Multi-Operational Planning of Shale Gas Pad Development

Abigail Ondeck[1], Markus Drouven[2], Nathan Blandino[2], and Ignacio E. Grossmann*[1]

[1]Dept. of Chemical Engineering, Carnegie Mellon University
[2]EQT Corporation

July 30, 2018

Abstract

In this paper, the economical development of a shale gas pad and the optimal production of shale gas is studied. Utilizing a fixed sequence of development operations and gas curtailment, a mixed integer linear program (MILP) formulation is developed, which when solved, yields the economical scheduling of well development operations and shale gas production. The MILP formulation is applied to two case studies to demonstrate the benefits of optimizing shale gas development at the pad level. Lastly, a sensitivity analysis is completed to demonstrate the impact of development resource (i.e., drilling rigs and fracturing crews) mobilization prices on pad development, providing insight into the elements that govern development resource mobilization prices.

Keywords: Shale gas, well development operations, resource mobilization

1 Introduction

The discovery of horizontal drilling and fracturing for shale gas production has led to an abundance of natural gas supply in the United States [1, 2]. With 211.5 trillion cubic feet (TCF) of natural gas proved reserves from shale [3], shale gas production is expected to double in the next 34 years, going from 14 TCF in 2016 to approximately 29 TCF in 2040 [4]. This increase in production will help natural gas become the top electricity generation fuel by 2050, supporting 40% of electricity generation [5].

Although shale gas is expected to play a large part in meeting the the natural gas demand, the shale gas industry is still young [6], and has room for advancement. Many shale gas companies have just started to rigorously model and optimize their systems. This includes

*grossmann@cmu.edu

operation optimization, which has the potential to provide companies with better control over their assets [6]. Academic research is slightly ahead of its industrial counterpart, but articles on the optimization of shale gas did not become prominent in research journals until after 2010. One area that is still overlooked is the operational development of wells at the pad level, and the consequent shale gas production.

To develop a well to production (Figure 1), four operations must happen in the following order: 1) top setting (TS), 2) horizontal drilling (HZ), 3) hydraulic fracturing (FRAC), and 4) turning in line (TIL). The first operation, top setting, is the process of drilling a well down to the selected shale gas formation and properly encasing the well to prevent the release of gas and other chemicals into the ground surrounding the well bore. Once the vertical part of the well has been developed, the next step is to drill a horizontal well through the formation. This horizontal section can be as short as 5,000 feet and as long as 15,000 feet, depending on the geology of the ground and the availability of the land (i.e., land leases). Next, the horizontal part of the well is fractured, creating fissures of 100-300 feet long, increasing the volume of gas to be released. Once the fracturing is complete, the well can be turned in line to release the gas. Based on the desired production, the entire well or sections of the well can be turned in line. From start to finish, the process of completing a well can take anywhere from a few weeks to two months, based on the geology of the ground, the length of the well, and the availability of resources.

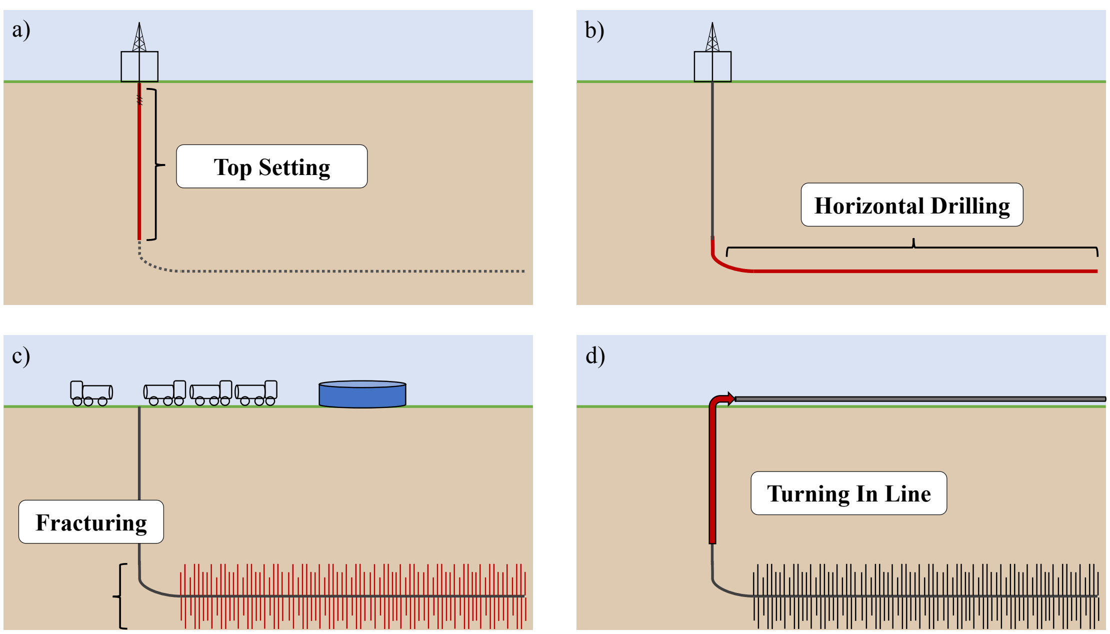


Figure 1: The four operations necessary to develop a well to completion: a) top setting, b) horizontal drilling, c) hydraulic fracturing, and d) turning in line.

The historical development strategy utilized by many shale gas producing companies was a method where the development resources were brought to a pad to complete *one* operation (i.e., top setting, horizontal drilling, fracturing, or turning in line) on *all* wells. While this method worked for pads with a small number of wells, one pad can now contain over twenty wells. Today, turning in line all the wells at a large pad at the same time can create a large amount of initial gas production that quickly drops within the first year [7]. While historical development strategy decreases the effort and economic penalties incurred from development resource mobilization, which is the process of assembling, disassembling, and transporting the resources, it can also lead to economic inefficiencies. First, it can take several months to a year to complete all four operations on all wells at a pad, leading to months with large negative cash flows and no gas production. Second, when all wells are turned in line at the same time, contracts for pipelines with large volumes must be available to transport the gas. These contracts, which can last anywhere from ten to twenty years, include a fixed expense over the length of the contract, which is a function of the pipeline's capacity. Although the wells at the pad only produce enough gas to fill the pipeline to capacity for at most one year, the company must pay the fixed cost for the entire length of the contract.

Another consequence of not optimizing the shale gas development is the absence of knowledge on non-conventional development approaches. With the current preferred pad development method, the development resource for each operation is brought to the pad once every couple years to operate on many wells. This method is conventionally preferred because it reduces the operational challenges associated with transporting, assembling, and disassembling the development resources. The cost to transport, assemble, and disassemble the development resources can be estimated from the cost of development resource downtime, which is the time when a development resource is not operating but is still under contract. However, this estimate has not been verified, and the true mobilization cost may be higher if it includes operational challenges that are not physically measured or known. Thus, by optimizing the development and production of shale gas at the pad level, a sensitivity analysis can be completed to study the impact of development resource mobilization costs on development and production decisions.

In this paper, optimization is used to determine the most profitable development and production of a prospective set of wells at a pad in a shale gas development area. By initially formulating the pad development scheduling using General Disjunctive Programming (GDP), we can systematically derive mixed-integer inequalities for all disjunctions and logic propositions to obtain a discrete-time mixed-integer linear program (MILP) formulation. The major contributions of this work include:

1. a modeling framework for the fixed sequence of development operations and production of shale gas at the pad level

2. a sensitivity analysis to identify the impact of development resource mobilization costs on the scheduling of shale gas pad development and production

The paper is structured as follows. First, an overview of related work in the field of shale gas scheduling is presented. Then, the scope of this paper is described in detail, including an overview of decisions that need to be made for the development and production of the prospective wells. Next, the pad development and production scheduling is formulated using GDP, which is used as a basis for deriving the MILP problem. The MILP problem is applied to two case studies, including an industrial case based on data from the Marcellus shale gas region, to demonstrate the impact of economic optimization on pad-level development decisions. Included in the industrial case study, is a sensitivity analysis on development resource mobilization costs and how they relate to pad development practices. The paper ends with conclusions extracted from the results of the case studies and sensitivity analysis.

2 Related Work

With the importance of shale gas in the energy sector, optimization research on the design, development, and performance of shale gas systems has become more prominent. This research can be grouped into three levels based on the field of reference and time scale: design/planning, scheduling, and operation performance. The most targeted level of shale gas optimization, operation performance, corresponds to operational decisions on a daily to weekly time scale. These articles often maximize well performance through optimizing well placement or operation techniques. For well placement optimization, the shale gas reservoir models are regularly reduced before determining the number of wells, well placement, and number of fracturing stages [8, 9]. Others have used more rigorous models of the shale gas reservoirs, but use an algorithm to determine the optimal well locations [10,11]. For operation techniques, there are many different procedures to optimize as a result of the complexity of developing shale gas wells to production. One such instance that is widely studied is the placement of hydraulic fracture stages [12, 13], because of its large impact on maximizing well production.

The next level of shale gas optimization is scheduling, which consists of coordinating asset decisions for a fixed shale gas network. The formulations found in literature for scheduling shale gas development and production often concentrate on vigorously modeling one aspect/operation of the network. At the operation level, Knudsen and Foss found a more efficient formulation to solve the scheduling of multi-well shut-ins [14] with a proxy model [15], and utilized the efficient formulation to schedule multi-well production based on natural gas demand for electric power production [16]. Also, Cafaro et al. developed discrete [17] and continuous time [18] well production models for refracturing, and utilized the models when optimizing the scheduling of multiple well fractures. Since hydraulic fracturing is water-intensive, Yang and Grossmann proposed a MILP model to schedule the fracturing of wells while coordinating the transportation, treatment, and reuse of water [19]. Lastly, Drouven and Grossmann scheduled the turning in-line of wells for a shale gas system, concentrating on modeling and maintaining optimal line pressure profiles [20]. While all these papers provide their own methods of improving well development and production, there has been no research concerning the scheduling of multiple operation procedures on a well-to-well basis.

The most encompassing level of shale gas optimization is design/planning, where the goal is to identify the structure of the shale gas network over several years, considering the allocation of resources. In most cases, the objective of the design/planning is to maximize the net present value of the shale gas superstructure. Cafaro and Grossmann utilized a branch-refine-optimize (BRO) strategy to solve the mixed-integer nonlinear program (MINLP) that determines the most profitable supply chain design (from well to gas demand node), including variable shale gas wetness and gas pipeline pressures [21]. Guerra et al. studied a similar design problem with the addition of water treatment plants. They utilized the solver GloMIQO to optimize the mixed-integer quadratic program (MIQP) problem, with the gas composition and total dissolved solids concentrations described using nonlinear constraints [22]. While these papers were singular in their objective, Gao and You did expand the optimization of the design/planning of a shale gas supply chain to include both cost and financial risk [23]. Because of the size and scope of the design/planning problems (i.e., the entire supply chain network), the well development is represented using a drilling variable that encompasses all development operations [7, 21, 24–26]. This paper will provide a more encompassing operation scheduling, that can be incorporated into future design/planning studies.

Lastly, as mentioned in the Introduction (Section 1), a consequence of not rigorously optimizing shale gas production is the absence of knowledge on non-conventional development approaches. The historical development strategy for pad development did not require development resources to return to pads, as all wells were developed together. Some papers in the energy sector have implicitly allowed development resources to return to a pad and develop smaller groups of wells [7], and tracked the availability of development resources [27]. However, there are no papers documenting the economical impact of development resource mobility on the value of shale gas asset development. The only studies on the direct impact of development resource mobilization analyze environmental issues [28, 29] or the effect of increased road usage (from development resource transportation) on the transportation infrastructure [30]. In this paper, we introduce a sensitivity analysis to demonstrate the impact of shale gas development resource mobilization cost from a development perspective. This will aid in identifying the cost of operational challenges for development resource mobilization, allowing for more accurate economic representation of shale gas development and production.

3 Problem Statement

Consider the representative pad development area in Figure 2, where the potential well sites have been identified a priori. The wells, if completed, are connected via a prospective gathering pipeline to a pad-to-pipeline connection. The pipeline from the pad will relay any produced gas to a sales point, via a larger midstream pipeline. Utilizing this representative pad and knowledge specific to the pad development area, the objective is to apply modeling and optimization to determine the best practices for pad development.

The specific goal of this work is to determine the optimal development of wells and production of gas from a pad with the objective of maximizing the net present value (NPV). The optimization will be used to identify: 1) when and which wells should be developed to completion, 2) the timing of the operations performed on the well, 3) when and which development resources must be brought to the pad to perform operations on the well, and 4) when and how much gas should be released from the completed wells. The development of the pad is subject to legal and physical constraints, and the production is limited by capacity constraints.

In addition, development resource mobilization will be studied using a sensitivity analysis and the previously mentioned optimization model. Based on the mobilization of development resources to develop the wells at the pad, insights can be obtained on the economic value of development resource mobilization.

