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# Optimal design of supply chain network with carbon dioxide injection for enhanced shale gas recovery



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#### HIGHLIGHTS

- Integration of the CO2 injection approach as an enhanced gas recovery technique into an existing SGSCN model.
- Development of an optimization framework to determine the optimal SGSCN configuration that improves gas productivity and reduces air pollution.
- Case studies to examine the effect of CO<sub>2</sub> pulse injection on enhanced gas recovery.

#### ARTICLE INFO

# Keywords: Enhanced gas recovery Mixed-integer linear programming Optimization CO<sub>2</sub> capture CO<sub>2</sub> purchase Marcellus shale

#### ABSTRACT

To optimize the configuration of a supply chain network for shale gas production (SGSCN), we develop a novel optimization model that considers 'enhanced gas recovery by carbon dioxide ( $CO_2$ ) injection' (EGR- $CO_2$ ) technology, which simultaneously achieves decrease in net  $CO_2$  emissions. Then, the developed framework is used to identify the optimal SGSCN configuration in a mixed-integer linear programming problem that maximizes the overall profit of shale gas production. The optimal framework of the proposed SGSCN model is compared to the case (Case 1) when the improvement technology for the shale gas production rate like EGR- $CO_2$  is not used, to demonstrate its superiority over existing approaches. The simulation results that consider application on the Marcellus shale play indicate that the overall profit of SGSCN that uses EGR- $CO_2$  technology and purchases the  $CO_2$  on the market (Case 2) achieves 2.56% higher profit than the SGSCN without an injection strategy (Case 1) and 10.00% higher profit than the SGSCN that uses  $CO_2$  that is recovered from the flue gases generated during combustion of shale gas to produce electricity (Case 3). The profitability of Case 3 is reduced by the cost of constructing and operating a  $CO_2$ -capture facility. For Case 3 to achieve the same profitability as Case 2, the  $CO_2$  purchase must be more expensive than 5 US\$ per MCF  $CO_2$  (0.18 US\$ per M).

# 1. Introduction

Shale gas is natural gas that is trapped in such unconventional reservoirs is becoming an increasingly important source of natural gas in the United States; interest in shale gas also spreads to the rest of the world [1–4]. Compared to conventional reservoirs, the permeability of unconventional reservoirs is very low [5–7]. Therefore, to make shale gas production economically feasible in these reservoirs, the rock must be fractured, so advanced horizontal drilling and hydraulic fracturing (fracking) technologies are being evaluated [5,8–11].

Improvements in reservoir stimulation and shale gas production have made shale gas an economically feasible energy resource [5]. Generally, extraction of shale gas requires a huge amount of freshwater

with added sand and chemicals [12–14]. The profit achieved by shale gas production is accompanied by pollution of water and air. Specifically, at shale wells, after hydraulic fracturing has been completed, flow-back wastewater during shale gas production returns to the surface [12,15], and electricity generation by burning the extracted natural gas generates a significant amount of greenhouse gas (GHG) including carbon dioxide ( $\rm CO_2$ ) [16–18]. These pollutants must be treated appropriately to reduce their environmental impacts. Moreover, extracted shale gas is a hydrocarbon mixture, composed mainly of single-carbon chemicals such as methane [19], so an additional processing unit is required for its subsequent use [16]. Therefore, effective use of shale gas requires understanding of the supply chain network of shale gas production, water management, and GHG mitigation, and related

