the estimated EUR of the unit lateral length was plotted. Finally, the well with P50 EUR was selected as the typical well.

3.3.2. EUR Estimation Using Decline Curve Analysis. In order to determine the optimal DCA methods for EUR estimation, a typical well with a 12-year production history was selected which could represent the decline feature of a single MSHFHW in the Montney Formation tight sandstone gas reservoirs in the Groundbirch area. Five DCA methods including two-segment Arps decline, modified hyperbolic decline, power law exponential decline, stretched exponential decline, and Duong decline are used to fit and predict the productivity of the typical well with a 12-year production history. The results indicate that the two-segment Arps decline method had a relatively high goodness-of-fit and moderate EUR estimation compared with the other methods (Figure 6). The stretched exponential decline method showed a poor match after seven years of production and gave the lowest EUR forecasts among all the models. The gas rate was overestimated after eight years of production by using the modified hyperbolic decline method. The modified hyperbolic decline, power law exponential decline, and Duong decline gave the highest EUR estimation.

The results of the DCA method comparison indicate that the two-segment Arps decline method should be employed in the Montney tight gas reservoirs in the Groundbirch area of the WCSB. In the early stage, there was a rapid decline and a large change in the rate of decline, so hyperbolic decline with a decline index of greater than 1 was used. In the late stage, the decline was slow and the decline rate did not change considerably, so exponential decline was adopted. The actual production showed that the two-segment conversion of hyperbolic decline and exponential decline in the Groundbirch area occurred at an annual decline rate of about 10%.

3.3.3. Determination of the Economic Limit Production of a Single Well. The parameters were derived from the actual investment and economic evaluation parameters for the Groundbirch area. The calculation method used is as follows:

\[
\text{Economic limit production of a single well} = \frac{(\text{operation cost of single wellhead})}{(\text{long-term gas price} - \text{unit operating cost})} \div (\text{number of production days per year}).
\]
Whereas the lateral length of the well is 3,000 m, the stage spacing is 56 m and the proppant tonnage is 0.9 t/m. The long-term gas price is 0.104 Canadian dollars/m³. The unit operating cost is 0.093 Canadian dollars/m³, including gathering and transportation costs, processing costs, management costs, and sales costs. The operation cost of a single wellhead is 13,200 Canadian dollars per well, and the annual number of production days is 330 days.

According to the above equation, the economic limit production of a single MSHFHW in the Montney tight gas reservoirs in the Groundbirch area of the WCSB is about 3,636 m³/d.

### 3.3.4. Example of Type Well Prediction

(1) Division of the Development Layer of the Upper Montney Formation in the Groundbirch Area. Based on the stratum’s distribution characteristics, the well interference, and the analysis of the implementation performance of the fracturing and completion, the Upper Montney Formation in the Groundbirch area was divided into two development layers: upper and lower (Figure 7).

**Upper layer system**: the E layer, D layer, and F layer were developed, and the system was deployed in the middle and...
lower parts of the E layer, considering the D layer downward (about 50% of the total thickness of the D layer) and the F layer upward.

Lower layer system: the D layer, C layer, B layer, A layer, and AA layer were developed, and the system was deployed below the C layer, considering both the B layer and the A layer downward and the D layer upward (accounting for about 50% of the total thickness of the D layer).

(2) Prediction of the Type Well of the Upper Layer System in the S Block of the Groundbirch Area. Based on similar fracturing and completion parameters (i.e., the PnP fracturing method, a cluster spacing of 50 m, and a proppant tonnage of 0.6 t/m), 26 gas-producing MSHFWs in the upper layer in the S block were screened out. The average lateral length was 2,054 m, the average number of stages was 12, the average stage spacing was 202 m, and the average peak daily gas production was 128,000 m³. After normalizing the time and lateral length, the decline parameters of the type well of the unit lateral length were as follows. The decline rate of the first stage was 46%, the decline index of the first stage was 1.2, and the decline rate of the second stage was 13%. The dividing point between the two stages was the 61st month, and the average peak daily gas production per meter was 62.30 m³ (the red curve in Figure 8).