The major assumptions in this work are:

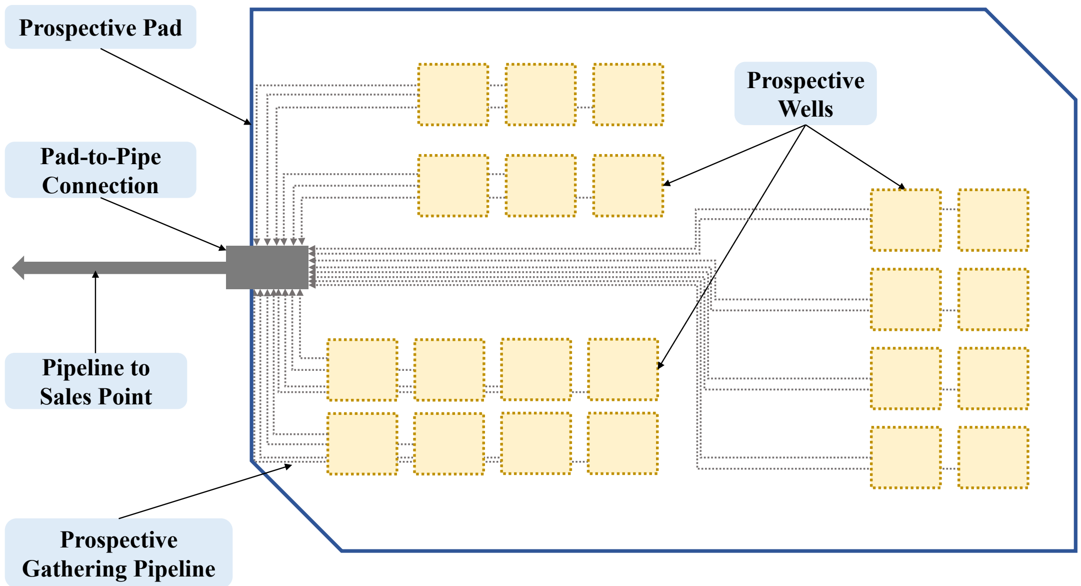


Figure 2: Prospective pad.

1. The locations and information relating to the development of the prospective wells are known a priori. This includes the lengths of the wells as well as the production curves, which are functions of the wells' length.

2. The development cost for all four operations and the time to complete each operation are known for each well.

3. Every operation is performed for the entire well. A well can not be "partially" completed.

4. Every operation can be performed at most once at a well. There are no refracturing of wells at a later time.

5. Price of the gas is known with certainty. Along this line, all gas transported to a sales point will be sold at that sales point.

6. The development resource mobilization cost is a one time fee that includes transportation, assembly, and disassembly. The initial value is an assumed estimate, calculated based on past experience.

7. The optimization is solved using a discrete time model with time intervals of weeks.

4 Problem Formulation

The pad development and production problem can be formulated as a discrete-time MILP model with the objective of maximizing pad profit. The objective is limited by both developmental and production-based constraints, namely legal and physical limits. These constraints include:

- Development date constraints: Wells cannot be drilled and/or developed until after the development dates.
- Well development: The operations performed on a well must follow a predetermined order.
- Well interference: A well can only be fractured while the adjacent wells are not producing gas.
- Capacity limits: Wells' production capacities and pad capacity may not be exceeded.
- Well production: A well, once completed, will naturally produce gas following an exponential decline production curve.
- Production repression: Gas production from completed wells may be curtailed.

The main decision variables are a combination of binary (0 - 1) variables for the development and curtailment decisions, and continuous variables that are associated with the production and curtailment of gas and the associated costs to develop the pad.

In this problem, the optimization will schedule the development of a pad and the production of gas for one year. However, the cost to develop the wells at a pad is large compared to the revenue that could be made from producing gas from the completed wells during the one-year horizon. It usually takes several years of gas production before any well can become economically feasible. Although it is possible to optimize the development of a pad for one year and schedule the production of gas for the next ten years, the resulting problem size would be very large. Therefore, the pad development and the production of gas are scheduled for one year using weekly time intervals. Based on when wells are turned in line during the optimization horizon, the production for the well will be forecasted for the next 10 years, and the revenue from selling gas will be included in the economic optimization (see Section 4.7).

4.1 Development date constraints

Before certain operations are performed on wells, all legal documents must be acquired. This constraint is represented as an equality (Equation (1)) to prevent any operations happening before the development date restrictions are lifted.

$$y_{t',w,o} = 0 \quad \forall\, t' < t^{per}_{w,o}, w \in W, o \in O \tag{1}$$

where $y_{t,w,o}$ is a binary equal to one if at time t operation o started at well w, and $t^{per}_{w,o}$ is the time period when operation o can be started at well w. In this paper, the operations set ($o = \{1, 2, 3, 4\}$) corresponds to the four operations described in the Introduction, where *Top Setting = 1*, *Horizontal Drilling = 2*, *Fracturing = 3*, and *Turning In Line = 4*.

4.2 Well development

As stated in the assumptions, each operation can only be performed at most once on each well during the development horizon, which can be represented by the following inequality:

$$\sum_{t \in T} y_{t,w,o} \leq 1 \quad \forall\, w \in W, o \in O \tag{2}$$

To reduce the number of nodes visited in the branch and bound, $y_{t,w,o}$ can be treated as special ordered set (SOS) [27,31] by introducing a dummy variable $y^{dum}_{w,o}$ such that:

$$\sum_{t \in T} (y_{t,w,o}) + y^{dum}_{w,o} = 1 \quad \forall\, w \in W, o \in O \tag{3}$$

In order to reduce the environmental impact of shale gas drilling, companies strive to reduce the surface impact by limiting the pad size [32]. Because of the small pad size and the multitude of development resources needed to complete each operation, the pad can only hold the development resources for one operation at any time. This corresponds to constraining the problem so that only one operation can be performed at one well at any time t:

$$\sum_{w \in W} \sum_{o \in O} \sum_{t - t^{op}_{w,o} < t'}^{t} y_{t',w,o} \leq 1 \quad \forall\, t \in T \tag{4}$$

where $t^{op}_{w,o}$ is the time needed to perform operation o at well w. To reduce the number of nodes visited by Equation (4), $y_{t,w,o}$ is treated as a SOS and a dummy variable is added, which leads to Equation (5).

$$\sum_{w \in W} \sum_{o \in O} \sum_{t - t^{op}_{w,o} < t'}^{t} y_{t',w,o} + y^{dum,2}_{t} = 1 \quad \forall\, t \in T \tag{5}$$

Because some operations take more than one time step to finish ($t^{op}_{w,o} > 1$), no other development resource for a different operation can be brought to the pad until the pad is clear.

As mentioned in the introduction, before a well can produce gas, it must undergo four operations in sequence: 1. top setting, 2. horizontal drilling, 3. hydraulic fracturing, and 4. turning in line. To account for the fixed sequence of development operations and to prevent overlapping of operations at a well, the following logic constraints are proposed:

$$\bigvee_{t : t' \leq t - t^{op}_{w,o-1}}^{T} H_{t,t',w,o} \Leftrightarrow Y_{t',w,o-1} \quad \forall\, t' \in T, w \in W, o > 1 \tag{6}$$

$$\bigvee_{t' : t' \leq t - t^{op}_{w,o-1}}^{T} H_{t,t',w,o} \Leftrightarrow Y_{t,w,o} \quad \forall\, t \in T, w \in W, o > 1 \tag{7}$$

where the boolean variable $H_{t,t',w,o}$ is *true* if at well w, operation o started at time t and the previous operation, designated as *o-1*, started at time t', and the boolean variable $Y_{t,w,o}$ is *true* if at well w, operation o starts at time t. The logical disjunctions in Equations (6) and (7) state that operation o can only happen after the previous operation, *o-1*, has finished at well w. They also require all four operations to occur at well w during the optimization horizon if any one operation transpires at well w.

Similar to $Y_{t,w,o}$, the boolean variable for starting an operation, $H_{t,t',w,o}$ can only happen once in the development horizon, shown by disjunctions (8) and (9).

$$\neg \left[\bigvee_{t \neq t''} \left(H_{t,t',w,o} \wedge H_{t'',t',w,o} \right) \right] \quad \forall\, t, t^{'}, t^{''} \in T, w \in W, o \in O \tag{8}$$

$$\neg \left[\bigvee_{t' \neq t''} \left(H_{t,t',w,o} \wedge H_{t,t'',w,o} \right) \right] \quad \forall\, t, t^{'}, t^{''} \in T, w \in W, o \in O \tag{9}$$

Equations (6) and (7) can be transformed into the following inequalities [33]:

$$\sum_{t:t' \leq t - t^{op}_{w,o-1}} h_{t,t',w,o} = y_{t',w,o-1} \quad \forall\, t^{'} \in T, w \in W, o > 1 \tag{10}$$

$$\sum_{t':t' \leq t - t^{op}_{w,o-1}} h_{t,t',w,o} = y_{t,w,o} \quad \forall\, t^{'} \in T, w \in W, o > 1 \tag{11}$$

where $h_{t,t',w,o}$ is a binary that equals one if at well w, operation o has happened at time t and the previous operation, designated as *o-1*, happened at time $t^{'}$. Because of Equation (2), which states an operation can only happen once at each well in the scheduling horizon, and Equations (10) and (11) which set an upper bound of one for $h_{t,t',w,o}$, Disjunctions (8) and (9) are implicitly specified and are not needed in the model formulation.

To tighten the initial LP relaxation, another constraint is included in the formulation to enforce the sequence of operations. Equation (12) states that an operation (o) can not start at a well until the previous operation (*o-1*) has been started and completed:

$$y_{t,w,o} \leq \sum_{t'}^{t - t^{op}_{w,o-1}} y_{t',w,o-1} \quad \forall\, t \in T, w \in W, o > 1 \tag{12}$$

Lastly, to prevent terminal effects where the optimization could turn in line ($o = 4$) a well during the last week of the horizon, T, without accounting for the impact of the well's production on the total pad production, the following constraint is included:

$$y_{T,w,4} = 0 \quad \forall\, w \in W \tag{13}$$

4.3 Well interference

When developing a pad, the main goal is to produce gas from the wells. One incident that needs to be avoided is downhole communication. Downhole communication occurs when the fractures of two wells, usually located next to each other, interact. This can lead to a loss of production from the producing well, as the fracturing fluid from the other well can block fractures in the producing well. By shutting in the producing well, pressure can build up in the producing well and reduce fooding. A constraint is included in pad development to force a producing well to shut if the well next to it is being fracked, and prevent flooding.

$$(i_{w,w'} \wedge Y_{t,w',FRAC}) \Leftrightarrow C_{t',w} \quad \forall\, t \in T, t \leq t^{'} < t + t^{op}_{w',FRAC}, w \neq w^{'}, w, w^{'} \in W \tag{14}$$

where $i_{w,w'}$ is a binary parameter with information on well interaction, and $i_{w,w'}$ equals one if well w and $w^{'}$ could have overlapping fractures, and equals zero otherwise. $C_{t,w}$ is a boolean variable that is *true* if well w is closed at time t. The disjunctive logic in Equation (14) says that if well w and well $w^{'}$ have overlapping fractures, and well $w^{'}$ is being fractured, then well w must be closed. The propositional logic statement in Equation (14) is reformulated to the following inequalities:

$$i_{w,w'} + \sum_{t-t^{op}_{w',FRAC}<t'}^{t} y_{t',w',FRAC} \leq c_{t,w} + 1 \quad \forall\, t \in T, w \neq w^{'}, (w, w^{'}) \in W \tag{15}$$

$$c_{t,w} \leq \sum_{w':w \neq w'} \sum_{t-t^{op}_{w',FRAC}<t'}^{t} y_{t',w',FRAC} \quad \forall\, t \in T, w \in W \tag{16}$$

$$c_{t,w} \leq \sum_{w':w \neq w'} i_{w,w'} \quad \forall\, t \in T, w \in W \tag{17}$$

where $c_{t,w}$ is a binary variable equal to one if well w is shut at time t. Equation (15) states that if well w and well $w^{'}$ interfere with each other, and if well $w^{'}$ is in the process of being fractured, then well w must be shut. Equation (16) states that a well can only be shut if any other well is in the process of being fracked. And lastly, Equation (17) states that a well can only be shut if it could interfere with any other well. While all three equations are the product of reformulating the proposition in Equation (14), Equation (17) is only necessary if there are wells that do not interfere with any other well. Otherwise, Equation (17) is not tight, and should not be included in the formulation.

4.4 Well production

Once a well has gone through all four operations sequentially (1 - TS, 2 - HZ, 3 - FRAC, and 4 - TIL), the well is called "completed". At this time, gas can be produced from the well ($P_{t,w}$) following a production curve described by $\gamma_{t,w}$, which is estimated using information about the well, such as the ground porosity, fracture lengths, and past production curves from existing wells in the same region. These production curves follow the structure of the average production profiles for major wells, depicted in the Annual Energy Outlook 2012 [34], which are characterized by a large amount of production at the beginning and then exponentially decreases over time. Using production curves, the gas produced, $P_{t,w}$, can be calculated based on when the well was turned in line (i.e., $o = 4$), which indicates to the age of the well.

$$P_{t,w} = \sum_{t'}^{t} \left(\gamma_{t-t',w} \cdot l_w \cdot y_{t',w,4}\right) \quad \forall\, t \in T, w \in W \tag{18}$$

where l_w is the lateral length of well w.

4.4.1 Well production curtailment

Once a well is producing, the optimization has the option to curtail production and limit the volume of gas produced from the well. The volume of gas withheld from production that is kept in the well, which is classified as curtailed gas. This gas can be released from the well at any time, as long as the well's production does not exceed its maximum production capacity.