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Nomenclature		rCEPCI pa	Wastewater recovery ratio after completing hydraulic
Sets		•	fracturing at shale site $i$ [–] Wastewater recovery ratio by OT facility $o$ [–]
	0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	$rr_o^{ot}$	, , , ,
c ,	Centralized wastewater treatment (CWT)	$total_{i,tp}^{SP}$	Amount of shale gas produced at shale site <i>i</i> during time
d	Disposal well (DW)	4 - 4 - 1 SP - e1	period t (original production) [MCF/period]
i	Shale site	$total_{i,tp}^{SP-er}$	
k	Transportation mode	acai	time period <i>t</i> (enhanced production) [MCF/period]
m	Power plant	$uc_{s,t}^{acqi}$	Unit freshwater acquisition cost at freshwater site s during
mm	CO <sub>2</sub> capture plant capacity	CWT	time period t [\$/bbl]
n	Number of the hydraulic fracturing job	$uc_c^{CWT}$	Unit cost of CWT facility c [\$/bbl]
0	Onsite treatment (OT)	$uc_d^{dw}$	Unit cost of disposal well d [\$/bbl]
p	Shale gas processing plant	$uc_{i,t}^{hydraulic}$	Unit cost of hydraulic fracturing at shale site <i>i</i> during time
рi	Pipeline capacity		period t [\$/well]
pr	Shale gas processing plant capacity	$uc^{NGLsto}$	Unit cost of NGL at storage units [\$/MCF]
S	Freshwater site	$uc_o^{ot}$	Unit cost of OT facility o [\$/bbl]
t	Time period of supply chain network	$uc_m^{power}$	Unit cost of electricity at power plant $m$ [\$/MCF]
	Time period of shale gas production rate	$uc^{pro}$	Unit cost of shale gas at each processing plant [\$/MCF]
tp 			Unit cost of shale gas production at shale site <i>i</i> during
и	Underground reservoir	ι,ι	time period $t$ [\$/MCF]
D		$uc_u^{under-i}$	Unit cost of injection at underground reservoir $u$ [\$/MCF]
Paramete	ers —	$uc_u^{under-w}$	Unit cost of withdrawal at underground reservoir <i>u</i>
		$uc_u$	[\$/MCF]
$acdw_i$	Amount of freshwater consumed for each hydraulic frac-	ucane <sup>1</sup>	Unit capital cost of transportation mode <i>k</i> from freshwater
	turing job at shale site $i$ [bbl/well] [1 bbl = 42	$ucapc_{s,i,k}^1$	site $s$ to shale site $i$ [\$/mile]
	gallon = 158.97 L]	$up_t^{NGL}$	
$capc_{pr}^{pro}$	Unit capital cost of a shale gas processing plant with ca-	$up_t$	NGL selling price during time period <i>t</i> [\$/MCF]
	pacity pr [\$]	$utcc_{m,i,k}^{CO2}$	Unit capital cost of transportation mode $k$ from power
$capc_{pi}^{\it pipe}$	Unit capital pipeline cost with capacity pi [\$]	CWT	plant <i>m</i> to shale site <i>i</i> [\$/mile]
CCR	Capital charge rate per year of the total cost [\$/period]	$utcc_{i,c,k}^{CWT}$	Unit capital cost of transportation mode <i>k</i> from shale site <i>i</i>
$ccsw_i$	Correlation coefficient between the amounts of produced	J	to CWT facility c [\$/mile]
	shale gas and recovered wastewater at shale site i [bbl/	$utcc^{dw}_{i,d,k}$	Unit capital cost of transportation mode <i>k</i> from shale site <i>i</i>
	$MCF$ [1 $MCF = 1000 \text{ ft}^3 = 28.3168 \text{ m}^3$ ]	G02	and disposal well d [\$/mile]
$CEPCI^{CO}$	<sup>2</sup> Chemical engineering plant cost index (CEPCI) for a CO <sub>2</sub>	$uvct_k^{CO2}$	Unit variable cost of transportation mode $k$ for $CO_2$
	capture plant [–]		[\$/(bbl mile)]
CEPCIpro	CEPCI for a shale gas processing plant [–]	$uvct_k^{fresh}$	Unit variable cost of transportation mode $k$ for freshwater
	© CEPCI for a pipeline [–]		[\$/(bbl mile)]
	<sup>p</sup> Unit capital cost of a $CO_2$ capture plant with capacity $mm$	$uvct^{pi-n}$	Unit variable cost of pipeline for natural gas [\$/(MCF
cosimm	[\$]		mile)]
$cost_{mm}^{CC-op}$		$uvct^{pi-s}$	Unit variable cost of pipeline for the shale gas [\$/(MCF
cosimm	mm [\$]		mile)]
$d^{well}$	Well depth at each shale well [1 mile = 1.60934 km]	$uvct_k^{waste}$	Unit variable cost of transportation mode <i>k</i> for the was-
	Distance from freshwater site <i>s</i> to shale site <i>i</i> [mile]	ĸ	tewater management [\$/(bbl mile)]
$dis_{s,i}^1$	Distance from shale site $i$ to CWT facility $c$ [mile]	vc	Unit CO <sub>2</sub> storage cost [\$/MCF]
$dis_{i,c}^2$	•		omt coz storage cost [4/ mer]
$dis_{i,d}^3$	Distance from shale site <i>i</i> to disposal well <i>d</i> [mile]	Continuo	us variables
	Distance from shale site $i$ to shale gas processing plant $p$	Continuo	au variables
	[mile]	$C^{cc-cap}$	Total capital cost of CO <sub>2</sub> capture plants [\$]
$dis_{p,m}^5$	Distance from shale gas processing plant <i>p</i> to power plant	Ccc-oper	Total operating cost of $CO_2$ capture plants [\$]
- 6	m [mile]	Ccc-sto	
$dis_{p,u}^6$	Distance from shale gas processing plant <i>p</i> to underground	Ccc-tra	Total storage cost at CO <sub>2</sub> capture plants [\$]
	reservoir <i>u</i> [mile]	Cec in	Total transportation cost from CO <sub>2</sub> capture plants to shale
$dis_{u,m}^7$	Distance from underground reservoir $u$ to power plant $m$	CWT two	sites [\$]
	[mile]	$C^{CWT-tra}$ $C^{CWT-tt}$	Total transportation cost to CWT facilities [\$]
$dis_{m,i}^8$	Distance from power plant <i>m</i> to shale site <i>i</i> [mile]		Total treatment cost of CWT facilities [\$]
disr	Discount rate per each time period	C <sup>dw-injecti</sup>	Total injection cost of disposal Wells [4]
$emp_{m,t}$	Emission factor for the electricity generation at power	$C^{dw-tra}$	Total transportation cost to disposal wells [\$]
	plant <i>m</i> during time period <i>t</i> [MCF/period]	$C^{fresh-a}$	Freshwater acquisition cost at freshwater sites [\$]
$m^1$	Cost parameter for well construction [mile <sup>-1</sup> ]	$C^{fresh-t}$	Freshwater transportation cost from freshwater sites to
$m^2$	Cost parameter for well injection [-]		shale sites [\$]
$OM^{injection}$	<sup>n</sup> Operation and maintenance cost rate per year of the total	$C^{NG-pm}$	Natural gas transportation cost between shale gas pro-
	cost for injection wells [\$/well period]		cessing plants and power plants [\$]
$pr_{tp}^{shale}$	Shale gas production rate at shale sites during time period	$C^{NG-pu}$	Natural gas transportation cost between shale gas pro-
	tp [MCF/period]		cessing plants and underground reservoirs [\$]
	Electricity selling price [\$/kWh]	$C^{NG-um}$	Natural gas transportation costs from underground re-
rCEPCI <sup>C</sup>	O2 CEPCI of the reference year for a CO <sub>2</sub> capture plant [–]		servoirs to power plants [\$]
$rCEPCI^{pt}$	TO CEPCI of the reference year for a shale gas processing	$C^{ot}$	Total onsite treatment cost [\$]
	plant [-]	Cpro-const	ruction Total construction cost of shale gas processing plants

 $C^{pro-construction}$  Total construction cost of shale gas processing plants

plant [-]

