Paper ID APEN-MIT-2019_173
Applied Energy Symposium: MIT A+B
May 22-24, 2019 • Boston, USA

Optimization framework for integration of shale gas supply chain network and dynamic model of hydraulic fracturing

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Abstract—Several approaches have been developed to illustrate shale gas supply chain network (SGSCN) in economically viable manner, but the connection between fracture geometry, gas production, and wastewater recovery has not received much attention. When fractures are created in unconventional reservoirs, the final fracture geometry significantly affects shale gas production rate and it indirectly determines the amount of recovered wastewater. To achieve a sophisticated understanding of this complex interaction, we focus on the development of a new framework to integrate dynamic modeling of hydraulic fracturing (HF), a reservoir simulator call CMG, and SGSCN. Based on this developed framework, we will determine the optimal configuration of SGSCN that maximizes the profit over a long-term planning horizon formulating a mixed-integer linear programming problem. The proposed method has been applied to two case studies to demonstrate its superiority over other existing approaches.

Keywords— shale gas, hydraulic fracturing, dynamic modeling, supply chain network, Marcellus shale play

I. Introduction

As energy demand is growing globally, natural gas is one of the most important energy sources used to meet global energy demand. Recently, extraction of shale gas to produce natural gas has received much attention. With recent advances of hydraulic fracturing (HF) oil and gas companies have become able to economically produce large volume of shale gas [1]. Since shale gas is an unconventional resource different from the conventional fossil fuels, shale gas supply chain network (SGSCN) should be developed taking into account the entire supply chain of materials from raw materials (i.e., freshwater) to end products (i.e., electricity) in an economically viable manner [2].

Recently, several approaches have been developed to study SGSCN. Optimal water usage for well-drilling is decided to minimize the total costs [3,4] and maximize profit [5] while determining fracturing schedule [3], facility capacity of wastewater treatment [4], and potential location of freshwater source and treatment options [5], considering uncertainty [4] and environmental impact [5] using MILP [3,4] and MINLP [5]. Moreover, a shale gas supply chain network (SGSCN) was developed to optimize the economic performance while accounting for various factors related to design and operation decisions of the entire SGSCN. Optimal network configuration of SGSCN can be decided by maximizing net present value [6], economic and environmental performance [7], and profit [8] while determining the number of drilled wells [6-8], shale gas production [7,8], and electricity generation [8], formulated by MINLP [6-8]. Although many researches have focused primarily on water management of SGSCN, the impact of fracture geometry on shale gas production and the amount of recovered wastewater has not received much attention.

Recently, another group of various efforts has been made to improve well performance by regulating the uniformity of proppant bank height and of suspended proppant concentration inside fracture. Initially, to maximize the gas and oil production rates using the section-based optimization method developed by Liu and Valko [9], the number of wells, number of fractures per well, fracture half-length, and total proppant amount are calculated. A model predictive controller (MPC) was then used to obtain a pumping schedule that determines the flow rate and proppant concentration of fracturing fluids; this will allow us to achieve a proppant bank with uniform height across the fracture at the end of pumping [10-13].

It is important to note, however, that the resulting pumping schedule does not take into account post-fracking economic considerations, such as shale gas production, wastewater treatment, and wastewater reuse. For this purpose, our previous work [14] incorporates sustainability considerations of post-fracturing processes into model-based pumping schedule (MbPS) techniques to minimize the annual cost of entire HF while reducing environmental impacts. However, the previous study [14] focused on wastewater management only and did not consider the entire SGSCN. Furthermore, scheduling of well-drilling at shale sites is highly dependent on the freshwater requirement for well-drilling; however, it was not considered in [14].

Motivated by these considerations, we focus on the development of a new framework to integrate dynamic modeling of HF and a reservoir simulator called CMG, produced by Computer Modelling Group Ltd; this integrated approach will allow us to achieve a sophisticated understanding of the complex connections between hydraulic fracturing, wastewater generation and management, shale gas production and is able to place our research within this integrated context. Therefore, the computed operating strategy, whose feasibility is not constrained by the reliability and available of data, can be more generally applicable to broader operating conditions.

