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Research on Dynamic Control Method of Wellbore Pressure in Deep-Oil-and-Gas-Well Drilling

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Abstract

Aiming at the problems of narrow safe pressure window and significant bottom-hole pressure fluctuation during connection making and gas influx in deep oil and gas wells, this paper proposes a wellbore pressure dynamic control method integrating hydraulic prediction, state correction and cooperative execution. The bottom-hole pressure is predicted based on wellbore temperature-pressure, drilling-fluid rheology and annulus flow parameters, and the state is corrected online using downhole-while-drilling pressure and multi-source surface data. Rolling optimization of throttle valve-pump displacement is implemented subject to the safe pressure window constraint, and control objectives are switched for drilling, connection-making and abnormal working conditions. Numerical case studies of a 7200 m deep well show that the maximum pressure deviations under disturbances of connection-making and gas influx are 0.82 MPa and 0.72 MPa respectively, with a root-mean-square error of 0.25 MPa, which is 84.6 % lower than that under the fixed-valve-position condition. The pressure is always maintained within the safe range of 120.6-124.2 MPa. The results demonstrate that the proposed method has potential to improve pressure stability in deep well sections with narrow pressure windows.

Keywords

Deep Oil and Gas Well; Wellbore Pressure; Managed-Pressure Drilling; State Estimation; Cooperative Control; Safe Pressure Window.

1. Introduction

Deep oil and gas wells are mostly located in formations with high temperature, high pressure and complex structures. As well depth increases, the variations of drilling-fluid density, viscosity and compressibility along the wellbore become more pronounced, and the adjustable range among pore pressure, collapse pressure and fracture pressure is correspondingly narrowed. Drilling practices of the Deep Earth Take-1 Well indicate that wellbore structure, pressure system and disposal of complex working conditions should be comprehensively considered for ten-thousand-meter-level wellbores; static density design alone cannot cover all operation stages[1]. When pumps are shut down for connection-making, annulus circulating pressure loss disappears within a short time; such pressure loss recovers as displacement rises after pumps are restarted. If back-pressure compensation is not synchronized with pump displacement, the bottom-hole pressure tends to swing drastically between pore pressure and fracture pressure. Long wellbores also extend the time lag for surface operations to propagate downhole, so manual adjustment is prone to delayed actions or excessive compensation.

Controlled pressure drilling achieves continuous adjustment in narrow pressure window formations through closed annular space, automatic choke control, and backpressure compensation. Existing equipment already supports pressure prediction, real-time verification during drilling, and multi-condition pressure control, with research now focusing on closed-loop collaboration among downhole sensing, wellbore regulation, and surface feedback[2]. However, three main challenges remain in

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actual control: drilling fluid properties and annular frictional resistance vary with operating conditions, causing cumulative errors when using fixed models; real-time pressure data are delayed, making it difficult for surface signals to directly reflect downhole conditions; and different control objectives exist during drilling, pipe connection, pump start/stop, gas invasion, and leakage, making single proportional-integral control inadequate to balance response speed, stability, and control amplitude. Accordingly, this paper establishes an online-corrected wellbore pressure model, conducts rolling optimization under constraints of the safe window and actuator limits, and triggers mode switching via working-condition discrimination. The core of the method lies in directly applying state-correction results to throttle-valve-pump cooperative control, and triggering mode switching through dual channels of operation commands and residuals.

2. Dynamic Characteristics and Control Requirements of Wellbore Pressure

2.1 Pressure Components and Main Disturbances

During circulating drilling, bottom-hole pressure is superimposed by hydrostatic pressure, annulus circulating pressure loss, wellhead back-pressure and additional pressure induced by drill-string motion. For deep wells with large temperature-pressure spans, drilling-fluid density cannot be treated as a single constant value. Variations in cuttings concentration change apparent viscosity and friction loss, while velocity profiles in eccentric annuli are affected by well deviation. Upon gas influx, gas dissolution, precipitation and expansion inside the wellbore alter the density and compressibility of the mixture, so pressure distribution must be calculated based on temperature-pressure coupling relationships[3]. The bottom-hole pressure can be expressed as:

$$p_b = \int_0^H \rho(z,T,p)g\mathrm{d}z + \Delta p_f\left(q,\theta_f\right) + p_c + \Delta p_s \tag{1}$$

where p_b denotes bottom-hole pressure; H is well depth; ρ is drilling-fluid density varying with well depth, temperature and pressure; Δp_f is annulus circulating pressure loss; q is circulating displacement; θ_f is comprehensive frictional resistance correction factor; p_c is wellhead back-pressure; Δp_s represents additional pressure generated by drill-string motion, pump acceleration-deceleration and local flow variations. Equation (1) adopts a lumped-parameter model that can be rapidly updated for the control layer, while temperature and physical-property distributions are updated by a hydraulic module with a slower cycle to balance real-time performance and calculation accuracy.