To determine if gas is being curtailed, a boolean variable, $SB_{t,w}$, is added and it is *true* if production is being curtailed. Based on this boolean variable, Disjunction (19) is formulated as:

$$\begin{bmatrix} SB_{t,w} \\ S^{out}_{t,w} = 0 \\ S^{in}_{t,w} \leq P^{max}_{w} \end{bmatrix} \vee \begin{bmatrix} \neg SB_{t,w} \\ S^{out}_{t,w} \leq P^{max}_{w} \\ S^{in}_{t,w} = 0 \end{bmatrix} \quad \forall\ t \in T, w \in W \tag{19}$$

where $S^{out}_{t,w}$ is the volume of curtailed gas leaving the well w during time t, and $S^{in}_{t,w}$ is the volume of gas being curtailed at well w during time t. Disjunction (19) states that if production is being curtailed, then the past volumes of curtailed gas cannot be released from the well. Also, the volume of gas curtailed cannot exceed the maximum production from a well (P^{max}_{w}). Lastly, if gas is not curtailed, then past volumes of curtailed gas can be released, as long as they are less then the maximum well production.

Using the Big-M reformulation, Disjunction (19) can be represented by the following set of inequalities,

$$S^{out}_{t,w} \leq P^{max}_{w} \left(1 - sb_{t,w}\right) \quad \forall\, t \in T, w \in W \tag{20}$$

$$S^{in}_{t,w} \leq P^{max}_{w} sb_{t,w} \quad \forall\, t \in T, w \in W \tag{21}$$

where $sb_{t,w}$ is a binary variable that equals one if gas production is curtailed at well w at time t.

To track the total volume of gas production curtailed ($L_{t,w}$), Equations (22) and (23) are introduced. Equation (22) states that the volume of gas curtailed at time t is equal to the total volume of gas curtailed at the previous time period, plus any additional gas curtailed, minus any gas released from curtailment. Because Equation (22) does not include the first time period, Equation (23) calculates the volume of gas curtailed at $t = 1$.

$$L_{t,w} = L_{t-1,w} + S^{in}_{t,w} - S^{out}_{t,w} \quad \forall\, 1 < t, w \in W \tag{22}$$

$$L_{1,w} = S^{in}_{1,w} - S^{out}_{1,w} \quad \forall\, w \in W \tag{23}$$

Also, the volume of gas curtailed at the end of the optimization horizon is fixed to zero (Equation (24)), to specify terminal conditions. Without Equation (24), the optimization will curtail gas production from producing wells in the final time periods, so that it can develop and complete as many wells as possible without exceeding the pad production capacity constraint. While this may be economic, curtailing production for more than a year can decrease the productivity of wells, leading to reduced production volumes.

$$L_{T,w} = 0 \quad \forall\, w \in W \tag{24}$$

Taking into consideration the effects of curtailment, the production of gas from a well can be determined from Equation (25). The final production ($P^{fin}_{t,w}$) is equal to initial gas production, based on the production curve, minus any gas curtailed, plus any gas released from curtailment.

$$P^{fin}_{t,w} = P_{t,w} - S^{in}_{t,w} + S^{out}_{t,w} \quad \forall\, t \in T, w \in W \tag{25}$$

Lastly, before a well is turned in line ($o = 4$), there will be no gas produced from the well, and consequently no gas released from curtailment. To tighten the initial LP relaxation, Equation (26) is included, which fixes $sb_{t,w}$ to zero if a well has not been turned in line so that no gas can be released from curtailment.

$$1 - sb_{t,w} \leq \sum_{t'=1}^{t} y_{t',w,4} \quad \forall\, t \in T, w \in w \tag{26}$$

4.4.2 Well shut-In

If a well is closed at any time ($C_{t,w} = true$) due to interference from fracturing a neighbor well, the gas production from the closed well must be curtailed completely (i.e., no gas can be produced). This is represented with the following disjunction,

$$\begin{bmatrix} \neg C_{t,w} \\ P^{fin}_{t,w} \leq P^{max}_{w} \end{bmatrix} \vee \begin{bmatrix} C_{t,w} \\ P^{fin}_{t,w} = 0 \end{bmatrix} \quad \forall\ t \in T, w \in W \tag{27}$$

Disjunction (27) is represented by Equation (28).

$$P^{fin}_{t,w} \leq P^{max}_{w} \left(1 - c_{t,w}\right) \quad \forall\, t \in T, w \in W \tag{28}$$

4.5 Pad production constraint

Before gas from the wells can enter the main pipeline, it must flow through a pad connection. This connection has a capacity limit ($P^{pad,max}$), which is enforced by Equation 29.

$$\sum_{w \in \{W\}} P^{fin}_{t,w} \leq P^{pad,max} \quad \forall\, t \in T \tag{29}$$

where $P^{pad,max}$ is the maximum amount of gas that can be produced from the pad for the entire optimization horizon at every time t.

4.6 Development resource mobilization

Before an operation can be performed on a well, the development resources for that operation must be brought to the pad. Because of the size and complexity of the development resources and the pad's remote location, it can take a day or two to transport the resources to the pad, and another day for resource assembly. The same is true for disassembly and transportation of the resources away from the pad. This process of development resource mobilization comes with operational challenges and financial losses from development resource downtime.

To penalize for operational challenges and development resource downtime, the MILP must determine when one development resource is dismantled and another development resource is brought to the pad. As mentioned in Section 4.2, only one development resource can be present at a pad at any time period. Also, this paper assumes the development resource mobilization is a one time event at the start of an operation, that includes resource disassembly of the previous operation, and resource assembly of the current operation. By tracking the continuity of operations at a pad from one time period to the next, one can determine if a new operation o has started at time t, requiring the development resources to be transported to the pad. Equation (30) does this, where if operation o is not active at any well w at time *t-1*, but starts at any well at time t, then the development resources for operation o must be brought to the pad at time t.

$$\left(\bigvee_{w\in W} Y_{t,w,o} \wedge \neg\left[\bigvee_{w\in W} Z_{t-1,w,o}\right]\right) \Rightarrow M_{t,o} \quad \forall\, t>1, o\in O \tag{30}$$

where $Z_{t,w,o}$ is a boolean variable that is *true* if at time t, operation o is actively being completed at well w, and $M_{t,o}$ is a boolean variable that is *true* if the development resources for operation o are mobilized at time t. Equation (30) can be transformed into Equation(31):

$$\sum_{w\in W} y_{t,w,o} - \sum_{w\in W} z_{t-1,w,o} \le m_{t,o} \quad \forall\, t>1, o\in O \tag{31}$$

where $z_{t,w,o}$ is a binary variable equal to one if at time t, operation o is actively being completed at well w, and $m_{t,o}$ is a binary variable equal to one if the development resources for operation o are mobilized at time t.

To determine if the development resources are being engaged, the following logic constraint is used:

$$\bigvee_{t-t^{op}_{w,o}\le t'}^{t} Y_{t',w,o} \Leftrightarrow Z_{t,w,o} \quad \forall\, w\in W, o\in O, t\in T \tag{32}$$

and can be transformed into the following linear equality:

$$z_{t,w,o} = \sum_{t-t^{op}_{w,o}\le t'}^{t} y_{t',w,o} \quad \forall\, w\in W, o\in O, t\in T \tag{33}$$

By substituting Equation (33) into Equation (31), and treating $m_{t,o}$ as a SOS, the following linear inequalities are derived and used to identify when development resources must be mobilized for operation o:

$$m_{t,o} \geq \sum_{w \in W} y_{t,w,o} - \sum_{w \in W} \sum_{t-t^{op}_{w,o} \leq t'}^{t} y_{t',w,o} \quad \forall\, t > 1, o \in O \tag{34}$$

$$m_{t,o} - m^{not}_{t,o} = \sum_{w \in W} y_{t,w,o} - \sum_{w \in W} \sum_{t-t^{op}_{w,o} \leq t'}^{t} y_{t',w,o} \quad \forall\, t > 1, o \in O \tag{35}$$

where $m^{not}_{t,o}$ is a dummy variable used to treat $m_{t,o}$ as a SOS. It is assumed, that if an operation is not actively being completed, then the associated development resources for that operation are not present at the pad.

Lastly, Equation 36 is included to determine if any development resources are mobilized during the first time period:

$$m_{1,o} = \sum_{w \in W} y_{1,w,o} \quad \forall\, o \in O \tag{36}$$

4.7 Objective

The objective of the scheduling of the prospective pad is to maximize the net present value (NPV) of the pad taking into consideration the long production horizon of shale gas wells. The NPV includes the revenue from selling the produced gas, as well as the costs associated with developing the wells at the pad:

$$NPV = R^d - (MC^d + OC^d) \tag{37}$$

where R^d is the discounted revenue, MC^d is the discounted mobilization cost to transport, assemble, and disassemble the development resources, and OC^d is the discounted operating cost from developing the wells at the pad.

The revenue of the problem is comprised of two parts: 1) the revenue from selling shale gas within the optimization horizon, and 2) the revenue from selling shale gas outside of the optimization horizon, that will be produced over the next T^{rev} time periods. The production of gas within the scheduling horizon is calculated at every time t, and can be multiplied by the associated discount rate (ϕ_t) and the price of natural gas at time t (π_t) to obtain the revenue inside the scheduling horizon (RI^d):

$$RI^d = \sum_{t \in T} \left[\phi_t \, \pi_t \sum_{w \in W} \left(NRI_w \, P^{fin}_{t,w} \right) \right] \tag{38}$$

where NRI_w is the net revenue interest that the company owns in well w [35]. For example if a company owns 100% of the working interest for a well and the landowner is entitled to a 15% royalty, then the company's NRI on that well is 75%. The discount rate is calculated by Equation 39, where r is the rate of return.

$$\phi_t = (1 + r)^{-t/52} \quad \forall\, t \in T \tag{39}$$

To determine the true economic feasibility of well development at a pad, it is important to include long-term revenue in the optimization. When extracting shale gas, the one-time development costs in the short-term overpower the revenue from the small fraction of gas that can be produced during that same time period. Thus, the revenue from future production of completed wells must be included. The discounted revenue from the gas remaining in the completed wells after the optimization (RO^d) is calculated as follows,

$$RO^d = \sum_{t \in T} \sum_{w \in W} \left[y_{t,w,4} \, R^{far}_{t,w} \right] \tag{40}$$

where $R^{far}_{t,w}$ is the revenue from the total volume of gas produced from well w over the next T^{rev} time periods *after* the optimization horizon, assuming the well is turned in line ($o = 4$) at time t during the optimization horizon. $R^{far}_{t,w}$, a parameter, can be calculated prior to the optimization using Equation (41):

$$R^{far}_{t,w} = NRI_w \, l_w \sum_{t':T<t'}^{T+T^{rev}} \left(\gamma_{t'-t,w} \, \pi_{t'} \, \phi_{t'} \right) \quad \forall \, t \in T \tag{41}$$

which includes the net revenue interest of the well (NRI_w), the length of the well (l_w), the production of the well based on when it was turned in line ($\gamma_{t'-t,w}$), the expected price of natural gas ($\pi_{t'}$), and the discount rate ($\phi_{t'}$).

The total discounted revenue is the sum of the two sources of revenue:

$$R^d = RI^d + RO^d \tag{42}$$

The two sources of cost included in the development and production of gas from a pad are the development cost and the mobilization cost. The development cost is a function of the type of operation completed and the physical characteristics of the well, such as the geology of the ground drilled and the length of the well. The total discounted development cost for the pad over the scheduling horizon, OC^d, is,

$$OC^d = \sum_{t \in T} \left[\phi_t \sum_{(w,o) \in \{W,O\}} \left(y_{t,w,o} \, OP_{w,o} \right) \right] \tag{43}$$

where $OP_{w,o}$ is the price to perform operation o at well w.

In order to perform any operation, the development resources for that operation must be transported to the pad and assembled. After the operation has been completed, then the development resources must be disassembled and removed from the pad. The development resource transportation, assembly, and disassembly comes with a price that is both stipulated in contract, and influenced by operational challenges. When a contract is made with an outside company to procure development resources, the contract contains a downtime clause, where a fixed fee must be paid for every day the development resources are not operating. Known as a downtime penalty, this fee applies to days when the development resources are transported, assembled, and disassembled. In addition, transportation, assembly, and disassembly of development resources produce operational challenges, which result in an additional financial penalty. This financial penalty is difficult to identify as it is not tied to specific factors (see the last paragraph of Section 2 for more information).

Together, the downtime and operational challenge penalties form the development resource mobilization penalty (MP_o), which is incurred every time development resources are transported, assembled, and disassembled. Using the mobilization penalty and knowledge of when development resources are brought to the pad ($m_{t,o}$), the discounted mobilization cost (MC^d) is calculated using Equation 44.

$$MC^d = \sum_{t \in T} \left[\phi_t \sum_{o \in O} (m_{t,o}\, MP_o) \right] \tag{44}$$

5 Case Studies

The proposed MILP model for pad development and production is applied to two case studies to demonstrate the value of scheduling well development operations and development resource mobilization and shale gas production.

5.1 Case Study 1

In the first case study, the proposed model is applied to an illustrative pad to demonstrate the application of the optimization and its ability to identify pad-level development improvements for shale gas industry.

The illustrative pad is comprised of four wells ($W = \{A, B, C, D\}$), with horizontal well lengths of 10,000, 11,000, 13,000, and 15,000 feet respectively. The production curves are represented as decreasing power functions [17] of the form:

$$\gamma_{t,w} = k_w t^{-a_w} \quad \forall\, t \in T, w \in W \tag{45}$$

where k_w is the initial production peak parameter, and a_w is the production decline parameter. Using the parameters in Table 1, discrete-time production curves for the four wells are obtained. Note that the production curves, $\gamma_{t,w}$, represent the gas produced per foot of well developed.

