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Engineering Optimization of Gas Gathering and Vapor Recovery Systems for Flare Reduction in Onshore Oil and Gas Facilities

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Abstract
Flaring in onshore oil fields often stems from gathering, compression and vapor recovery systems sized without regard to how gas is lost. This study optimizes them for a representative twelve-pad field developed over three years. Weymouth gathering hydraulics with back-pressure effects on production are combined with daily simulation of compressor failures, midstream outages and vapor recovery downtime over ten years. The decision variables are trunk and lateral diameters, compressor count, vapor recovery configuration, vapor recovery towers, gas-to-power units and curtailment during outages. NSGA-II minimized flaring and venting intensity while maximizing net present value. Inputs are representative literature values, not field data. The legacy design captured 90.8 percent of gas at 10.1 kg CO2e per barrel of oil equivalent, with two thirds of flaring caused by gathering pressure limits. The maximum-value design added USD 108 million and cut intensity to 7.6 kg per barrel, but shifted flaring to compression shortfalls and tank vapor. The highest-value design meeting 98 percent capture cut intensity to 2.3 kg per barrel for USD 19 million less, about USD 103 per tonne of CO2e avoided. A seventh compressor and vapor recovery on high-volume pads achieved 95.7 percent capture for USD 2 million. Even a USD 200 per tonne carbon price did not make 98 percent capture optimal. Capture fell below 98 percent when midstream outages exceeded about five per year.

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1. Introduction

Gas flaring remains one of the most visible and avoidable sources of greenhouse gas emissions from oil production. Satellite surveys using the Visible Infrared Imaging Radiometer Suite (VIIRS) estimated that about 143 billion cubic metres of associated gas were flared worldwide in 2012 [1], and analyses of global flaring have estimated its contribution to emissions and the potential role of flaring reduction in meeting mitigation targets [2–4]. In the United States, flaring rose sharply with tight oil development: flaring in North Dakota more than doubled between 2011 and 2013 [5], and flaring in the Permian and Bakken basins has been linked to pipeline takeaway constraints that depressed regional gas prices [6, 7]. Flares do not destroy all the methane they receive. Aerial measurements in the Permian, Eagle Ford and Bakken basins found that inefficient and unlit flares make flaring a larger methane source than inventories assume [8], and earlier studies measured methane destruction efficiencies and black carbon emissions from flares associated with shale production [9–11].

Flaring and venting at onshore facilities have several engineering causes. Gas gathering systems built for early production can become pressure-limited as new pads come online, so that gas must be flared at the pad [6, 12]. Compressor failures and midstream outages force gas to the flare at central facilities [13, 14]. Storage tanks emit flash gas, working and breathing losses that must be

captured by vapor recovery units (VRUs) or routed to combustors, and aerial surveys have identified tanks as frequent sources of large emissions [15, 16]. Regulators have responded. North Dakota set gas capture targets under Industrial Commission Order 24665 [17], the New Mexico Oil Conservation Division adopted natural gas waste reduction rules in 2021 that raise the required gas capture rate to 98 percent [18], and the Environmental Protection Agency has applied performance standards to new oil and gas sources since 2016 [19]. The World Bank Zero Routine Flaring initiative, launched in 2015, provides a global industry commitment [20].

Engineering studies have addressed parts of this problem. Flare gas recovery and utilization options, including gas-to-power, gas-to-liquids, natural gas liquids recovery and reinjection, have been evaluated techno-economically [21–23]. VRU installation has been documented by the Natural Gas STAR programme [24, 25]. Gas pipeline network design and operation have been optimized with mixed-integer nonlinear programming [26, 27], and production systems have been optimized for gas-lift allocation and well scheduling [28, 29]. These studies rarely consider gathering design, compression redundancy, vapor recovery and operating policy together, under the uncertainty of equipment failures and midstream outages, and with flaring intensity and value as joint objectives. Regulatory capture targets raise a further question: what does it cost to meet a 98 percent capture requirement, and which combination of measures meets it most efficiently [18, 30]?

This paper addresses these questions with a simulation-optimization study of a representative onshore field. It makes four contributions. First, it couples Weymouth gathering hydraulics with back-pressure effects on production, daily stochastic simulation of compressor, VRU and midstream availability, and tank vapor handling in a single model [13, 24, 31]. Second, it applies the non-dominated sorting genetic algorithm II (NSGA-II) to ten design and operating variables and traces the trade-off between flaring and venting intensity and net present value [32, 33]. Third, it decomposes flaring by cause for representative designs, showing how optimization shifts the causes of flaring. Fourth, it evaluates the cost of meeting a 98 percent capture requirement, the effect of carbon prices and the sensitivity of compliance to midstream reliability. Section 2 reviews the literature, Section 3 describes the model, Section 4 presents results, Section 5 discusses implications and Section 6 concludes.

2. Literature Review

This section reviews the literature on the scale and measurement of flaring, flare emissions and their impacts, flaring regulation, flare gas recovery and utilization, methane emissions from production sites, vapor recovery, leak detection and mitigation costs, gas network optimization and production system optimization. The review draws on overviews that describe flaring as an engineering, economic and regulatory problem [3, 4, 34] and on the observation that flaring persists because the value of the recovered gas is often lower than the cost of the infrastructure needed to capture it [35–37]. It also reflects regulatory reviews of flaring and venting data and policy in the United States [19, 38].

2.1. Scale and Measurement of Flaring

Satellite remote sensing has transformed the measurement of flaring. VIIRS Nightfire satellite pyrometry [39] and methods for a global survey of flaring [1] built on a fifteen-year record derived from earlier sensors [40], and detection limits have been extended with short-wavelength channels [41]. The Along Track Scanning Radiometer series and successors have monitored flaring [42–44], the Sea and Land Surface Temperature Radiometer has detected persistent hot spots [45], and MODIS and VIIRS fire products have been compared [46]. Landsat-based and other methods estimate flaring at individual stations [47, 48], the RST-FLARE algorithm has characterized flaring at the Val d'Agri oil centre [49–51], VIIRS has been used to identify industrial heat sources [52], quantify methane consumed in Bakken flares [53] and learn from nighttime observations in North Dakota [7], and satellite data have linked changes in Mexico's offshore flaring to regulation [54]. Differences between the MODIS and VIIRS fire products in Khanty-Mansiysk [46] and the detection limits that still apply to small flares [41] show the remaining uncertainty.