II. Problem statement

A. Technology overview

1) Hydrofraulic fracturing (HF) process

HF is performed to create fractures with a pressurized liquid containing water, proppant, and other chemicals [15]. HF begins with creating perforations along the wellbore for initial fracture paths. Then, a high-pressure fracturing fluid, mostly consisting of water, is injected into the wellbore to further break the rock formation and promote fracture propagation [10]. Next, a fracturing slurry consisting of water, additive, and proppant is injected into the wellbore to distribute proppants inside fractures. Some proppants are suspended, moved along fractures at the velocity of fracture fluids, and the other settle down and form a proppant bank. Once pumping is stopped, the created fractures will be closed by the natural stress after treatment. Specifically, during the closing process, remaining fracturing fluid will leak off and proppants will be trapped by closing walls, resulting in a conductive channel (i.e., propped fractures). Propped fractures promote the economically viable extraction of hydrocarbons from reservoirs to the wellbore, and massive leaking fluid stimulates the vicinity of created fractures improves the permeability of stimulated volume of formation.

2) Shale gas processing plant

Shale gas processing plants separate various fluid hydrocarbons from shale gas to produce natural gas. In other words, shale gas must be purified for commercial uses before transportation. Relevant hydrocarbons such as ethane, propane, and butane, etc. named as natural gas liquids (NGLs), are valuable products that can be obtained after separating shale gas [7]. These NGLs can be supplied as energy sources or raw materials to oil refineries or petrochemical plants, respectively [16]. NGLs have a much higher market value than natural gas, but its transportation cost is more expensive than natural gas. Therefore, using NGLs as a feedstock for the local petrochemical processes is more cost-effective than to make other valuable products in the shale gas production. However, NGLs have a much higher market value than natural gas, but its transportation cost is more expensive than natural gas. Therefore, using NGLs as a feedstock for local petrochemical processes is more cost-effective than to make other valuable products in shale gas production process.

3) Power plant

A gas turbine combined cycle power plant is considered to produce electricity with an efficiency of 50% based on the lower heating value determined by subtracting the heat of vaporization of water from the higher heating value [17]. Natural gas separated by processing plants is consumed by power plants for electricity generation, which is then sold to external markets for profit.

4) Wastewater management

Once HF is completed, a fraction of injected water and existing formation water will flow back to the surface along with shale gas production [7]. This wastewater contains toxic chemicals so it must be handled via wastewater management options. In this work, we considered the following technologies [7]: onsite treatment; centralized wastewater treatment (CWT); disposal well. On-site treatment for wastewater reuse includes multi-effect distillation (MED), multi-stage flash (MSF), and reverse osmosis (RO) [7]. The treated wastewater can be mixed with fresh water for reuse at another nearby HF site. On the other hand, CWT facilities can be used to treat wastewater, which will be discharged to surface water without reusing it. Lastly, wastewater can be transported to disposal wells without any treatment and can be pumped down to the ground for disposal.

5) Trnasportation and storage

Two transportation modes for SGSCN, truck and pipeline, are considered [7]. Freshwater is transported from its sources to shale sites via both truck and pipeline, but shale gas and natural gas can be delivered by pipeline only. Two storage options considered for SGSCN are underground reservoir and NGL storage unit. Natural gas, separated from shale gas at processing plants, is transported to power plants and underground reservoirs. Underground reservoirs are considered to handle fluctuations in demand and price of electricity, both of which have a large effect on profit of SGSCN [18]. Separated natural gas can be stored in underground reservoirs for an indefinite period of time before it is transported to power plants, while NGLs are sold directly to an external market.

B. MbPS design

In HF, it is very important to achieve fractures with uniform proppant bank height and a desired geometry for the maximum gas production rates. To achieve this objective, we will adopt a MbPS design developed by Siddhamshetty et al. [10]. Specifically, we first construct a reduced-order model (ROM) using data from a high-fidelity model of HF. Then, we develop a Kalman filter to estimate unmeasurable variables using available measurements which include the fracture width at the wellbore and fracture length. Then, we develop a MPC formulation to compute an optimal pumping schedule which will achieve uniform proppant bank height over the optimal fracture length.

C. SGSCN configuration

The objective of this study is to determine the optimal configuration of SGSCN (Fig. 1) for maximal economic performance by optimizing the following strategic and operational decisions: (1) amount of freshwater required via transportation modes, (2) amount of wastewater generated after HF and wastewater management options, (3) schedules of well-drilling and amount of shale gas produced at shale sites, (4) capacity and location of shale gas processing plants, (5) amount of natural gas stored in each underground reservoir and amount of NGLs in NGLs stored in each storage unit, (6) amount of electricity generated at power plant, (7) investment and capacity of pipelines among shale sites, shale gas processing plants, underground reservoirs, and power plants.