Table 1: (Case Study 1) Well product curve parameters utilized in the illustrative case study.

Well	k_w	a_w
A	10	0.60
B	12	0.66
C	14	0.60
D	18	0.70

The time, in weeks, needed to complete each operation o on well w ($t^{op}_{w,o}$) is shown in Table 2, and the associated one-time costs for each operation ($OP_{w,o}$) are shown in Table 3.

As mentioned in Section 4.3, if a producing well is located adjacent to a well being fractured, then the producing well must be closed (i.e., not producing) to reduce/eliminate

Table 2: (Case Study 1) Time (in weeks) needed to complete each operation o on well w.

Well	*Top-Setting*	*Horizontal Drilling*	*Fracturing*	*Turning-In-Line*
A	1	1	1	1
B	1	1	1	1
C	1	2	2	1
D	1	2	3	1

Table 3: (Case Study 1) Cost to perform operation o on well w.

Well	*Top-Setting*	*Horizontal Drilling*	*Fracturing*	*Turning-In-Line*
A	\$ 1,500,000	\$ 2,000,000	\$ 5,000,000	\$ 1,000,000
B	\$ 1,500,000	\$ 2,400,000	\$ 6,000,000	\$ 1,000,000
C	\$ 1,200,000	\$ 2,800,000	\$ 7,000,000	\$ 1,200,000
D	\$ 1,200,000	\$ 3,200,000	\$ 7,800,000	\$ 1,600,000

flooding. The interference parameter matrix used to indicate well interactions, is shown in Table 4.

Table 4: (Case Study 1) Interference parameter matrix, where a value of 1 indicates that the fracturing of well w will interfere with the production of well $w^{'}$, and visa versa.

Wells	**A**	**B**	**C**	**D**
A	0	1	0	0
B	1	0	1	0
C	0	1	0	1
D	0	0	1	0

In terms of development date restrictions, the land where the horizontal length is drilled for wells C and D is unavailable through Week 8. Thus, $t^{per}_{w,o}$ is assigned the following values for the horizontal drilling ($o = 2$), fracturing ($o = 3$), and turning in line ($o = 4$) operations:

$$t^{per}_{w,o} = 8 \quad \forall\, w = \{C, D\}, o > 1 \tag{46}$$

Lastly, the optimization horizon is set to 32 weeks, with 10 additional years to collect revenue from the gas produced from any developed wells. Based on the optimization horizon and the additional years to collect revenue, an estimate for the cost of shale gas is needed for 552 weeks. The values used to estimate the cost of shale gas are obtained from the EIA's Henry Hub natural gas spot prices [36], using weekly price data from October 19, 2007 to March 30, 2018. The NRI of the individual wells (NRI_w) are 90%, 84%, 86%, and 88%, respectively. Finally, the rate of return (r) is 10%.

To demonstrate the application and utility of the MILP optimization model for the pad-level development and production of shale gas, the illustrative case study is solved for two scenarios: 1) restricted development resource mobility: the development resources for each operation are only allowed to be brought to the pad once (Section 5.1.1), and 2) unrestricted development resource mobility: the development resources for each operation can be brought to the pad as many times as is needed (Section 5.1.2).

5.1.1 Restricted development resource mobility

Before optimizing the pad-level development and production of the illustrative case study, an additional constraint is included in the formulation (for this instance only) to prevent development resources from returning to the pad multiple times. Equation (47) restricts resource mobilization to at most once during the optimization horizon.

$$\sum_{t \in T} m_{t,o} \leq 1 \quad \forall\, o \in O \tag{47}$$

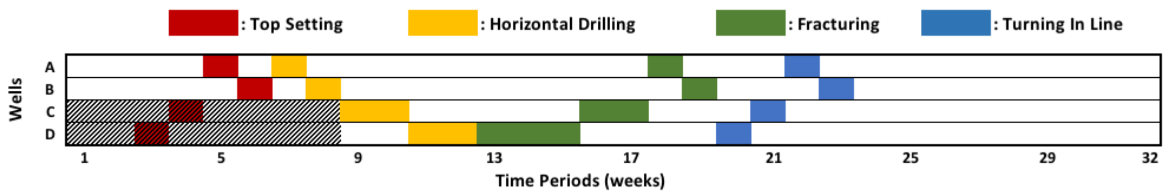
The MILP, given by Equations (1 - 5, 10 - 13, 15 - 18, 20 - 26, 28, 29, 31, 33 - 46), including Equation (47), is optimized with GAMS 24.8.5 using the commercial solver CPLEX 12.7.1.0 on a PC Intel Core i7, 3.60 GHz, 16 GB RAM, 64 bit, and Windows 10. The problem for the illustrative case contains 2,809 equations and 7,012 variables, of which 6,447 are binary. Starting with an initial gap of 13.37% , CPLEX is able to close the gap to 0% in just over 13 seconds.

The optimal scheduling of the development operations is shown in Figure 3a, with the shaded blocks (Wells C and D, Weeks 1 - 8) indicating the weeks when horizontal drilling, fracturing, and turning in line cannot be completed because of development date restrictions. All four wells are developed, with the development resources only visiting the pad once during the optimization horizon, as stipulated by Equation (47). Because of the development date restrictions on horizontal drilling for Wells C and D, and the resource mobilization constraint, the pad development does not start until Week 3. While top setting of Wells C and D could take place earlier, the delay in development decreases the net present value of the operations.

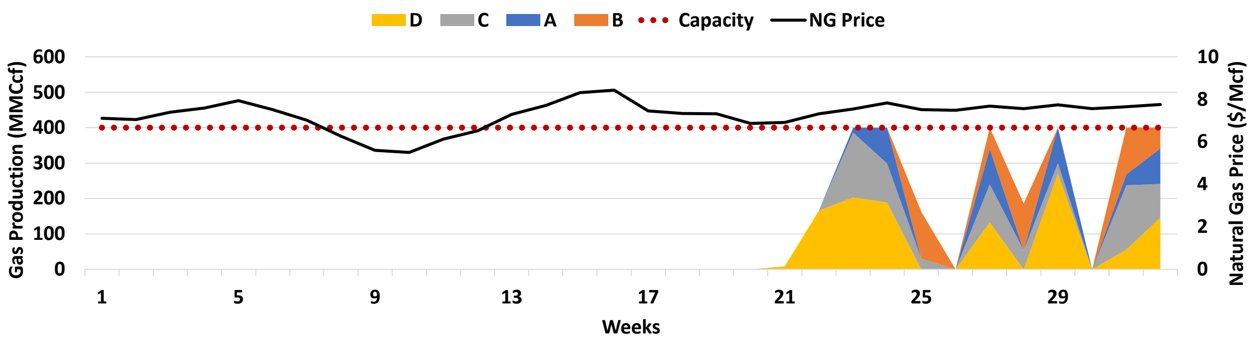
When restricting development resource mobility, the wells' order-of-development for the three pre-production operations (top setting, horizontal drilling, and fracturing) depends on the operating cost, as well as the operating time. Because of the discount factor used to assess the current value of future expenses, more expensive operations are completed later in the optimization horizon if the delay does not hamper production. For example, the horizontal drilling of all four wells must occur in one after the other, but the order of horizontal drilling the wells does not affect the turning in line and production of gas. As shown in Figure 3a, the sequence of horizontal well drilling, A-B-C-D, is selected because it develops the cheaper wells earlier and the more expensive wells later, allowing the more expensive wells to have a smaller present cost.

While the operating cost drives the order-of-development for horizontal drilling the four wells, the operating time can influence the order-of-development when the wells' operating times greatly vary. This can be seen with the fracturing of all four wells, from Weeks 13 - 19. The cost to fracture Well D is more expensive than the cost to fracture all other wells. Based on the logic used for horizontal drilling where the most expensive operations are performed later, Well D should be fractured last. However, by fracturing Well D first, which requires 3 weeks to complete, the fracturing of the three other wells are pushed later into the optimization horizon, where the discount factor is smaller. Thus, the optimization saves around \$55,000 by fracturing Well D first.

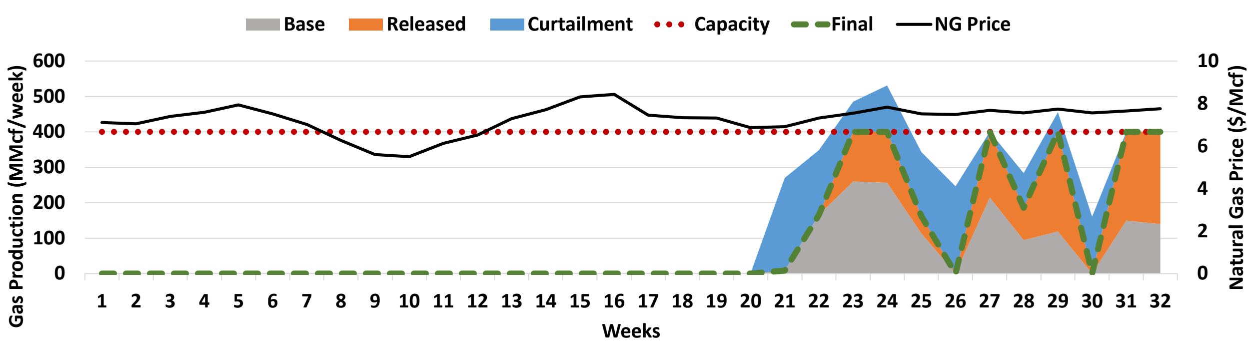
The start date and order-of-development for the turning in line for all wells is driven, in this case, by the the price of natural gas. The earliest date for turning in line, because of resource development constraints and development date restrictions, is Week 20. While this does not correspond to a peak in natural gas price, the optimization starts the turning in line process as early as possible in order to have enough production available for later weeks when the natural gas price does peak.



(a) Scheduling of development operations at the illustrative pad.



(b) Optimal production of gas from the wells at the illustrative pad.



(c) Optimal production of gas, including curtailment, at the illustrative pad.

Figure 3: (Case Study 1.1) Development and production of shale gas from the illustrative pad, when the development resources for each operation are only allowed to be brought to the pad at most once during the optimization horizon.

The production of shale gas from the illustrative pad is shown in Figure 3b. Although all pads are turned in line in sequential weeks, the total pad production does not exceed the pad capacity because of curtailment. The volume of gas production from individual wells is influenced by both the price of natural gas and the NRI of the wells. Take for example

Weeks 27 - 30, when all four wells have been completed (i.e., able to produce gas). During Week 27, the price in natural gas is \$7.96/Mcf, and all four wells are producing a similar volumes of gas, except Well A which is producing slightly more. When the price peaks even higher during Week 29, at \$8.03/Mcf, Wells A and D dominate production, while Well C production is minimal and Well B is not producing. Wells B and C have NRI's of 84% and 86%, respectively, which are lower than the NRI's of Well A and D (90% and 88%). Thus, the production of gas from Wells A and D will result in a larger percentage of revenue, during a time when natural gas prices are high. On the other hand, when natural gas price peaks are slightly lower (e.g. Week 27), it is less beneficial to produce from the more valuable wells. Of note, in practice, it is very uncommon to exploit price fluctuations for gas production. The natural gas prices are usually forecasted using a flat rate over time.

The ability to manipulate the production of gas at the well level and the dynamic natural gas prices result in peaks and valleys in pad-level production. Shown in Figure 3c, the production of gas is curtailed greatly after the wells are turned in line, and only stops at the end of the optimization horizon because Equation 24 requires the level of curtailed gas to be zero by Week 32. The curtailment of gas from the wells is driven by the objective function, which looks to maximize revenue, especially during the earlier weeks when the discount factor is larger. To maximize gas production during on-peak (i.e., higher natural gas prices), the optimization reduces well productions during off-peak (i.e., lower natural gas prices) weeks. Curtailment is also used to manipulate well production based on NRI, as discussed in the previous paragraph.

Overall, the maximum net present value obtained from developing the pad and producing shale gas is \$16,800,000. However, a large portion of the revenue, approximately 70%, is acquired after the optimization horizon (*Future Rev.*) (see Table 5). The largest source of cost is from development, while mobilization costs are minimal because the development resources for each operation are only allowed to visit the pad at most once during the optimization horizon.

Table 5: (Case Study 1.1) Discounted revenue (initial and future) and costs (development and mobilization) when only allowing development resources for each operation to visit the pad once during the optimization horizon.

Initial Rev.	*Future Rev.*	*Development*	*Mobilization*	**NPV**
\$19.2 MM	\$43.8 MM	-\$45.3 MM	-\$0.9 MM	**\$16.8 MM**

5.1.2 Unrestricted development resource mobility

Once the base scenario, with restricted development resource mobility, is solved, Equation (47) is removed from the formulation, and the MILP is optimized to determine whether the historical development strategy of limited development resource mobility is more economical for the illustrative case. The problem involves 2,805 equations and 7,012 variables, of which 6,447 are binary. Starting with an initial gap of 11.38%, CPLEX is able to close the gap to 0% in just over 28 minutes.

