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CHAPTER 4

Fast Choke Overrides and Slow Waterflood Planning in a Smart Well Simulator

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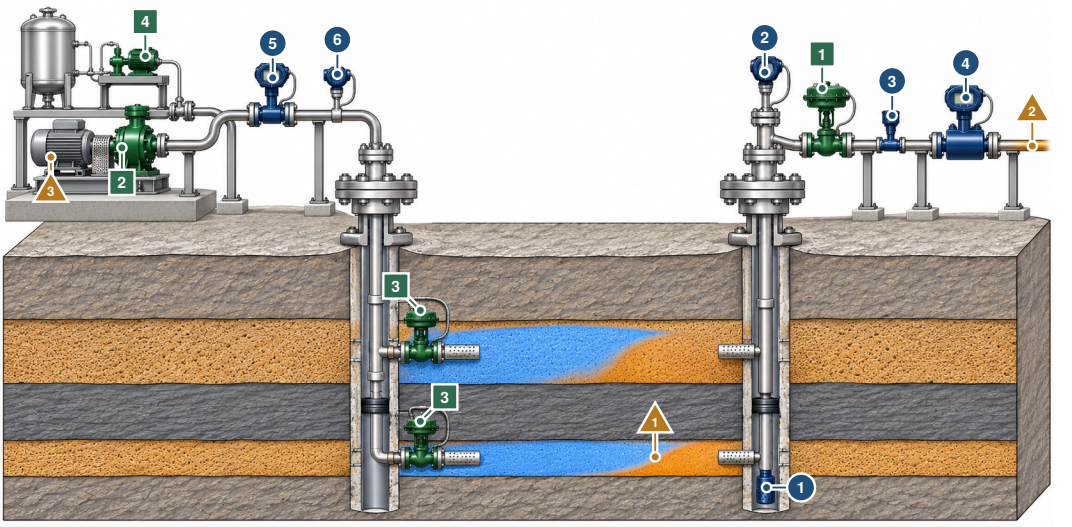
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CHAPTER 4

Fast Choke Overrides and Slow Waterflood Planning in a Smart Well Simulator



The controller moves 1 production choke 2 injection pump speed
3 two downhole valves that split the water between the layers 4 polymer dosing

The controller reads 1 bottomhole pressure 2 wellhead pressure 3 sand detector
4 multiphase meter for the oil and water rates 5 injection flow 6 injection wellhead pressure

What disturbs it 1 a thin layer that takes most of the water 2 flowline pressure 3 injection pumps out of service

The water in the thin lower layer has run ahead of the water in the thick upper layer, far below the choke that sets the rate. Illustration, not to scale.

IN PLAIN TERMS **Two Clocks on One Oil Well**

The main idea. Water pumped down one well pushes oil through rock to a second well. A valve at the top of that well sets its flow within minutes and holds back sand and extra water, while the water takes weeks to cross the rock.

The challenge. One thin layer of rock lets water through easily, so the water races along it and leaves oil behind. Settings that make the most oil this month can recover less by the end of six months.

Why it matters. In the chapter's simulator, a plan that looks six months ahead makes 2.33 times the oil of a fixed valve setting.

THREE WAYS TO READ THIS CHAPTER

Explore	12 min	This page, the Did you know? box in the Introduction, the two History boxes in Section 4.2, the first Try it box in Section 4.4, the second Try it box and the second Did you know? box in Section 4.6, and Key points in Section 4.9. No equations.
Study	55 min	The whole chapter in order, stopping at the three pause points, then Exercises 1 to 12.
Practice	20 min	This page, Section 4.6 with Figure 4.5, Section 4.7 and Section 4.8 with its Open challenge boxes.

The control question A production choke changes the rate of an oil well within minutes, but the water it produces was injected weeks earlier, and the layer that water came through decides how much oil the flood leaves behind. How do fast choke overrides and a slow plan for the sweep share one well, and why do the settings that make the most oil this month recover less by the end of a campaign?

Learning objectives

- Compute the lead-lag of the wellbore seen from the choke and the time constants of the two zone pressures from the model's parameters.
- Explain how four PI loops in external-reset form share one choke through a low selector without windup, and predict which limit takes it.
- Estimate a thief zone's breakthrough from the fractional-flow curve and the Welge tangent, and explain how a zone split or polymer delays it.
- Show that a choke can only spend reservoir pressure that injection provides, and that the injector's fracture limit bounds that injection.
- Compare planning horizons over a 180-day campaign and explain why the plan that leads on day 30 does not lead on day 180.

Prerequisites Sections 1.4.2 (inflow, choke and the share of a choke move that reaches the rate), 1.4.8 (selectors and external reset), 1.6.2 (the framework's PID) and 1.6.4 (scenarios, scorecard and CSV).

The app https://apmonitor.com/apps/wellhead-eor/

See also Volume 9, Chapter 7 for a slow store planned days ahead on forecasts with errors. Volume 4, Chapter 14 for a fast actuator that drains a finite store, and Volume 4, Chapter 4 for a feed loop under a low selector with overrides measured late. Volume 5, Chapter 11 for a state that no instrument reaches, inferred from a model.

4.1 Introduction

A waterflooded oil field runs on two clocks. At the wellhead a production choke sets the rate within minutes, against limits on drawdown, sand and produced water that act just as fast. In the reservoir, the water injected to replace the produced volume advances as a front whose speed follows the fractional-flow theory of immiscible displacement [1, 2], and a permeable layer carries water to the producer long before the tighter rock is swept [3]. Downhole inflow control valves decide where the injected water goes [4], polymer thickens the water so that it displaces more oil [5, 6], and optimal control of the valves of smart wells has been used to improve a heterogeneous waterflood [7].

+ DID YOU KNOW? Hundreds of Polymer Floods

Polymer flooding has been evaluated at field scale for more than five decades. A survey published in 1983 already identified 273 polymer projects, abandoned, current, planned or contemplated. A 2017 review still counted large commercial floods as relatively few outside Canada and China [8].

The control problem has a general shape. A fast actuator draws on a store that refills slowly, and the move that maximizes today's output is not the one that maximizes the output over the life of the store. Volume 4, Chapter 14 meets the same shape in a vault of reserves with a floor. Reservoir management has been posed as closed-loop model-based control of a flood over its life [9], long-term recovery and short-term production have been optimized as two layers on two time scales [10], and process systems engineering has asked when production optimization may be treated as static and when it must be dynamic [11]. The arrangement mirrors the layered practice of process control, in which fast regulatory loops run beneath slower model-based layers [12], and the limits that share one actuator are handled by selectors and overrides [13].

The misconception the simulator targets is that the choke setting producing the most oil now also recovers the most. In the campaign of Section 4.6, the shipped configuration, a 1300 m^3/d target with both injection valves open and no polymer, is 48 % ahead of a fixed-choke waterflood on day 30 and only 7.1 % ahead on day 180, while a planner that looks 180 days ahead produces 2.33 times

the fixed-choke oil. A second misconception is that a choke controls the rate. The choke sets the bottomhole pressure, and the rate follows from a reservoir pressure that the choke cannot raise, so when the injection plant trips the rate loop holds its target for 49.6 h and then runs out of travel.

However, the fast and the slow half of this problem are usually studied apart. Waterflood optimization takes well rates or bottomhole pressures as its controls [7, 10], and a tuning study of a choke treats the reservoir as a fixed pressure behind a resistance, so neither shows the drawdown that ties the choke to the front. Good practice in control education favors laboratories, physical or virtual, whose plants behave like the real ones [14].

This chapter joins a producer with its choke overrides and an injector with its valves, pumps and polymer through one two-zone reservoir on one simulated clock, so that a choke move and a sweep decision can be traced to the same barrel of oil. Waterflood theory, override control and receding-horizon planning are all established practice. Section 4.2 traces the domain. Section 4.3 builds the model on two clocks, an hourly transport step that moves exactly the volumes integrated on a one-minute clock, so that the phase balances close to 3×10^{-14}. Section 4.4 reads its time scales from the wellbore to the flood. Section 4.5 gives the two control layers, the four choke loops at a low selector and a planner whose quasi-steady forecast stays within 0.31 % of the dynamic plant over 180 days, and it splits the planner's forecast error into model error and grid coarsening. Section 4.6 runs eight cases and a campaign that separate what the fast loops protect from what the slow decisions recover. Section 4.7 sets the hardware of a real producer and injector beside the model. Sections 4.8 and 4.9 state the limits of the model and what the chapter has shown.

4.2 Waterflood Sweep, Mobility Control and Smart Wells

The engineering of waterflooding rests on a theory of displacement published in 1942. It treats water and oil as flowing together with a water fraction set by their relative mobilities, and it predicts a sharp front whose speed follows from the slope of that fraction [1]. A tangent construction ten years later turned the calculation into a graphical one that gives the front saturation, the volume injected at breakthrough and the average saturation behind the front [2]. The simulator uses the first result as its transport equation and the second as a check that its numerics must pass.

Reservoirs are layered, and a layered flood is limited by its most permeable layer. A 1949 method for waterflood performance used the distribution of permeability to flood the layers in order, the most permeable first, so that the producer sees water from the fastest layer while the slow layers still hold most of their oil [3]. The thief zone of this chapter is that fastest layer. It holds 29 % of the pore volume and takes 77 % of the injected water at the start of a plain flood.

Mobility control followed. A water-soluble polymer lowers the mobility of the injected water so that it pushes oil ahead of it rather than fingering past. The first History box below follows the idea from its first report to field scale.

> ⧖ HISTORY **1964: Thickening the Flood Water**
>
> Engineers had long wanted a better water-oil mobility ratio in waterfloods, above all for viscous crudes. Thicker water would do it, but glycerin, sugar or glycols cost far too much to use [5]. In 1964 a paper reported that a few synthetic polymers, the earliest of them containing acrylamide, cut the mobility of water in rock 5 to 20 times more than their viscosity predicted. Field pilots then recovered 80 and 100 percent more oil than comparable waterflood pilots, in fields with oils of 16 and 130 centipoise [5]. A 1991 monograph gathered the properties of polymer solutions, their retention on the rock and their transport through it [6]. A 2010 review of enhanced recovery counted chemical flooding among the growing trends of recent years, beside carbon dioxide and high-pressure air injection [15].