2.2. Flare Emissions and Impacts

Flare performance depends on design, gas composition and wind. Parametric models of flare efficiency in crosswinds [55, 56], theoretical and observational assessments [57], computational fluid dynamics of wind-tunnel experiments [58], numerical simulation of ethylene flares [59], the Texas Commission on Environmental Quality flare study [60], and direct measurement of volatile organic compound destruction [61] establish that combustion efficiency can fall well below design values. Methane destruction efficiencies have been measured for shale flares [9], and inefficient and unlit flares emit large quantities of methane [8]. Black carbon from flaring is significant regionally and globally [62–66], including in the Bakken [10, 67], the United States [68], Russia [69] and West Africa [70], and nitrogen oxides from oil and gas regions have increased [71]. Carbon dioxide, methane and black carbon emissions from upstream flares have been quantified [11]. Flaring has been associated with air pollution hotspots and health risks [72–76], adverse birth outcomes [77], exposure of nearby populations [78], paediatric asthma [79], disproportionate exposure of minority communities in South Texas [80] and changes in emissions in Nigeria [81, 82]. The usefulness of flares for air pollution control has been reviewed [83].

2.3. Regulation and Policy

Flaring regulation varies by jurisdiction. North Dakota's gas capture policy set targets that rose over time [17], New Mexico adopted a 98 percent capture requirement in 2021 [18] and federal performance standards for new sources were introduced in 2016 [19]. Reporting obligations add a further layer: greenhouse gas disclosure and ESG compliance requirements now shape how energy and infrastructure enterprises account for flared and vented volumes [84], and regulatory reform of statutory bidding workflows in emerging energy markets affects how quickly gas utilization projects can be procured [85]. Analyses of state regulation of unconventional development [86], policy options for tight oil fields [35], federal and state regulatory overviews [19], data improvement [38], regulation of gas-to-wire offshore [87], flaring reduction in Brazil [88], stimulation of associated gas use [89], domestic market development to eliminate routine flaring [90] and the Zero Routine Flaring initiative [20] provide context. Pipeline constraints that depress regional prices create incentives to flare [6], and the Bakken experience shows

how rapid development outpaces gathering infrastructure [5, 91].

2.4. Flare Gas Recovery and Utilization

Flare gas recovery has been studied extensively in refineries and gas plants [92–97], olefin plants [98, 99], Egyptian and other oil and gas operations [100, 101], giant gas refineries [95] and the natural gas processing industry [12], and recovery technologies have been reviewed for their contribution to energy security, environmental performance and resource efficiency [23]. Techno-economic feasibility [36, 102, 103], multi-objective decision models [104], process optimization [105], separator optimization [101], crude stabilization through multi-stage separation [106], plantwide dynamic simulation for flare minimization [107], ejector systems [108], exergoeconomic analyses [109, 110], power generation [111, 112], organic Rankine cycles [113], solid oxide fuel cells [114], hydrogen production [115, 116], algal protein [117] and liquefied natural gas or compressed natural gas production [118] have been examined. Gas-to-liquids routes have been reviewed [119, 120] and simulated [121–125], natural gas liquids recovery has been evaluated [126, 127], gas-to-wire projects have been reviewed [128], liquefaction has been assessed [129], and comparisons of GTL and LNG [130] and other gas monetization options [131] inform decisions. Reviews of utilization options [21, 22, 132], small-scale utilization [133, 134], abatement costs in Brazil [37] and industry innovation [135] show that small, remote and declining volumes are the hardest to monetize, which is the situation of many onshore tight oil pads. Gas processing fundamentals are covered in standard texts [136].

2.5. Methane Emissions from Production Sites

Measurement campaigns have shown that methane emissions from the United States oil and gas supply chain exceed inventory estimates [137–140] and follow heavy-tailed distributions dominated by super-emitters [141–144]. Ground-level measurements have been synthesized [145], divergent estimates reconciled [146], and production sites studied with mobile flux plane [147], mobile measurements [148, 149] and direct component measurements [150–152]. Well pad emissions vary across basins [153–155], including marginal and low-production wells [156, 157], abandoned wells [158–161], gathering and processing facilities [162, 163], compressor stations [164, 165], pneumatic controllers [166], liquid unloading [167] and storage tanks [15, 16, 168]. Basin studies cover the Barnett [169–174], Denver-Julesburg [175, 176], Four Corners [177–179], Haynesville, Fayetteville and Marcellus [180–182], Uintah [183, 184], central and western United States [185], the Bakken [186, 187], Alberta [188, 189] and California [190, 191]. Permian studies have quantified emissions with satellites [192, 193], aircraft [194, 195] and well pad measurements [196], and observed variation with oil price during the COVID-19 pandemic [197]. Aerial surveys [15, 198–203], unmanned aerial vehicle monitoring of pipelines and corridors [204], satellite observations [205–211], controlled release tests [212–215], mass balance methods [216] and the Aliso Canyon blowout [217] demonstrate the range of methods. Temporal variability [218–220], inventory gaps [221–224], the greenhouse gas footprint of shale gas [225], oil and gas emissions and air quality [226], supply chain emissions [227], the global methane budget [228], sampler malfunctions [229, 230], global ultra-emitters [208] and abatement benefits [231] complete the picture.

2.6. Vapor Recovery and Tank Emissions

Vapor recovery has a long history in oil production. Early applications [232], practical design approaches [233], field use in the Austin Chalk [234], vapor jet systems [235], the American Petroleum Institute tank vapors project [236], heavy oil tank emissions [237] and methods for estimating methane from crude oil stock tanks [168] established the engineering basis. The Natural Gas STAR programme documented VRU installation, costs and payback [24, 25]. Recent aerial surveys show that tanks are frequent sources of large emissions, often because of open thief hatches or malfunctioning control systems [15, 16, 142], which implies that VRU availability and tank control effectiveness matter as much as installation.

2.7. Leak Detection, Repair and Mitigation Costs

Leak detection and repair (LDAR) technologies have been reviewed [238] and compared by single-blind tests [239], and the effectiveness of optical gas imaging [240, 241], mobile surveillance [242], aerially guided LDAR [243], repeated surveys [244], virtual field simulation [245], agent-based equivalence modelling [246] and the cost-effectiveness of new technologies [247] have been studied. Policy design for distributed small sources [248], rapid deployment of mitigation [249], mitigation potential from reported venting and flaring [30] and assessments of methane abatement from oil and gas [250] indicate that many measures have low or negative net cost. Data-driven frameworks for controlling occupational safety risk in large energy infrastructure projects [251] show that the same field surveys can serve safety as well as emission objectives. These studies treat mitigation measures one at a time, whereas the cost of meeting a capture target depends on how measures interact in a specific system.