facilities [\$] [\$] Cpro-operating Total operating cost of shale gas processing plants [\$] Total cost of SGSCN [\$] TotalCost Cpro-transportation Total transportation cost between shale gas proces-Recovered wastewater after completing hydraulic frac- $WP_{i,t}^h$ sing plants and shale sites [\$] turing at shale site i during time period t [bbl/period]  $WP_{i,t}^{s}$ Recovered wastewater during shale gas production at  $capturedCO2_{m,t}$  Amount of  $CO_2$  captured at power plant m during time period *t* [MCF/period] shale site *i* during time period *t* [bbl/period] WTICi,c,k,t Wastewater transportation amount via transportation  $CTMI_{m,i,t}$  Amount of  $CO_2$  transported from power plant m to shale site *i* during time period *t* [MCF/period] mode *k* from shale sites *i* to CWT facility *c* during time period *t* [bbl/period]  $FWD_{i,t}$ Freshwater requirement at shale site *i* during time period *t* [bbl/period] WTID<sub>i,d,k,t</sub> Wastewater transportation amount via transportation  $FWR_{s,i,k,t}$  Amount of supplied freshwater via transportation mode kmode k from shale site i to disposal well d during time from freshwater site s to shale site i during time period t t period *t* [bbl/period] Wastewater treatment amount by OT facility o at shale site  $WTIO_{i,o,t}$ [bbl/period]  $GE_{m,t}$ *i* during time period *t* [bbl/period] Electricity generation amount at power plant m during time period *t* [kWh/period] Binary variables NTPM<sub>p,m,t</sub> Transportation amounts of natural gas between shale gas processing plant p and power plant m [MCF/period]  $XMI_{m,i,k}^{7}$ 1 if transportation mode k is selected for CO<sub>2</sub> transporta-NTPU<sub>p,u,t</sub> Transportation amounts of natural gas between shale gas tion from power plant s to shale site i; otherwise 0 processing plant p and underground reservoir u [MCF/  $XT^1_{s,i,k}$ 1 if transportation mode k is selected for freshwater transportation from freshwater site s to shale site i; NTUM<sub>u,m,t</sub> Transportation amounts of natural gas from underotherwise 0 ground reservoir u to power plant m [MCF/period]  $XT_{i,c,k}^2$ 1 if transportation mode k is selected for wastewater Overall profit of SGSCN [\$] transportation from shale site i to CWT facility c; other $powerCO2_{m,t}$  Amount of  $CO_2$  emitted at power plant m during time wise 0 period *t* [MCF/period] 1 if transportation mode k is selected for wastewater  $XT_{i,d,k}^3$  $PS_{i,t}$ Shale gas production amount at shale site i during time transportation from shale site i to disposal well d; otherperiod t [MCF/period]  $PSLS_{p,t}$ wise 0 Amount of NGL sold at shale gas processing plant p during 1 if shale gas processing plant p is selected with capacity pr time period *t* [MCF/period] for separation of shale gas; otherwise 0 Profit Profit of SGSCN [\$]  $Y_{m,mm}^{PCC}$ 1 if  $CO_2$  capture plant is selected with capacity mm for  $CO_2$ required $CO2_{i,t}^{pulse}$   $CO_2$  requirement at shale site *i* during time period *t* capture at power plant m; otherwise 0 [MCF/period]  $Y_{pi,i,p}^{pipe-TCP}$ 1 if the pipeline capacity pi is selected for the transporta- $SA_{n,t}^{NGL}$ Storage amount of NGL in NGL storage units at shale gas tion of natural gas from shale site *i* to shale gas processing processing plant p during time period t [MCF/period] plant p; otherwise it is 0 SIelectricity Sale income by selling electricity [\$]  $Y_{pi,p,m}^{pipe-TCPM}$ 1 if the pipeline capacity pi is selected for the transporta- $SI^{NGL}$ Sale income by selling NGL [\$] tion of natural gas from shale gas processing plant p to  $STIP_{i,p,t}$ Shale gas transportation amount between shale site i and power plant m; otherwise it is 0 shale gas processing plant p during time period t [MCF/  $Y_{pi,p,u}^{pipe-TCPU}$ 1 if the pipeline capacity pi is selected for the transportaperiod] tion of natural gas from shale gas processing plant p to  $storedCO2_{m,t}$  CO<sub>2</sub> storage amount at power plant m during time underground reservoir u; otherwise it is 0 period t [MCF/period] 1 if the pipeline capacity pi is selected for the transpor-Total electricity generation [kWh] TAGEtation of natural gas from underground reservoir u to TCCO2capture Total CO2 capture costs at shale sites [\$] power plant m; otherwise it is 0 TCCO2inject Total CO2 injection costs at shale sites including transportation costs [\$] Integer variables  $TC^{fresh}$ Total operation cost of freshwater at freshwater sites [\$]  $TC^{gas-trans}$  Total gas transportation cost for natural gas [\$]  $NHF_{i,t}$ The number of hydraulic fracturing jobs at shale site i TC power Total power plant cost to generate electricity [\$]

during time period t [well/period]

 $NHF_{i,t,tp}^{SP}$ The number of hydraulic fracturing jobs at shale site ibetween time period t and tp [well/period]

processes that supply raw materials, and transport the final products to markets [20].

TCprocessing Total processing cost at shale gas processing plants [\$]

Total shale gas production cost at shale sites [\$]

Total wastewater management cost at management

Total storage cost for natural gas and NGL [\$]

 $TC^{shale}$ 

 $TC^{storage}$ 

 $TC^{waste}$ 

Many previous optimization approaches have been developed to determine the configuration and operating strategy of the supply chain network for shale gas production (SGSCN) [12,15,21-27]. The SGSCN models developed in previous studies consist of two major parts: (1) a water network to provide freshwater that is required in shale wells, and to manage recovered wastewater; (2) a shale gas network to process shale gas and to separate and store natural gas, and to generate electricity by burning it. By formulating a mixed-integer non-linear programming (MINLP) problem, Gao and You [16] further developed

previous studies [21-23] to perform a study of the economics and environmental impact of an SGSCN. The trade-off between two objectives (economics and environmental impacts) was obtained by finding the optimal amount of produced shale gas, wastewater management options, and identifying the ideal number of hydraulic fracturing jobs by using the obtained Pareto-optimal front. To consider the uncertainty in market conditions such as fluctuations in natural gas demand and price, Chebeir et al. [25] determine an optimal configuration of SGSCN as well as management options of wastewater by developing a two-stage stochastic programming model. To optimize the life cycle of a SGSCN, Chen et al. [26] used an inexact multi-criterion decision-making

method under uncertain natural gas production. Recently, in unconventional reservoirs, significant efforts have been made to design a model-based pumping schedule of hydraulic fracturing for enhanced productivity [5,8,28-34]; particularly, they focused on regulating proppant distribution and final fracture geometry at the end of hydraulic fracturing. Motivated by these studies, Ahn et al. [27] integrates a model predictive control-based pumping schedule of hydraulic fracturing [5,8,28-34] and an SGSCN model. Etoughe et al. [15] and Cao et al. [12] proposed a novel framework for an SGSCN, focusing on the wastewater management to optimize their goals with model-based pumping schedules. However, shale gas production by advanced hydraulic fracturing has technological impediment that gas production rates decrease rapidly at shale wells within a year after hydraulic fracturing has been completed, and the environmental disadvantage that CO2 is produced when the natural gas is burned to generate electricity. The maximum amounts of produced shale gas at shale wells and reduction of CO2 emission at power plants should be guaranteed to achieve the economic and environmental benefits of shale gas production. Many studies have developed mathematical models of an economically-viable SGSCN [12,15,21-27,35,36], but did not explicitly consider decreasing shale gas production rates or the CO2 emission in the context of SGSCN.

Enhanced gas recovery by  $CO_2$  injection (EGR- $CO_2$ ), which is a technique to increase the shale gas production rates while decreasing  $CO_2$  emissions, has been proposed as a novel approach to solve these issues simultaneously [37–44]. When a huge amount of  $CO_2$  is injected into shale wells after completing hydraulic fracturing, the  $CO_2$  blows out the trapped shale gas and thereby increases the shale gas recovery rate [40,42,44]. Specifically,  $CO_2$  injected into the shale rocks reaches a higher pressure than the initial pressure of shale gas in the fracture;  $CO_2$  adsorbs to shale rocks more strongly than shale gas, so the  $CO_2$  can liberate adsorbed shale gas [40,42,44]. The shale rock has the potential to sequester a huge amount of the  $CO_2$  that is captured from flue gas emitted at power plants that generate electricity by burning natural gas. Therefore,  $EGR-CO_2$  technology should be considered when determining the optimally-profitable configuration of the SGSCN.

Here we develop a novel framework to apply EGR-CO<sub>2</sub> technology in a model of an SGSCN; this approach will allow simultaneous increase in shale gas production and decrease in net CO<sub>2</sub> emission. In addition to water and shale gas networks described in the previous studies, the proposed model considers a CO<sub>2</sub> network to capture CO<sub>2</sub> at the power plant to reduce the amount of emitted CO<sub>2</sub> and to inject it into shale wells to increase shale gas production; therefore, the proposed framework determines the optimal SGSCN configuration that maximizes overall profits by using the pulsed CO<sub>2</sub> injection. Section 2 presents the problem statement of this study. Section 3 presents constraints and objective function for the proposed SGSCN model. Section 4 applies the proposed model to three case studies to illustrate its superiority over existing approaches. Section 5 presents results and discussion by the proposed model. Conclusions are presented in Section 6.