The well has its own short time scales. Wellbore storage and skin were given an analytical treatment in 1970 that explains why a bottomhole pressure answers a rate change only after the wellbore volume has been drawn down or filled [16]. Multiphase flow through a wellhead choke

Table 4.1 Roles, Defaults and Ranges of the Model Variables

Variable	Role	Default	Range
q_L	CV of FIC-101, MPFM	900 m^3/d SP	300–1600
$\Delta\hat{P}$	CV of PDIC-102, model	50 bar limit	5–90
$\dot{m}_s$	CV of SIC-103, SD-103	0.30 g/s SP	0.05–2
q_w	CV of FIC-104, MPFM	760 m^3/d SP	100–2000
q_{inj}	CV of FIC-201, FT-201	VRR 1.00	0.6–1.4
p_{iwh}	CV of PIC-202, PT-202	145 bar limit	60–200
x	MV, production choke	56.49 %	0–100
n	MV, injection pump speed	65.75 %	0–100
s, C_{inj}	MVs, thief share, polymer	open, 0 ppm	20–90, 0–2000
p_{fl}	DV, flowline pressure	20 bara	10–60
a	DV, pumps in service	100 %	0–100
$\dot{s}_{pl}$	DV, injector plugging	0 per day	0–10
b_s	DV, sand detector bias	0 g/s	±0.3
p_1, p_2	states, zone pressures	250 bar	—
p_{wf}, x, n	states, well and actuators	213.2 bar	—
s, s_{pl}	states, valve share, skin	0.769, 0	—
V, M, m_s, E	states, 12 cumulatives	0	—
S_j, C_j, Γ_j	slow states, 48 cells	S_{wi}, 0, 0	—

becomes critical, and insensitive to the downstream pressure, once the pressure ratio across it falls low enough [17]. Weak sandstones fail when too much drawdown is taken across the sandface, and the ways in which arriving water triggers sand production have been examined [18].

Automation reached the reservoir through smart wells, completions with downhole valves and gauges that let each zone be produced or injected on its own, reviewed for reservoir management in 2005 [4]. The second History box below follows these wells into closed-loop control, and the application implements the hierarchy that ends it in reduced form, with a receding-horizon enumeration above a regulatory layer of overrides.

> ⧖ HISTORY **2004 to 2011: Closing the Loop Around a Reservoir**
>
> In 2004 optimal control theory set the valves of smart wells in a waterflood of a heterogeneous reservoir. For wells held to a rate, it found large scope to speed up production and raise recovery while the water produced fell sharply [7]. A review of 2005 held that a well with intelligent components is smart only when it maximizes its value over the life of the project [4]. The same year an ensemble Kalman filter updated a reservoir model continuously from measured production, permeability included, and the forecasts improved as data accumulated [19]. In 2011 a hierarchy put the value over the field's life first and short-term production second, and in one study it doubled the first year's production for a loss of value of only 0.3 percent [10].

4.3 A Producer, an Injector and Two Zones

The simulated sector is a strip 300 m long and 300 m wide between an injector and a producer 2000 m deep. It extends the single-zone well W-1 of Section 1.4.2, whose inflow, tubing column and choke it shares, with a second zone, an injector and the fronts between them. The notation follows Section 1.3. Two zones fill it, a tight zone 12 m thick at 700 mD and porosity 0.20 and a thief zone 4 m thick at 7000 mD and porosity 0.25, with no communication between them except through the two wellbores. Their pore volumes are 216 000 and 90 000 m^3, and the sector holds 204 000 Sm^3 of oil at the connate water saturation. The wells, the zones, the instruments and the symbols of the equations are shown in Figure 4.1. Inside the model time is in hours, pressures in bar and reservoir rates in m^3/h, and the daily rates quoted here are conversions, with liquid and water in m^3/d and oil in Sm^3/d at standard conditions.

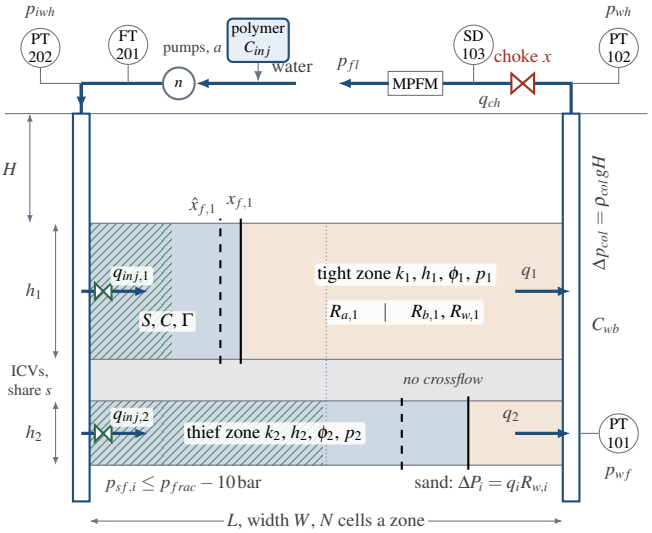


Figure 4.1 Producer, injector and the two-zone sector as modeled. Water (blue, the darker shading) has displaced oil (brown, the lighter shading) behind the true fronts $x_{f,i}$ (solid), the operator's model places them at $\hat{x}_{f,i}$ (dashed), and polymer is hatched. Each zone keeps its pressure p_i at its midpoint (dotted), with the resistance $R_{a,i}$ toward the injector and $R_{b,i} + R_{w,i}$ toward the producer. The inflow control valves (ICVs) split the injection, PT-101 reads the bottomhole pressure p_{wf} behind the wellbore storage C_{wb}, the tubing loses Δp_{col}, and the choke passes q_{ch} past the sand detector SD-103 and the multiphase meter (MPFM) to the flowline at p_{fl}. FT-201 and PT-202 meter the injection. The drawing is not to scale.

Table 4.1 classifies the variables. Nineteen fast states are integrated every minute: the two zone pressures, the bottomhole pressure, the choke and pump positions, the injector skin, the valves' thief share and twelve cumulative quantities that cross the well terminals (injection, production and polymer per zone, choke throughput, surface oil and water, injected water, sand and erosion). The saturation, dissolved polymer and adsorbed polymer of the 48 cells are slow states, advanced once an hour.

4.3.1 Transport in Each Zone

Within each zone the water saturation S and the polymer concentration C in the water move along x from the injector at $x = 0$ to the producer at $x = L$. Relative permeabilities follow the Corey form in the normalized saturation, as shown in Equation (4.1).

$$\begin{aligned} S_n &= \frac{S - S_{wi}}{1 - S_{wi} - S_{or}}, & f_w &= \frac{\lambda_w}{\lambda_w + \lambda_o} \\ \lambda_w &= \frac{k^0_{rw} S_n^{n_w}}{\mu_w R(C)}, & \lambda_o &= \frac{k^0_{ro}(1 - S_n)^{n_o}}{\mu_o} \end{aligned} \tag{4.1}$$

where λ_w and λ_o are the phase mobilities, f_w is the fractional flow of water and $R(C) = 1 + aC + bC^2$ is the viscosity multiplier of the polymer solution, 7.0 at 1000 ppm. At the end points water is 9.41 times as mobile as the 10 cP oil, and 1200 ppm of polymer ($R = 8.92$) brings the ratio to 1.06.

Water and polymer are transported by the Darcy flux u of the zone, as shown in Equation (4.2).

$$\begin{aligned} \phi \frac{\partial S}{\partial t} + \frac{\partial (u f_w)}{\partial x} &= S \frac{\partial u}{\partial x} \\ \phi \frac{\partial (SC + \Gamma)}{\partial t} + \frac{\partial (u f_w C)}{\partial x} &= SC \frac{\partial u}{\partial x} \\ \Gamma \leftarrow \max\Big(\Gamma,\, \Gamma_{max} \frac{C}{C + C_{1/2}}\Big) & \end{aligned} \tag{4.2}$$

where u falls linearly from the injection rate at $x = 0$ to the production rate at $x = L$, both divided by the cross-section $A_i = W h_i$, and Γ is the adsorbed polymer per unit pore volume. The right-hand sides remove the share of a voidage imbalance that each phase stores elastically, in proportion to its saturation, so that the saturation bookkeeping stays that of an incompressible displacement while the zone pressure takes up the imbalance. Adsorption is irreversible, so Γ grows toward the Langmuir isotherm and never falls, and the polymer front trails the water that carries it.

Each zone has $N = 24$ cells, and the update is explicit and upwind. Once every simulated hour a zone is advanced by the injected volume, the produced volume and the polymer mass that crossed its two ends in that hour, which are states of the minute-scale integration. The face volumes fall linearly from the injected to the produced volume, each cell's stored share is moved to an elastic ledger, and the step would be sub-cycled if its Courant number passed 0.5. In every shipped case the largest Courant number is 0.065, so no sub-cycling occurs. Injected minus produced equals the change in place plus the elastic ledger to 1.9×10^{-14} in relative terms for oil, water and polymer over 20 days of polymer injection at a voidage ratio of 0.9.

4.3.2 Zone Pressures and Resistances

Each zone keeps one pressure p_i at its midpoint, with the storage $c_t PV_i$, and the resistances between that midpoint and each well come from the mobilities of the cells they cross, as shown in Equation (4.3).

$$\begin{aligned} c_t PV_i \frac{\mathrm{d}p_i}{\mathrm{d}t} &= q_{inj,i} - q_i, \quad q_i = \max\Big(0,\, \frac{p_i - p_{wf}}{R_{b,i} + R_{w,i}}\Big) \\ R_{a,i} &= \sum_{j<N/2} \frac{\Delta x}{k_i A_i \lambda_{t,j}}, \qquad R_{b,i} = \sum_{j \geq N/2} \frac{\Delta x}{k_i A_i \lambda_{t,j}} \\ R_{w,i} &= \frac{F}{2\pi k_i h_i \lambda_{t,N}}, \qquad R_{wi,i} = \frac{F + s_{pl}}{2\pi k_i h_i \lambda_{t,1}} \end{aligned} \tag{4.3}$$

where $\lambda_t = \lambda_w + \lambda_o$, $\Delta x = L/N$, $F = \ln(r_e/r_w) + s_0 = 2.5$ lumps the radial near-well geometry and a skin s_0, $R_{wi,i}$ is the injector's near-well resistance and s_{pl} is a plugging skin that grows at the rate set by a disturbance. The resistances are recomputed every hour, so a zone whose cells fill with water, the more mobile phase, flows more easily. At the connate saturation the tight zone delivers 6.78 and the thief zone 22.60 $\mathrm{m^3/d}$ per bar of drawdown, a productivity index J of 29.38 $\mathrm{m^3/d}$ per bar in the sense of Equation (1.1), and the thief zone's share of 76.9 % is its share of the permeability-thickness product.