Wellbore disturbances are processed separately according to predictability. Operations such as weight-on-bit adjustment, rotary-speed regulation, pump-displacement modification, connection-making and tripping have relatively definite commands or motion trajectories, so back-pressure compensation can be scheduled prior to actual actions. Gas influx, lost circulation, blockage and equipment performance degradation generally have no definite onset moments, which need to be identified by combining inlet-outlet flow rates, pressure residuals and pit-volume changes. If identical judgment criteria are applied to both categories of disturbances, normal pump shutdown may be misidentified as overflow, whereas over-intensive filtering may mask incipient pressure variations caused by gas influx.

2.2 Safe Pressure Window and Control Indices

The lower limit of bottom-hole pressure is the larger value between pore pressure and pressure required for wellbore stability; the upper limit is the smaller value between formation fracture pressure and converted pressure allowable for casing and wellhead assemblies.Considering prediction errors, sensor errors and actuation lags, safety margins δ_l and δ_u are set for upper and lower bounds respectively to obtain the operable pressure range:

$$
\begin{aligned}
p_{\min} &= \max\left(p_p, p_{\text{col}}\right) + \delta_l \\
p_{\max} &= \min\left(p_{\text{frac}}, p_{\text{eq}}\right) - \delta_u
\end{aligned} \tag{2}
$$

where p_p , p_{col} , p_{frac} and p_{eq} stand for pore pressure, collapse pressure, fracture pressure and converted equipment-allowable pressure respectively. Target pressure is adjusted according to risk orientation: it shifts toward the upper bound when gas-influx risk exists and toward the lower bound under lost-circulation risk; symmetric adjustment margins are reserved during normal drilling. Control evaluation indices include maximum absolute deviation, root-mean-square error, pressure over-limit duration, anomaly identification time and recovery time. The system composition and signal closed-loop are illustrated in Figure 1.

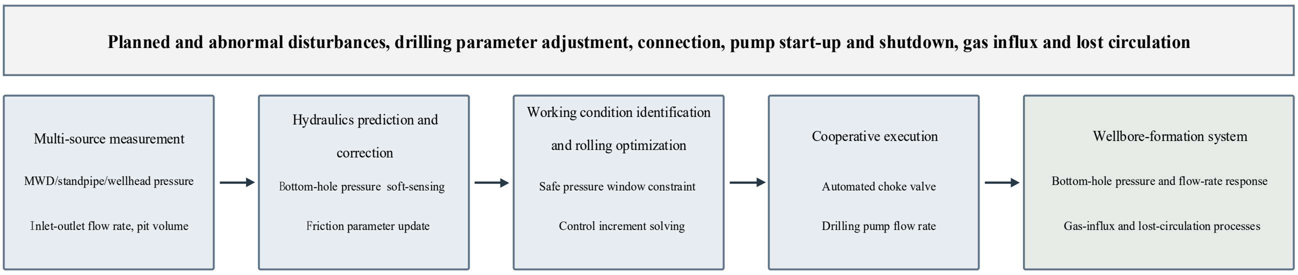

Figure 1. Composition and signal closed-loop of the wellbore pressure dynamic control system

As shown in Figure 1, the wellbore pressure dynamic control system forms a closed-loop control chain consisting of multi-source measurement, hydraulic prediction, working-condition identification, cooperative execution and wellbore-formation response. First, real-time wellbore states are acquired by collecting multi-source operating parameters such as drilling-fluid density, outlet flow rate and wellhead pressure. Pressure distribution is then predicted via hydraulic models, and pressure-window parameters are updated accordingly. On this basis, abnormal conditions such as gas influx and lost circulation are identified by the system, control objectives and pressure margins are dynamically revised, and control commands are transmitted to actuators including automatic throttle valves and drilling pumps to realize coordinated wellbore-pressure regulation. Ultimately, the control results are fed back to the wellbore-reservoir system, and the control strategy is continuously refined based on response information such as gas invasion and leakage, thereby achieving dynamic and stable control of bottomhole pressure within the safe operating window.