# 2. Problem statement

This study determines an optimal configuration of the SGSCN model that uses techno-economic assessment of improving gas productivity by EGR-CO<sub>2</sub> technology over a given planning horizon. An optimization problem is formulated by linking several sources (transportation for the freshwater, shale gas, and CO<sub>2</sub>) and sinks (management technologies for wastewater, CO<sub>2</sub> injection options for enhanced gas recovery, and consumption options for generating electricity) in an SGSCN model. Several technologies are considered: hydraulic fracturing; CO<sub>2</sub> capture and injection; water management; shale gas processing; transportation; storage; electricity generation.

#### 2.1. Technology overview

# 2.1.1. Hydraulic fracturing

Hydraulic fracturing technology performs to break rocks in the shale formation and thereby release trapped shale gas. The process is conducted using a highly-pressurized freshwater with added sand and chemicals; it begins with perforation using wellbore explosions to create initial fracture paths. Then, a fracturing fluid is pumped into the wellbore to break the gas-bearing rock and to propagate fractures in the shale formation. Next, water, additives, and proppant (most often sand), called a fracturing slurry, are injected into the wellbore to enable further fracture propagation at a high pressure operating condition; hydraulic fracturing requires a large amount of freshwater because of this step. Some injected proppant is suspended and travels along the fracture; the remaining proppant settles out to form a proppant bank. Due to the natural stress in the formation, once the pumping is stopped, fractures are closed. The remaining fracturing fluid is expelled at the closure process, but by the closing fracture walls, the proppant is trapped. The hydrocarbon flow is facilitated by the propped fracture from the reservoirs to the wellbore.

#### 2.1.2. CO<sub>2</sub> capture and injection

The materials (e.g., natural gas, CO<sub>2</sub>) can be used to increase the gas productivity when the gas production rate at fractured wells begins to decrease after hydraulic fracturing is completed [37–44]. In this study, we consider injection of CO<sub>2</sub> captured from flue gases emitted at power plants that generate electricity by burning natural gas produced at shale sites. CO<sub>2</sub> can be supplied to shale sites from a CO<sub>2</sub> capture plant, which is retrofitted to a power plant that uses natural gas. In this study, an amine-based CO<sub>2</sub> absorption technology is applied because it has high efficiency to capture CO<sub>2</sub> from flue gas; liquid CO<sub>2</sub> is available [45,46]. CO<sub>2</sub> that is captured from flue gas should be stored in the CO<sub>2</sub> storage unit, then transported by truck to be injected into shale wells [40,45]. This study considers two types of injection methods: (1) continuous injection; (2) pulsed injection [40].

Continuous injection of  $CO_2$  is intended to improve the shale gas production rates over a multi-period planning horizon; this method can recover more shale gas than the original shale gas production without any improvement technology [40]. However, the enhanced shale gas extracted after continuous injection operations contains some  $CO_2$  from the injected  $CO_2$ ; so an additional process is required to separate  $CO_2$  from the gas mixture. The pulsed injection method injects  $CO_2$  periodically; although this method can achieve only a small (9.24%) increase in shale gas productivity, the extra shale gas does not contain injected  $CO_2$ , so the additional separation unit is not required [40].

To increase shale gas production, two shale wells are required: an injector and a producer.  $CO_2$  is injected only into an injector. When  $CO_2$  is injected at shale wells, an injector cannot produce shale gas. However, a producer can produce shale gas continuously without cutoff (Fig. 1). The operating steps of pulsed  $CO_2$  injection are as follows: (1) for the first year, production occurs naturally; (2) after 1 year, pulsed  $CO_2$  injection is performed for 3 months (one time period) at an injector; (3) after the completion of  $CO_2$  injection, shale gas produced is increased for 3 years (twelve time periods); (4) after 3 years, pulsed  $CO_2$  injection is performed for 3 months at the injector; (5) Steps (3) and (4) are repeated until production is no longer economically viable.

The total amount of produced shale gas at a producer (208,760 MCF) is 11.11% higher than at an injector (199,716 MCF). Considering the two wells (a producer and an injector), the EGR-CO<sub>2</sub> technology increases the total amount of produced shale gas (408,746 MCF) by 4.53% compared to the original shale gas (390,250 MCF) (Fig. 2).

# 2.1.3. Water management

Use of hydraulic fracturing to break the rocks in shale formations requires a huge amount of freshwater. After fracking has been completed, shale gas trapped in shale formations is extracted from the

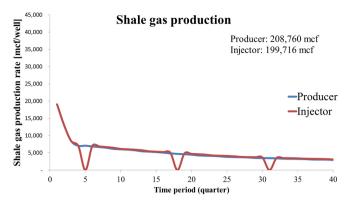


Fig. 1. Shale gas production profiles at a producer and injector.

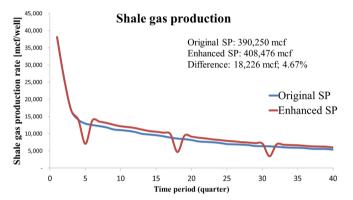


Fig. 2. Comparison of production profiles between original and enhanced shale gas.

stimulated wells. Along with the shale gas, a part of the freshwater that had been pumped into the shale well returns to the surface. This wastewater (i.e., flowback or produced water) contains organic environmental contaminants [47], so it should be managed using appropriate technologies such as a disposal well (DW) [48–51], centralized wastewater treatment (CWT) [48,50–53], or on-site treatment (OT) [48–50,52,53]. A DW is used when the wastewater is supplied and pumped into deep wells without a further treatment. CWT is used to return wastewater to the same condition as surface water, and

discharge the water into a surface field. OT can be used to treat wastewater in various ways [54,55]. Wastewater that has been treated using OT can be mixed with freshwater and reused in other hydraulic fracturing jobs.

#### 2.1.4. Processing shale gas

Shale gas contains hydrocarbons such as butane, propane, and ethane, in addition to the natural gas (methane) [19]; these hydrocarbons, which are called natural gas liquids (NGL), can be used to produce valuable products by other petrochemical industries [16,27], so they can be sold at a high price. Therefore, the extracted shale gas must be separated into natural gas and NGL at shale gas processing plants. The separated natural gas is transported by pipeline from shale gas processing plants to power plants to be burned for electricity generation, and NGL is first stored then transported to market and sold.

#### 2.1.5. Transportation

The SGSCN model considers trucks and pipelines, as modes for transport of freshwater, wastewater, captured  $\mathrm{CO}_2$ , shale gas, and natural gas. Freshwater and wastewater can be transported to shale sites and to wastewater management sites by trucks and/or pipelines. Since the freshwater demand and amount of recovered wastewater at shale sites vary with time, trucks are used to respond flexibly to these variations. Shale gas extracted at shale sites and natural gas separated at shale gas processing plants is generally delivered by pipelines, because the volumes to be transported are large. In this study, however,  $\mathrm{CO}_2$  can be transported from power plants to shale sites by trucks, because we consider pulsed  $\mathrm{CO}_2$  injection; particularly, pulsed  $\mathrm{CO}_2$  injection would require a less amount of  $\mathrm{CO}_2$  than continuous  $\mathrm{CO}_2$  injection.