4.3.3 The Producer and Its Choke

The wellbore is a capacitance C_{wb} between the zones and the choke, the tubing carries a constant flowing gradient $\Delta p_{col} = \rho_{col} g H = 127.5$ bar to the wellhead, and the choke passes the flow of

Equation (4.4).

$$\begin{aligned} C_{wb}\frac{\mathrm{d}p_{wf}}{\mathrm{d}t} &= q_1 + q_2 - q_{ch}, \qquad q_{ch} = K_{ch}\,C_v(x)\sqrt{\Delta p_{ch}} \\ \Delta p_{ch} &= \min\big(p_{wh} - p_{fl},\ (1-r_c)\,p_{wh}\big) \\ p_{wh} &= p_{wf} - \Delta p_{col} - k_f q_{ch}^2 \\ C_v(x) &= \frac{R^{x-1} - 1/R}{1 - 1/R} \end{aligned} \tag{4.4}$$

where $x \in [0,1]$ is the opening, $R = 20$ the rangeability of the modified equal-percentage trim and $r_c = 0.5$ the critical pressure ratio. The second branch of Δp_{ch} is critical flow, in which the choke no longer feels the flowline [17], and the friction term is solved in closed form with it. At the design point of 900 m³/d the wellhead is at 82.7 bar and the drop across the choke is 41.3 bar, exactly half, so the 20 bar flowline does not reach the well. The choke carries the inflow's composition at once, and the surface oil and water are $q_{ch}(1-w)/B_o$ and $q_{ch}w/B_w$, where $w = (q_1 f_{w,1} + q_2 f_{w,2})/(q_1 + q_2)$ is the water cut on a reservoir basis evaluated at each zone's producer cell. The actuators follow Equation (4.5).

$$\begin{aligned} \tau_{ch}\frac{\mathrm{d}x}{\mathrm{d}t} &= x_{cmd} - x, \qquad \tau_n\frac{\mathrm{d}n}{\mathrm{d}t} = n_{cmd} - n \\ \frac{\mathrm{d}s}{\mathrm{d}t} &= \mathrm{sat}_{\pm r_s}\left(\frac{s^* - s}{\tau_s}\right) \end{aligned} \tag{4.5}$$

where x_{cmd} and n_{cmd} are the controller's commands of Section 4.5, $\tau_{ch} = \tau_n = 1$ min, s is the thief zone's share of the injection, s^* the share requested, or the natural share when both valves are open, $\tau_s = 5$ min, and $\mathrm{sat}_{\pm r_s}$ limits the travel to r_s, 1 point of share per minute.

4.3.4 The Injector and Its Valves

Two variable-speed pumps in parallel deliver a discharge pressure $P_d = P_{sh}n^2 - k_p(q/a)^2$, where a is the share of pumping capacity in service, and the water-filled tubing adds $\rho_w g H = 201.1$ bar less its friction $k_t q^2$. The two inflow control valves realize a requested split by throttling the zone that needs less pressure, so the injection rate is the intersection of the pump curve with the system curve of Equation (4.6).

$$\begin{aligned} P_{sh}n^2 - k_p\left(\frac{q}{a}\right)^2 + \rho_w g H - k_t q^2 \\ = \max_i\big[p_i + s_i q\,(R_{a,i} + R_{wi,i})\big] \end{aligned} \tag{4.6}$$

where $s_2 = s$ and $s_1 = 1 - s$. With both valves open the zones share one bottomhole pressure p_{bh} and each takes $(p_{bh} - p_i)/(R_{a,i} + R_{wi,i})$. The sandface pressure of zone i is $p_{sf,i} = p_i + s_i q(R_{a,i} + R_{wi,i})$, and the higher one must stay 10 bar below the fracture pressure $p_{frac} = 360$ bar. An injection wellhead pressure of 145 bar therefore puts the higher sandface near 344.5 bar at the design rate, 5.5 bar short of the 350 bar limit. Chapter 2 holds a bottomhole pressure below a fracture pressure of the same kind while a well is drilled.

4.3.5 Sand and Erosion

Sand is an explicitly illustrative proxy. A zone sheds sand once its near-well drawdown $\Delta P_i = q_i R_{w,i}$ passes a critical drawdown that falls as water reaches its sandface, and the sand through the choke accumulates an erosion indicator, as shown in Equation (4.7).

$$\begin{aligned} \dot{m}_s &= \sum_i \kappa_i\left[\frac{\Delta P_i}{\Delta P_{c,i}} - 1\right]_+^2 q_i \\ \Delta P_{c,i} &= \Delta P_{c0,i}\,(1 - \beta_w S_{n,i}), \qquad \frac{\mathrm{d}E}{\mathrm{d}t} = \dot{m}_s\,\frac{2C_d^2\,\Delta p_{ch}}{\rho_{ch}} \end{aligned} \tag{4.7}$$

where $[\cdot]_+$ is the positive part, $S_{n,i}$ the normalized saturation of the producer cell, $\beta_w = 0.45$ the water weakening, $C_d = 0.85$ a discharge coefficient and ρ_{ch} the mixture density in the choke throat. The thief zone fails at 20 bar of drawdown when dry and at 11 bar when fully watered, and the tight zone at 120 bar. The erosion indicator is sand mass times the throat velocity squared, so choking back reduces the sand and speeds up whatever sand remains.

4.3.6 Numbers, Initialization and the Two Clocks

The parameters are listed in Table 4.2. A case in automatic mode starts at the operating point the fast loops would reach. The zone rates that meet the liquid target at the inflow's own water cut are found with every active limit acting as a floor under the bottomhole pressure, the choke opening that passes exactly that inflow is found by Newton iteration, and the pump speed is found by bisection for the injection target, so the default well starts at 56.49 % open with the pump at 65.75 %. The zones start at 250 bar and at the connate saturation with no polymer, except cases 6 to 8, which start from a waterflood of 30 or 40 days computed at reset with the wells solved quasi-steadily. At the reset of a plain flood the largest time derivative of a fast state is 1.4×10^{-12} in model units.

The 19 fast states are integrated with classical fourth-order Runge-Kutta at a one-minute step, the controllers scan once per step before the integration, and the historian logs six samples per simulated hour, the three clocks of Section 1.6.1. A fourth, slow clock is this model's own. It runs inside the post-step correction, once every 60 fast steps, on the volumes the fast clock recorded. Halving the fast step changes the bottomhole pressure 1.5 h into case 1 by 0.0024 bar and the liquid produced by 0.0048 %, and halving the hourly transport step moves a breakthrough by 0.04 d. These are among the application's 43 automated checks, which also cover the phase balances, the Welge front, the quasi-steady reference and bit-for-bit replay, and all 43 pass. The application runs from 0.05 to 120 times one simulated hour per second, one by default, so at the fastest setting a 180-day campaign plays in a nominal 36 s of wall time, which computation and drawing can extend. For the flowline and separator applications the export also carries a produced stream, with mass rates from oil and gas densities of 860 and 0.85 kg/Sm^3 and the gas-oil ratio, and a wellhead temperature $T_{wh} = T_{amb} + (T_{res} - T_{amb})\, q_{ch}/(q_{ch} + q_T)$ with $T_{res} = 90\,^\circ$C, $T_{amb} = 30\,^\circ$C and $q_T = 20\,\mathrm{m}^3/\mathrm{h}$. Nothing in the model reads them.

4.3.7 Assumptions

Two one-dimensional zones. There is no crossflow between the zones, no gravity, no capillary pressure and no areal sweep, so the damage a thief zone does appears entirely as early breakthrough. Real layers cross-flow where they touch, and a real pattern sweeps an area rather than a strip.

Lumped storage in a closed sector. Each zone's elastic storage sits at its midpoint, and no aquifer supports the sector, so injection is its only pressure support. A zone's pressure is therefore a volume average, and the pressure profile along it is not resolved.

A dead oil. The formation volume factor and the gas-oil ratio are constant and no gas leaves solution, so the model is invalid if the bottomhole pressure approaches a bubble point. The fluid is also given constant viscosities and Corey relative permeabilities.

An illustrative polymer. The viscosity multiplier and the irreversible Langmuir adsorption are the whole polymer model, with no shear thinning, no degradation, no permeability reduction and no inaccessible pore volume. A real solution thins in the fast flow near an injector, so the model overstates the injectivity a polymer costs.

Illustrative sand, erosion and fracture limits. None is calibrated to a formation, a choke trim or a completion, and the sand law is chosen to make sand a steep consequence of drawdown.

A lifted tubing. The flowing gradient is constant, so a well at a high water cut does not load up and die, and the tubing transit is folded into the meter delay. The injector hydraulics are quasi-steady and the valves realize any requested split.

Numerical smearing. Explicit upwind transport in 24 cells smears the fronts and brings the thief zone's breakthrough 1.25 days earlier than 48 cells do, which Section 4.4 quantifies.

Table 4.2 Parameters of the Well, the Sector and the Instruments. Visible Ones Can Be Changed in the Parameter Panel and Hidden Ones Cannot

Symbol	Meaning	Value	Unit	Class
Sector				
L, W	spacing, width	300, 300	m	hidden
N	cells per zone	24	—	hidden
h_1, ϕ_1	tight zone	12, 0.20	m, —	hidden
k_1	tight permeability	700	mD	visible
h_2, ϕ_2	thief zone	4, 0.25	m, —	hidden
k_2	thief permeability	7000	mD	visible
p_{init}	initial pressure	250	bar	visible
c_t	total compressibility	2×10^{-4}	1/bar	visible
F	$\ln(r_e/r_w) + s_0$	2.5	—	hidden
Fluids				
μ_o	oil viscosity	10	cP	visible
μ_w	water viscosity	0.5	cP	hidden
S_{wi}, S_{or}	connate water, residual oil	0.20, 0.25	—	hidden
n_w, n_o	Corey exponents	2.5, 2.0	—	hidden
k^0_{rw}, k^0_{ro}	end-point permeabilities	0.40, 0.85	—	hidden
B_o, B_w	formation volume factors	1.20, 1.02	—	hidden
—	gas-oil ratio, stream only	100	Sm^3/Sm^3	hidden
ρ_w	produced water density	1025	kg/m^3	hidden
Polymer and sand				
a, b	viscosity coefficients	$3 \times 10^{-3}, 3 \times 10^{-6}$	1/ppm, $1/ppm^2$	hidden
Γ_{max}	adsorption capacity	80	g/m^3 PV	visible
$C_{1/2}$	half-saturation	100	ppm	hidden
$\Delta P_{c0,1}$	tight critical drawdown	120	bar	hidden
$\Delta P_{c0,2}$	thief critical drawdown	20	bar	visible
β_w	water weakening	0.45	—	visible
κ_1, κ_2	sand coefficients	2, 3	kg/m^3	hidden
Producer				
H	reservoir depth	2000	m	hidden
ρ_{col}	flowing tubing density	650	kg/m^3	hidden
k_f	tubing friction	0.0015	$bar\,h^2/m^6$	hidden
K_{ch}	choke capacity, open	30	$m^3/h/\sqrt{bar}$	visible
R, r_c	rangeability, critical ratio	20, 0.5	—	hidden
C_{wb}	wellbore storage	0.25	m^3/bar	visible
τ_{ch}, r_x	choke lag, travel	1, 5	min, %/min	hid., vis.
C_d, ρ_{ch}	throat coefficient, density	0.85, 500	—, kg/m^3	fixed, hid.
Injector and facility				
P_{sh}, k_p	pump shut-off, droop	230, 0.006	bar, $bar\,h^2/m^6$	hidden
k_t	injection tubing friction	0.0008	$bar\,h^2/m^6$	hidden
τ_n	pump speed lag	1	min	hidden
$P_{d,max}$	discharge rating	200	bar	visible
r_s, τ_s	valve travel, lag	1, 5	%/min, min	vis., fixed
p_{frac}	fracture pressure	360	bar	visible
—	required fracture margin	10	bar	visible
—	water capacity, hourly	800	m^3/d	visible
—	polymer budget	60	t	visible
Operator's model and instruments				
—	thief pore volume, μ_o, c_t	1.35, 0.85, 1.25	×	hidden
—	MPFM delay, averaging	3, 2	min	vis., hid.
—	MPFM noise	2	%	visible
—	SD-103 averaging, noise	1, 0.03	min, g/s	hid., vis.
—	pressure gauge noise	0.2	bar	hidden
—	FT-201 noise	1	%	fixed
—	sand limit, hard	0.5	g/s	visible

Table 4.3 Time Scales of the Default Well and Sector

Process	Time scale
choke and pump actuator lags	1 min
multiphase meter delay and averaging	3 and 2 min
wellbore, choke fixed, Equation (4.8)	10.1 min
wellbore, choke flow held, C_{wb}/J	12.25 min
full choke stroke at 5 %/min	20 min
thief zone pressure, $c_t PV_2(R_{b,2}+R_{w,2})$	19.1 h
tight zone pressure, $c_t PV_1(R_{b,1}+R_{w,1})$	153 h
thief breakthrough in a plain flood (case 4)	27.5 d
polymer benefit at the producer (case 6)	41 d
campaign (challenge)	180 d

4.4 Time Scales of the Well and the Flood

The plant spans more than four orders of magnitude in time, as listed in Table 4.3, and each scale sets a different part of the control problem.