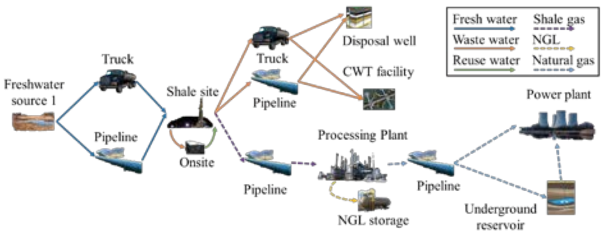

Fig. 1. Superstructure of the shale gas supply chain network

III. Model Formulation

A. MbPS design

In HF, the required optimal fracture geometry depends on the geological properties of rock formation. Recently, Liu and Valkó [9] proposed a section-based optimization method, which is an offline optimization based technique to find the number of wells, n_c, number of fractures per well, n_r, and fracture half-length, x_f, that maximizes the productivity from unconventional shale formations for a given amount of fracturing resources such as the amount of water and proppant to be injected. In this work, we considered the total amount of proppant to be injected is $M_{prop}=2.38\times10^7$kg, and the optimal decision variables for this proppant using the section-based optimization method are $n_c=6$, $n_r=55$, and $x_f=120$m.

In unconventional reservoirs, due to the use of slickwater, the proppant settles quickly forming a proppant bank, which will eventually reach an equilibrium height, h_{eq}. It is very important to achieve this equilibrium height of proppant bank over the required fracture half-length, x_f, which can be translated into achieving the following average fracture width at the end of pumping:

$$W_{avg,target}=M_{prop,frac}/2\rho_p\ h_{eq}\ x_f\ (1-\emptyset) \quad \text{(M1)}$$

where $M_{prop,frac}$ denotes the total injected proppant per fracture, ρ_p is the proppant particle density, $\emptyset$ is the porosity of proppant bank, h_{eq} is the equilibrium height of proppant bank for the considered flow conditions, and $W_{avg,target}$ is the calculated average fracture width at the end of pumping.

To achieve the uniform proppant bank height and optimal fracture geometry, it is important to develop a pumping schedule to inject fracturing fluids. One of the most commonly used pumping schedules is developed by Nolte [19], which is formulated as follows:

$$C_0\ (tt) = C_{target}\ ((tt-tt_p)/(tt_e-tt_p))^{\epsilon} \quad \text{for } tt\ge tt_p \quad \text{(M2-1)}$$

$$C_0\ (tt) = 0 \quad \text{for } tt<tt_p \quad \text{(M2-2)}$$

where C_{target} is the target proppant concentration, ϵ is an exponent calculated based on the fracturing fluid efficiency, tt_e is the total pumping time, and tt_p is the pad time during which only water is injected. Nolte's pumping schedule has a few practical limitations such as: proppant settling is not considered, fracturing fluid flowrate is constant and only proppant concentration is varied, and plant-model mismatch due to the open-loop operation may lead to early termination of operation leading to a short propped fracture length.

1) *MPC formulation*

To deal with the limitations of Nolte's pumping schedule, we use the MPC formulation developed by Siddhamshetty et al. [10] to achieve the desired average fracture width, $W_{avg,target}$, which will lead to uniform proppant bank height over the optimal fracture half-length at the end of pumping. The MPC is formulated in the following form, which will compute the optimal pumping schedule by minimizing the squared deviation of average fracture width at the end of pumping from its set-point:

Minimize

$$C_{stage,j},\ldots,C_{stage,9},\quad (W_{avg}\ (tt_f) - W_{avg,target})^2 \quad \text{(M3-1)}$$

$$Q_{stage,j},\ldots,Q_{stage,9} \quad \text{(M3-2)}$$

s.t. ROM and Kalman filter (M4)

$$W_0(tt_i) = W_0(tt_i),\ L(tt_i) = L(tt_i) \quad \text{(M5)}$$

$$C_{stage,j-1+m}\le C_{stage,j+m}\le 2PPGA,\quad m=1,\ldots,9-j \quad \text{(M6)}$$

$$Q_{min}\le Q_{stasge,j+m}\le Q_{max},\quad m=1,\ldots,9-j \quad \text{(M7)}$$

$$\Delta(\textstyle\sum_{j=1}^{9} 2Q_{stage,j}\ \ C_{stage,j}) = M_{prop,frac} \quad \text{(M8)}$$