3. Wellbore Pressure Prediction and Online State Correction

3.1 Layered Hydraulic Prediction Model

The wellbore is discretized into several segments along the depth. Static hydrostatic pressure and frictional pressure drop are calculated based on well diameter, drillstring outer diameter, well inclination, temperature, and rheological parameters. During single-phase flow, a modified power-law model is used, with flow regime determined by the generalized Reynolds number. In gas invasion stages, gas holdup and gas expansion terms are incorporated, while gas-liquid slip effects are retained in the monitored zones. In ultra-deep wells, multiple fluid phases may undergo supercritical conditions or phase transitions between gas and liquid; improper handling of property boundaries can lead to abrupt changes in density and compressibility[4]. The model updates the temperature field and property tables at slow cycles, while fast cycles perform only interpolation, ensuring that pressure prediction completes within sampling intervals.

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In lumped parameter representation, the dynamic of annular average pressure can be approximately described by an equivalent compressibility relation:

$$C_a \frac{\mathrm{d}p_a}{\mathrm{d}t} = q_{\text{in}} + q_f - q_{\text{out}} - q_{\text{disp}} \tag{3}$$

where $C_a = \frac{\mathrm{d}V_a}{\mathrm{d}p_a}$ denotes annulus equivalent volume compliance,unit: m³/MPa; p_a is average annulus pressure; q_{in} and q_{out} are inflow and outflow volumetric rates of the annulus respectively; q_f represents formation-fluid exchange volume (positive for gas influx, negative for lost circulation); q_{disp} is equivalent flow rate induced by drill-string displacement.All flow rates are converted uniformly into m³/s within the model, and both sides of Equation (3) have consistent dimensions of m³/s. This equation serves as the state-transition equation for prediction-correction and controllers, rather than replacing full-scale along-well hydraulic calculations.

3.2 Multi-source Measurement Fusion and Parameter Correction

The system collects data on pump displacement, riser pressure, wellhead backpressure, choke valve opening, inlet and outlet flow rates, and mud pit volume, and corrects the bottomhole condition when real-time drilling pressure data arrives. Real-time downhole pressure measurement can directly constrain bottomhole pressure but is affected by transmission and refresh cycles; surface pressure responds quickly, yet it is simultaneously influenced by pressure loss within the drillstring and pipeline fluctuations. This paper adopts a "real-time soft-sensing + delayed measured-data backtracking" fusion scheme: bottom-hole pressure is estimated by the model in fast cycles; upon receiving downhole-while-drilling measurements, corresponding historical states are backtracked and corrected, then propagated forward to the current time.The annulus friction-loss correction coefficient θ_f is updated recursively with bounded constraints to compensate for slow variations in drilling-fluid performance and cuttings concentration.

An adaptive observer can jointly estimate gas-influx rate, annulus friction loss and bottom-hole flow rate, enabling bottom-hole-pressure tracking even with incomplete downhole feedback[5]. In this paper, parameter variation rates are further constrained and data-quality weights are configured: correction weights for downhole-while-drilling data are reduced when measurements are long-term absent or discontinuous; friction-loss updating is suspended if pump-stroke, flow and pressure signals violate mass-balance constraints, preventing gas influx from being misinterpreted as friction-loss variations. The corrected pressure residual r_p and flow-rate difference r_q are:

$$\begin{aligned} r_p &= p_{\text{meas}} - \hat{p}_b \\ r_q &= q_{\text{out}} - q_{\text{in}} - q_{\text{disp}} \end{aligned} \tag{4}$$

where p_{meas} is available pressure measurement mapped to bottom hole; hat symbols denote estimated bottom-hole pressure; q_{disp} is correction term for drill-string displacement on inlet-outlet flow-rate difference. Under normal conditions, both residuals fluctuate around zero; during gas influx, r_p remains persistently positive and r_q gradually turns negative, while opposite trends occur for lost circulation.Cross-validation using residual direction, duration and pit-volume changes mitigates false alarms caused by single-sensor drift.