4.4.1 The Wellbore Seen From the Choke

A choke move changes the flow through the choke at once and the inflow from the zones only as the wellbore drains. Linearizing Equation (4.4) about a steady point gives the response of the choke flow to a step δx in the opening as the lead-lag of Equation (4.8).

$$\begin{aligned} \delta q_{ch}(t) &= \frac{\partial q_{ch}}{\partial x}\,\delta x\left[1-(1-g)\left(1-\mathrm{e}^{-t/\tau_{wb}}\right)\right] \\ g &= \frac{J}{J+\partial q_{ch}/\partial p_{wf}}, \qquad \tau_{wb} = \frac{C_{wb}}{J+\partial q_{ch}/\partial p_{wf}} \end{aligned} \tag{4.8}$$

At the design point $\partial q_{ch}/\partial p_{wf} = 0.263\,\mathrm{m^3/h}$ per bar against $J = 1.224\,\mathrm{m^3/h}$ per bar, so the rate jumps with the opening and relaxes to $g = 0.82$ of the jump with $\tau_{wb} = 10.1$ min. The share g is that of Equation (1.3), with the choke's sensitivity taken to the bottomhole pressure so that it includes the tubing friction. A manual step from 56.5 to 60 % takes the rate from 900 $\mathrm{m^3/d}$ to a peak of 1009 $\mathrm{m^3/d}$ 4 min later, behind the actuator lag, and settles it at 992 $\mathrm{m^3/d}$, against the 1017 $\mathrm{m^3/d}$ that the new opening passes at the old bottomhole pressure. When the rate loop holds the choke flow instead, the wellbore relaxes with $C_{wb}/J = 12.25$ min, which is the time constant the drawdown shows in closed loop. The relative gain of the trim, $(\mathrm{d}C_v/\mathrm{d}x)/C_v$, is 3.7 per unit of opening at the design point and 3.2 wide open, so the loop gain in $\mathrm{m^3/d}$ per percent grows roughly with the rate.

4.4.2 The Zone Pressures

With the bottomhole pressure fixed, a zone's pressure relaxes with $c_t PV_i(R_{b,i}+R_{w,i})$, 19.1 h for the thief zone and 153 h for the tight zone. The thief zone holds a small pore volume and delivers most of the flow, so its pressure moves eight times faster and is the first to fall when the voidage is not replaced. On the minute scale both are fixed pressures behind resistances, and in the first case a choke step moves them by at most 0.39 bar in 6 h.

4.4.3 The Fronts

The fractional-flow curves of the default fluids are shown in Figure 4.2. The Welge tangent from the connate saturation touches the water curve at a front saturation of 0.425 with $f_w = 0.742$, so a homogeneous layer breaks through after 0.303 pore volumes, with an average saturation of 0.503 behind the front. For the thief zone that is 27 300 $\mathrm{m^3}$ of injection. In the plain flood of case 4 the thief zone breaks through after 24 191 $\mathrm{m^3}$, 0.269 pore volumes, because upwind transport in 24 cells

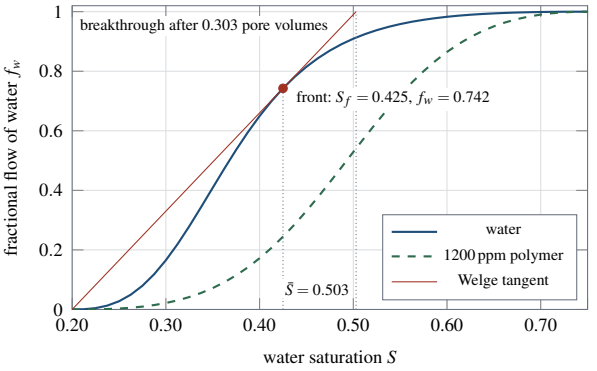


Figure 4.2 Fractional flow of water for the default fluids, without polymer (thick solid) and with 1200 ppm of polymer (thick dashed). The Welge tangent (thin straight line) from the connate saturation gives the front saturation of a plain waterflood and the volume injected at breakthrough.

smears the front ahead of the shock. The same flood with quasi-steady wells breaks through on day 28.25 with 24 cells, 29.5 with 48 and 30.5 with 96, later at each refinement by a smaller step, and with the thief zone at the tight zone's permeability it breaks through on day 85.0, three times later. Polymer moves the curve to the right, and 1200 ppm lowers the fractional flow at the waterflood front saturation from 0.742 to 0.244.

> **TRY IT IN THE APP** **4 · Thief-zone breakthrough**
>
> Load the case, set the speed to 24 hours per second on the Recovery view and press Run. Watch the solid fronts. The thief zone's water reaches the producer on day 27.5, when the front in the tight zone has traveled only 13 % of the way, and the thief zone's share of the injection keeps rising, from 76.9 % to 89.0 % by day 60.

4.4.4 Floors Under the Bottomhole Pressure

Every production limit acts as a floor under the bottomhole pressure, and the choke sets the last one, as on W-1 in Section 1.4.2. With the choke wide open the bottomhole pressure cannot fall below $\Delta p_{col} + p_{fl}$ plus the tubing friction and the small drop left across the open choke, $127.5 + 20 + 2.5 + 1.9 = 151.9$ bar on day 90 of the campaign. A thief zone at 170 bar can then supply only 7.0 bar of near-well drawdown, which is why the best campaigns of Section 4.6 run with the choke wide open for most of their length.

Pause. Try Exercise 4.1 before reading on.

4.5 Control Layers as Implemented

The control structure is shown in Figure 4.3. Its fast layer scans every minute and moves the choke and the pump, and its slow layer re-plans every five days and sets the rate target, the valve split and the polymer concentration.

4.5.1 Instruments

No controller reads a front, a saturation or a zone rate. The multiphase meter reads oil and water after a 3 min transport and processing delay and a 2 min first-order average, with multiplicative colored noise of 2 % and a 3 min correlation time. The acoustic sand detector averages over 1 min and adds 0.03 g/s of noise and a bias that a disturbance can set. The bottomhole, wellhead and injection wellhead gauges carry 0.2 bar of noise, and the injection meter 1 %.

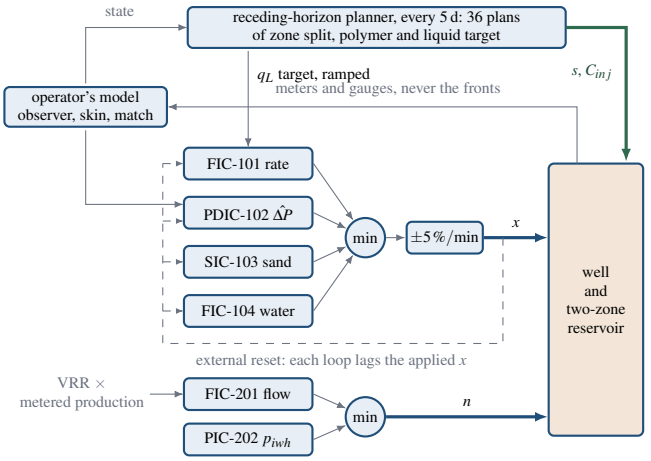


Figure 4.3 Control structure. Four PI loops share the choke through a low selector and a travel limit, and every loop's reset term follows the applied opening. FIC-201 and PIC-202 share the pump the same way. The operator's model supplies the drawdown estimate and the planner's state, and the planner sets the rate target, the zone split and the polymer.

4.5.2 The Choke Selector

Four PI loops share the production choke. FIC-101 holds the metered liquid at its target, PDIC-102 holds the larger of the two estimated drawdowns below the completion limit, SIC-103 holds the detected sand below its setpoint and FIC-104 holds the metered water below its setpoint. Each loop uses the framework's velocity-form PID of Section 1.6.2 with its integral switched off, and supplies its integral action as an external reset, as shown in Equation (4.9).

$$\begin{aligned} e_{j,k} &= \mathrm{SP}_{j,k} - \mathrm{PV}_{j,k}, \qquad P_{j,k} = K_{c,j}\, e_{j,k} \\ S_{j,k} &= S_{j,k-1} + (P_{j,k} - P_{j,k-1}) \\ u_{j,k} &= \mathrm{clamp}\big(S_{j,k} + I_{j,k-1},\ 0,\ 100\big) \\ x_k &= \mathrm{clamp}\big(\min_j u_{j,k},\ x_{k-1} - r_x \Delta t,\ x_{k-1} + r_x \Delta t\big) \\ I_{j,k} &= I_{j,k-1} + \big(1 - \mathrm{e}^{-\Delta t/\tau_j}\big)\big(x_k - I_{j,k-1}\big) \end{aligned} \tag{4.9}$$

where $\Delta t = 1\,\mathrm{min}$, $r_x = 5\,\%/\mathrm{min}$ is the choke's travel rate, and τ_j is the integral time $\tau_{I,j}$ of the selected loop and $\min(\tau_{I,j}, 2\,\mathrm{min})$ for the others. The accumulator $S_{j,k}$ equals $P_{j,k}$ for the gain in force, the clamp acts on the emitted output, and with no integral term the framework's back-calculation never runs, so the reset term I_j is each loop's only memory. For the selected loop away from its limits the last line becomes $I_{j,k} = I_{j,k-1} + (1 - \mathrm{e}^{-\Delta t/\tau_I}) K_c e_{j,k}$, a PI controller with an effective integral time of $\Delta t/(1 - \mathrm{e}^{-\Delta t/\tau_I})$, 8.51 min for the default 8 min. A loop that is not selected follows the applied opening with a lag of 2 min. At a fixed applied opening its output tends toward that opening plus its proportional term, the external-reset form of Equation (1.14) that Chapter 13 also uses on its pumps. During movement the finite tracking lag also affects which loop wins the selector. This feedback keeps the reset terms bounded while the loops wait [13], and Section 1.4.8 shows on W-1 how a waiting override without it breaks its limit. None of the six loops uses derivative action.

🕮 **Pause.** Try Exercise 4.2 before reading on.