#### 2.1.6. Storage

For storage, the proposed model considers underground reservoirs to store natural gas, and NGL storage units to store NGL before it is transported to the market and sold. Natural gas is the main resource to generate electricity at power plants. Underground reservoirs are used because they allow response to fluctuations in electricity price and demand, which affect the overall profit of the SGSCN model. Natural gas separated from shale gas can be stored for an indefinite time in underground reservoirs before it is supplied to power plants.

#### 2.1.7. Electricity generation

Electricity is the main product considered here; it is generated by

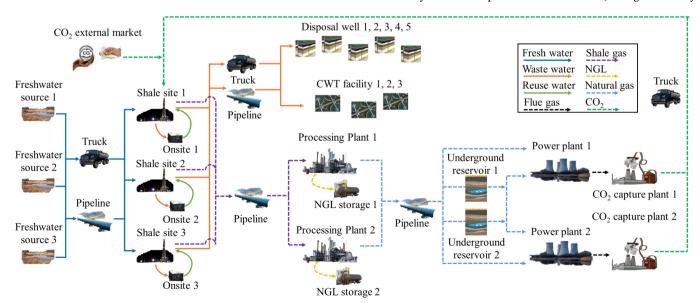


Fig. 3. The superstructure of the SGSCN model.

burning the separated natural gas at power plants. A gas-turbine combined-cycle power plant, which generates electricity with 50% generation efficiency, is considered to be the sink node in the SGSCN model. The electricity is sold on the market to generate profit, but also produces atmospheric CO<sub>2</sub>.

#### 2.2. Configuration of SGSCN model

The objective of the proposed model, which use a typical scheme of supply chain networks, is to decide the SGSCN configuration (Fig. 3) to optimize the following operational strategies while maximizing its profitability: (1) amount of required freshwater: (2) amount of recovered wastewater during shale gas production; (3) management options to process wastewater; (4) shale gas production rates and hydraulic fracturing schedule (original and enhanced production rates); (5) amount of injected CO<sub>2</sub> to increase shale productivity; (6) numbers and capacities of shale gas processing plants at potential locations; (7) storage amounts of natural gas and NGL in storage options; (8) numbers and capacities of power plants to generate electricity at potential locations; (9) amount of CO2 captured from the flue gas emitted at power plants; (10) capacities of trucks and pipelines for freshwater, wastewater, and CO2 among freshwater sites, shale sites, wastewater management facilities, and power plants; (11) capacities of pipeline for two gases (shale gas and natural gas) among power plants, underground reservoirs, shale gas processing plants, and shale sites. The proposed model consists of source and sinks nodes for CO2, shale gas and water networks, as described in Fig. 3.

The water network is composed of nodes for shale sites, freshwater sites, and wastewater management sites. To break the rocks and release the shale gas, a huge amount of freshwater is supplied by appropriate transportation modes between freshwater sites and shale sites. Shale gas is extracted after hydraulic fracturing is completed, along with some of freshwater that had been injected to the shale wells. This recovered wastewater with toxic contaminants is managed using DW, CWT, or OT facilities, to which it must be transported by trucks or pipelines.

The shale gas network is composed of nodes that represent the source and sinks; specifically, these nodes include power plants, underground reservoirs, shale gas processing plants, and shale sites. Extracted shale gas is transported to shale gas processing plants to separate the shale gas into NGL and natural gas. The separated natural gas can be transported to power plants immediately for electricity generation, or stored in underground reservoirs and transported to power plants later. The NGL is stored and later transported to market and sold.

The  $CO_2$  network is composed of nodes for  $CO_2$  capture at power plants, and for  $CO_2$  injection at shale sites. To increase the shale gas production rates, the required  $CO_2$  at shale sites is captured from the flue gas emitted at power plants that burn the natural gas to generate electricity. From the  $CO_2$  capture process at power plants, the captured  $CO_2$  is transported using appropriate modes to shale sites and then injected to increase the gas productivity.

# 3. Model formulation

The proposed SGSCN model is composed of an objective function and several constraints; it was developed from freshwater sites to power plants for the strategic planning design of SGSCN, to simultaneously satisfy demand, resource and technology constraints over a given planning horizon. This study modifies a previous SGSCN [27] to consider the increased gas productivity by CO<sub>2</sub> injection while determining the optimal SGSCN configuration. Most of the parameters and assumptions used in this study are adopted from previous studies [27,40]. The developed model follows a decision structure similar to a previous study [27], but incorporates the reduction in net CO<sub>2</sub> emission at power plants, and the increased gas productivity at shale sites over a given planning horizon. Most of the constraints and objective function are

presented below; the rest of the equations with additional details regarding the proposed model are described in the electronic supplemental information (ESI).

#### 3.1. Objective function

The optimal SGSCN configuration is determined while maximizing Overall profit of SGSCN which is calculated as

$$Overeall \quad profit = Profit - Total \quad cost \tag{1}$$

In the SGSCN model, electricity is the main product and NGL is the byproduct, and when  $\mathrm{CO}_2$  is used at shale sites to increase shale gas productivity, *Profit* can be calculated from the sale incomes  $SI^{electricity}$  of electricity, and  $SI^{NGL}$  of NGL, and benefits  $SI^{CO2}$  by reducing  $\mathrm{CO}_2$  emission:

$$Profit = SI^{electricity} + SI^{NGL} + SI^{CO2}$$
 (2)

where  $SI^{electricity}$  is determined by multiplying the electricity selling price  $pri^{electricity}$  and the total amount of electricity generated TAGE at power plants:

$$SI^{electricity} = pri^{electricity} TAGE$$
 (3)

where TAGE is calculated from the sum of the amount  $GE_{m,t}$  of generated electricity at power plant m during time period t:

$$TAGE = \sum_{m} \sum_{t} GE_{m,t} \tag{4}$$

 $SI^{NGL}$  is calculated from the quantity  $PSLS_{p,t}$  of NGL produced by the SGSCN and sold at shale gas processing plant p during time period t:

$$SI^{NGL} = \sum_{p} \sum_{t} \frac{up_t^{NGL} PSLS_{p,t}}{(1 + disr)^t}$$
 (5)

where disr denotes the discount rate per time,  $PSLS_{p,t}$  is the amount of NGL sold at shale gas processing plant p during time period t, and  $up_t^{NGL}$  denotes the NGL selling price during time period t.

 $SI^{CO2}$  is determined by the reduction in the net amount of  $CO_2$  emission by  $CO_2$  injection at shale sites:

$$SI^{CO2} = \sum_{m} \sum_{i} \sum_{t} pri^{CO2}CTMI_{m,i,t}$$
(6)

where  $pri^{CO2}$  denotes the CO<sub>2</sub> selling price, and  $CTMI_{m,i,t}$  is the amount of CO<sub>2</sub> transported from power plant m to shale site i during time period t.