Based on the production practices, the lateral length, and the advancement of the fracturing technology, the curve for the PnP fracturing method, a cluster spacing of 50 m, and a proppant tonnage of 0.6 t/m were adopted, and the RTA was used to adjust the fracturing parameters to the designed stage spacing (56 m) and the proppant tonnage (0.9 t/m) (Table 2). As a result, the type well of the unit lateral length of the E-layer system with a proppant tonnage of 0.9 t/m and
Table 3: Primary parameters of the type wells with designed completion parameters in S block.

| Parameter                        | Upper layer system | Lower layer system |
|----------------------------------|--------------------|--------------------|
| Designed lateral length (m)      | 3,000              | 3,000              |
| Designed stage spacing (m)       | 56                 | 56                 |
| Initial gas production $Q_i$ ($10^9$ m$^3$/d) | 310                | 190                |
| Initial decline rate in the first stage $D_1$ (%) | 46                 | 48                 |
| Decline index in the first stage $b$ | 1.2                | 1.5                |
| Decline rate in the second stage $D_2$ (%) | 13                 | 10                 |
| Estimated ultimate recovery (EUR) ($10^8$ m$^3$) | 3.91               | 3.21               |

A stage spacing of 56 m was obtained (blue curve in Figure 8). The calculations show that when the lateral length was 3,000 m, the peak daily gas production of a single well in the upper layer in the S block was $3.1 \times 10^5$ m$^3$.

(3) Prediction of the Type Well of the Lower Layer System in the S Block in the Groundbirch Area. Based on the similar fracturing and completion parameters (i.e., the PnP fracturing method, a cluster spacing of 50 m, and a proppant tonnage of 0.6 t/m), 45 gas-producing MSHFHWs in the lower layer in the S block were screened out. The average lateral length was 2289 m, the average number of stages was 13, the average stage spacing was 193 m, and the average peak daily gas production was 103,700 m$^3$. After normalizing the time and lateral length, the decline parameters of the type well of the unit lateral length were as follows. The decline rate of the first stage was 48%, the decline index of the first stage was 1.5, and the decline rate of the second stage was 10%. The dividing point between the two stages was the 69th month, and the average peak daily gas production per meter was 45.31 m$^3$ (the red curve in Figure 9).

Based on the production practices, the lateral length, and the advancement of the fracturing technology, the curve for the PnP fracturing method, a cluster spacing of 50 m, and a proppant tonnage of 0.6 t/m were adopted, and the RTA was used to adjust the fracturing parameters to the designed stage spacing (56 m) and the proppant tonnage (0.9 t/m). As a result, the type well of the unit lateral length of the lower layer system with a proppant tonnage of 0.9 t/m and a stage spacing of 56 m was obtained (blue curve in Figure 9). The calculations show that when the lateral length was 3,000 m, the peak daily gas production of a single well in the lower layer in the S block was $1.9 \times 10^8$ m$^3$.

Based on the above analysis, considering the fact that the economic limit production of a single well was $3,636 m^3/d$ and the lifetime of a single well was 25 years, the EUR of the type well for the MSHFHWs with a lateral length of 3,000 m in the upper layer system in the S block in the Groundbirch area was finally predicted to be $3.91 \times 10^8 m^3$, and the EUR of the type well for the MSHFHWs with a lateral length of 3,000 m in the lower layer system was predicted to be $3.21 \times 10^8 m^3$ (Table 3).

4. Conclusions

Based on the drilling, fracturing, and production data for more than 1,800 MSHFHWs in the Montney Formation tight sandstone gas reservoir in the Groundbirch area of the WCSB, in this study, the fracturing completion parameters affecting the production performance of the MSHFHWs were determined. According to the existing production data, a set of RTA-assisted type well construction methods was proposed and applied to the Groundbirch area. The following 3 conclusions were drawn from the results.

(1) The continuous advancement of horizontal well drilling and the fracturing technique is an important foundation for the continuous improvement of single well production in the Montney Formation tight sandstone gas reservoir in the Groundbirch area. Since 2011, the development of multistage fracturing horizontal wells in this area has undergone 4 stages, and the average initial production of a single well has increased by 3.5 times.

(2) The results of this study indicate that the main engineering parameters affecting the production performance of the MSHFHWs in the Montney Formation in the Groundbirch area are the lateral length and proppant tonnage. The lateral length was selected as the basis for the normalization of the single well productions, and the proppant tonnage was used as the main basis for predicting the production of the MSHFHWs for different fracturing parameters.

(3) A set of RTA-assisted type well construction methods considering factors such as the lateral length and the fracturing parameters was proposed. The type well of the Montney Formation in the S block in the Groundbirch area and the predicted EUR result obtained using this method were consistent with the production practice.

Nomenclature

$t$: Time
$q$: Production rate at time $t$
$q_i$: Initial production rate
$q_i(0)$: Initial rate (at $t = 0$)
$b$: Decline index
$D_1$: Nominal initial decline rate
$D_2$: Seshadri’s decline rate
$D_{\infty}$: Decline constants for infinite time
$D_1$: Decline constants for starting time
$D_2$: Initial decline rate
$\tau$: Characteristic time constant
$n$: Exponent
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Data Availability

All data included in this study are available from geoLOGIC systems.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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