All six loops act in the same sense. With $e = \mathrm{SP} - \mathrm{PV}$ and positive gains they are reverse acting in ISA terms, since a wider choke raises the rate, the drawdown, the sand and the water together, and a faster pump raises both the injection and its wellhead pressure. The rate loop's setpoint ramps

Table 4.4 Loops, Setpoints and Default Tunings

Loop	PV	SP	K_c	τ_I
FIC-101	liquid, MPFM	900 m³/d, ramped	0.020 % per m³/d	8 min
PDIC-102	drawdown, model	50 bar	1.0 %/bar	10 min
SIC-103	sand, SD-103	0.30 g/s	20 % per g/s	10 min
FIC-104	water, MPFM	760 m³/d	0.030 % per m³/d	10 min
FIC-201	injection, FT-201	VRR 1.00	0.010 % per m³/d	3 min
PIC-202	wellhead, PT-202	145 bar	0.30 %/bar	3 min

toward a new target at 15 m³/d per minute, the way a well is beaned up, and in manual mode it tracks the metered rate so that the change to automatic starts with no error. In manual mode, and for any override switched off, each loop tracks by setting $I_j = x - S_j$, so its output equals the applied opening and both transfers are bumpless. The defaults are listed in Table 4.4. Against the choke step of Section 4.4, 33.4 and 26.2 m³/d per point at once and at steady state, the default rate gain gives a loop gain of 0.67 at once and 0.52 at steady state, with an effective integral time a little shorter than the wellbore's 10.1 min.

4.5.3 The Injection Pump

FIC-201 holds the metered injection at its target by moving the pump speed, and PIC-202 takes the pump through a second low selector before the injection wellhead passes 145 bar, with the same external reset and no travel limit beyond the pump's lag. The target is either fixed or the metered production in reservoir volume, averaged over 1 h, times the voidage replacement ratio (VRR), and it is always the ratio while the planner runs. When PIC-202 holds the pump, or the pump is flat out, for most of a quarter hour while the injection runs more than 3 % short over the last hour, the application flags the target as unreachable, and it clears the flag when the limit lets go or the shortfall falls below 1 %. No hidden actuator makes up the difference. A dosing skid adds polymer at the commanded concentration and stops at the scan whose dose, reckoned on the metered injection with a 10 % allowance, would pass the 60 t budget.

4.5.4 The Operator's Model

The drawdown estimate and the planner's state come from an operator's model that runs the equations of Section 4.3 with three built-in errors, a thief pore volume 35 % too large, an oil viscosity 15 % too low and a compressibility 25 % too high. Every scan it allocates the metered production between its zones by its own resistances at the measured bottomhole pressure, which yields the drawdown estimate, and every hour it moves its fronts by the metered injection, split as commanded, and by its allocated production. A pressure observer then moves its zone pressures toward the rate the producer shows at its measured bottomhole pressure, a fifth of the correction and at most 2 bar per hour, and an injectivity monitor reads any gap between the injection gauge and the model as injector skin, a fifth at a time. Once a day, if the model's water cut differs from the meter's by more than two points while the model's tight front is short of 80 % of the way, the thief pore-volume multiplier moves toward the measurement by at most 5 %, within 0.5 to 2, and the thief profile is remapped to it. Nothing else is adjusted, and the model never sees how the production divides between the zones. It starts from the plant's initial state, or from its own run of the preflood of cases 6 to 8 with its own parameters. This is a bounded, one-parameter version of the continuous model updating that closed-loop reservoir management performs with an ensemble of models [19].

4.5.5 The Receding-Horizon Planner

Every five days, and at reset, the planner coarsens the operator's model to 12 cells per zone and forecasts 36 candidate plans, four splits (both valves open or a thief share of 65, 50 or 40 %) by three polymer concentrations (0, 600 and 1200 ppm) by three liquid targets (900, 1100 and 1300 m³/d),

Table 4.5 Forecasts of One Fixed Policy Over 180 Days, a Thief Share of 40 % With 1200 ppm and a 1300 m^3/d Target

Model	Cells, step	Oil (Sm^3)
dynamic plant	24, 1 min	103 120
quasi-steady, true reservoir	24, 6 h	103 093
quasi-steady, true reservoir	12, 1 d	99 290
operator's model, as the planner uses it	12, 1 d	113 083
true reservoir, thief pore volume error only	12, 1 d	106 716
true reservoir, oil viscosity error only	12, 1 d	103 837
true reservoir, compressibility error only	12, 1 d	99 637

each held over a horizon H with the wells solved quasi-steadily in daily steps. In each step the choke delivers the target unless a drawdown, sand, water or wide-open floor under the bottomhole pressure binds first, the injector replaces the voidage unless the injection wellhead limit or the pump binds, the zone pressures advance semi-implicitly with the production following the new pressure, and the dosing stops at the budget. The final forecast interval uses a reduced concentration if its full dose would exceed the remaining polymer. The injection constraint applies PIC-202 directly on wellhead pressure, including the rate-dependent tubing friction term. The objective is the forecast oil less 0.01 Sm^3 per kilogram of polymer, the plan in force is kept unless another beats it by 0.5 %, and only the targets of the chosen plan are applied until the next re-plan. The horizon is the lesser of its setting and the time left in a campaign, and never less than one day. The planner is an enumeration over held policies, not the quadratic program of Section 1.6.3. Volume 9, Chapter 7 plans the releases of another slow store days ahead on forecasts whose error grows with lead time.

4.5.6 Four Models Kept Apart

The plant is the 24-cell reservoir with its wellbore on the minute clock. The operator's model has the same structure with three errors and its own state, the planner's forecast is a 12-cell copy of the operator's model with quasi-steady wells in daily steps, and the fixed-choke reference of Section 4.6 is a quasi-steady run of the true reservoir in 6 h steps. None of the controllers uses an identified model, and the PI loops carry no model at all. Forecasting one fixed policy for 180 days, a thief share of 40 % with 1200 ppm and a 1300 m^3/d target, separates their errors, as listed in Table 4.5. The quasi-steady shortcut is within 0.03 % of the dynamic plant, the planner's coarse grid makes the forecast 3.7 % pessimistic, and the operator's model makes it 13.9 % optimistic. Taken one at a time, the thief pore-volume error accounts for 7.5 %, the oil viscosity error for 4.6 % and the compressibility error for 0.3 %. On its own model the planner ranks a 50 % thief share with 1200 ppm and a 1300 m^3/d target first on day 0, at 113 511 Sm^3, and the same plan at a 40 % share third, at 113 083 Sm^3. On the true reservoir the 40 % plan ranks first, at 99 290 Sm^3, and the planner's choice fourth, at 98 382 Sm^3. The model's errors raise every forecast by far more than they separate these two plans, which differ by 0.38 % on the operator's model and by 0.9 % on the true reservoir.

4.6 Scenarios and Measured Results

Table 4.6 names each case, its event and its lesson, and Table 4.7 collects the measured results of the eight cases. Each begins from the defaults of Table 4.4, with both valves open, no polymer, the planner off and the history match and every override on, apart from the changes named, and the numbers come from headless runs of the engine with its default random seed (Section 1.6.1). Scheduled events act at their nominal minute boundary, and response delays below are measured from that boundary. Case clocks start at reset, so days reported for cases 6 to 8 exclude their initialization waterflood. Reservoir water cuts are used for transport results, while the CSV and water-cut trends use surface volumes. Quantities that the meter noise moves are averaged over the stated window.

Table 4.6 Cases, Events and Lessons

#	Case and event	Lesson
1	target 900 to 1100 m^3/d and back	a choke sets drawdown
2	injection plant down 6 to 96 h	a choke cannot make pressure
3	target 1400 m^3/d	sand comes with drawdown
4	plain waterflood, valves open	the thief zone takes the water
5	thief share 50 % at 12 h	sweep costs injection pressure
6	1000 ppm after a 30 d flood	the benefit arrives late
7	injector skin +5 per day	an unreachable target
8	target 1200 m^3/d at 69 % water	more liquid is mostly water
9	180-day campaign, fixed-choke score	graded challenge

Table 4.7 Measured Results of the Eight Cases

Case	Result
1, 2–3.5 h means	choke 63.6 %, p_{wf} 205.1 bar, ΔP_2 19.7 bar of 20.0
1, after the step	true 1000 m^3/d at 11 min, meter at 16 min
2, no injection	choke open at 55.6 h, 427 m^3/d at 96 h
2, 48 h	p_2 184.3 bar, p_1 234.1 bar
3, SIC-103 on, 3–6 h	1205 m^3/d, 0.30 g/s, peak 0.45, 52 kJ
3, SIC-103 off	1408 m^3/d, 3.24 g/s, 416 kJ
4, breakthrough	day 27.5, tight front at 0.13
4, day 60	water cut 77.8 %, 33 544 Sm^3, model PV $\times 0.96$
5, PIC-202	holds day 1.6 to 3.4, margin $\geq$ 15.0 bar
5, day 60	breakthrough day 44.2, 38.3 %, 49 212 Sm^3
6, water cut	72.2 % on day 41.2, 50.1 % on day 60
6, day 80	24 130 Sm^3 against 13 934 Sm^3 without
7, PIC-202	takes the pump day 14.5, flag day 15.3
7, day 30	757 m^3/d of 943, $\bar{p}$ 216.6 bar, margin $\geq$ 14.3
8, FIC-104 on, 24–48 h	1028 m^3/d, oil 270, water 758
8, FIC-104 off, 24–48 h	1197 m^3/d, oil 314, water 883, 46 of 48 h over

4.6.1 Minutes: The Choke, the Wellbore and the Sand

Case 1 raises the target from 900 to 1100 m^3/d. The setpoint ramps for 13.3 min, the true rate passes 1000 m^3/d 11 min after the change and the meter 16 min after it, and the 10 min mean of the rate is within 2 % of the new target after 40 min. Averaged from 2 to 3.5 h, the choke sits at 63.6 % against 56.5 % before, only 7 points further open for 22 % more rate, and the bottomhole pressure has fallen from 213.2 to 205.1 bar. The thief zone's drawdown has risen from 16.3 to 19.7 bar, against a critical drawdown of 20.0 bar, while the zone pressures have barely moved. The meter noise makes the rate loop wander, so the choke reads 63.11 % at 3 h and 63.9 % in the same run without noise.

Case 3 asks for 1400 m^3/d. The true sand passes 0.01 g/s 32 min after the change, at a thief drawdown of 20.5 bar, and SIC-103 takes the choke 9 min later. From 3 to 6 h the well makes 1205 m^3/d with 0.30 g/s of sand, peaking at 0.45 g/s while the loops hand over, against the 0.5 g/s limit. With SIC-103 off the choke delivers 1408 m^3/d with 3.24 g/s, 17 % more liquid for eleven times the sand, 50.2 kg of it in 6 h. The erosion indicator reaches 416 kJ against 52 kJ, although the throttled choke of the first run passes its smaller sand at a higher throat velocity, with v^2 of 9758 against 8132 m^2/s^2 at 6 h.