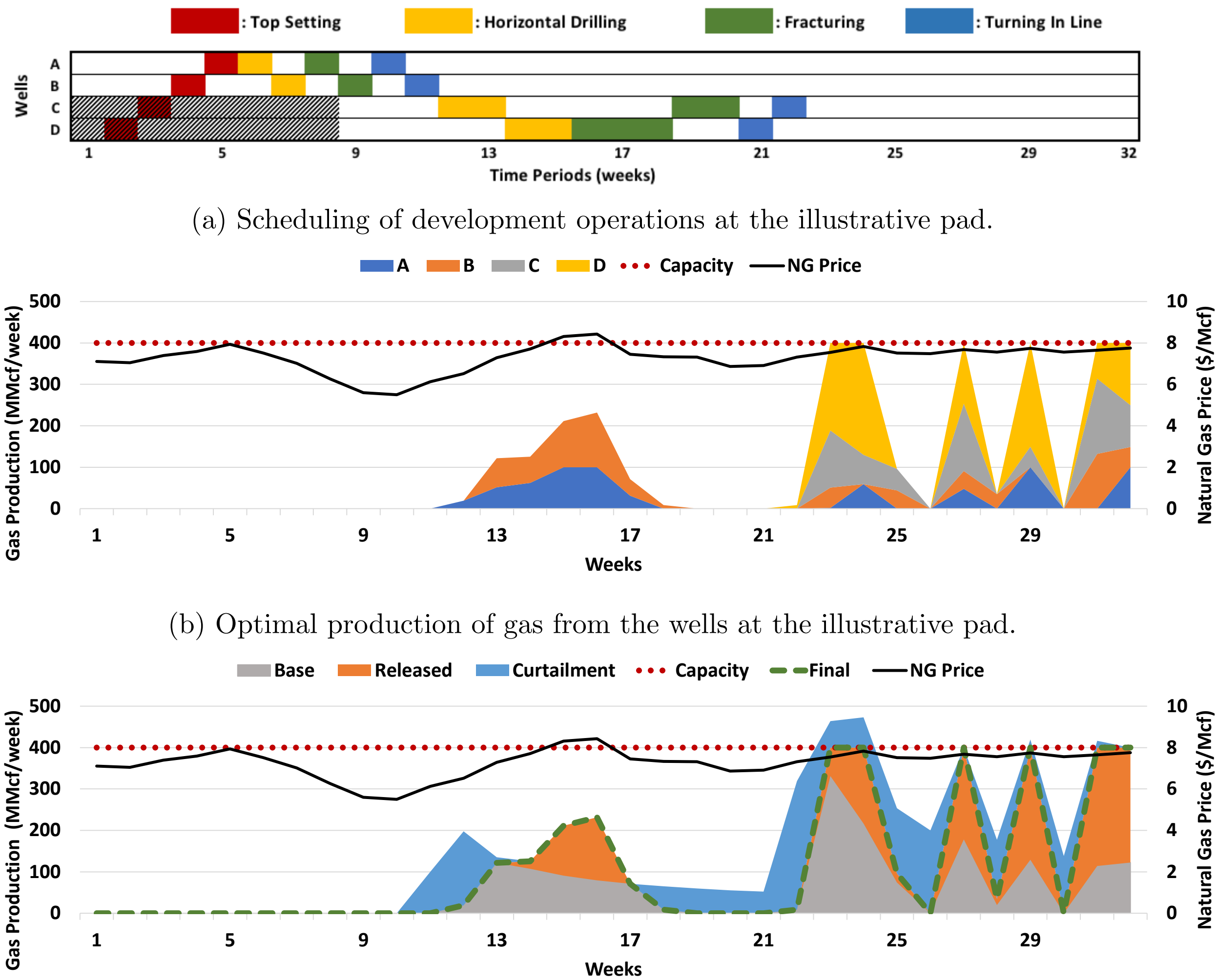
The optimal scheduling of the development operations is shown in Figure 4a, with the shaded blocks indicating the weeks when horizontal drilling, fracturing, and turning in line cannot be completed because of development date restrictions. Again, all four wells are developed, but the development resources for horizontal drilling, fracturing, and turning in line are brought to the pad on two separate occasions. While the optimization could have had one well producing gas as early as Week 5, the optimization determines it is most economical to top set all four wells, and continue developing Wells A and B to completion so they are able to produce gas for the largest peak in natural gas price during Weeks 15 and 16. The optimization that runs with restricted development resource mobility is not able to meet this deadline, because each operation has to be performed on all four wells in sequence. As seen in Section 5.1.1, the logic behind the wells' order-of-development still holds true when resource mobility is not constrained. The wells' order-of-development for the three pre-production operations depends on the operating cost, as well as the operating time.

Because of development resource mobility and the consequent development of Wells A and B earlier in the optimization horizon, the pad starts to produce gas in Week 12 (Figure 4b). This earlier production corresponds to the weeks with highest price of natural gas in the optimization horizon, resulting in \$5,500,000 of revenue in just 7 weeks. While Weeks 15 and 16 have the highest price, the optimization is only able to develop two of the smaller wells in the first fourteen weeks, so the total pad production does not near the maximum capacity of the pad. The pad capacity can only be reached with the production of gas from three or four wells, seen during Weeks 27 and 29. The final twelve weeks of the optimization horizon show similar pad and well production profiles when compared to the production of gas when resource mobility is restricted (3b). However, the earlier gas production from Wells A and B limits the availability of gas, leading to a 13% decrease in gas production from Weeks 21 to 32.

As expected, the total production from all wells never exceeds the pad's production capacity because of curtailment. However, because the development resources are brought to the pad multiple times, shale gas production from Wells A and B can start as early as Week 9, instead of Week 21 as was seen in the previous scenario. Because the wells are developed in two batches, the pad must consider the possibility of interference during Weeks 15 and 16, when Well B production is closed because Well C is being fractured (Figure 4a). During this time, the gas from Well B is curtailed, as shown in Figure 4c.

The development resource mobility allows Wells A and B to be completed earlier, but they both start producing when prices are low. This leads to gas curtailment right from the start (Figure 4c), so the gas can be withheld until natural gas prices are higher. During Weeks 15 and 16, the base production of gas from Wells A and B drops as the pressure in the well drops. However, the curtailed production is released right as the natural gas price peaks, helping the pad to earn \$5,500,00 of revenue from Weeks 12 through 18. Wells A and B could continue to produce gas after Week 18, but the gas production is curtailed until Week 23 at the earliest, where it is released when the price of natural gas peaks.

Overall, the maximum net present value obtained from developing the pad and producing shale gas is \$17,100,000, a \$300,000 (1.7%) increase in profit when compared to the base case with restricted resource mobility. While the future revenue decreases because more gas is produced during the optimization horizon, the revenue made during the optimization horizon



(a) Scheduling of development operations at the illustrative pad.

(b) Optimal production of gas from the wells at the illustrative pad.

(c) Optimal production of gas, including curtailment, at the illustrative pad.

Figure 4: (Case Study 1.2) Development and production of shale gas from the illustrative pad, when the development resources can be brought to the pad multiple times.

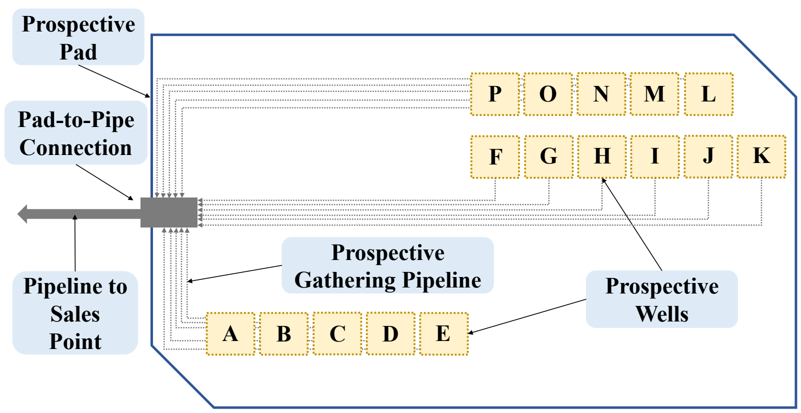
greatly increases, because more gas is being produced with a higher present value (Table 6). The development costs slightly increases when development resource mobility is allowed, because the operations are performed earlier in the optimization horizon, presenting a larger present value. Also, as expected, mobility increases by almost 100% because the development resources with the most expensive mobilization costs are brought to the pad twice.

Table 6: (Case Study 1.2) Discounted revenue (initial and future) and costs (development and mobilization) to develop the illustrative pad when development resources are allowed to make multiple trips to the pad.

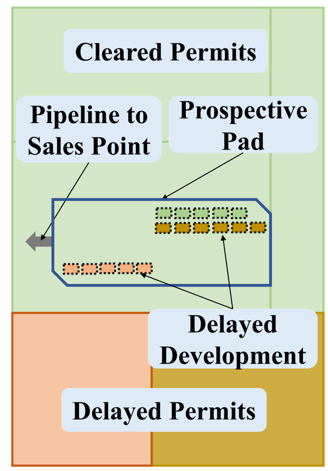
Initial Rev.	*Future Rev.*	*Development*	*Mobilization*	**NPV**
$22.3 MM	$41.9 MM	-$45.4 MM	-$1.7 MM	**$17.1 MM**

5.2 Case Study 2

In this case study, the MILP formulation is applied to a prospective pad (Figure 5) whose properties were derived from industrial data. The pad consists of 16 different, prospective wells with varying horizontal well lengths and gas production curves. Once a well is developed, a gathering pipeline is installed to transport the gas away from the well and to the Pad-to-Pipe Connection. Each well has its own associated gathering pipeline. From the Pad-to-Pipe Connection, the gas is directed into the main pipeline, and eventually reaches a sales point, where it will be sold for revenue.



(a) Pad-level diagram of the prospective pad, including prospective wells and their associated gathering pipelines.



(b) Development area of the prospective pad.

Figure 5: (Case Study 2) Overview of the prospective pad used in the industrial study

While Figure 5a provides an informative view of the pad from a production level, the development constraints require information of the area surrounding the pad, as shown in Figure 5b. The image contains a brief overview of the prospective pad and the 16 prospective wells, as well as information on the land, under which the wells will be drilled. The land in green has all permits cleared, and development on all operations of the well (i.e., 1 - TS, 2 - HZ, 3 - FRAC, and 4 - TIL) can begin at any time during the optimization horizon. However, the land in red and gold have development date restrictions for the horizontal drilling, fracturing, and turning in line operations. For this case study, the three mentioned operations cannot be performed on the wells under the land in red until after Week 13 (Restricted Dates 1), and on the wells under the land in gold until after Week 26 (Restricted Dates 2).

The objective of this case study is to determine the development and production of shale gas from the identified prospective pad and the associated wells in order to maximize the NPV. The optimization is divided into 52 time periods of 1 week each, with revenue after the horizon calculated for an additional 10 years. The MILP is optimized with GAMS 24.8.5 using the commercial solver CPLEX 12.7.1.0 on a PC Intel Core i7, 3.60 GHz, 16 GB RAM, 64 bit, and Windows 10. The problem has just under 26,500 equations and 69,050 variables, of which 65,058 are binary, and solves from an initial gap of 7.67% to a relative gap of 2.88% in just under 1.4 hours.

5.2.1 Pad Development and Production

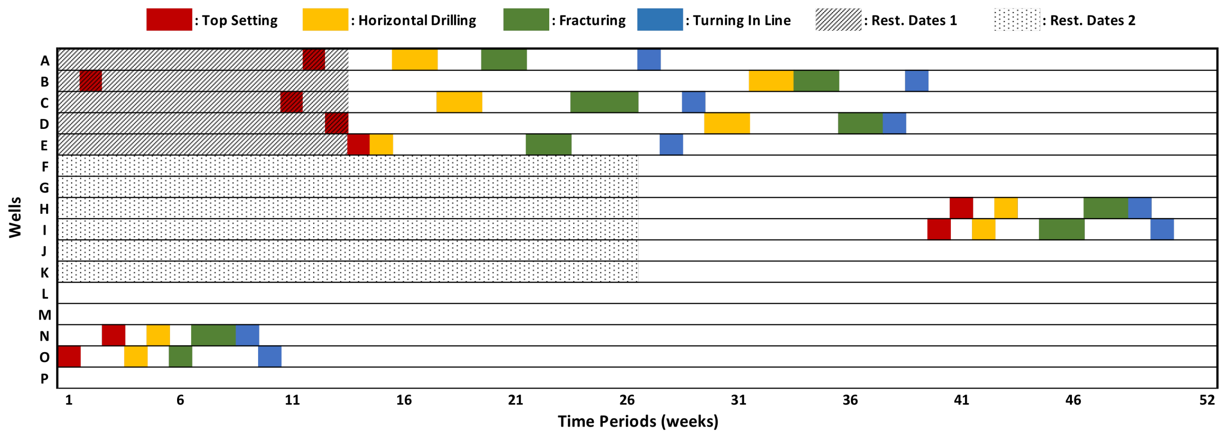
For the one year horizon, the optimization finds it most economical to develop nine of the sixteen wells (Figure 6a). None of the development date restrictions are infringed upon, as the top setting operation is not included in the restrictions enforced by Restricted Dates 1. The development resources are brought to the pad three times for top setting, four times for horizontal drilling, four times for fracturing, and four times for turning in line. The pad is continuously occupied by development resources from Weeks 1 to 50, excluding Week 44. No additional wells can be developed because the total development time, from top setting to turning in line, takes a minimum of four weeks for all prospective wells, and there are only three weeks when the pad is open for development resources.