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4. Dynamic Pressure Control Method under Constraints

4.1 Rolling Optimization and Cooperative Execution

The controller uses throttle valve opening and pump displacement as control variables: the throttle valve is responsible for rapid backpressure adjustment, while the drilling pump handles planned displacement changes and slow operating point transitions. Since throttling flow depends on effective orifice area and differential pressure across the valve, and actuator gain changes drastically near fully-closed or fully-open positions, piecewise valve characteristics calibrated from field data are adopted in the control model. At each sampling instant, future N-step bottom-hole pressure responses are predicted, and the following objective function is solved:

$$J = \sum_{k=1}^{N} \left(w_p e_k^2 + \Delta \mathbf{u}_k^{\mathrm{T}} \mathbf{R} \Delta \mathbf{u}_k + w_s \left\| \mathbf{s}_k \right\|_2^2 \right) \tag{5}$$

where $e_k = p_{b,k} - p_k^*$ denotes pressure-tracking error; the superscript star of p_k represents the target pressure trajectory $\mathbf{u}_k = \begin{bmatrix} \alpha_k \\ q_{p,k} \end{bmatrix}$, α_k and $q_{p,k}$ includes throttle-valve opening and pump displacement; R is positive-definite weight matrix for control increments; $\mathbf{s}_k = \begin{bmatrix} s_{l,k} \\ s_{u,k} \end{bmatrix}$ is non-negative slack vector; w_p 和 w_s are weighting coefficients for pressure tracking and safety slack variables respectively, with w_s assigned large values. Constraints is $p_{\min} - s_{l,k} \le p_{b,k} \le p_{\max} + s_{u,k}$, include limits on pressure bounds, valve opening and its rate-of-change, pump displacement and acceleration. Only the first control increment is implemented each cycle, and rolling prediction is repeated based on new measurements to cope with wellbore time-delay and actuator saturation.

Throttle valves and drilling pumps operate at different regulation rhythms. During normal drilling, drilling pumps maintain process-specified displacement, and throttle valves compensate minor pressure deviations. Prior to planned displacement reduction, the controller pre-increases wellhead back-pressure to offset upcoming circulating-pressure-loss reduction, and measured states are used to correct residual errors. When required compensation back-pressure approaches the effective regulation boundary of the throttling system, pump displacement or drilling-fluid operating points are slowly adjusted to restore valve opening to the intermediate range. Such actuation strategy mitigates pressure drop during pump shutdown for connection-making and avoids severe erosion caused by long-term small-opening operation of throttle valves.

4.2 Working-Condition Identification and Mode Switching

Parameters and target values for drilling, connection-making, pump start-stop and anomaly handling are stored separately in control programs. After receiving the driller's command to connect a stand or start/stop the pump, the system first generates the corresponding backpressure compensation trajectory. If no command is received but the pump discharge rate has already decreased according to the preset slope, the system initiates compensation as if the pump were being shut down. During the recovery circulation phase, both pump discharge rate and choke valve opening increase along a coordinated trajectory, ensuring that the combined value of hydrostatic pressure, circulating pressure loss, and wellhead backpressure does not experience sudden jumps. The new mode starts from the actual valve position and pump discharge rate before the transition, without separately inputting abrupt initial values.

Abnormal conditions are handled progressively based on the degree of deviation in monitoring parameters. In the initial stage, data sampling frequency is increased and frictional resistance

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parameter updates are suspended. If pressure residuals, flow differences, or changes in pit volume continuously exceed confirmation thresholds, gas invasion or leakage is diagnosed. When pressure approaches the boundary of the safe window or when the remaining adjustment capacity of valves or pumps becomes insufficient, the system issues a well control interlock request. After confirming gas invasion, the target pressure is raised within the allowable safety margin and the choke valve opening is reduced to allow controlled release of the invading fluid. For leakage conditions, the target pressure is lowered and the choke passage is enlarged, with pump discharge rate reduced synchronously if necessary. Combining observation status with residual criteria improves early detection of gas invasion[6]. After abnormal conditions are resolved, a lower reverse threshold is applied, and all criteria must remain stable before exiting the handling mode, thereby minimizing frequent switching.

4.3 Implementation Procedure of Control System

Each control cycle sequentially completes data validation, state prediction, parameter correction, condition identification, target updating, constraint optimization, and command issuance. When drilling data is valid, delayed backtracking correction is applied; during interruptions, soft measurements are maintained using surface pressure and flow rate. Commands, after being subject to rate-of-change constraints, are sent to the choke and pump control systems, with actual valve positions, pump strokes, and wellhead backpressure read back to calculate execution deviation. The digital twin integrates the wellbore physics model, equipment status, and real-time data, serving as a platform for risk early warning and parameter updates[7]. To prevent computational or communication failures from escalating risks, the system retains three degraded operation strategies: local pressure hold, valve position freeze, and manual takeover. In cases of model mismatch or insufficient sensor reliability, the system switches to conservative targets and prompts manual confirmation.