In this formulation, we use the ROM developed by Siddhamshetty et al. [10] using the data from a high fidelity model of HF. In HF, the available real-time measurements are the fracture width at the wellbore, $W_0\ (tt_i)$, and the fracture length, $L(tt_i)$, which are used to estimate average fracture width, $W_{avg}(tt_f)$, using a Kalman filter; it plays a role as a soft sensor to estimate unmeasurable variables. The pumping schedule, consisting of fracturing fluid flow rate $Q_{stage,i}$ and proppant concentration $C_{stage,i}$, is obtained by solving the above optimization problem in the shrinking prediction horizon, $N_p=tt_f - tt_i$, where tt_f is the total HF operation time and tt_i is the current time. In this formulation, we considered the practical constraints on maximum proppant concentration injected, minimum and maximum allowable limits on fracturing fluid flow rate, and the amount of proppant to be injected at the end of pumping. After we obtain the pumping schedule, the total water injected during the HF per well is calculated using the following equation:

$$Q_{fresh\ water} = n_r\Delta\textstyle\sum_{j=1}^{9}2Q_{stage,j}(1-C_{stage,j}) \quad \text{(M9)}$$

2) *Flowback water model*

In this subsection, we developed a dynamic model to predict the flowrate of flowback water generated from each well during shale gas production. The data used to develop this model is taken from [20]. Using this data and a regression method, we developed the following equation to predict the flowrate profile of flowback water generated from a well for a given amount of water injected:

$$Q_f(tt) = Q_{fresh\ water}\ (a\ \ln(tt)+b) \quad \text{(M10)}$$

where a and b are the parameters determined by a regression method, and $Q_{fresh\ water}$ is the volume of injected water per well. In this work, we considered 90 days (one time period) to collect the flowback water, and the recovery ratio of flowback water out of the total injected freshwater is calculated using the following equation:

$$rr^{drill}_i= \textstyle\sum_{tt=1}^{90}Q_f(tt)dt/Q_{fresh\ water} \quad \text{(M11)}$$

3) *Reservoir simulator*

In this subsection, we use reservoir simulation software to generate the shale gas production profile based on the final fracture geometry at the end of pumping. In this work, we use a reservoir simulator called CMG to predict gas production. Using the propped fracture geometry as the input, the shale gas production profile per each quarter (pa^{shale}_{tp}) is obtained.

B. SGSCN model

In this study, the proposed model is obtained by modifying the previous model of SGSCN [7] based on following assumptions: (1) optimal HF operation data such as the amount of fresh water required at each fracture, amount of flowback water generated from each well, and amount of shale gas production can be determined by MbPS design [10]; (2) consider fixed capacities for processing plants and pipelines. This approach allows determining many decisions within one framework of a profit-maximization model, which can be formulated using a MILP problem. A MILP model was developed for optimal design of SGSCN from freshwater sources to electricity generation, simultaneously taking into account technologies, resources, and capacity constraints over a multi-period planning horizon. This model involves numerous key parameters and variables.

1) Objective function

In this study, the objective is to maximize the expected profit (Profit) of SGSCN. Profit can be obtained by subtracting total cost (TotalCost) from benefits (Benefit):

$$\text{Maximize} \quad \text{Profit} = \text{Benefit} - \text{TotalCost}. \quad \text{(S1)}$$

In SGSCN, there are two products, electricity and NGLs,which will be sold externally. Benefit can be determined by adding the sum of their sales values, given by:

$$\text{Benefit} = SI^{elec} + SI^{NGLs}. \quad \text{(S2)}$$

TotalCost required to produce shale gas from SGSCN includes: (1) Freshwater supply cost (TC^{fresh}); (2) Shale gas production cost (TC^{shale}); (3) Wastewater management cost (TC^{waste}); (4) Operating cost of shale gas processing plants (TC^{proc}); (5) Natural gas transportation cost ($TC^{pro\text{-}tra}$); (6) Storage cost of natural gas and NGLs ($TC^{storage}$); (7) Power plant operating cost (TC^{power}).

$$\text{TotalCost} = TC^{fresh} + TC^{shale} + TC^{waste} + TC^{proc} + TC^{pro\text{-}tra} + TC^{storage} + TC^{power}. \quad \text{(S3)}$$