For the most part, the wells are developed and completed in batches, where all four operations are performed on a few of the wells without interruption. There are a few irregularities in this development method, which may be attributed to the 2.88% relative gap. First, Well B is top set during Week 2, but is not horizontally drilled until Week 32. This kind of break in development is abnormal in the shale gas industry, and could be amended by shifting Week B's top setting to Week 10, and shifting up in time the operations scheduled for Weeks 3 - 10. There is also a break in development during Week 44, which could be removed by shifting up in time the fracturing and top setting of Wells H and I, given no pad production constraints.

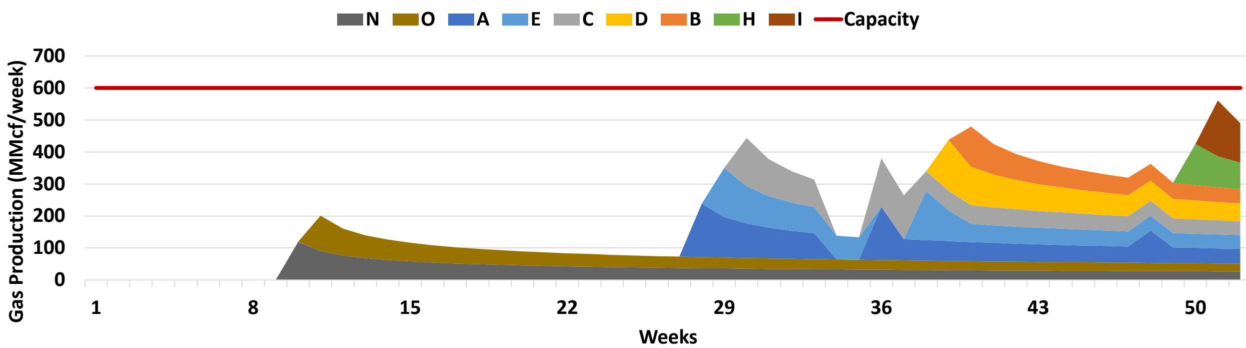
Because the turning-in-line resources occupy the pad multiple times, the production of shale gas from the prospective pad, shown in Figure 6b, experiences several peaks in natural gas production, followed by a decline in production. The production at the pad level, although never at the constraint, does near the pad capacity during Week 51. This could impact the selection of wells, preventing higher producing form being developed later in the optimization horizon.

During Weeks 34 and 35, the production of gas from Wells A and C drops to zero, essentially cutting the total pad production in half. During this time, Well B is being fractured (see Figure 6a), and interferes with the production from Wells A and C. Thus, Wells A and C are shut-in, and gas production is curtailed. Some of this curtailed production is later released during Weeks 36 and 48 for Well A, and Weeks 36 and 37 for Well C. Interference is also the cause for curtailment of Well E production during Weeks 36 and 37, when Well D is being fractured. The curtailed gas production from Well E is later released during Weeks 38 and 39.

The curtailment of gas at the pad level is shown in Figure 7. Because the price of gas is a flat rate and the pad gas production is not near the pad capacity, gas curtailment is not frequent. The only weeks when gas production is curtailed is when interference causes certain wells (Wells A, C, and E) to shut-in and curtail production because other wells are being fractured (Wells B and D). The release of curtailment does lessen the effects of interference when it is released earlier in the optimization horizon, where it has a higher present value. However, a small volume of gas is released during Week 48, to ensure that all curtailed gas has been released by the end of the optimization horizon.



(a) Scheduling of operations at the pad using original estimate of mobilization costs.



(b) Optimal production of gas from the wells using the original estimate of mobilization costs.

Figure 6: (Case Study 2) Development of the wells and production of shale gas.

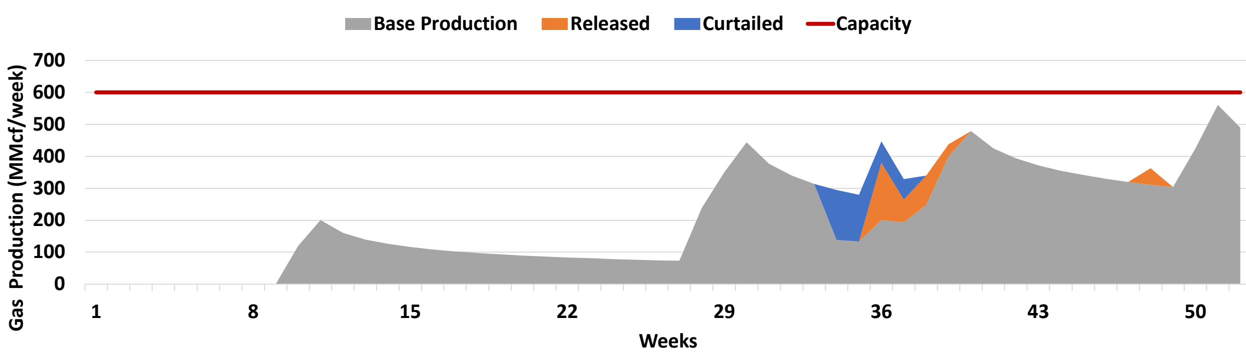


Figure 7: (Case Study 2) Optimal production of gas, including curtailment, from the wells using the original estimate of mobilization costs.

5.2.2 Economics

As mentioned in Section 4.7, the objective of this optimization is to maximize the net present value of the prospective pad, taking into consideration the long production horizon of the

Table 7: (Case Study 2) Overall economics for the prospective pad, taking into consideration the long-term revenue from well production ten years past the optimization horizon.

Initial Rev.	*Future Rev.*	*Development*	*Mobilization*	**NPV**
\$ 28.5 MM	\$ 138.2 MM	\$ -60.9 MM	\$ -3.4 MM	**\$ 102.4 MM**

shale gas wells. The results of this case study demonstrate *why* it is so important to include the long-term production of the shale gas wells. Figure 8 contains information pertaining to the costs and revenue of the optimal development and production of shale gas. Whenever there is any type of development besides turning in line, the cost of development exceeds the revenue from selling shale gas. This especially occurs in the early months of the optimization, when there is no production and the optimization schedules back-to-back operations until it can finally start producing gas at Week 10.

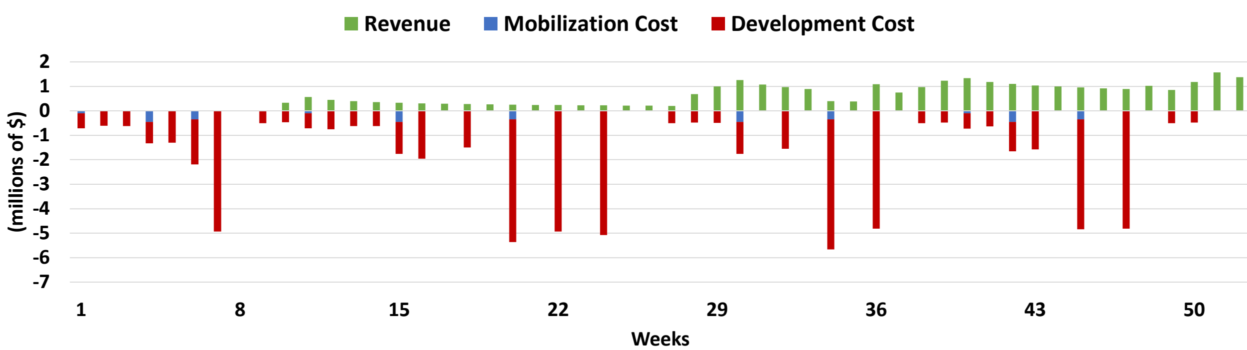


Figure 8: (Case Study 2) Economics of developing and producing gas from the prospective pad for one year.

If only considering the economics of the pad for the first year, the optimization would decide not to develop any wells and not produce any gas. It is the the long-term production of the shale gas wells that makes these operations profitable. Table 7 shows the overall economics of the prospective pad for one year of development and ten additional years of production. Without the future revenue, the initial revenue from the optimization horizon (*Revenue*) would not cover the cost of mobilization and development. However, because the optimization includes revenue from the ten years following the development, the wells can generate approximately \$166.7 MM in revenue, with 83% of it coming in 10 years after the development. Overall, the NPV of the pad, including development and mobilization costs, is approximately \$102.4 MM.

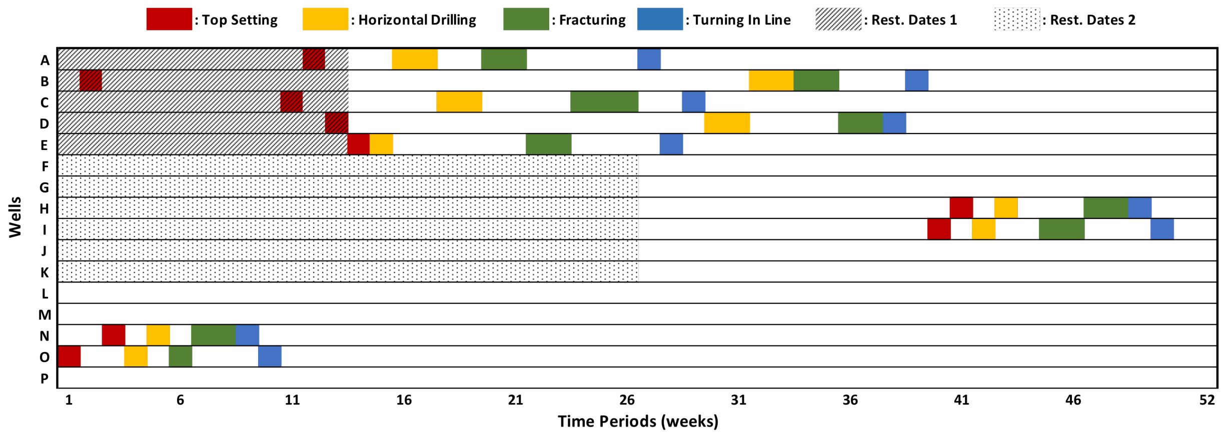
5.2.3 Sensitivity Analysis: Mobilization Cost

As mentioned in the Introduction, the true cost of development resource mobilization is not well known. The value can be estimated from data on past development budgets and contracted costs of development resource downtime. But this value may not include the full cost of operational challenges associated with transportation, assembly, and disassembly of the development resources. Therefore, a sensitivity analysis is completed on the mobilization cost to study how the cost of operational challenges influences the development and production of a shale gas pad. For Case Study 2 (Section 5.2), the mobilization cost is estimated using the approximate cost of development resource downtime for one week. The original value is then doubled and tripled, and the optimizations is solved to gaps of 2.99% in 14 hours and 4.15% in 24 hours, respectively.

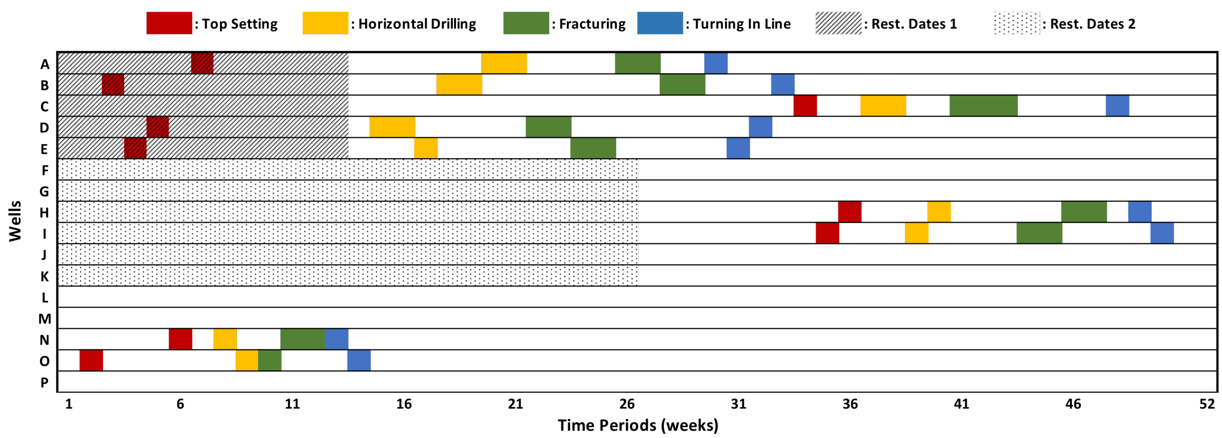
As shown in Figure 9, the mobilization cost for the development resources greatly impacts the development of the prospective pad. When doubling the original estimate, the development resources make far fewer trips to the pad, and operate on more wells per trip. For example, with the original estimate, the fracturing resources are brought to the pad four separate times, where it fractures two to three wells. When the mobilization cost for fracturing is doubled, the fracturing resources are brought to the pad three times, where it once fractures four wells. Overall, the development resources are brought to the pad only two times for top setting, three times for horizontal drilling, three times for fracturing, and three times for turning in line. The wells are still developed in batches, but in order to reduce resource mobilization trips, the top setting of Wells A, D and E are now completed in the first few months, and these wells must wait almost three months to be horizontally drilled. These operations, as well as the top setting of Well B, could be moved to a later time if Wells N and O's operations are shifted up in time, but this would add another trip for the top setting resources, and consequently increase the cost of development.

Tripling the mobilization cost (Figure 9c) does not impact the number of trips the development resources makes to the pad, when compared to doubling the cost. The biggest difference is in the timing of the top setting operations. Instead of grouping many of the top settings in the first weeks of the optimization, seven of the nine wells are top-setted from Weeks 10 to 16. Unfortunately, four of the seven top-setted wells must wait until the second half of the optimization horizon to be completed. However, this allows Wells N and O to be turned in line and produce gas earlier with a higher present value. Another difference between double and triple the resource mobilization cost is the number of wells turned in line during the second and third trips made by the turning in line reousrces. In Figure 9b, when resource mobilization costs are doubled, four wells and three wells are turned in line, respectively. However, when resource mobilization costs are tripled, three wells then four wells are turned in line, respectively. This will affect the production of gas from the pad.