5. Case-study Verification and Result Analysis

5.1 Case Parameters and Working-Condition Setup

Table 1. Main parameters of the deep-well case

Parameters	Values	Parameters	Values
Well depth/m	7200	True vertical depth/m	6840
Borehole diameter/mm	215.9	Drill-pipe outer diameter/mm	127.0
Drilling fluid density/($g·cm^{-3}$)	1.76	Plastic viscosity/(mPa·s)	34
Normal flow rate/($L·s^{-1}$)	30	Target bottom-hole pressure/MPa	122.2
Safety lower limit/MPa	120.6	Safety upper limit/MPa	124.2
Control period/s	1	Prediction horizon/s	30

To evaluate the dynamic adjustment capability of the method in deep, narrow pressure window sections, a deep well case was constructed with a measured depth of 7,200 m and a true vertical depth of 6,840 m. This case does not correspond to any specific field well; parameters were set according to typical magnitudes for deep wells, intended for comparing the relative performance of different control strategies. A high-density water-based drilling fluid system was used, with a safe bottomhole pressure range of 120.6–124.2 MPa and a target normal drilling pressure set at 122.2 MPa. The control cycle is 1 second, with a prediction horizon of 30 seconds; choke valve opening is limited to 8%–

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92%, with no more than a 3% change per cycle; the pump rate variation rate does not exceed 1.5 L/(s²). Main parameters are shown in Table 1.

Three working conditions are configured: stable drilling from 0 s to 180 s; connection-making simulation from 180 s to 300 s, where pump displacement decreases from 30 L/s to zero within 20 s and recovers with identical slope after shutdown; gas-influx disturbance of 0.8 L/s applied from 420 s to 510 s. Measurement uncertainty bounds are set as ±0.05 MPa for pressure and ±0.12 L/s for flow rate.Gas-influx confirmation criteria are: flow-rate difference $r_q > 0.30$ L/s, pressure residual $r_p < -0.15$ MPa within a 12-s sliding window, and pit-volume increment $> 0.006\ m^3$. Thresholds are configured according to noise upper bounds of this case and are not universal field values.

The baseline for comparison is a fixed choke position condition, where the choke opening remains constant during normal drilling and is adjusted only manually according to predefined rules when pressure exceeds limits. Both methods use identical initial values, wellbore models, 1-second time steps, and disturbance inputs. This baseline serves to quantify risks associated with the absence of dynamic backpressure compensation and does not represent a complete automated pressure control system; therefore, the comparison results are not extrapolated to other advanced pressure control algorithms.

5.2 Dynamic Pressure Control Results

Figure 2 shows the changes in bottomhole pressure under two operating conditions.

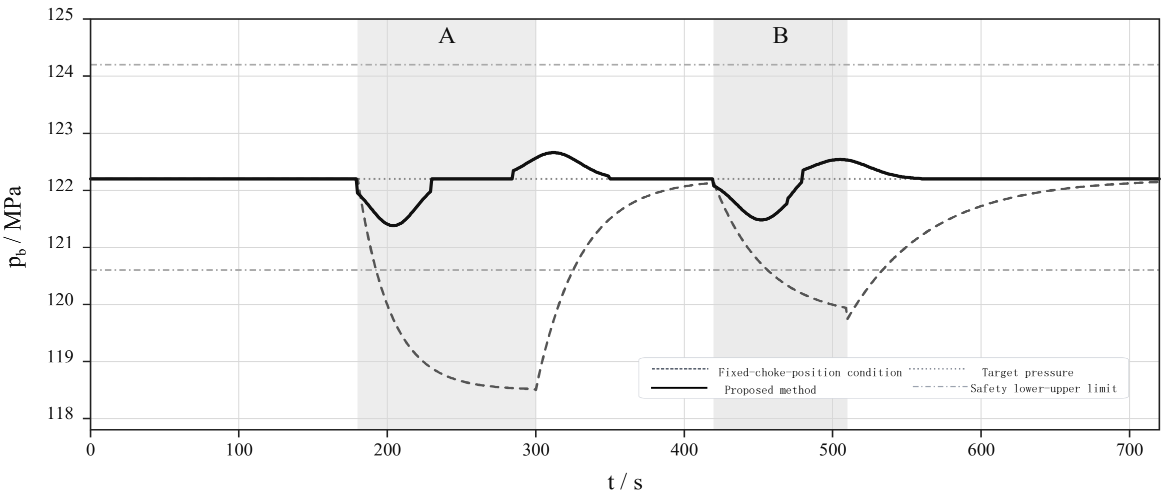

Figure 2. Dynamic response of bottomhole pressure under different control methods