Case 8 starts 40 days into a flood at a reservoir water cut of 69.3 %, making 245.8 Sm^3/d of oil in 900 m^3/d of liquid, and raises the target to 1200 m^3/d. FIC-104 takes the choke 17 min after the change, when the metered water reaches 760 m^3/d, and over the second day the well makes 1028 m^3/d with 270 Sm^3/d of oil and 758 m^3/d of water, with the hourly water peaking at 773 m^3/d against the 800 m^3/d capacity. The oil has risen by 24 Sm^3/d for 104 m^3/d more water. With the override off the well makes 1197 m^3/d with 314 Sm^3/d of oil and 883 m^3/d of water over the second day, above the



Figure 4.4 Campaign challenge, listed in the scenario menu as Challenge · 180-day campaign, with the planner on and a 180-day horizon, on the Recovery view with the clock at 90d 00:00 (2160 h), cropped to the plant view. (1) The badge reads +105.9 % against the fixed choke, and the first chip shows the choke wide open. (2) The tight zone's true front (solid) near 0.8 of the way, with the operator's model front (dashed) just behind it. Below it the thief zone is watered out from the injector to the producer, polymer hatching shows in both zones, and the labels give the thief zone near 170 bar against 240 bar in the tight zone. (3) 574 m^3/d of injection enter the tight zone and 383 m^3/d the thief zone. (4) The cumulative oil plot shows 72 418 Sm^3 against 35 180 Sm^3 for the fixed choke, with the plan's forecast dotted to day 180. (5) The status line reports the choke wide open with the well short of its target. The ledger gives a recovery of 34.9 % of the oil in place, 60.0 t of the 60 t of polymer used and the plan in force, a 40 % thief share with no polymer and a 900 m^3/d target.

capacity in 46 of the 48 hours.

4.6.2 Days: Pressure Support

Case 2 trips the injection plant at 6 h. The thief zone falls from 249.9 to 218.7 bar in 18 h and to 184.3 bar at 48 h, while the tight zone falls only to 234.1 bar, as their time constants in Table 4.3 predict. The rate loop opens the choke to hold 900 m^3/d until it is wide open at 55.6 h, and the rate then falls with the pressure, to 427 m^3/d at the restart at 96 h. The returning water goes mostly into the depleted thief zone, and the rate is back within 2 % of its target at 146.8 h. With a voidage ratio of 1 the lost pressure is never rebuilt, and at 240 h the tight zone is at 191.9 bar and the thief zone at 199.2 bar. Over 10 days of a plain flood, a ratio of 1 holds the average pressure within 0.03 bar while 0.8 lets it fall 35.1 bar.

Case 7 grows the injector's skin by 5 units a day after a 30-day flood. The sandface climbs from 266.0 bar to the 345 bar that PIC-202 holds from day 14.5, the target is flagged unreachable on day 15.3, and by day 30 the injection is 757 m^3/d against a target of 943 m^3/d, a VRR of 0.80, while the average reservoir pressure has fallen from 249.6 to 216.6 bar. The fracture margin never falls below 14.3 bar. The injectivity monitor infers a skin of 153.6 against 150.0 true on day 30, and the model's zone pressures are within 1.8 bar of the truth.

4.6.3 Weeks: Where the Water Goes

Case 4 is a plain flood with both valves open. The thief zone's share of the injection rises from 76.9 % to 89.0 % by day 60, because a watered-out zone flows more easily, and its water reaches the

producer on day 27.5, when the tight zone's front has traveled 13 % of the way. The reservoir water cut is 46.8 % on day 30 and 77.8 % on day 60, the oil falls from 444 to 173 Sm^3/d, and 33 544 Sm^3 are produced by day 60. The operator's model, with its thief pore volume 35 % too large, places the thief front at 66 % of the way on day 25 when it is at 89 %, and its own water cut first passes 2 % on day 31.6. The history match brings the multiplier within 10 % of the truth on day 32.0 and to 0.96 by day 60. The arriving water also weakens the sandface, the thief zone's critical drawdown falls from 20.0 to 15.5 bar, by about day 58.3. SIC-103 holds an earlier sand episode on day 28.1 to 0.40 g/s.

Case 5 sets the valves to a 50 % thief share at 12 h, and the tight zone's injection doubles from 260 to 531 m^3/d within two hours. The sandface rises from 290 to 339 bar in the first day, PIC-202 first takes the pump on day 1.4, and from day 1.6 to 3.4 it mostly holds the pump with the injection 2.0 % short on average, which the application flags as unreachable from day 2.1 to 3.2. The pressure then eases to 298 bar by day 60 as the near-injector rock fills with more mobile water. The tight zone's pressure rises to 267.3 bar and the thief zone's falls to 206.5 bar, so the producer draws more from the tight zone, whose drawdown rises from 16.3 to about 35 bar. The operator's model reads that drawdown as 30.2 bar on day 20 when it is 35.3 bar, so an override acting on it would act late. The thief zone's water arrives on day 44.2 instead of 27.5, and on day 60 the water cut is 38.3 % against 77.8 % and the oil produced 49 212 Sm^3 against 33 544 Sm^3, 47 % more.

Case 6 adds 1000 ppm of polymer at 12 h, 30 days into a flood that has just broken through. The sandface rises from 266.0 to 283.5 bar by day 60 and the thief zone's share falls from 83.7 to 78.1 %, but for 41 days the water cut keeps rising, to 72.2 % on day 41.2 against 80.6 % in the same flood without polymer. Then the oil the polymer has displaced reaches the producer ahead of it, the water cut falls to 50.1 % on day 60, and the hourly oil peaks at 419 Sm^3/d near day 61 against 128 Sm^3/d without polymer on day 60. The polymer front is still at 88 % of the thief zone on day 60, held back by adsorption. By day 80 the case has made 24 130 Sm^3 against 13 934 Sm^3, for the whole 60 t budget.

> **TRY IT IN THE APP** **6 · Polymer arrival delay**
>
> Load the case, set 24 hours per second on the Recovery view and press Run. The hatched polymer enters both zones at 12 h, yet the water cut keeps rising for 41 days, to 72.2 % on day 41.2. Then the oil the polymer displaced reaches the producer ahead of it, and the water cut falls to 50.1 % on day 60.

4.6.4 Months: The Campaign

The challenge asks for 98 000 Sm^3 in 180 days, 2.2 times fixed-choke waterflooding, with the true sand never above 0.5 g/s, the hourly water never above 800 m^3/d, the higher sandface at least 10 bar below the fracture pressure and no more than 60 t of polymer. The reference holds the choke at 45 %, the largest opening in 5 % steps that keeps a fixed-choke run inside the sand and water limits, with both valves open, no polymer and the pump at the speed that replaced the day-0 voidage. It makes 44 547 Sm^3, and at 50 % its water would reach 921 m^3/d. The full dynamic model run in manual mode with the same choke and pump makes 44 684 Sm^3, within 0.31 %. The configurations are compared in Table 4.8, and Figure 4.5 sets their oil on day 30 and on day 180 side by side.

As shipped, with a 1300 m^3/d target, both valves open, no polymer and the planner off, the campaign is 48 % ahead of the reference on day 30 and only 7.1 % ahead on day 180, having recovered 23.4 % of the oil in place. The rate loop holds its choke for only 0.008 % of the campaign. FIC-104 holds it for 85.5 % of the campaign and SIC-103 for the remaining 14.5 %, at a mean drop of 51.4 bar across the choke against 4.0 bar for the 180-day planner, and the well passes 688 kg of sand against 17 kg, so its erosion indicator reaches 7854 kJ against 146 kJ. With the planner on and a 180-day horizon, the plan chosen on day 0 sends half the water into the tight zone with 1200 ppm of polymer and a 1300 m^3/d target. The budget is spent on day 44.9, the day-45 re-plan keeps 60 % of the water in the tight zone with no polymer and a 900 m^3/d target, and a re-plan on day 120 raises the target to 1300 m^3/d. The campaign makes 103 912 Sm^3, 2.33 times the reference, with a sand peak of

Table 4.8 The Campaign Over 180 Days. Oil in Sm^3, Worst Sand in g/s, Hourly Water in m^3/d and Worst Fracture Margin in bar

Configuration	Day 30	Day 180	RF	Sand	Water	Margin	Pass
fixed choke	19 375	44 547	22.2	0	746	—	—
shipped	28 698	47 731	23.4	0.43	775	55.2	no
planner, 30 d	37 620	89 270	43.7	0.39	774	16.4	no
planner, 90 d	31 762	101 753	49.4	0.37	773	15.1	yes
planner, 180 d	29 183	103 912	50.3	0.36	773	14.9	yes
by hand[a]	25 054	103 120	49.9	0.37	770	14.4	yes

RF, recovery factor in percent. The fixed-choke row is the quasi-steady reference, with no margin record. [a] thief 40 %, 1200 ppm from day 0

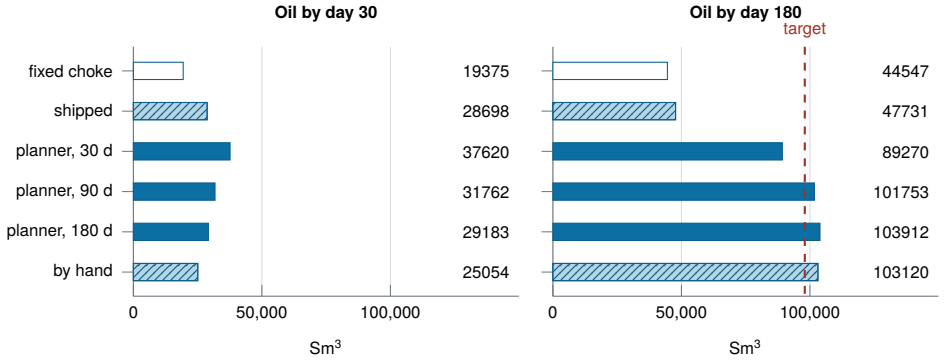


Figure 4.5 The campaign of Table 4.8 on one scale. White is the fixed-choke reference, hatched bars run with the planner off and solid bars with it on, and the dashed line is the 98 000 Sm^3 target. Notice that the order on day 30 is not the order on day 180: the 30-day planner leads early and misses the target, while the hand-set policy starts slowest of the three that pass it.

0.36 g/s, a water peak of 773 m^3/d, a worst margin of 14.9 bar and 60.0 t of polymer, and it recovers 50.3 % of the oil in place.

The horizon decides the plan. A 30-day horizon starts with a 65 % thief share and no polymer, moves to 50 and 40 % on days 10 and 30, and never doses polymer, because inside 30 days its best polymer plan forecasts only 233 Sm^3 more oil than the plan it chose, less than the 562 Sm^3 charged for its 56 t of polymer. It is 29 % ahead of the 180-day planner on day 30 (37 620 Sm^3 against 29 183 Sm^3) and finishes at 89 270 Sm^3, short of the target. A 90-day horizon makes 101 753 Sm^3. Among the three horizons the ranking on day 30 is exactly the reverse of the ranking on day 180. A fixed setting of a 40 % thief share with 1200 ppm, chosen by hand at reset, makes 103 120 Sm^3, within 0.8 % of the planner, so the planner's value here is that it finds such a policy from a model with errors in it, not that it beats the best fixed policy. In the three passing runs the choke is wide open for most of the campaign, from 55.5 % of the time with the 90-day planner and 76.0 % with the 180-day planner to 92.7 % by hand, because moving water into the tight zone draws the thief zone down to about 170 bar and leaves the rate to the reservoir.