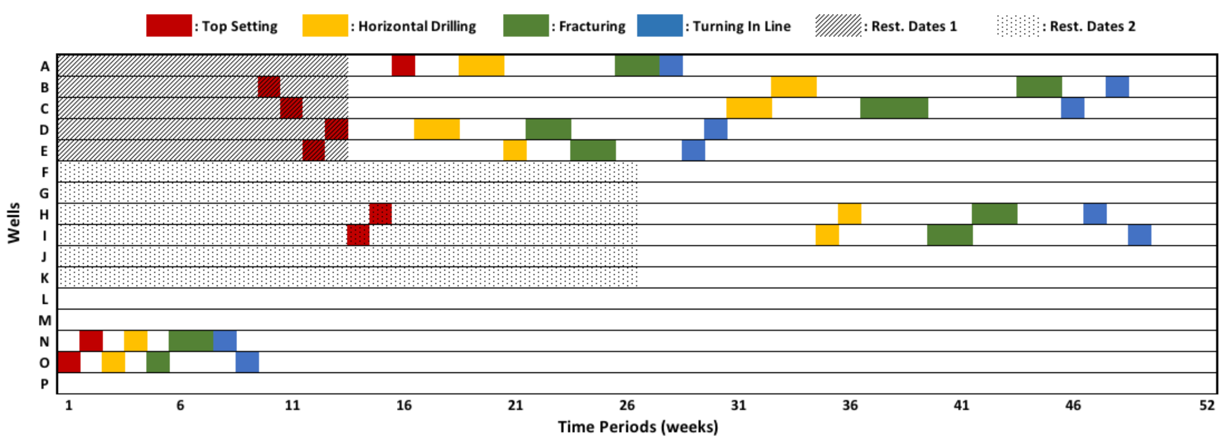
Due to the reduced number of trips by the turn-in-line crew, the production of shale gas from the pad, shown in Figure 10, has fewer production peaks as the mobilization cost increases. However, the pad gas production does reach the pad capacity as more wells are turned in line sequentially. When the turning in line resources visit the pad four times in Figure 10a, the pad is able to spread out the production and maintain a higher pad production level from Week 28 and on. When the resource mobilization cost is doubled and tripled, there is less time to turn in line the final seven wells in two trips. This leads to the pad reaching the production capacity limit during Week 51 for double the cost and Week 50 for triple the cost. Overall, the doubling and tripling of resource mobilization costs lead to a 9.07% and 7.17% decrease in gas production during the optimization horizon, respectively, when compared to the original estimate. More gas is produced when the cost is tripled because the optimization chooses to complete Wells N and O right from the start, whereas when the cost is doubled, six wells are top set before Wells N and O are completed.



(a) Scheduling of operations at the pad using original estimate of resource mobilization costs.



(b) Scheduling of operations at the pad assuming resource mobilization costs are two times the original estimate.



(c) Scheduling of operations at the pad assuming resource mobilization costs are three times the original estimate.

Figure 9: (Sensitivity Analysis) Optimal scheduling of development operations at the prospective pad, comparing varying mobilization costs.

Table 8: (Sensitivity Analysis) Economic comparison of the optimal pad development and production with varying mobilization costs.

	Initial Rev.	*Future Rev.*	*Development*	*Mobilization*	**NPV**
Original Est.	\$ 28.5 MM	\$ 138.2 MM	\$ -60.9 MM	\$ -3.4 MM	**\$ 102.4 MM**
2x Original Est.	\$ 25.7 MM	\$ 140.0 MM	\$ -60.8 MM	\$ -5.1 MM	**\$ 99.8 MM**
3x Original Est.	\$ 26.4 MM	\$ 140.0 MM	\$ -60.8MM	\$ -7.7 MM	**\$ 97.9 MM**

When the resource mobilization costs are doubled and tripled, the pad continues to experience interference when fracturing wells. When a well is shut-in because of interference, the curtailed gas production is released right when the well is re-opened, so that the gas can be sold for a higher present value when compared to a later release. The release of gas from curtailment can take a couple weeks, such as Well E during Weeks 40 and 41, because of the maximum well production constraint.

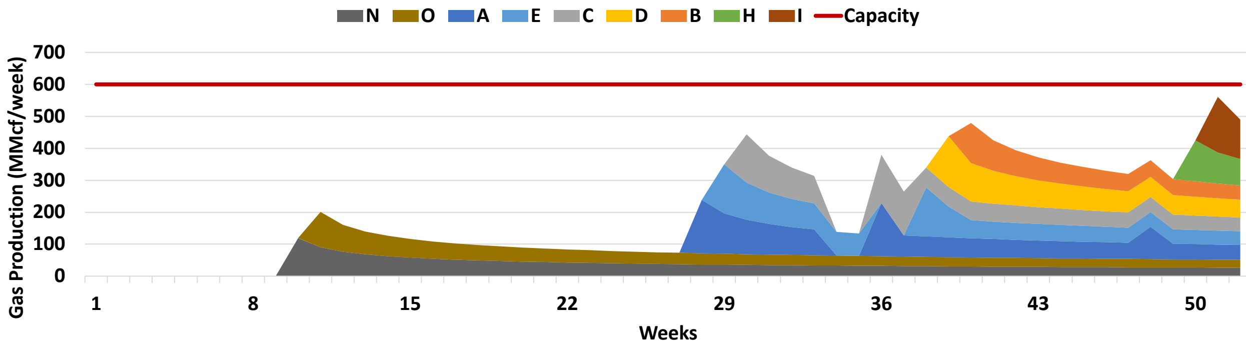
Production curtailment is only used when well fracturing interferes with the production of another well in the cases where the original and double the resource mobilization costs are used(Figure 11). When the resource mobilization cost is tripled, the well interference is also seen. However, it has the additional benefit of aiding in the sequential turn in line of four wells from Weeks 46 - 49. Without curtailment, the production from the four wells would put the pad production over its production capacity limit. But, as shown in Figure 10c, the gas production is curtailed for one week and then released the next week, so the gas will have its highest present value, and the optimization will not violate the terminal condition for gas curtailment.

In terms of economics, as the resource mobilization costs increases, the NPV of the pad decreases (Table 8). By assuming the cost of operational challenges and the resource downtime fees are equal, effectively doubling the mobilization cost, the NPV decreased by 2.5%, from \$102,400,000 to \$99,800,000. The optimization is able to reduce its losses by minimizing the number of times development resource are brought to the pad, so the difference in mobilization cost is only around \$1,700,000. But it does lose \$1,000,000 in total revenue because it produces less gas during the optimization horizon when it has a higher present value.

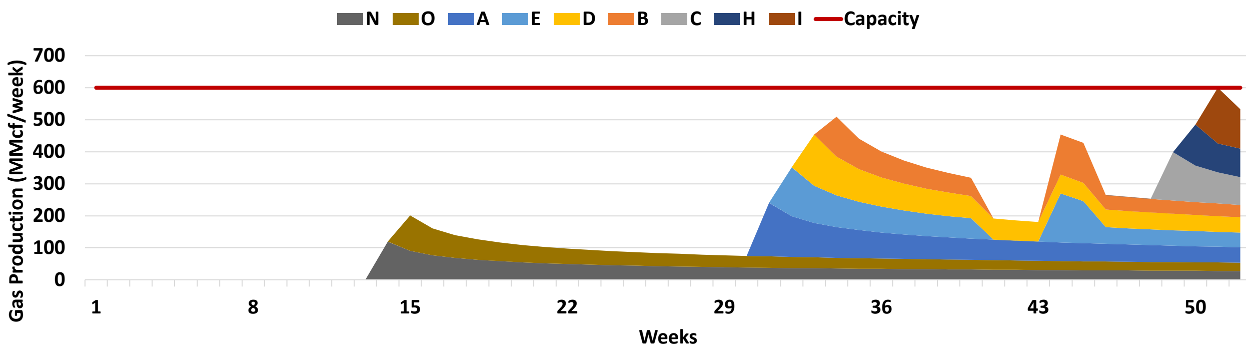
When the resource mobilization costs are tripled, the number of trips to the pad does not decrease when compared to double the mobilization cost. Because of the higher costs, the total mobilization cost increases by \$1,600,000, up to \$7,700,000. Although the timing of operations changes, the development cost is \$60,800,000, the same as when the resource mobilization cost is doubled. By quickly developing two wells in the first eight weeks, the revenue during the optimization horizon increases by \$700,000, while the post optimization revenue stays approximately the same.

6 Conclusions

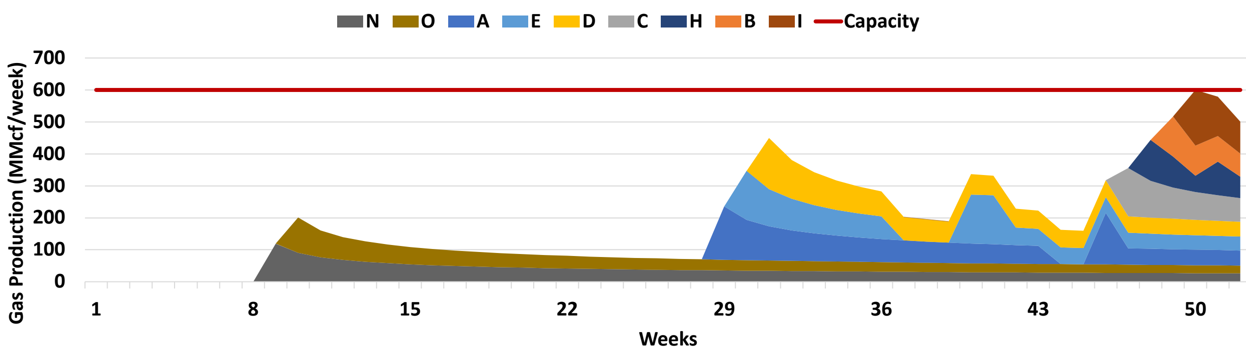
In this paper, the fixed sequence of development operations and production of a prospective shale gas pad was optimized to maximize the net present value, taking into consideration



(a) Optimal production of gas from the wells using the original estimate of mobilization costs.

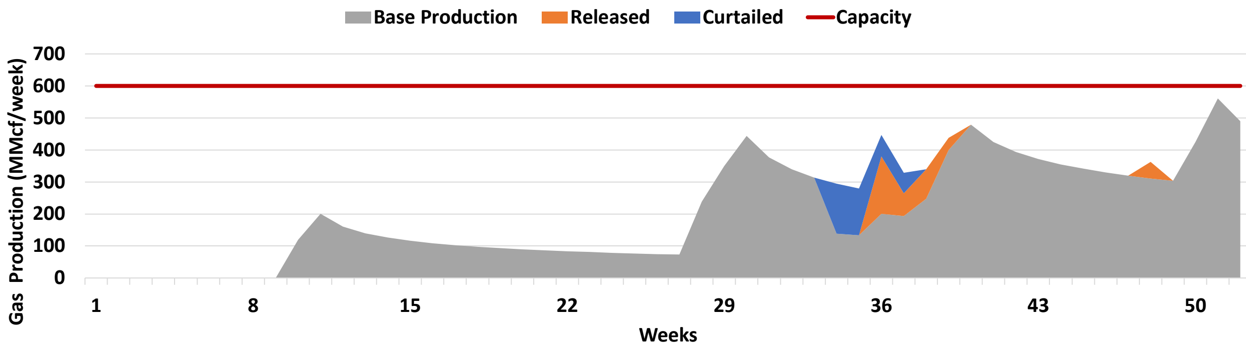


(b) Optimal production of gas from the wells assuming mobilization costs are two times the original estimate.

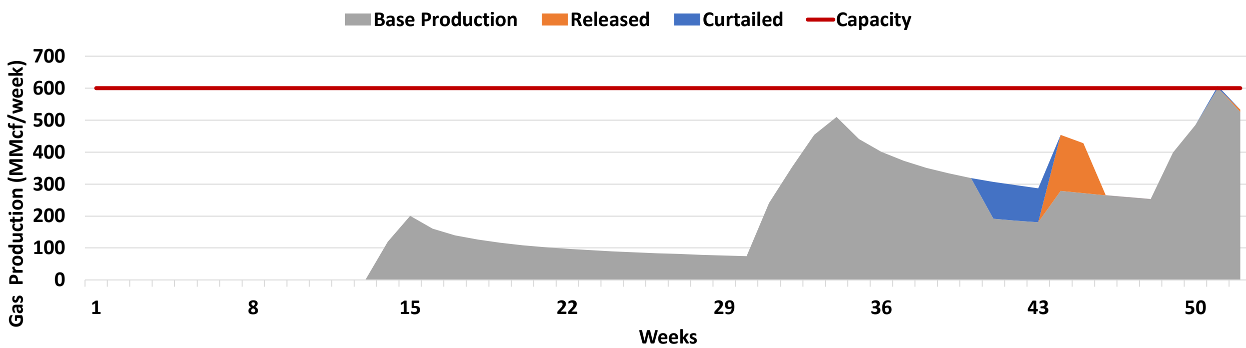


(c) Optimal production of gas from the wells assuming mobilization costs are three times the original estimate.