As shown in the figure, when the valve position is fixed, pump shutdown causes a circulation pressure loss of approximately 3.7 MPa without synchronized backpressure compensation, reducing the bottomhole pressure to 118.50 MPa, 2.10 MPa below the safety lower limit. After restarting the pump, delayed throttling action triggers another pressure fluctuation. With dynamic control implemented, wellhead backpressure is gradually established before flow rate begins to decline, and state feedback adjusts subsequent actions based on measured deviations. During the pipe connection phase, the minimum pressure reaches 121.38 MPa, with a maximum negative deviation of 0.82 MPa; during the pump startup phase, the peak pressure is 122.66 MPa, still leaving sufficient margin below the safety upper limit.

After gas invasion occurs at 420 s, the fixed-valve condition fails to detect the abnormal state, causing the bottomhole pressure to continue dropping, with a maximum deviation of 2.45 MPa during the gas invasion phase. The proposed method enters the anomaly handling mode and establishes additional backpressure once the sliding window of 12 seconds simultaneously meets the criteria of flow rate difference, negative pressure residual, and mud pit volume increase. The lowest pressure achieved

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under this approach is 121.48 MPa. Recovery time is defined as the duration from the moment of extreme pressure in the affected phase until the pressure enters and remains within ±0.20 MPa of the target value. The recovery times for the two methods are 138 s and 74 s, respectively. After the anomaly ends, a reverse threshold is used for exit, avoiding any repeated mode switching.

5.3 Comparative Evaluation and Application Boundaries

Table 2. Comparison of control performances

Evaluation indices	Fixed-choke-position condition	Proposed method	Variation amplitude
Maximum absolute deviation/MPa	3.70	0.82	Reduce77.8%
Root-mean-square error/MPa	1.59	0.25	Reduce84.6%
Pressure over-limit time/s	210	0	Elimination
Gas-invasion identification time/s	—	12	—
Gas-invasion recovery time/s	138	74	Shorten46.4%

All indices in Table 2 are directly calculated from the 0-720 s pressure series: root-mean-square error covers the full time domain; over-limit duration is accumulated at 1-s sampling instants; recovery time follows the aforementioned sustained-bandwidth criterion. Cumulative valve actuation quantities derived purely from actuator time-series outputs are not reported, avoiding misinterpreting objective-function action penalties as actual actuation reductions. Results show that under configured working conditions, the proposed method eliminates pressure over-limit and mitigates tracking errors.

This method applies to wellheads equipped with closed circulation, automatic throttling and reliable inlet-outlet flow-rate measurement, where formation-pressure windows, equipment rated pressures and valve characteristics have been verified. Under large-scale gas influx, total lost-circulation, wellhead-assembly failure or pressure approaching equipment limits, rolling optimization cannot replace well-shut-in and well-killing procedures, and automatic optimization shall be exited. This paper provides deterministic numerical verification and does not constitute field-performance proof. Prior to engineering deployment, target-well rheology, temperature, well-diameter and valve-calibration data shall be used for model identification, and statistical validation covering parameter uncertainty, measurement time-delay and multiple concurrent faults is required.

6. Conclusion

(1) Bottom-hole pressure in deep wellbores is jointly determined by hydrostatic pressure, circulating pressure loss, wellhead back-pressure and transient additional pressure. Combining layered hydraulic calculation with lumped dynamic models and implementing online correction using downhole-while-drilling pressure and multi-source surface data balances prediction accuracy and control real-time performance.

(2) Rolling optimization control constrained by a safety pressure window coordinates the throttle valve and pump displacement, utilizing feedforward compensation based on planned operating conditions to counteract changes in circulating pressure drop, while suppressing frequent valve actuations through incremental control constraints. A mode-switching mechanism employs different objectives for pipe running, pump start/stop, and abnormal conditions, avoiding delays and oscillations caused by using a single control parameter throughout the entire process.

(3) In numerical simulation of the 7200 m deep well, maximum pressure deviations of the proposed method under connection-making and gas-influx disturbances are 0.82 MPa and 0.72 MPa respectively; pressure remains within the 120.6-124.2 MPa safe window throughout the process. Root-mean-square error decreases by 84.6 % compared with fixed-valve-position operation, and gas-influx recovery time reaches 74 s. The above results only verify relative performance under established models and disturbances. Subsequent field calibration should be conducted by integrating actual wellbore temperature and pressure data, gas dissolution and release patterns, and equipment time delays, followed by validation of the safety degradation logic under parameter uncertainty and concurrent multiple faults.

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