🕮 **Pause.** Try Exercise 4.3 before reading on.

The run of Figure 4.4 is the 180-day planner on day 90, when it has made 72 418 Sm^3 against 35 180 Sm^3 for the reference, 105.9 % more. The thief zone is watered out, its water having broken through on day 47.5 against 27.5 in the plain flood, and the tight zone's true front is at 0.80 of the way with the model's at 0.77. The history match began on day 48 and took the thief multiplier from 1.35 to 0.94 in eight daily steps, and the model's own water cut first passed 2 % on day 53.0. The liquid

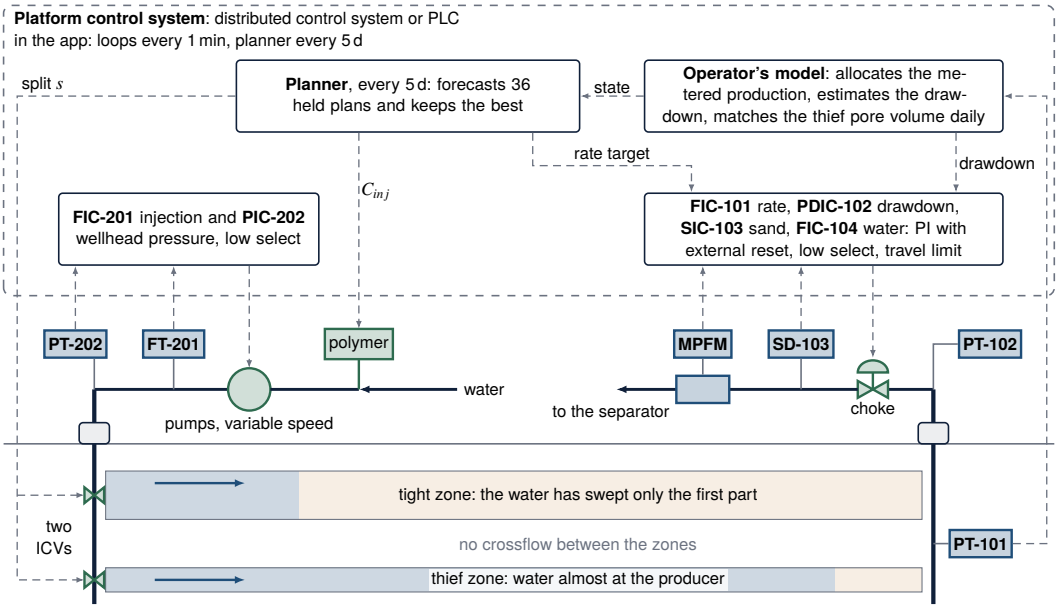


Figure 4.6 The loops of the smart well simulator with their hardware. Lettered boxes are sensing devices with the chapter's tags: the bottomhole gauge PT-101, the wellhead gauge PT-102, the clamp-on sand detector SD-103, the multiphase meter (MPFM), the injection meter FT-201 and the injection gauge PT-202. The production choke, the injection pumps, the polymer skid and the two inflow control valves (ICVs) are the final elements, and dashed arrows are signals. Notice that four loops reach the choke through one selector, and that the planner writes only targets: the rate target, the valve split and the polymer concentration. Not to scale, and not a piping diagram.

is 857 m^3/d against the plan's 900 m^3/d, with the choke wide open and the liquid rate loop saturated 96.7 % of the time so far. The badge and ledger water cut, 24 %, is on a reservoir basis, while the water-cut trend shows all three series on the surface basis: true 27.5, metered 26.8 and the model's 28.1 % at the latest historian sample.

> ✦ **DID YOU KNOW? The Slow Starter Wins the Campaign**
>
> From the simulator (Table 4.8). On day 30 the shipped settings have made 28 698 Sm^3 of oil, ahead of a fixed policy set by hand at reset, a 40 % thief share with 1200 ppm of polymer, at 25 054 Sm^3. On day 180 the hand-set policy has made 103 120 Sm^3 and the shipped settings 47 731 Sm^3.

4.7 Technology in Practice

Figure 4.6 draws the two selectors, the operator's model and the planner of Section 4.5 with the hardware of a producer and an injector.

What Measures It

The rate loop and the water override both read the multiphase meter, so its delay and noise sit inside two of the four choke loops. The sand override reads an acoustic detector clamped to the outside of the flowline. Sand grains striking the inside of a pipe at a bend give off acoustic energy that the detector picks up, and an intrusive variant instead measures the erosion of a probe placed in the stream [20]. In one field case the sand signals rose with the water cut, and a step-rate test found the liquid rate above which they began, so the rate was cut back below it. The same review warns that

such signals must be backed by other data [20]. The model's SD-103 averages over 1 min and carries noise and a bias that a disturbance can set.

> **TECHNOLOGY Sensor: The Multiphase Flow Meter**
>
> The conventional way to measure a well is a test separator, which splits the oil, gas and water and meters each phase alone. It is reliable and accurate but too slow to feed a control loop [21]. A multiphase meter measures the mixture in the line. In one common design gamma rays cross the pipe, and their attenuation gives the density and so the fraction of each phase, while a venturi or an orifice beside it gives the velocity. A meter with a radioactive source needs specially trained staff, and its pressure sensors drift from their zero over time and need recalibration [21]. The chapter's meter reads after a 3 min delay and a 2 min average, with 2 % colored noise.

What Moves It

The choke is the only final element of the fast production layer. On the injector, variable-speed pumps set the rate, the dosing skid sets the polymer concentration, and two downhole inflow control valves split the water between the zones, the smart completion of Section 4.2. The model lets the valves realize any requested split, moving one point of share per minute.

> **TECHNOLOGY Final Element: The Production Choke**
>
> Almost all flowing wells carry a wellhead choke to regulate the rate and to prevent water and gas coning and sand problems [22]. In critical flow the rate through it reaches a maximum that a change of pressure downstream no longer moves. The long-used correlation of 1954 holds only when the upstream pressure is at least 70 percent above the downstream one [22]. Produced sand erodes chokes, completions and surface equipment [20]. Equal-percentage trim counters the droop of a falling pressure drop, but its textbook law never reaches zero flow [23]. The chapter's modified law closes at zero, with a rangeability of 20, a 1 min lag and 5 %/min of travel.

Where the Controller Runs

Wells gathered at one site can be run from a distributed control system, which controls production within one geographic location and whose supervisory level oversees the controllers of each local process [24]. Loops in such systems run with cycle times from milliseconds to minutes [24]. The app's one-minute scan sits inside that range and well below the wellbore's 10.1 min time constant. The chapter's structure maps onto four PID blocks whose reset is fed back from the applied opening, a low-select block and a rate limiter on the choke, and the same pattern on the pump. The operator's model and the planner sit above them in a supervisory layer that writes setpoints once every five days.

> **IN PRACTICE The Injection Pressure Limit Is a Rule**
>
> Federal rules for Class II injection wells in the United States, which cover enhanced recovery, require a maximum wellhead injection pressure. It is calculated so that injection does not start new fractures or extend existing ones in the confining zone [25]. The operator must observe the injection pressure, flow rate and cumulative volume at least monthly for enhanced recovery, report a summary each year and demonstrate mechanical integrity at least every five years [25]. PIC-202 plays a similar part in the chapter. It takes the pump before the injection wellhead passes 145 bar, so the higher sandface stays at least 10 bar below the 360 bar fracture pressure.

What Is Modernizing It

Three developments touch this chapter. The first is the virtual flow meter, which infers the phase rates from ordinary field instruments and empirical algorithms. It costs far less than a multiphase meter but needs much calibration before start-up, and a 2019 review expects it to progress [21]. The second is fiber-optic distributed acoustic sensing along the whole well, which gives sand data in real time and

locates where the sand enters, something a surface detector cannot do [20]. The third is closed-loop reservoir management. Gradient-free methods such as the ensemble Kalman filter connect to any reservoir simulator for history matching and optimization [26]. The chapter's daily match of one pore-volume multiplier is the smallest version of that loop, and its 13.9 % forecast error shows what the full version has to remove.

4.8 Limitations

The reservoir is two strips without crossflow or gravity, so the thief zone costs recovery only through early breakthrough, and the fronts are smeared by 24 upwind cells, which bring the thief breakthrough 1.25 days earlier than 48 cells.

The sand law, the erosion indicator, the fracture pressure and the polymer are illustrative, and none has been calibrated to a formation, a choke or a field fluid. The targets of the challenge are the application's own design choices.

> ⚠ **OPEN CHALLENGE** **When Will the Sand Come?**
>
> Sand control remains an ongoing challenge in sand-rich reservoirs [20]. A 2002 study of deep high-pressure wells found that criteria based on critical drawdown, bottomhole pressure, depletion or fluid velocity missed the outcome by a large margin. All but one of the wells made no sand until water arrived, which the study traced to the loss of a capillary tension of about 1 psi that had held the loose grains together [18]. The chapter's sand law is a critical drawdown that falls as water arrives, made steep on purpose and calibrated to no formation. Progress would be a sand onset predicted for a real well and confirmed by measurement before it happens.

The operator's model corrects one parameter, the thief pore volume, and only while its tight front is short of 80 % of the way, so it cannot repair its oil viscosity or its compressibility and it cannot see the production split. In case 5 its drawdown estimate reads 5.1 bar low. The planner enumerates up to 36 plans held constant over the horizon, so it cannot shape a polymer slug in time. Its daily forecast caps the last dose at the remaining budget and uses that same dose in transport and cost. A partial final dose is spread over the daily interval, so the exact within-day shutoff time is unresolved. Model predictive control over the same equations, with moves that vary along the horizon and an estimator that updates all three uncertain parameters, is the natural extension [9, 19].

> ⚠ **OPEN CHALLENGE** **A Reservoir Model Nobody Can Fully Check**
>
> Closed-loop reservoir management couples automatic history matching with production optimization, and both are large optimization problems [26]. A 2015 review found most studies academic and far from field application. Field engineers care about processing time, the veracity of decisions and ease of use, and one simulation of a large reservoir can take several days. History matching is underdetermined: many parameter sets fit the data, and some of them forecast the future badly [26]. The chapter's operator's model matches its water cut yet forecasts 13.9 % high. Progress would be a loop that states the uncertainty of each forecast beside each plan, at a cost a field team can run.