Totalcost is the sum of (1) total operation cost  $TC^{fresh}$  of freshwater at freshwater sites; (2) total production cost  $TC^{shale}$  of shale gas at shale sites after hydraulic fracturing; (3) total wastewater management cost  $TC^{waste}$  including treatment and transportation costs; (4) total  $CO_2$  injection cost  $TC^{CO2inject}$  to increase gas productivity at shale sites, including transportation costs from power plants to shale sites; (5) total  $CO_2$  capture  $cost TC^{CO2capture}$  at power plants to use the captured  $cost TC^{CO2pur}$  at shale sites to increase gas recovery; (6) total  $cost TC^{CO2pur}$  at shale sites to use  $cost TC^{CO2pur}$  at shale sites to use  $cost TC^{CO2pur}$  at shale sites to separate the natural gas and NGL at shale gas processing cost  $cost TC^{processing}$  to separate the natural gas and NGL at shale gas processing plants; (8) total gas transportation  $cost TC^{gas-trans}$  for natural gas among shale sites, shale gas processing plants, underground reservoirs, and power plants; (9) total storage  $cost TC^{storage}$  for natural gas at underground reservoirs and NGL at NGL storage units; and (10) total power plant  $cost TC^{power}$  to generate electricity using natural gas:

Totalcost

$$= TC^{fresh} + TC^{shale} + TC^{CO2capture} + TC^{CO2inject} + TC^{CO2pur} + T$$

$$C^{waste} + TC^{processing} + TC^{gas-trans} + TC^{storage} + TC^{power}$$
(7)

#### 3.1.1. Supply cost of freshwater

A huge amount of freshwater is required to break the rocks and

release the shale gas at each shale site. The total cost  $TC^{fresh}$  of freshwater is the sum of acquisition cost  $C^{fresh-a}$  and the transportation cost  $C^{fresh-t}$  of freshwater from freshwater sites to shale sites:

$$TC^{fresh} = C^{fresh-a} + C^{fresh-t}$$
 (8)

where  $C^{fresh-a}$  is proportional to the amount of acquired freshwater:

$$C^{fresh-a} = \sum_{s} \sum_{i} \sum_{k} \sum_{t} \frac{uc_{s,t}^{acqi} FWR_{s,i,k,t}}{(1+disr)^{t}}$$

$$\tag{9}$$

where  $FWR_{s,i,k,t}$  is the supplied amount of freshwater from freshwater site s to shale site i by transportation mode k during time period t, and  $uc_{s,t}^{acqi}$  is the unit acquisition cost of freshwater at freshwater site s during time period t.  $C^{fresh-t}$  includes the capital cost and variable cost of the transportation modes:

$$C^{fresh-t} = \sum_{s} \sum_{i} \sum_{k} \sum_{t} \left( ucapc_{s,i,k}^{1} dis_{s,i}^{1} X T_{s,i,k}^{1} + \frac{uvct_{k}^{fresh} dis_{s,i}^{1} FWR_{s,i,k,t}}{(1 + disr)^{t}} \right)$$
(10)

where  $dis_{s,i}^1$  denotes the distance from freshwater site s to shale site i,  $ucapc_{s,i,k}^1$  and  $uvct_k^{fresh}$  denote, respectively, the unit capital cost and unit variable cost of transportation mode k from freshwater site s to shale site i, and  $XT_{s,i,k}^1$  is a binary variable (i.e., '1' if transportation mode k is selected from freshwater site s to shale site s to shale site s for freshwater transportation; '0' otherwise).

#### 3.1.2. Production cost of shale gas

The total production cost  $TC^{shale}$  of shale gas can be calculated from the number of hydraulic fracturing jobs and the produced amount of shale gas at shale sites; its cost includes the several costs for shale gas production and hydraulic fracturing jobs considering all shale sites:

$$TC^{shale} = \sum_{i} \sum_{t} \frac{uc_{i,t}^{hydraulic} NHF_{i,t}}{(1+disr)^{t}} + \sum_{i} \sum_{t} \frac{uc_{i,t}^{shale} \quad production}{(1+disr)^{t}}$$
(11)

where  $PS_{i,t}$  is the shale gas production amount at shale site i during time period t,  $NHF_{i,t}$  denotes the number of hydraulic fracturing jobs at shale site i during time period t,  $uc_{i,t}^{hydraulic}$  and  $uc_{i,t}^{shale}$  production describe, respectively, the unit costs for shale gas production and hydraulic fracturing jobs at shale site i during time period t.

#### 3.1.3. Capture and injection cost of CO2

 ${\rm CO_2}$  is captured from flue gas to supply the required  ${\rm CO_2}$  to shale sites; its cost,  $TC^{CO2capture}$ , is the sum of (1) capital  ${\rm cost}C^{cc-cap}$  of  ${\rm CO_2}$  capture plants, (2) operating cost  $C^{cc-op}$  of  ${\rm CO_2}$  capture plants, (3) storage  ${\rm cost}C^{cc-sto}$  of captured  ${\rm CO_2}$ , and (4) transportation  ${\rm cost}C^{cc-tra}$  from  ${\rm CO_2}$  capture plants to shale sites:

$$TC^{CO2capture} = C^{cc-cap} + C^{cc-op} + C^{cc-sto} + C^{cc-tra}$$
(12)

where  $C^{cc-cap}$  is determined by the capacities of  $CO_2$  capture plants:

$$C^{cc-cap} = \sum_{mm} \sum_{m} cost_{mm}^{CC-cap} Y_{m,mm}^{PCC} \left( \frac{CEPCI^{CO2}}{rCEPCI^{CO2}} \right)$$
(13)

where  $Y_{m,mm}^{PCC}$  is a binary variable (i.e., '1' if  $\mathrm{CO}_2$  capture plant m is selected with capacity mm for  $\mathrm{CO}_2$  capture; '0' otherwise),  $cost_{mm}^{CC-cap}$  is the capital cost of  $\mathrm{CO}_2$  capture plant with capacity mm, and  $CEPCI^{CO2}$  and  $rCEPCI^{CO2}$  denote, respectively, the chemical engineering plant cost index (CEPCI) for  $\mathrm{CO}_2$  capture plants and their CEPCI of the reference year.

 $C^{cc-op}$  is calculated from the amount of captured  ${\rm CO_2}$  and operating parameter of  ${\rm CO_2}$  capture plants:

$$C^{cc-op} = \sum_{m} \sum_{t} cost_{mm}^{CC-op} capturedCO2_{m,t}$$
(14)

where  $cost_{mm}^{CC-op}$  is the operating cost of  $CO_2$  capture plant with capacity mm, and  $capturedCO2_{m,t}$  is the amount of  $CO_2$  captured at power plant m during time period t. Before captured  $CO_2$  is transported from  $CO_2$ 

capture plants to shale sites, it should be stored in  $CO_2$  storage tanks at  $CO_2$  capture plants.