2) Constraints

Freshwater supply. A huge amount of freshwater is required to make fractures for shale gas production. The amount of water required at shale site i in time period t ($FWD_{i,t}$) is related to the number of drilled wells ($NDW_{i,t}$) as follows:

$$FWD_{i,t} = acdw_i \, NDW_{i,t}. \; \forall i,t. \quad \text{(S4)}$$

where $acdw_i$ denotes freshwater consumption of HF for each well at shale site *i*. $FWD_{i,t}$ should be equal to the amount of water supplied from freshwater sources and the amount of reused water supplied by onsite treatment:

$$\sum_o rr^{onsite}_o \, WTIO_{i,o,t} + \sum_s \sum_k FWR_{s,i,k,t} = FWD_{i,t}. \quad \forall i,t. \quad \text{(S5)}$$

where rr^{onsite}_o denotes recovery ratio of wastewater treated by onsite treatment *o*, $WTIO_{i,o,t}$ is the amount of wastewater treated at shale site *i* by onsite treatment *o* in time period *t.* $FWR_{s,i,k,t}$ is the amount of freshwater supplied using transportation mode k from its source *s* to shale site *i* in time period *t.*

Wastewater generation. The amount of wastewater generated during well-drilling ($WP^d_{i,t}$) is related to the number of drilled wells:

$$WP^d_{i,t} = acdw_i \, rr^{drill}_i \, NDW_{i,t}. \; \forall i,t. \quad \text{(S6)}$$

where rr^{drill}_i denotes recovery ratio of wastewater after well-drilling at shale site *i*. Also, the amount of wastewater generated during HF ($WP^h_{i,t}$) is proportional to the total amount of shale gas production:

$$WP^h_{i,t} = ccswPS_{i,t}. \quad \forall i,t. \quad \text{(S7)}$$

where ccsw denotes correlation coefficient between amounts of wastewater generated and shale gas produced at shale site *i*, $PS_{i,t}$ is the amount of shale gas produced at shale site *i* in time period *t*.

The total amount of produced wastewater ($WP^d_{i,t}$ + $WP^h_{i,}$) should equal to the total amount of wastewater handled by three water management options such as CWT ($WTIC_{i,c,k,t}$), disposal well ($WTID_{i,d,k,t}$), and onsite treatment ($WTIO_{i,o,t}$):

$$WP^d_{i,t} + WP^h_{i,t} = \sum_o \sum_k WTIO_{i,o,t} + \sum_c \sum_k WTIC_{i,c,k,t} + \sum_d \sum_k WTID_{i,d,k,t}, \; \forall i,t. \quad \text{(S8)}$$

Shale gas production. The total amount of shale gas produced from shale site *i* can be calculated with the production rate of shale gas and the number of drilled wells as follow:

$$\sum_{tp} NDW^{SP}_{i,t,tp} \, pa^{shale}_{tp} = PS_{i,t}, \; \forall i,t. \quad \text{(S9)}$$

This time-dependent parameter (pa^{shale}_{tp}) is used to present that the of shale gas produced in each well decrease with time.

IV. Case Study

To validate the performance of the proposed model, two case studies were adopted from [7], which was based on the Marcellus shale play. Specifically, one base case derived from Nolte's work [19] and one alternative case from MbPS design [10] are considered.

V. Results and Discussion

This section explains how to determine the important variables to use in the SGSCN model using the MbPS design and how to optimize the SGSCN model using these results.

A. MbPS design

In this section, we apply the proposed MbPS design to regulate the average fracture width at the end of pumping close to the set point, which will lead to uniform proppant bank height and optimal fracture geometry. Fig. 2a shows that the proppant bank height is uniform over the required fractures length compared to Nolte's pumping schedule (Fig. 2b) where the proppant bank height is uniform only until 106.5 m. With the obtained pumping schedule, including the flowrate and the proppant concentration of the fracturing fluid, the total volume of pure water used to make up the fracturing fluid is calculated. In our case, the volume of water required for each fractured well is $V_{freshwater}$ = 23,868 m^3. Using Nolte`s pumping schedule, $V_{freshwater}$ = 26,332 m^3. By applying the proposed dynamic input-output model, where the input is the volume of injected fracking water, and the output is the cumulative volume of the generated wastewater with time, the total amount of wastewater within the first ten years is $V_{wastewater}$ = 13,324 m^3 with the proposed MPC, while the volume is $V_{wastewater}$ = 14699 m^3 in Nolte`s case. Note that the overall recovery ratios in both cases are the same, which are R_1≅R_2≅0.56. Meanwhile, using the reservoir simulator, CMG, the shale gas production profiles for the two cases are also generated based on the corresponding fracture geometry, and it can be observed that the total gas production using proposed MbPS is higher than Nolte's pumping schedule because we are able to achieve the optimal fracture geometry using the proposed MbPS design.