2.8. Gas Network and Gathering System Optimization

Optimization of natural gas networks has a long history. Reviews of optimization problems in gas transportation [26], design and operation of transmission networks [27, 252], strategic planning [253], expansion planning with convex relaxations [254–256], variable-speed compressor optimization [257], transient optimization [258, 259], network reduction techniques [260], mixed-integer programming for gas purchase and transportation [261], the gas transmission problem [262], gas allocation [263], pooling problems [264–266], linepack planning under uncertainty [267], stochastic flow simulation [268], unsteady operation [269], risk loss costs [270], large-scale operation optimization [271], linearization for distribution [272], nonuniform elevation [273], power minimization in gunbarrel networks [274, 275], security regions [276], refinery fuel gas networks [277], compressor operation for flexibility [278], Norwegian production and transport [279], booking feasibility [280], transient simulation [281, 282] and multi-period infrastructure planning [283] have been reported. Pipe sizing for tree-shaped networks [284–287], convex reformulations and pruning for network design [288–290], capacity expansion [291], offshore pipeline system design [292], network layout [293], minimum-cost network design heuristics [294], operations research for pipeline planning [295], cost functions [296] and the dependence of mature-field production on gathering hydraulic resistance [297] are directly relevant to gathering design. Supply reliability of gas networks has been assessed by Monte Carlo and other methods [13, 298–300], and compressor standby schemes have been optimized for reliability [14, 301],

and risk-based process engineering has been proposed as a framework for strengthening reliability across complex natural gas infrastructure [302]. Shale gas infrastructure studies address modular and distributed facilities [303, 304], mobile plants to monetize associated gas [305, 306], investment and profitability [307–309], scheduling [310], water-energy nexus optimization under uncertainty [311–315]. Multi-objective optimization with NSGA-II has been applied to combined gas and electricity network expansion planning [32], genetic algorithms have been applied to gas lift allocation [33], and network expansion and uncertainty in coupled networks have been analysed [316, 317]. The standard reference on gas pipeline hydraulics provides the Weymouth and Panhandle equations used in gathering design [31].

2.9. Production System Optimization

Production system optimization connects wells, networks and facilities. Gas-lift allocation has been optimized by dynamic programming [318, 319], mixed-integer linear optimization [28, 320], piecewise-linear models [321], nonlinear programming [322], genetic algorithms [33, 323], global optimization [324, 325] and improved allocation procedures [326–328], supported by models of gas-lift performance [329, 330]. Compressor design and scheduling in gas-lifted fields [331], load sharing for gas compressors [332], well scheduling [29], short-term production optimization of offshore platforms [333, 334], pumpoff scheduling under power constraints [335], goal programming for mature field production [336], well management in reservoir simulation [337] and mathematical techniques for production system optimization [338] illustrate the field. Liquid loading in gas wells [339], compressor application to extend the production life of mature fields [340], artificial lift and multiphase flow [341], nodal analysis of production systems [342] and optimization methods [343] provide the engineering foundations. These studies show that back-pressure at the wellhead affects production, which links gathering design to production value.

2.10. Research Gap

The literature offers mature methods for measuring flaring and methane, recovering flare gas, optimizing gas networks and allocating production, but three gaps remain for onshore tight oil facilities. First, gathering design, compression redundancy, vapor recovery and outage operating policy are rarely optimized together, although each addresses a different cause of flaring [13, 24, 26]. Second, stochastic availability of compressors, VRUs and midstream outlets is seldom represented in design optimization, although it determines upset flaring [8, 13, 14]. Third, the cost of meeting regulatory capture targets such as New Mexico's 98 percent requirement has not been quantified as a trade-off against value [18, 30, 250]. The model described next addresses these gaps.

3. Methods

This section describes the representative field, the gathering hydraulics and production model, the stochastic simulation of compression, midstream and vapor recovery availability, the emission and economic calculations, and the multi-objective optimization. The model combines elements that are standard individually: Weymouth flow for gathering lines [31, 136], back-pressure effects on well deliverability [341, 342], Monte Carlo availability simulation of the kind used in gas supply reliability studies [13, 299, 300], and NSGA-II for multi-objective search [32]. Two-state failure and repair models of this kind are standard in reliability engineering and failure analysis of complex engineering systems [344]. All parameter values are representative values chosen from ranges reported in the literature cited; they are not data from a specific field, and the results demonstrate the method and the relative performance of designs rather than estimate outcomes for any operator.

3.1. Representative Field

The field comprises twelve well pads connected by three laterals of 3 miles each to an 8-mile trunk line that delivers gas to a central facility, where reciprocating compressors raise it to the pressure of a midstream outlet (Figure 1). Four pads come online at the start, four after one year and four after two years, representing staged development of a tight oil field [5, 91]. Initial gas rates range from 1.8 to 8.1 MMscf/d per pad, six pads being high-volume pads with initial rates of at least 5.4 MMscf/d, and rates decline hyperbolically:

$$q_i(t) = \frac{q_{i,0}}{(1+b\,D_i\,\tau_i)^{1/b}}, \qquad \tau_i = \max\left(0,\ t - t_{i,0}\right) \quad (1)$$

with initial decline $D_i = 0.65$ per year and $b = 1.1$, typical of tight oil wells [307, 308]. The unconstrained field gas rate peaks at about 38 MMscf/d when the third group of pads comes online. Oil production follows from a producing gas-oil ratio of 1.6 Mscf per barrel. Each pad has a separator, storage tanks and a combustor, and may have a VRU and a vapor recovery tower (VRT). The midstream outlet accepts up to 32 MMscf/d and experiences outages at an average of five per year with an exponentially distributed mean duration of 1.5 days, representing the takeaway and processing interruptions that cause upset flaring [6, 12].