 $C^{CC-sto}$  depends on the amount of stored  $CO_2$ :

$$C^{CC-sto} = \sum_{m} \sum_{t} \frac{vcstoredCO2_{m,t}}{(1+disr)^{t}}$$
(15)

where vc denotes the unit storage cost of CO<sub>2</sub>, and  $storedCO2_{m,t}$  is the storage amount of CO<sub>2</sub> at power plant m during time period t. The cost of CO<sub>2</sub> transport to the shale site is

$$C^{CC-tra} = \sum_{m} \sum_{i} \sum_{k} \sum_{t} \left( utcc_{m,i,k}^{co2} dis_{m,i}^{8} XMI_{m,i,k}^{7} + \frac{uvct_{k}^{CO2} dis_{m,i}^{8} CTMI_{m,i,t}}{(1 + disr)^{t}} \right)$$
(16)

where  $dis_{m,i}^{8}$  denotes the distance between power plant m and shale site i,  $utcc_{m,i,k}^{cO2}$  and  $uvct_k^{CO2}$  denote, respectively, the unit capital and variable cost of transportation mode k from power plant m to shale site i,  $XMI_{m,i,k}^{7}$  is a binary variable (i.e., '1' if transportation mode k is selected for captured  $CO_2$  transportation from power plant m to shale site i; '0' otherwise), and  $CTMI_{m,i,t}$  is the amount of  $CO_2$  transported from power plant m to shale site i during time period t.

The cost of injecting captured  $CO_2$  into the shale well is [56,57]:

$$TC^{CO2inject} = \sum_{i} \sum_{t} NHF_{i,t}(CCR + OM^{injection})(m^{1}d^{well} + m^{2})$$
(17)

where CCR is the capital charge rate per year of the total cost,  $OM^{injection}$  is the operation and maintenance cost rate per year of the total cost for injection wells,  $m^1$  is the cost parameter of well construction,  $d^{well}$  is the well depth at each shale well, and  $m^2$  the cost parameter of injection.

Total  $CO_2$  purchasing cost at shale sites  $TC^{CO2pur}$  from external markets is

$$TC^{CO2pur} = pri^{CO2}TIA^{CO2}$$
 (18)

where  $TIA^{CO2}$  denotes the total amount of injected  $CO_2$  at shale sites:

$$TIA^{CO2} = \sum_{i} \sum_{t} requiredCO2_{i,t}^{pulse}$$
(19)

where  $requiredCO2_{i,t}^{pulse}$  is the total amount of required  $CO_2$  at shale site i during time period t.

#### 3.1.4. Wastewater management cost

The total wastewater management cost  $TC^{waste}$  is the sum of (1) onsite treatment cost  $C^{ot}$ ; (2) injection cost  $C^{dw-injection}$  of disposal well; (3) transportation cost  $C^{dw-tra}$  of disposal well; (4) treatment cost  $C^{CWT-tt}$  of CWT facility; and (5) transportation cost  $C^{CWT-tra}$  of CWT facility:

$$TC^{waste} = C^{ot} + C^{dw-injection} + C^{dw-tra} + C^{CWT-tt} + C^{CWT-tra}$$
 (20)

where  $C^{ot}$  is the OT treatment cost, and includes the variable cost and capital cost of the treatment facilities that are selected to reuse the wastewater recovered during shale gas production. In this study, assuming that the OT facilities operate near the shale sites where hydraulic fracturing is done, the distance from shale sites to OT facilities is ignored:

$$C^{ot} = \sum_{i} \sum_{o} \sum_{t} \frac{uc_o^{ot} WTIO_{i,o,t}}{(1 + disr)^t}$$

$$\tag{21}$$

where  $WTIO_{i,o,t}$  denotes the treatment amount of wastewater by OT facility o at shale site i during time period t, and  $uc_o^{ot}$  is the unit cost at OT facility o to treat wastewater for reuse.

 $C^{dw-injection}$  is the injection cost of the wastewater for all disposal wells:

$$C^{dw-injection} = \sum_{i} \sum_{d} \sum_{k} \sum_{t} \frac{uc_{d}^{dw}WTID_{i,d,k,t}}{(1+disr)^{t}}$$
(22)

where  $WTID_{i,d,k,t}$  denotes the transportation amount of wastewater by

mode k between shale site i and disposal well d during time period t, and  $uc_d^{dw}$  is the unit disposal cost of disposal well d.

 $C^{dw-tra}$  is the total transportation cost between shale sites and disposal wells:

$$C^{dw-tra} = \sum_{i} \sum_{d} \sum_{k} \sum_{t} \left( utcc_{i,d,k}^{dw} dis_{i,d}^{3} X T_{i,d,k}^{3} + \frac{uvct_{k}^{waste} dis_{i,d}^{3} W T I D_{i,d,k,t}}{(1 + disr)^{t}} \right)$$
(23)

where  $dis_{i,d}^{dw}$  denotes the distance between disposal well d and shale site i,  $utcc_{i,d,k}^{dw}$  and  $uvct_k^{waste}$  denote, respectively, the unit capital and variable costs of transportation mode k between disposal well d and shale site i, and  $XT_{i,d,k}^3$  is a binary variable (i.e., '1' if transportation mode k is selected from shale site i to disposal well d for wastewater transportation; '0' otherwise).

 $C^{CWT-tt}$  is the CWT facility treatment cost, and includes the operating cost determined by the amount of wastewater transported:

$$C^{CWT-tt} = \sum_{i} \sum_{c} \sum_{k} \sum_{t} \frac{uc_{c}^{CWT} WTIC_{i,c,k,t}}{(1 + disr)^{t}}$$
(24)

where  $WTIC_{i,c,k,t}$  denotes the wastewater transported by mode k between CWT facility c and shale site i during time period t, and  $uc_c^{CWT}$  is the unit treatment cost of CWT facility c.

 $C^{CWT-tra}$  is the total transportation cost for CWT facilities between shale sites and CWT facilities:

$$C^{CWT-tra} = \sum_{i} \sum_{c} \sum_{k} \sum_{t} \left( utcc_{i,c,k}^{CWT} dis_{i,c}^{2} XT_{i,c,k}^{2} + \frac{uvct_{k}^{waste} dis_{i,c}^{2} WTIC_{i,c,k,t}}{(1+disr)^{t}} \right)$$

$$(25)$$

where  $dis_{i,d}^2$  denotes the distance from shale site i to CWT facility c,  $utcc_{i,c,k}^{CWT}$  denotes the unit capital cost of transportation mode k between CWT facility c and shale site i, and  $XT_{i,c,k}^2$  is a binary variable (i.e., '1' if transportation mode k is selected between shale site i and CWT facility c for wastewater transportation; '0' otherwise). The treated wastewater is discharged as surface water.