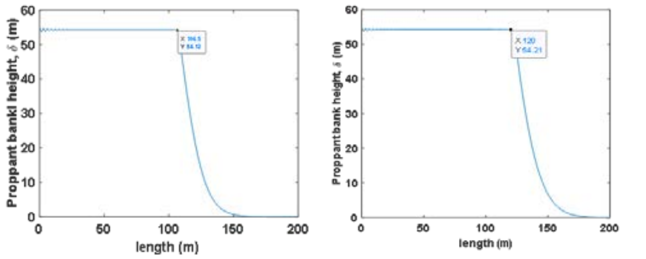

Fig. 2. Spatial proppant bank height profile obtained at the end of pumping using (a) proposed MbPS and (b) Nolte's pumping schedule

B. *SGSCN model*

1) Optimal costs

The expected profits of SGSCN are presented in Fig. 3. When considering shale gas production for 10 years operation, the expected profits for Alternative case (264 x10^6 US$) was about 5% higher (12 x10^6 US$ difference) than Base case (252 x10^6 US$) [19].

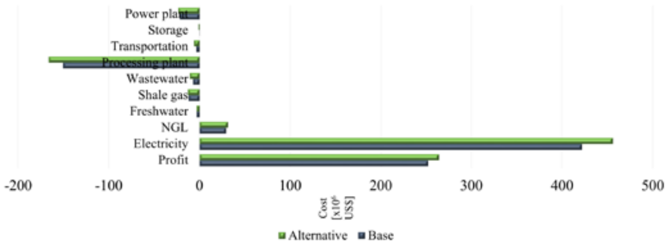

Fig. 3. Comparison of the optimal cost of SGSCN model between Base and Alternative cases

In Base and Alternative cases, the total benefits from sale incomes of electricity and NGLs were 451 and 487 x10^6 US$, respectively. In both cases, the electricity benefits were higher (392 and 424 x10^6 US$ difference) than NGLs benefits. The electricity benefit accounts for the most significant portion in the optimal cost strategy. Unlike other costs, processing cost includes the construction cost of processing plant, as well as the operating cost, because processing plant needs to be constructed at potential locations to separate shale gas toward natural gas and NGLs.

2) Optimal designs

To maximize the expected profit with generating electricity from shale sites including the maximum number of wells that can be drilled at each shale site, the optimal network design of Base case was determined as follows (Fig. 4): two freshwater sources; two shale sites with eleven drilled wells; two CWT facilities; two processing plants with two NGLs storage unit; one underground reservoir; two power plants.

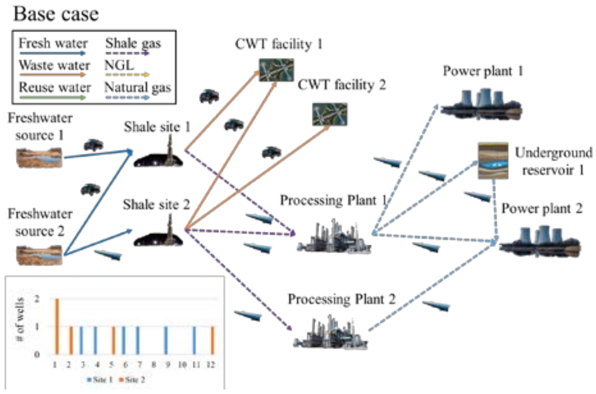

Fig. 4. Optimal network configuration of SGSCN model in Base case.