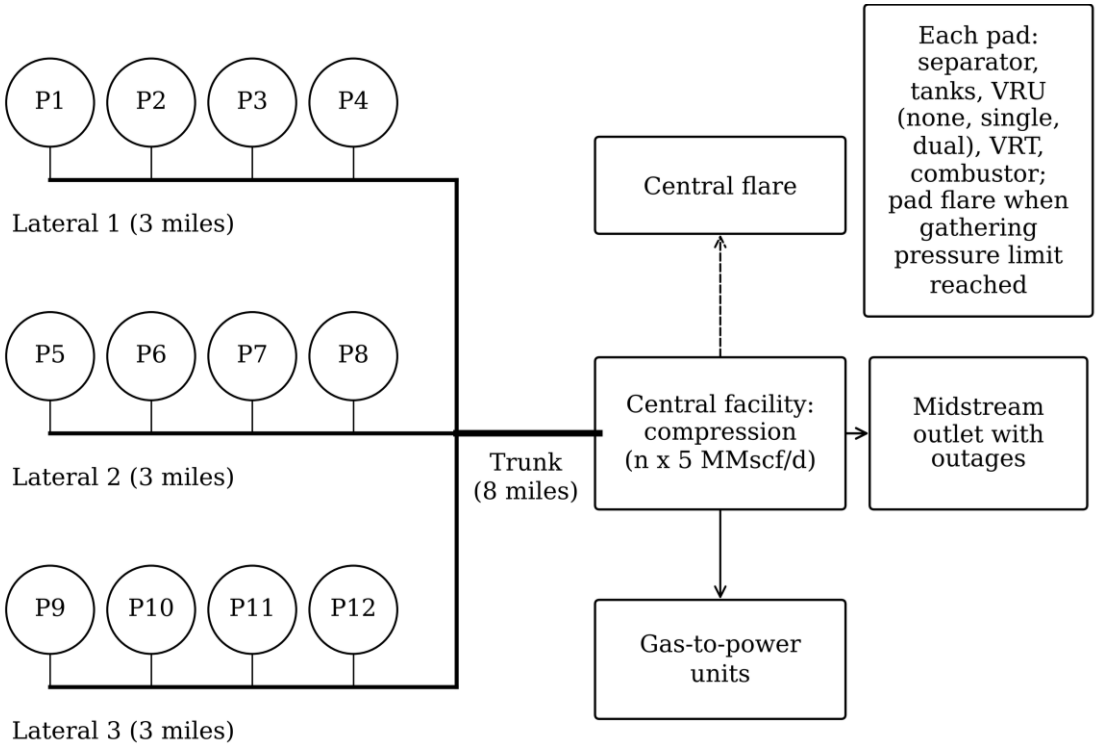


Fig 1: Representative field layout: twelve pads on three laterals, trunk line, central compression, gas-to-power units, central flare and midstream outlet.

3.2. Gathering Hydraulics and Production

Flow in Each Lateral and the Trunk Is Described by the Weymouth Equation [31, 136]:

$$Q = 433.5\,E\,\frac{T_b}{P_b}\left(\frac{P_1^2 - P_2^2}{G\,T\,L\,Z}\right)^{0.5} d^{8/3} \tag{2}$$

where Q is the flow in standard cubic feet per day, P_1 and P_2 are the upstream and downstream pressures in psia, d is the internal diameter in inches, L the length in miles, $G = 0.75$ the gas specific gravity, $T = 540$ R the flowing temperature, $Z = 0.9$ the compressibility factor, $E = 0.92$ the pipeline efficiency and $T_b = 520$ R and $P_b = 14.73$ psia the base conditions. Starting from a central suction pressure of 64.7 psia, the junction and pad pressures are computed upstream for the monthly flows. Higher wellhead pressure reduces production, which is represented by a deliverability factor [297, 342]:

$$f_i = \max\{0.5,\; 1 - \alpha \max(0,\; P_{\text{pad},i} - P_{\text{base}})\} \tag{3}$$

with $\alpha = 0.0008$ per psi and $P_{\text{base}} = 120$ psia. Flows and pressures are solved by fixed-point iteration. If a pad pressure would exceed the separator limit of 265 psia, the flow on that lateral is reduced by bisection until the limit is met, and the excess gas is flared at the pads; this represents gathering-constrained flaring [12, 297].

3.3. Stochastic Availability and Daily Gas Balance

Each day d of the ten-year horizon is simulated in 200 replications. Compressor units of 5 MMscf/d each follow a two-state Markov process with a daily failure probability of 1/42 and a mean repair time of 2 days, giving an availability of about 0.955, consistent with reliability data for reciprocating compression [14, 301]. The repair time assumes that spares are held on site, as in models of inventory availability and plant uptime [345] and of materials readiness for maintenance-driven supply chains [346]. Midstream outages occur as a Poisson process. VRU units have an availability of 0.90, reflecting the downtime reported for vapor recovery [24, 25]; a dual VRU is available when either unit is available. Tank vapor of 45 scf per barrel of oil is generated at each pad [168, 236]. A fraction escapes uncontrolled through thief hatches and pressure relief valves, set at 8 percent without a VRT and 2 percent with one, reflecting aerial evidence of tank control failures [15, 16]. The remainder is recovered by the VRU when it is available, or otherwise routed to the combustor. The gas reaching the central facility on day d is the gathered gas plus recovered tank vapor, G_d, and the daily balance is

$$S_d = \min\{G_d - U_d,\; 5\,n_d,\; C_d\}, \qquad F_d^c = G_d - U_d - S_d \tag{4}$$

where S_d is gas sold, U_d is gas used by gas-to-power units of 0.5 MMscf/d each, n_d is the number of compressor units available, C_d is the midstream capacity (zero during outages) and F_d^c is gas flared at the central facility. Under the curtailment policy, wells are shut in from the second consecutive day of an outage; 30 percent of the value of curtailed oil is treated as lost and the remainder as deferred.

3.4. Emissions, Capture and Economics

Gas Capture Is the Share of Produced Gas, Including Tank Vapor, That Is Sold or Used:

$$\kappa = \frac{\sum_d (S_d + U_d)}{\sum_d \left(Q_d^{\text{prod}}\right)} \tag{5}$$

Emissions combine carbon dioxide from combustion, methane slip from flares and combustors at a destruction efficiency of 95 percent, below design values but consistent with field measurements [8, 9, 60], and vented tank vapor:

$$E_{CO2e} = F\, e_{CO2} + F\, x_{CH4}(1-\eta)\rho_{CH4}\,\mathrm{GWP} + V\, x_{CH4,T}\,\rho_{CH4}\,\mathrm{GWP} \quad (6)$$

where F and V are the volumes flared and vented, $e_{CO2} = 0.060$ t CO2 per Mscf burned, $x_{CH4} = 0.72$ and $x_{CH4,T} = 0.45$ are the methane fractions of field gas and tank vapor, $\eta = 0.95$ is the destruction efficiency, $\rho_{CH4} = 0.0192$ t per Mscf and $\mathrm{GWP} = 29.8$ is the 100-year global warming potential of fossil methane. Flaring and venting intensity is E_{CO2e} divided by production in barrels of oil equivalent (boe), with 6 Mscf of gas per boe. Net present value at 10 percent combines oil margin (USD 40 per barrel), gas sales (USD 2.5 per Mscf), electricity from gas-to-power displacing purchased power at USD 0.06 per kWh up to a field load of about 4 MW, capital costs and operating costs (Table 1) [30, 296]. Installed equipment costs depend on procurement strategy, and the values in Table 1 assume competitively procured standard packages [347].

Table 1: Principal cost and economic parameters.