4.9 Conclusion

This chapter studied a producer and an injector on a two-zone reservoir on one simulated clock, with fast loops that protect the well and a slow planner that decides the sweep. The wellbore answers a choke move with a lead-lag of 10.1 min, the thief zone's pressure moves in 19.1 h and the tight zone's in 153 h, and a plain flood breaks through the thief zone on day 27.5 after 0.269 pore volumes against the Welge value of 0.303. Four PI loops in external-reset form share the choke without windup, so sand can be held at 0.30 g/s and water inside an 800 m^3/d capacity, and an injector at its fracture limit lets the pressure fall to 216.6 bar rather than relax the limit. Holding the thief zone to half the water makes 47 % more oil by day 60, and the 180-day planner makes 2.33 times the fixed-choke oil where

the shipped settings make 1.07 times and a 30-day horizon 2.00 times. The planner's forecasts are 13.9 % optimistic from the operator's model errors and 3.7 % pessimistic from its coarse grid, and a fixed policy chosen by hand comes within 0.8 % of it. The sand law, the polymer and the fracture limit are illustrative, and the targets are the application's own design choices. A fuller model would add crossflow, a shear-thinning polymer, tubing lift and an estimator of every uncertain parameter. The simulator is an accessible place to see that the oil a well makes this month and the oil a flood recovers are different quantities.

KEY POINTS

- A choke changes a well's rate within minutes, but the water that limits its oil was injected weeks earlier, and a permeable layer decides where it goes.
- The choke sets the bottomhole pressure, not the rate, so when the injection plant trips the rate loop holds its target for 49.6 h and then runs out of travel.
- Four PI loops in external-reset form share the choke through a low selector without windup.
- The 180-day planner makes 2.33 times the fixed-choke oil where the shipped settings make 1.07 times, and a fixed policy chosen by hand comes within 0.8 % of it.

Where else this applies. Volume 4, Chapter 14 meets the same shape, a fast actuator drawing on a store that refills slowly, and Chapter 13 uses the same external-reset selectors on its pumps.

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4.10 Exercises

4.1 Concept check · 2 min

In scenario 2 the injection plant trips at 6 h. The rate loop holds 900 m^3/d until about 55.6 h, and the rate then falls to 427 m^3/d by the restart at 96 h. Why can the rate loop not hold its target longer?

(a) The rate loop's integral winds up once the sand override has taken the choke

(b) The meter's delay lets the loop overshoot until the drawdown override cuts the rate

(c) The choke sets the bottomhole pressure, and once it is wide open the zone pressures set the rate

(d) The injector's pressure override closes the choke to protect the fracture margin

4.2 Concept check · 1 min

In scenario 3 the rate loop holds the choke while SIC-103 waits, and SIC-103 takes the choke within minutes once the sand passes its setpoint. What lets it take over without a windup delay?

(a) Its integral term is clamped at the top of its range while it waits

(b) The selector picks the loop with the largest error, not the smallest output

(c) Its integral time is the shortest of the four, so it acts first on any error

(d) Its reset term follows the applied opening, so its output waits just above it

4.3 Concept check · 2 min

In the campaign challenge the planner with a 30-day horizon never doses polymer, while the planner with a 180-day horizon spends the whole budget. What explains the difference?

(a) Within 30 days the forecast gain from polymer is smaller than the charge for its polymer

(b) The operator's model makes every polymer plan look worse than a plan of plain water

(c) The fracture limit forbids polymer, because the thicker water raises the sandface pressure

(d) The planner's grid offers polymer only with the lowest of its three liquid targets

4.4 Theory and calculation · 6 min

At the design point the zones deliver $J = 1.224\,\mathrm{m^3/h}$ per bar of drawdown, the choke passes $\partial q_{ch}/\partial p_{wf} = 0.263\,\mathrm{m^3/h}$ more per bar of bottomhole pressure, and the wellbore stores $C_{wb} = 0.25\,\mathrm{m^3/bar}$.

(a) Find the share g of an immediate choke response that remains at steady state, and the time constant τ_{wb} of Equation (4.8) with the choke fixed. *Checkpoint:* 0.82 and 10.1 min.

(b) Find the time constant of the wellbore when the rate loop holds the choke flow. *Checkpoint:* 12.25 min.

(c) The rate loop runs every $\Delta t = 1\,\mathrm{min}$ with $\tau_I = 8\,\mathrm{min}$ and $K_c = 0.020\,\%$ per $\mathrm{m^3/d}$. A one-point choke step raises the rate by 33.4 $\mathrm{m^3/d}$ at once and by 26.2 $\mathrm{m^3/d}$ at steady state. Find the effective integral time and the loop gain at once and at steady state. *Checkpoint:* 8.51 min, 0.67 and 0.52.

4.5 Theory and calculation · 7 min

The sector is 300 m by 300 m. The tight zone is 12 m thick at porosity 0.20 and 700 mD, and the thief zone 4 m thick at porosity 0.25 and 7000 mD. The connate water saturation is 0.20 and $B_o = 1.20$. The end-point relative permeabilities are 0.40 for water and 0.85 for oil, the viscosities 0.5 and 10 cP, and the polymer multiplies the water viscosity by $R(C) = 1 + aC + bC^2$ with $a = 3 \times 10^{-3}/\mathrm{ppm}$ and $b = 3 \times 10^{-6}/\mathrm{ppm^2}$.

(a) Find the pore volume of each zone and the oil in place at standard conditions. *Checkpoint:* 216 000 and 90 000 $\mathrm{m^3}$, 204 000 $\mathrm{Sm^3}$.

(b) Find the thief zone's share of the permeability-thickness product. *Checkpoint:* 76.9 %.

(c) Find the end-point mobility ratio of water to oil with no polymer and with 1200 ppm. *Checkpoint:* 9.41 and 1.06.

(d) The Welge tangent gives breakthrough after 0.303 pore volumes. Find the water the thief zone must take before its water reaches the producer. *Checkpoint:* 27 300 $\mathrm{m^3}$.

4.6 Theory and calculation · 7 min

Take $g = 9.81\,\mathrm{m/s^2}$, a depth of 2000 m, a flowing tubing density of 650 $\mathrm{kg/m^3}$ in the producer and water at 1025 $\mathrm{kg/m^3}$ in the injector. At the design point both wells pass 45 $\mathrm{m^3/h}$ of reservoir fluid, the bottomhole pressure is 213.24 bar, the producer's tubing friction is $k_f = 0.0015$ and the injector's $k_t = 0.0008$, both in $\mathrm{bar\,h^2/m^6}$, the flowline is at 20 bar and the critical pressure ratio is $r_c = 0.5$.

(a) Find the weight of each tubing column. *Checkpoint:* 127.5 bar and 201.1 bar.

(b) Find the wellhead pressure and the drop across the choke, and the flowline pressure below which the choke flow does not depend on it. *Checkpoint:* 82.7 bar, 41.3 bar, 41.3 bar.

(c) PIC-202 holds the injection wellhead at 145 bar. Find the injector sandface pressure and compare it with the fracture pressure of 360 bar less the required margin of 10 bar. *Checkpoint:* 344.5 bar, 5.5 bar inside the 350 bar limit.

4.7 App challenge · 8 min

Load scenario 3, Sand onset. The liquid target rises from 900 to 1400 $\mathrm{m^3/d}$ at 30 min. Use the default seed and a speed of 1, one simulated hour per second, and run each case to 6 h.

(a) Run the scenario as shipped. Read the Erosion indicator and Peak sand tiles, and find in the exported file the mean of the columns `q_liq_m3d` and `sand_gps` over the rows from 3 to 6 h. *Checkpoint:* 52 kJ, 0.45 g/s, 1206 $\mathrm{m^3/d}$ and 0.29 g/s.

(b) Press Reset, set Sand override to Off and run again. Read the same four values. *Checkpoint:* 416 kJ, 3.75 g/s, 1409 $\mathrm{m^3/d}$ and 3.26 g/s.

Accept the means within 5 m³/d and 0.03 g/s. State how much more liquid the second run makes and for how much more sand.

4.8 App challenge · 8 min

Load scenario 2, Declining pressure. The injection plant trips at 6 h and restarts at 96 h. Use the default seed and a speed of 24, and run each case to 240 h.

(a) Run the scenario as shipped. In the exported file find the first row at which `choke_saturated` is 1, the column `q_liq_m3d` at 96 h, and `p_thief_bar` and `p_tight_bar` at 48 h. How long did the choke hold the target after the trip? *Checkpoint:* 55.67 h, 427 m³/d, 184.3 and 234.1 bar, about 49.7 h.

(b) Press Reset, set Voidage replacement ratio to 1.20 on the FIC-201 card before Run, and run again. Read `p_avg_bar` at 240 h in both runs. *Checkpoint:* 194.0 bar as shipped and 214.4 bar at 1.20.

Accept times within 0.2 h, rates within 3 m³/d and pressures within 0.2 bar.

4.9 App challenge · 10 min

Load the challenge, listed as Challenge · 180-day campaign. Use the default seed and a speed of 120, at which each campaign takes a nominal 36 s, and let each run stop itself at day 180. Read the Oil produced, Day 30 vs fixed choke and vs fixed choke tiles after each run.

(a) Run the scenario as shipped. *Checkpoint:* 47 731 Sm³, +48.1 %, +7.1 %.

(b) Press Reset, set Recovery planner to On and Planning horizon to 30 d, and run again. *Checkpoint:* 89 270 Sm³, +94.2 %, +100.4 %.

(c) Set Planning horizon to 180 d, press Reset and run again. *Checkpoint:* 103 912 Sm³, +50.6 %, +133.3 %.

Which runs pass the challenge's 98 000 Sm³, and which plan leads on day 30?

4.10 Application area · 3 min

Forty days into a flood the well makes 245.8 Sm³/d of oil in 900 m³/d of liquid, and the platform treats at most 800 m³/d of water. Raising the target to 1200 m³/d gives 1028 m³/d with 270 Sm³/d of oil and 758 m³/d of water while FIC-104 holds the water, and 1197 m³/d with 314 Sm³/d of oil and 883 m³/d of water with the override off.

(a) Find the extra water per extra unit of oil for the step with the override on, and for the further step with it off. *Checkpoint:* About 4.3 and 2.8.

(b) Name the lever that buys oil on this well, and why the choke is not it. *Checkpoint:* Keeping water out of the well, through the injection split.

4.11 Application area · 4 min

In case 7 the injector's skin grows by 5 units a day. PIC-202 takes the pump on day 14.5, and by day 30 the injection is 757 m³/d against a target of 943 m³/d, the average reservoir pressure has fallen from 249.6 to 216.6 bar, and the fracture margin has never fallen below 14.3 bar, against 10 bar required.

(a) Find the voidage replacement ratio on day 30 and the average rate of pressure loss over the 30 days. *Checkpoint:* 0.80 and about 1.1 bar a day.

(b) A production engineer proposes raising the injection wellhead limit by 4 bar to restore the target. Give two reasons against it, and the remedy the case offers. *Checkpoint:* The skin keeps growing, and the margin would fall toward the fracture limit. Remove the damage.

4.12 Review the agent · 5 min

An AI assistant is asked how to set up the recovery planner for the campaign and replies as follows. “A 30-day horizon is best. In the app it is 29 % ahead of the 180-day horizon on day 30, and because the planner re-plans every five days it can always correct a plan later. A long horizon only adds forecast error, since the operator’s model is 13.9 % optimistic over 180 days.” Find the flaw in the advice and say how it could be checked.