Freshwater required in shale sites 1 and 2 was satisfied from freshwater sources 1 and 2 by trucks and from freshwater source 2 by pipeline. These selections were determined due to the constraints imposed on the capacity of freshwater transportation from freshwater sources to shale sites. In terms of well-drilling, six and five wells were drilled over three years (twelve time periods) in shale sites 1 and 2, respectively. To treat shale gas produced in the two shale sites, two processing plants were constructed with two NGLs storage units. After HF in eleven drilled wells, all and a part of shale gases produced in shale sites 1 and 2 were transported to processing plant 1 using pipeline, respectively. The remaining shale gas in shale site 2 was transported to process plant 2. After processing shale gas in processing plants, natural gas purified was supplied to power plant to generate electricity. Finally, two power plants were selected to generate electricity by natural gas transported by pipeline from processing plants and underground reservoir. Natural gas in processing plant 1 was supplied to power plants 1 and 2 and underground reservoir 1. Natural gas in processing plant 2 was supplied to power plant 2 only.

In Alternative case, the optimal design was determined as follows (Fig. 5): two freshwater sources; two shale sites with eleven drilled wells; two processing plants with two NGLs storage unit; one underground reservoir; two power plants; one onsite treatment; one CWT facility; one disposal well. Freshwater required in shale sites 1 and 2 was satisfied from freshwater sources 1 and 2 by trucks and from freshwater source 2 by pipeline.

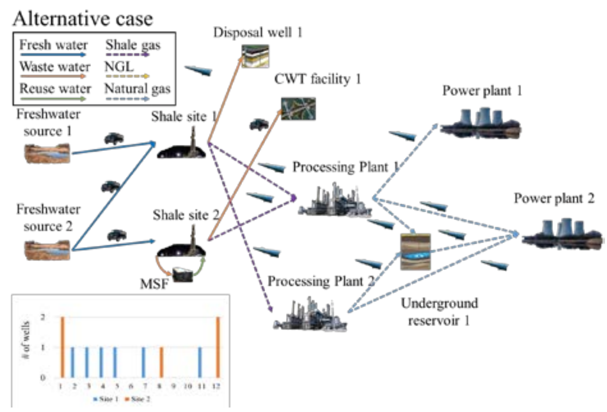

Fig. 5. Optimal network configuration of SGSCN model in Alternative case.

But, unlike Base case, one MSF facility as onsite treatment, one CWT facility, and one disposal well were selected to handle wastewater generated at shale sites. In shale site 1, wastewater was transported to disposal well 1 and it was disposed in deep well without any treatment. In shale site 2, some of generated wastewater was reused at another nearby site by MSF without transportation, and remainder was transported to CWT facility 1 by truck. In terms of well-drilling, like Base case, the same number of wells (six and five) were drilled over three years in shale sites 1 and 2, respectively, with different drilling schedules compared to Base case. Two processing plants were constructed with two NGLs storage units, and after HF in eleven drilled wells, portion and all of the shale gases produced in shale site 1 and 2 were transported to the processing plant 1 using pipeline. The remaining shale gas in shale site 1 was transported to the process plant 2. Finally, natural gas in processing plant 1 was supplied to power plant 1 and 2 and underground reservoir 1, and natural gas in processing plant 2 was supplied to power plant 2 and underground reservoir 1.

VI. CONCLUSIONS

In this study, we focus on the development of a new framework to integrate dynamic modeling of HF, a reservoir simulator call CMG, and SGSCN. The optimal configuration of SGSCN formulated a mixed-integer linear programming was determined while maximizing the profit over a long-term planning horizon with dynamic model of HF. We confirmed that when fractured are created in unconventional reservoirs, the final fracture geometry affects the optimal SGSCN by the amount of recovered wastewater and shale gas production rate.

ACKNOWLEDGMENT

The authors gratefully acknowledge financial support from Artie McFerrin Department of Chemical Engineering and the Texas A&M Energy Institute.

Model nomenclature

Sets

i shale site; k transportation mode; o onsite treatment; t time period of SGSCN; tp time period of shale gas production by MbPS design;

Parameters

$acdw_i$ Water consumption of well drilling process
rr^{onsite}_o Recovery ratio of wastewater
rr^{drill}_i Recovery ratio of wastewater after well drilling
ccsw Correlation for production of wastewater-shale gas

Variables

$FWR_{s,i,k,t}$ Amount of freshwater required
$NDW_{i,t}$ Number of drilled wells
$PS_{i,t}$ Production amount of shale gas
SI^{elec} Sale income of electricity
SI^{NGLs} Sale income of electricity
$WTIC_{i,c,k,t}$ Wastewater transportation amount to CWT
$WTID_{i,d,k,t}$ Wastewater transportation amount to disposal
$WTIO_{i,o,t}$ Wastewater amount treated by onsite treatment

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