Item	Value
Gathering pipe installed cost	USD 0.15 million per inch-mile
Compressor unit (5 MMscf/d), capital and annual operating cost	USD 1.6 million; USD 0.12 million per year
Vapor recovery unit, capital and annual operating cost	USD 0.25 million; USD 0.03 million per year
Vapor recovery tower	USD 0.15 million
Gas-to-power unit (0.5 MMscf/d), capital and annual operating cost	USD 2.2 million; USD 0.15 million per year
Oil net margin; gas price; displaced electricity price	USD 40 per barrel; USD 2.5 per Mscf; USD 0.06 per kWh
Share of curtailed oil value lost	30 percent
Discount rate; horizon	10 percent; 10 years

3.5. Multi-Objective Optimization

Table 2 Lists the Ten Decision Variables. the Optimization Problem Is

$$\min_{\mathbf{x}} \left\{ \bar{I}(\mathbf{x}),\ -\overline{\mathrm{NPV}}(\mathbf{x}) \right\} \quad (7)$$

where $\bar{I}$ and $\overline{\mathrm{NPV}}$ are the mean flaring and venting intensity and mean net present value over 30 replications with common random numbers. NSGA-II [32] was run with a population of 80 for 70 generations, using simulated binary crossover and polynomial mutation with integer rounding. The resulting non-dominated designs were re-evaluated with 200 independent replications. Four designs were selected for detailed comparison: the legacy baseline (D0), the maximum-NPV design (D1), the highest-NPV design whose mean capture meets the 98 percent requirement adopted in New Mexico (D2) [18] and the minimum-intensity design (D3). The selection of designs under carbon prices from USD 0 to 200 per tonne used the discounted CO2e emissions. Sensitivity analyses varied midstream outage frequency, VRU availability and midstream capacity.

Table 2: Decision variables and their ranges.

Variable	Options	Baseline D0
Trunk diameter	6, 8, 10, 12, 14, 16 in	10 in
Diameter of each of three laterals	6, 8, 10, 12, 14, 16 in	6 in
Number of compressor units	4 to 10	6
VRU configuration, high-volume pads	None, single, dual	Single
VRU configuration, other pads	None, single, dual	None
Vapor recovery tower at high-volume pads	No, yes	No
Gas-to-power units	0, 1, 2	0
Outage policy	Flare through, curtail	Flare through

4. Results

This section reports the Pareto front, the comparison of selected designs and the causes of flaring, the time profile of flaring, the effect of carbon prices and the sensitivity of the results to midstream reliability, VRU availability and midstream capacity. Because the inputs are representative, the relative performance of designs and the structure of the trade-offs are more informative than absolute values, as in other techno-economic optimization studies of flare reduction and gas networks [32, 104, 110]. All results are means over 200 independent replications that were not used in the optimization, so that the reported performance is not biased by the random numbers on which the search was conducted.

4.1. Pareto Front

Figure 2 shows the 80 non-dominated designs found by NSGA-II, re-evaluated with 200 replications. Every design dominates the legacy baseline, which has an intensity of 10.1 kg CO2e per boe and an NPV of USD 1,013.6 million. Along the front, intensity ranges from 2.0 to 7.6 kg CO2e per boe and NPV from USD 1,079.5 to 1,121.9 million. The front is flat at high intensity: moving from 7.6 to about 4 kg per boe costs less than USD 6 million. It becomes steep below about 2.5 kg per boe, where further reductions require curtailment during outages, dual VRUs on all pads and additional compression. Designs that curtail production during outages

occupy the low-intensity end of the front, and designs that flare through outages occupy the high-value end. All non-dominated designs use two gas-to-power units, whose displaced electricity is worth more than the gas sold at the assumed price, a finding consistent with techno-economic studies of power generation from flare gas [111, 112].

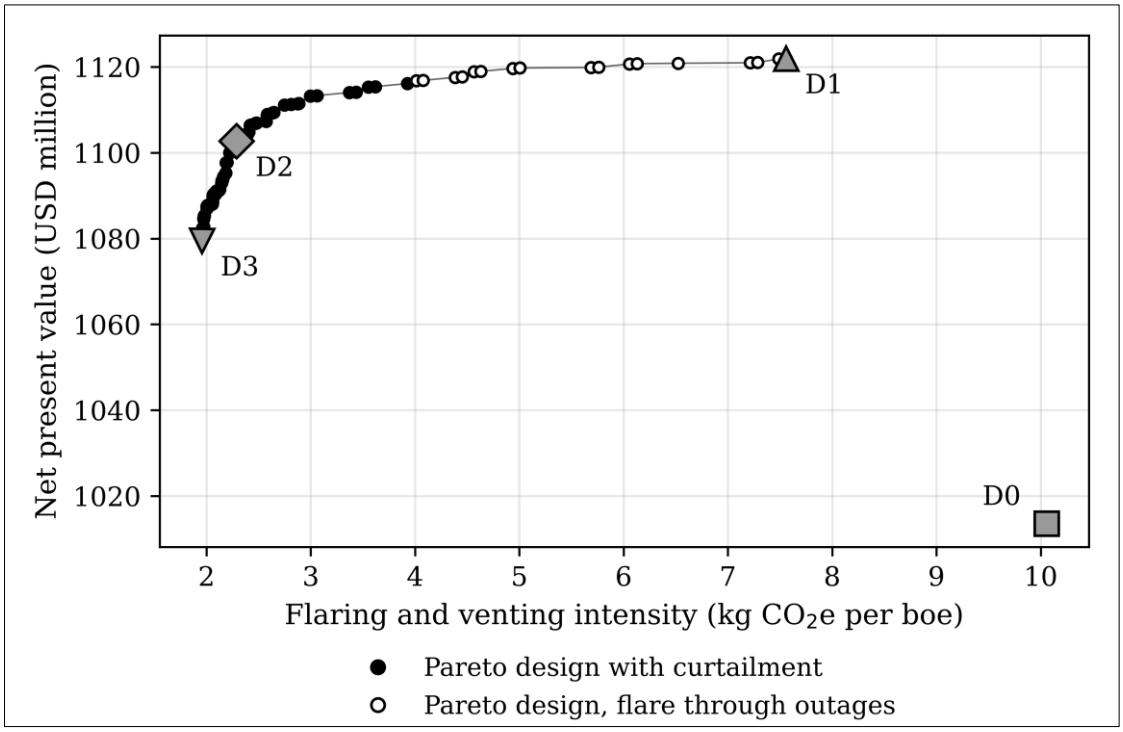


Fig 2: Non-dominated designs for flaring and venting intensity and net present value, with the baseline (D0), maximum-NPV (D1), highest-NPV design meeting 98 percent capture (D2) and minimum-intensity (D3) designs.