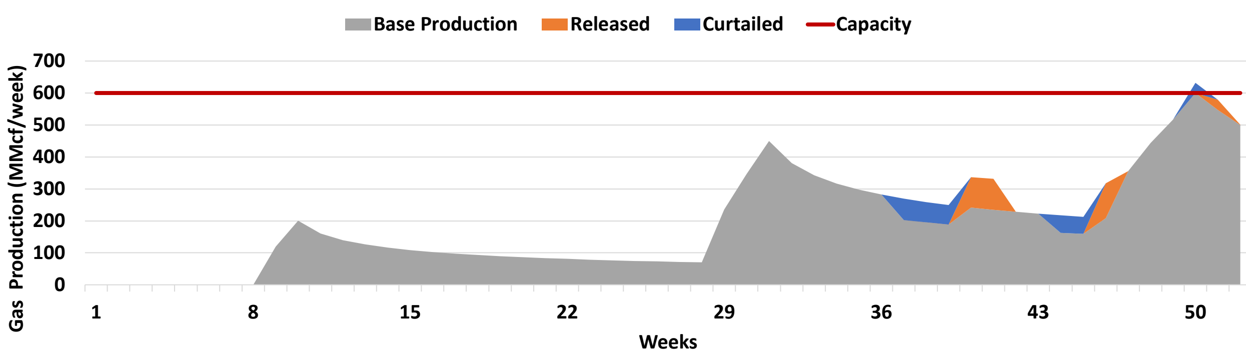
Figure 10: (Sensitivity Analysis) Optimal production of gas from the wells at the prospective pad, comparing varying mobilization costs.



(a) Optimal production of gas, including curtailment, from the wells using the original estimate of mobilization costs.



(b) Optimal production of gas, including curtailment, from the wells assuming mobilization costs are two times the original estimate.



(c) Optimal production of gas, including curtailment, from the wells assuming mobilization costs are three times the original estimate.

Figure 11: (Sensitivity Analysis) Optimal production of gas from the wells at the prospective pad, including curtailment, comparing varying mobilization costs.

developmental and production-based constraints. By initially formulating the development constraints using GDP, the mixed-integer inequalities were systemically derived to obtain a discrete-time MILP formulation. The MILP model was then applied to two case studies, an illustrative case study and an industrial case study. The results showed that the historical development strategy may not be economic depending on cost of development resource mobility, and this cost can greatly affect the number of trips the development resources will make to a pad. By allowing development resources to be brought to the pad multiple times and develop wells in small batches, gas production can start earlier in the optimization horizon, increasing the NPV of the pad. In addition, a sensitivity analysis was performed to identify the impact of operational challenges on the cost of development resource mobilization. If companies only want to operate under the condition that development resources for each operation can only be at a pad once every few years, they are placing a high value on operational challenges.

Future work will concentrate on extending the economic optimization of development and production to a larger shale gas region. For this optimization, the capacity of the pad, a parameter, is driven by the size of the pipeline that transports the shale gas away from the pad to a sales point. While incorporated as a parameter in this pad-level optimization, the size of the pipeline is a variable decision for a higher level optimization. By optimizing a system of pads considering the potential production of the wells, a more economically efficient solution for shale gas development and production can be found.

7 Acknowledgments

The authors gratefully acknowledge funding from EQT Corporation.

Nomenclature

7.1 Sets

$o \in O$: Operations ($\{$*TS, HZ, FRAC, TIL*$\}$) which correspond to the scalar set $\{1, 2, 3, 4\}$
$t \in T$: Time periods
$w \in W$: Wells at the pad

7.2 Binary Variables

$c_{t,w}$: Active if well w is closed at time t
$m_{t,o}$: Active if the development resources for operation o are mobilized at time t
$m_{t,o}^{not}$: Active if no development resources for operation o are mobilized at time t
$sb_{t,w}$: Active if production at well w is curtailed at time t
$y_{t,w,o}$: Active if operation o has started at well w at time t
$y_{w,o}^{dum}$: Active if operation o has not started at well w during the optimization horizon T
$y_t^{dum,2}$: Active if no operation is performed on any wells at time t
$z_{t,w,o}$: Active if operation o is being actively completed at well w at time t

7.3 Boolean Variables

$C_{t,w}$: True if well w is closed at time t
$H_{t,t',w,o}$: True if for well w, operation *o-1* started at time t' and operation o started at time t
$M_{t,o}$: True if the development resources for operation o are mobilized at time t
$SB_{t,w}$: True if production at well w is curtailed at time t
$Y_{t,w,o}$: True if operation o has started at well w at time t
$Z_{t,w,o}$: True if operation o is being actively completed at well w at time t

7.4 Continuous Variables

$L_{t,w}$: Total volume of gas curtailed from production at well w at time t (Mcf)
MC^d: Discounted development resource mobilization cost ($)
NPV: Net present value ($)
OC^d: Discounted operating cost ($)
$P_{t,w}$: Volume of gas produced from w at time t (Mcf/week)
$P^{fin}_{t,w}$: Volume of gas released from well w at time t, taking into consideration curtailment (Mcf/week)
R^d: Discounted revenue ($)
RI^d: Discounted revenue from selling gas inside the optimization horizon ($)
RO^d: Discounted revenue from selling gas outside the optimization horizon ($)
$S^{in}_{t,w}$: Volume of gas put curtailed at well w at time t (Mcf/week)
$S^{out}_{t,w}$: Volume of curtailed gas released from well w at time t (Mcf/week)

7.5 Parameters

a_w: Production decline parameter for well w
$i_{w,w'}$: Binary parameter where a value of one indicates that well w interferes with well w' (nu)
k_w: Initial production peak of gas from well w (Mcf/week)
l_w: Lateral length of well w (ft)
MP_o: Price to mobilize development resoures for operation o ($) NRI_w: Net revenue interest that the company owns in well w (%)
$OP_{w,o}$: Price to perform operation o at well w ($)
P^{max}_w: Maximum production of gas from well w (Mcf/week)
$P^{pad,max}$: Maximum production of gas from the pad (Mcf/week)
r: Rate of return (%)
$R^{far}_{t,w}$: Revenue from the total volume of gas produced from well w over the next T^{rev} time periods after the optimization horizon if the well is turned in line ($o = 4$) at time t
$t^{op}_{w,o}$: Time periods needed to perform operation o at well w (weeks)
$t^{per}_{w,o}$: Time period when operation o can start at well w (weeks)
T^{rev}: Time after the optimization horizon over which the revenue of the well is calculated

(weeks)
$\gamma_{t,w}$: Production volume of w at age t (Mcf/ft/week)
π_t: Price of gas at time t (\$/Mcf)
ϕ_t: Discount rate at time t (%)

References

[1] U.S. Department of Energy. Why is Shale Gas Important? https://www.energy.gov/sites/prod/files/2013/04/f0/why_is_shale_gas_important.pdf, 2013.

[2] D. Blackmon. Horizontal drilling: A technological marvel ignored. https://www.forbes.com/sites/davidblackmon/2013/01/28/horizontal-drilling-a-technological-marvel-ignored/#75d985ca6f11, 2013.

[3] U.S. Energy Information Administration. U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2016. https://www.eia.gov/naturalgas/crudeoilreserves/, 2018.

[4] U.S. Energy Information Administration. Most natural gas production growth is expected to come from shale gas and tight oil plays. https://www.eia.gov/todayinenergy/detail.php?id=26552, 2016.

[5] U.S. Energy Information Administration. Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf, 2017.

[6] A. Morris. Optimizing Shale Gas Production from Well to Wire. http://www.mccormick.northwestern.edu/news/articles/2015/06/optimizing-shale-gas-production-from-well-to-wire.html, 2015.

[7] M.G. Drouven and I.E. Grossmann. Multi-period planning, design, and strategic models for long-term, quality-sensitive shale gas development. *AIChE Journal*, 62(7):2296–2323, 2016.

[8] F. Forouzanfar and A.C. Reynolds. Joint optimization of number of wells, well locations and controls using a gradient-based algorithm. *Chemical Engineering Research and Design*, 92:1315–1328, 2014.

[9] K.C. Wilson and L.J. Durlofsky. Optimization of shale gas field development using direct search techniques and reduced-physics models. *Journal of Petroleum Science and Engineering*, 108:304–315, 2013.

[10] S. Kang, A. Datta-Gupta, and W.J. Lee. Impact of natural fractures in drainage volume calculations and optimal well placement in tight gas reservoirs. *Journal of Petroleum Science and Engineering*, 109:206–216, 2013.

[11] B. Yeten, L.J. Durlofsky, and K. Aziz. Optimization of nonconventional well type, location, and trajectory. *SPE Journal*, 8(3):200–210, 2003.

[12] X. Ma, T. Plaksina, and E. Gilden. Optimization of placement of hydraulic fracture stages in horizontal wells drilled in shale gas reservoirs. In *Unconventional Resources Technology Conference*, pages 1479–1489, 2013.

[13] W. Yu and K. Sepehrnoori. Optimization of multiple hydraulically fractured horizontal wells in unconventional gas reservoirs. *Journal of Petroleum Engineering*, 2013, 2013.

[14] B.R. Knudsen, I.E. Grossmann, B. Foss, and A.R. Conn. Lagrangian relaxation based decomposition for well scheduling in shale-gas systems. *Computers & Chemical Engineering*, 63:234–249, 2014.

[15] B.R. Knudsen and B. Foss. Shut-in based production optimization of shale-gas systems. *Computers & Chemical Engineering*, 58:54–67, 2013.

[16] B.R. Knudsen, C.H. Whitson, and B. Foss. Shale-gas scheduling for natural-gas supply in electric power production. *Energy*, 78:165–182, 2014.

[17] D.C. Cafaro, M.G. Drouven, and I.E. Grossmann. Optimization models for planning shale gas well refracture treatments. *AIChE Journal*, 62(12):4297–4307, 2016.

[18] D.C. Cafaro, M.G. Drouven, and I.E. Grossmann. Continuous-time formulations for the optimal planning of multiple refractrue treatments in a shale gas well. *AIChE Journal*, 64(5):1511–1516, 2018.

[19] L. Yang and I.E. Grossmann. Optimization models for shale gas water management. *AIChE Journal*, 60(10):3490–3501, 2014.

[20] I.E. Grossmann M.G. Drouven. Mixed-integer programming models for line pressure optimization in shale gas gathering systems. *Journal of Petroleum Science and Engineering*, 157:1021–1032, 2017.

[21] D.C. Cafaro and I.E. Grossmann. Strategic planning, design, and development of shale gas supply chain network. *AIChE Journal*, 60(6):2122–2142, 2014.

[22] O.J. Guerra, A.J. Calderón, L.G. Papageorgiou, J.J. Siirola, and G.V. Reklaitis. An optimization framework for the integration of water management and shale gas supply chain design. *Computers & Chemical Engineering*, 92:230–255, 2016.

[23] J Gao and F. You. Risk management of shale gas supply chain under estimated ultimate recovery uncertainty. *Computer Aided Chemical Engineering*, 38:529–534, 2016.

[24] J. Gao and F. You. Shale gas supply chain design and operations toward better economic and life cycle environmental performance: Minlp model and global optimization algorithm. *ACS Sustainable Chemistry &Engineering*, 3(7):1282–1291, 2015.

[25] K. Arredondo-Ramírez, J.M. Ponce-Ortega, and M.M. El-Halwagi. Optimal planning and infrastructure development for shale gas production. *Energy Conversion and Management*, 119:91–100, 2016.

[26] K. Arredondo-Ramírez, J.M. Ponce-Ortega, and M.M. El-Halwagi. Optimal planning of infrastructure for the supply chain of shale gas. In *Advances in Energy Systems Engineering*, pages 3–19. Springer, 2017.

[27] R.R. Iyer, I.E. Grossmann, S. Vasantharajan, and A.S. Cullick. Optimal planning and scheduling of offshore oil field infrastructure investment and operations. *Industrial & Engineering Chemistry Research*, 37(4):1380–1397, 1998.

[28] H. Cooley, K. Donnelly, N. Ross, and P. Luu. Hydraulic fracturing and water resources: separating the frack from the fiction. *Pacific Institute. Oakland*, 2012.

[29] A. Banerjee, J. Prozzi, and J. Prozzi. Evaluating the effect of natural gas developments on highways: Texas case study. *Transportation Research Record: Journal of the Transportation Research Board*, 2282:49–56, 2012.

[30] S. Abramzon, C. Samaras, A. Curtright, A. Litovitz, and N. Burger. Estimating the consumptive use costs of shale natural gas extraction on Pennsylvania roadways. *Journal of Intrastructure Systems*, 20(3):06014001, 2014.

[31] G.L Nemhauser and L.A. Wolsey. *Integer and Combinatorial Optimization*. Wiley, New York, 1988.

[32] D. Arthur and D. Cornue. Technologies reduce pad size, waste. *The American Oil & Gas Reporter*, 2010.

[33] R. Raman and I.E. Grossmann. Modelling and computational techniques for logic based integer programming. *Computers & Chemical Engineering*, 18(7):563–578, 1994.

[34] U.S. Energy Information Administration. Annual Energy Outlook 2012. https://www.eia.gov/outlooks/aeo/pdf/0383(2012).pdf, 2012.

[35] S. Rae. How to calculate net revenue interest for oil & gas. http://smallbusiness.chron.com/calculate-net-revenue-interest-oil-gas-78537.html.

[36] U.S. Energy Information Administration. Henry Hub Natural Gas Spot Price. https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm, 2018.