4.2. Selected Designs and Causes of Flaring

Table 3 compares the selected designs and Figure 3 decomposes flaring by cause. The baseline captured 90.8 percent of gas. Its 6-inch laterals could not carry the peak production after the second and third groups of pads came online, pad pressures reached 405 psia, and 3.37 Bcf of the 5.20 Bcf flared over ten years, about two thirds, was flared at pads because of the gathering pressure limit. High back-pressure also reduced well deliverability by up to 23 percent. Midstream outages caused a further 1.30 Bcf of flaring and tank vapor routed to combustors 0.50 Bcf.

Table 3: Comparison of selected designs over the ten-year horizon (mean of 200 replications).

Measure	D0 Baseline	D1 Maximum NPV	D2 Highest NPV with 98 percent capture	D3 Minimum intensity
Trunk and lateral diameters (in)	10; 6, 6, 6	16; 10, 10, 12	14; 10, 12, 8	12; 10, 8, 8
Compressor units	6	6	8	10
VRU high-volume pads; other pads	Single; none	None; none	Dual; single	Dual; dual
Vapor recovery towers; gas-to-power units	No; 0	No; 2	Yes; 2	Yes; 2
Outage policy	Flare through	Flare through	Curtail	Curtail
Capital cost (USD M)	31.2	47.6	52.9	53.4
Gas capture (percent)	90.8	93.2	98.0	98.3
10th percentile of capture (percent)	90.3	92.7	97.8	98.1
Intensity (kg CO2e per boe)	10.1	7.6	2.3	2.0
Emissions (kt CO2e)	452	372	110	93
Gas flared (Bcf)	5.20	4.17	1.17	0.96
Gas vented (Bcf)	0.13	0.14	0.06	0.06
Oil produced (million bbl)	35.3	38.6	37.9	37.3
NPV (USD M)	1,013.6	1,121.9	1,102.7	1,079.5

The maximum-NPV design D1 removed the gathering constraint with a 16-inch trunk and 10- and 12-inch laterals, which lowered peak pad pressure to 132 psia, raised oil production by 3.3 million barrels and added USD 108 million of NPV. It reduced intensity to 7.6 kg per boe, but it did not eliminate flaring; it shifted its causes. With six compressors handling a larger gas stream, compression shortfalls caused 1.17 Bcf of flaring, and without VRUs tank vapor routed to combustors rose to 1.60 Bcf. Midstream outages caused 1.40 Bcf. This shift illustrates that debottlenecking gathering without matching compression and vapor recovery moves flaring downstream rather than removing it [12, 14].

Design D2, the highest-NPV design meeting 98 percent capture, combined a 14-inch trunk with eight compressors, dual VRUs on high-volume pads, single VRUs elsewhere, VRTs and curtailment during outages. It reduced flaring to

1.17 Bcf, of which 0.80 Bcf arose on the first day of midstream outages before curtailment took effect and 0.32 Bcf from compression shortfalls, and reduced intensity to 2.3 kg per boe, 77 percent below the baseline and 70 percent below D1. Its NPV was USD 19.3 million below D1, and its discounted emissions were 188 kt CO2e lower, an implied abatement cost of about USD 103 per tonne. The minimum-intensity design D3 achieved 2.0 kg per boe and 98.3 percent capture with ten compressors and dual VRUs on all pads, but at a further USD 23.2 million for 14 kt of discounted emissions, more than USD 1,600 per tonne.

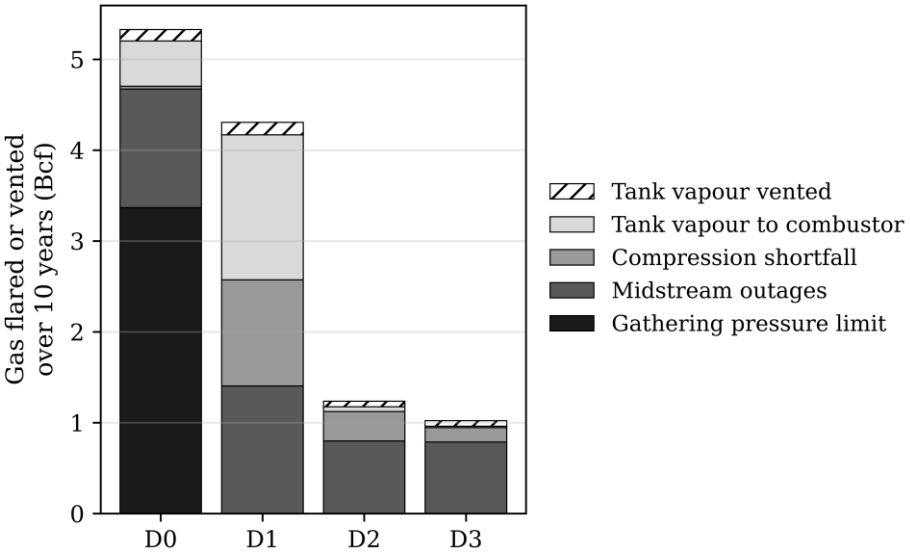


Fig 3: Gas flared or vented over ten years by cause for the selected designs.

4.3. Time Profile of Flaring

Figure 4 shows the monthly share of gas flared or vented. The baseline flared 25 percent of gas in the first month, 25 percent when the second group of pads came online and 44 percent when the third group came online, because each new group of pads pushed the gathering system past its pressure limit; flaring then declined as production fell and settled at about 3 percent, driven by midstream outages and tank vapor. D1 flared up to 26 percent when the third group came online, because compression rather than gathering became the bottleneck, and settled at about 5 percent, higher than the baseline in later years because it had no VRUs. D2 and D3 kept the flared share near 1 to 2 percent except for a short peak of 14 and 10 percent when the third group came online. The profile shows that the timing of development relative to infrastructure capacity is a major driver of flaring, as in the Bakken [5, 91].

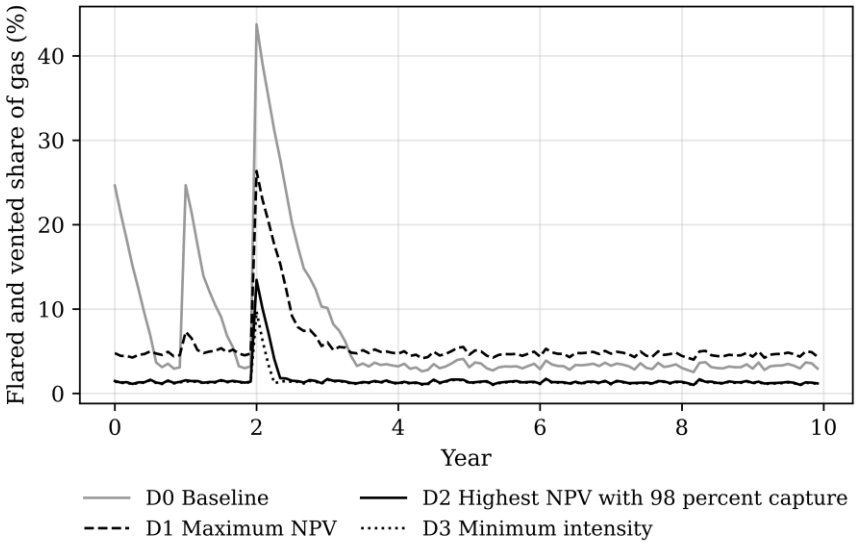


Fig 4: Monthly share of produced gas flared or vented for the selected designs.

4.4. Carbon Prices

Table 4 shows the design that maximizes NPV less the cost of discounted emissions at carbon prices from USD 0 to 200 per tonne. A price of USD 25 per tonne was sufficient to add a seventh compressor and single VRUs on high-volume pads, which raised capture from 93.2 to 95.7 percent and cut

emissions by a third for a loss of USD 2.2 million in NPV, an abatement cost of about USD 24 per tonne of discounted emissions. VRTs entered at USD 75 per tonne and curtailment during outages at USD 100 per tonne. Even at USD 150 to 200 per tonne, the optimal design captured 97.3 percent of gas, below the 98 percent requirement, because the last increments of capture require curtailment and redundancy whose cost per tonne is very high. This pattern of rising marginal cost matches analyses of methane abatement costs in the industry [30, 250].

Table 4: Design maximizing NPV net of carbon cost at different carbon prices.

Carbon price (USD per t CO2e)	Main changes from D1	Capture (percent)	Intensity (kg CO2e per boe)	NPV before carbon cost (USD M)
0	D1	93.2	7.6	1,121.9
25	Seventh compressor, single VRU on high-volume pads	95.7	5.0	1,119.8
50	As above, third lateral reduced to 10 inches	95.7	4.9	1,119.7
75	As above, with VRTs	95.8	4.6	1,118.9
100	As above, with curtailment	96.8	3.6	1,115.3
150	As above, single VRU on other pads	97.3	3.0	1,113.2
200	As at USD 150	97.3	3.0	1,113.2

4.5. Sensitivity

Figure 5 and Table 5 show the sensitivity of capture to midstream reliability, VRU availability and midstream capacity, each evaluated with 100 independent replications, so base-case values differ slightly from Table 3. Midstream outage frequency had the largest effect. With two outages per year, D2 captured 98.8 percent; with ten, its capture fell to 96.8 percent and its intensity rose to 3.6 kg per boe. D1 fell from 94.5 to 91.0 percent over the same range. Reducing midstream capacity from 32 to 28 MMscf/d reduced D2 capture to 96.9 percent, and raising it to 40 MMscf/d raised capture to 98.5 percent. VRU availability between 0.80 and 0.97 changed D2 capture by less than 0.2 percentage points, because dual units on high-volume pads already provide redundancy. Compliance with a 98 percent capture requirement therefore depends on midstream reliability and capacity, which are outside the operator’s facility design [6, 13].

Table 5: Sensitivity of gas capture (percent) to midstream and VRU parameters.

Parameter and value	D0	D1	D2	D3
Midstream outages 2 per year	92.2	94.5	98.8	99.1
Midstream outages 5 per year (base)	90.9	93.3	98.1	98.4
Midstream outages 10 per year	88.5	91.0	96.8	97.1
VRU availability 0.80	90.7	93.3	98.0	98.3
VRU availability 0.97	91.0	93.3	98.1	98.4
Midstream capacity 28 MMscf/d	90.9	92.7	96.9	97.4
Midstream capacity 40 MMscf/d	90.9	93.3	98.5	98.7

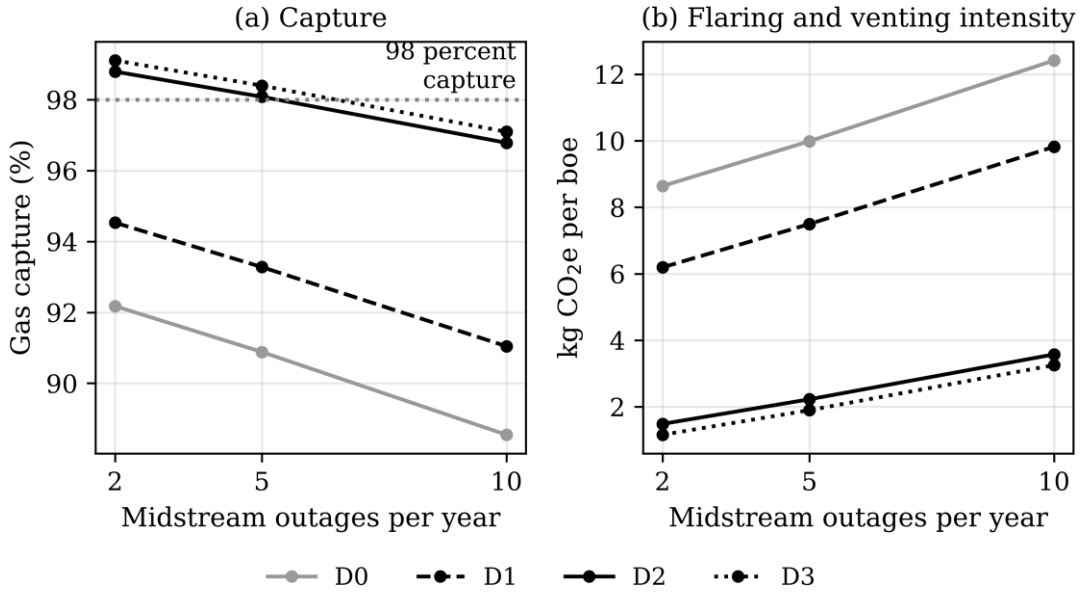


Fig 5: Sensitivity of (a) gas capture and (b) flaring and venting intensity to midstream outage frequency.

5. Discussion

This section interprets the results in relation to the literature, draws implications for operators and regulators, considers how the approach can be applied to real fields and sets out the limitations of the study. The discussion is framed by the evidence that flaring and venting at onshore facilities arise

from a combination of infrastructure constraints, equipment unavailability and tank control failures [8, 12, 15], and by marginal abatement cost analyses showing that the cost of reducing emissions varies widely between measures [30, 247, 250]. It focuses on what the interaction between gathering, compression, vapor recovery and outage policy implies for engineering practice and regulation.

5.1. Principal Findings

Three findings stand out. First, the dominant cause of flaring in the legacy design was not midstream outages or tank vapor but gathering capacity: undersized laterals could not carry peak production from staged pad development, so gas was flared at the pads and back-pressure also reduced production. Debottlenecking gathering was both the most valuable and a substantial emission-reducing measure, which reinforces evidence from the Bakken and Permian that flaring rises when development outpaces gathering and takeaway infrastructure [5, 6, 91] and the dependence of mature-field production on gathering hydraulic resistance [297]. Second, debottlenecking alone shifted flaring to compression and tank vapor rather than removing it, so the most valuable design flared 4.2 Bcf over ten years and captured only 93 percent of gas. Effective flare reduction requires that gathering, compression, vapor recovery and outage policy be designed together, a conclusion that single-measure studies of flare gas recovery and mitigation cannot reach [21, 22, 247].

Third, the cost of capture rises steeply near regulatory targets. The first increments, a seventh compressor and VRUs on high-volume pads, cost about USD 24 per tonne of CO2e avoided, consistent with the low or negative costs reported for many methane mitigation measures [30, 247, 250]. Meeting 98 percent capture cost about USD 103 per tonne relative to the maximum-value design, and pushing beyond it more than USD 1,600 per tonne. Even a carbon price of USD 200 per tonne did not make 98 percent capture optimal in the model, which implies that a 98 percent requirement such as New Mexico's is a binding constraint that goes beyond what plausible carbon prices alone would achieve [18, 231].

5.2. Implications for Operators and Regulators

For operators, the results suggest four practical priorities. The first is to size gathering for the peak of staged development rather than for initial pads, because gathering-constrained flaring and back-pressure losses are expensive in both value and emissions [284, 293]. The second is to provide compression redundancy matched to the gathered volume, an N+1 or N+2 arrangement, in line with reliability-based standby optimization for gas pipelines [14, 301], and to support it with predictive maintenance and condition monitoring of the compressor fleet [348]. The third is to install VRUs at high-volume pads, preferably with redundancy and VRTs, and to maintain tank controls, because aerial surveys show that tank emissions often arise from control failures rather than design [15, 16, 24]; thief hatch and pressure relief inspections belong in the same maintenance routines that prevent incidents in industrial maintenance [349], and non-intrusive inspection of separators and pressure vessels can shorten the shutdowns that take VRUs out of service [350]. The fourth is to plan for midstream outages through curtailment protocols and on-site gas use, since outages caused the largest residual flaring in the compliant designs [6, 111, 128]. Curtailment protocols must balance production against compliance, a balance that integrity frameworks for high-risk upstream operations address explicitly [351]. Gas sales and gathering agreements can also allocate outage risk: supply chain resilience frameworks for gas processing plants [352], force majeure provisions in energy supply contracts [353] and liability mitigation in high-value energy service contracts [354] bear directly on who carries the cost of flaring when the midstream outlet is unavailable, and supply chain risk management for gas processing projects affects when new compression and gathering capacity arrives [355].

For regulators, the results show that capture compliance depends on midstream reliability and capacity, which individual operators do not control. With ten outages per year, even the minimum-intensity design fell below 98 percent capture. Capture rules may therefore need to be accompanied by attention to midstream reliability and to the treatment of upset events, as in the North Dakota and New Mexico frameworks [17–19]. Satellite and aerial monitoring can verify flaring and venting performance independently of operator reporting [1, 194, 205], and comparisons of measured emissions with inventories can check whether facility designs deliver the expected reductions [188, 221]. Internal QHSE audit systems provide the operator-side counterpart to such external verification [356].

5.3. Application to Real Fields

The model can be calibrated to a specific field. Decline curves and gas-oil ratios can be fitted to production data [307, 308], gathering hydraulics can be calibrated against measured pressures with steady-state or transient network models [31, 271, 281], compressor and VRU availability can be estimated from maintenance records [13, 14] kept under reliability and integrity management programmes such as those for upstream fired heaters and boilers [357], and midstream outage statistics can be obtained from operator and midstream data [6]. Gathering routes and pad locations can be taken from GIS-based asset management systems [358]. Tank vapor generation can be estimated from separator conditions and laboratory flash analysis [168, 236], and flare destruction efficiency from measurement campaigns [8, 9]. The optimization could be extended to mixed-integer formulations of gathering network design with exact hydraulics [288, 289], to stochastic programming over development scenarios [267, 312, 315], to modular and relocatable facilities [303–305] to integrated production optimization including gas lift [28, 331, 333], and to data-driven control of compressors and VRUs using machine learning [359].

5.4. Limitations

The study has several limitations. All parameters are representative values from the literature rather than data from a specific field, so the absolute results should not be transferred without calibration. The gathering model uses the Weymouth equation for single-phase gas and neglects liquids, elevation and transient effects, which can be significant in rich-gas gathering [273, 339]. Liquids also drive internal corrosion of gathering lines and vessels, so integrity costs from corrosion management [360] and NDT-based risk assessment [361] are not included. The back-pressure effect on production is represented by a linear deliverability factor rather than a coupled reservoir and well model [337, 342]. Compressor, VRU and midstream availability are modelled as independent processes, whereas common causes such as weather can affect several at once [268, 299]. The gas price is assumed constant, although regional prices can fall sharply

when takeaway is constrained [6]. Finally, the economic treatment of curtailment, with 30 percent of curtailed oil value lost, is a simplification of deferral and reservoir effects, and the optimal designs near the 98 percent threshold are sensitive to it.

6. Conclusion

This study optimized the gathering, compression, vapor recovery and outage policy of a representative onshore oil field for flaring and venting intensity and net present value, using Weymouth gathering hydraulics, back-pressure effects on production, daily stochastic simulation of compressor, vapor recovery and midstream availability, and NSGA-II.

The legacy design flared mainly because its gathering system could not carry the peak production of staged development. Debottlenecking gathering created most of the value but shifted flaring to compression shortfalls and tank vapor, so that flaring reduction required gathering, compression, vapor recovery and outage policy to be designed together. A seventh compressor and vapor recovery on high-volume pads achieved most of the achievable reduction at about USD 24 per tonne, whereas meeting 98 percent capture cost about USD 103 per tonne and exceeding it far more. Even a high carbon price did not make 98 percent capture the value-maximizing choice, and compliance depended on midstream reliability and capacity.

For operators, the results support sizing gathering for the development peak, providing compression redundancy, installing vapor recovery with redundancy at high-volume pads and planning for midstream outages. For regulators, they show that capture targets interact with midstream reliability. Further work should calibrate the approach with field data, add multiphase and transient hydraulics and couple it with reservoir and development planning.

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