# 3.1.5. Processing cost of shale gas

To separate the shale gas that is extracted after hydraulic fracturing, a shale gas processing plant is necessary; its total cost  $TC^{pro-cessing}$  is determined by considering (1) construction  $costC^{pro-construction}$ , (2) operating  $cost C^{pro-operating}$ , and (3) transportation  $cost C^{pro-transportation}$ , of shale gas processing plants:

$$TC^{processing} = C^{pro-construction} + C^{pro-operating} + C^{pro-transportation}$$
 (26)

 $C^{pro-construction}$  is calculated from the capacities of shale gas processing plants, given by:

$$C^{pro-construction} = \sum_{pr} \sum_{p} cap c_{pr}^{pro} Y_{pr,p}^{PC} \left( \frac{CEPCI^{pro}}{rCEPCI^{pro}} \right)$$
(27)

where  $Y_{pr,p}^{PC}$  is a binary variable (i.e., '1' if shale gas processing plant p is selected with capacity pr for separation of shale gas; '0' otherwise),  $capc_{pr}^{pro}$  is the capital cost of shale gas processing plants with capacity pr,  $CEPCI^{pro}$  is the CEPCI for shale gas processing plants, and  $rCEPCI^{pro}$  is their CEPCI for the reference year.

 $C^{pro-opeating}$  is the operating cost of shale gas processing plants:

$$C^{pro-operating} = \sum_{i} \sum_{p} \sum_{t} \frac{uc^{pro}STIP_{i,p,t}}{(1 + disr)^{t}}$$
(28)

where  $STIP_{i,p,t}$  is the transportation amount of shale gas between shale site i and shale gas processing plant p during time period t, and  $uc^{pro}$  is the unit processing cost of shale gas at each processing plant.

 $C^{pro-transportation}$  is the shale gas transportation cost from shale sites to shale gas processing plants, and includes the capital cost and operating cost for pipelines:

cpro-transportation

$$= \sum_{pi} \sum_{i} \sum_{p} cap c_{pi}^{pipe} Y_{pi,l,p}^{pipe-TCP} \left( \frac{CEPCI^{pipe}}{rCEPCI^{pipe}} \right) +$$

$$\sum_{i} \sum_{p} \sum_{t} \frac{uvct^{pi-s} dis_{i,p}^{4} STIP_{i,p,t}}{(1+disr)^{t}}$$
(29)

where  $CEPCI^{pipe}$  is the CEPCI for pipelines and  $rCEPCI^{pipe}$  is that of the reference year,  $Y_{pi,i,p}^{pipe-TCP}$  is a binary variable (i.e., '1' if pipeline capacity pi is selected for the transportation of natural gas between shale site i and shale gas processing plant p; '0' otherwise),  $dis_{i,p}^{4}$  is the distance from shale site i to shale gas processing plant p,  $capc_{pi}^{pipe}$  is the capital cost of the pipeline with capacity pi, and  $uvct_{i}^{pi-s}$  is the unit variable cost of pipeline transportation for shale gas from shale sites to shale gas processing plants.

#### 3.1.6. Transportation cost of separated natural gas

To generate electricity, which is the main product in this study, natural gas separated from shale gas extracted at shale sites must be transported to power plants; this process entails three costs: (1)  $C^{NG-pm}$  between shale gas processing plants and power plants; (2)  $C^{NG-pu}$  between shale gas processing plants and underground reservoirs; and (3)  $C^{NG-um}$  between underground reservoirs and power plants. The total transportation cost considering these three options is calculated as:

$$TC^{gas-trans} = C^{NG-pm} + C^{NG-pu} + C^{NG-um}$$
(30)

 $C^{NG-pn}$ 

$$= \sum_{pi} \sum_{p} \sum_{m} \left( capc_{pi}^{pipe} Y_{pi,p,m}^{pipe-TCPM} dis_{p,m}^{5} \left( \frac{CEPCI^{pipe}}{rCEPCI^{pipe}} \right) \right) +$$

$$\sum_{p} \sum_{m} \sum_{t} \left( \frac{uvct^{pi-n} dis_{p,m}^{5} NTPM_{p,m,t}}{(1+disr)^{t}} \right)$$
(31)

CNG−pı

$$= \sum_{pi} \sum_{p} \sum_{u} \left( capc_{pi}^{pipe} Y_{pi,p,u}^{pipe-TCPU} dis_{p,u}^{6} \left( \frac{CEPCI^{pipe}}{rCEPCI^{pipe}} \right) \right) +$$

$$\sum_{p} \sum_{m} \sum_{t} \left( \frac{uvct^{pi-n} dis_{p,u}^{6} NTPU_{p,u,t}}{(1+disr)^{t}} \right)$$
(32)

 $C^{NG-un}$ 

$$= \sum_{pl} \sum_{u} \sum_{m} \left( cap c_{pl}^{pipe} Y_{pl,u,m}^{pipe-TCUM} dis_{u,m}^{7} \left( \frac{CEPCI^{pipe}}{rCEPCI^{pipe}} \right) \right) +$$

$$\sum_{u} \sum_{m} \sum_{t} \left( \frac{uvct^{pl-n} dis_{u,m}^{7} NTUM_{u,m,t}}{(1 + disr)^{t}} \right)$$
(33)

where  $dis_{p,m}^5$ ,  $dis_{p,u}^6$ , and  $dis_{u,m}^7$  denote, respectively, the distances from shale gas processing plant p to underground reservoir u, and from underground reservoir u to power plant m.  $Y_{pi,p,m}^{pipe-TCPM}$ ,  $Y_{pi,p,u}^{pipe-TCPU}$ , and  $Y_{pi,u,m}^{pipe-TCUM}$  are binary variables (i.e., respectively, '1' if the pipeline is selected with capacity pi for the natural gas transportation from shale gas processing plant p to power plant m, from shale gas processing plant p to underground reservoir pi, and from underground reservoir pi to power plant pi, pi to the transportation amounts of natural gas from shale gas processing plant pi to underground reservoir pi to power plant pi, from shale gas processing plant pi to underground reservoir pi to power plant pi, from shale gas processing plant pi to underground reservoir pi to power plant pi, from shale gas processing plant pi to underground reservoir pi to power plant pi, and pi to underground reservoir pi to power plant pi, and pi to underground reservoir pi to power plant pi, and pi to underground reservoir pi is the unit variable cost of pipeline for natural gas.

# 3.1.7. Storage of natural gas and NGL

Two storage options are considered: underground reservoirs for natural gas and NGL storage units for NGL. The total storage cost  $TC^{storage}$  sums the costs of these two options:

 $TC^{storage}$ 

$$= \sum_{u} \sum_{t} \left( \frac{\left(\sum_{p} u c_{u}^{under-i} NTPU_{p,u,t} + \sum_{m} u c_{u}^{under-w} NTUM_{u,m,t}\right)}{(1 + disr)^{t}} \right) + \sum_{p} \sum_{t} \frac{u c^{NGLsto} SA_{p,t}^{NGL}}{(1 + disr)^{t}}$$
(34)

where  $SA_{p,i}^{NGL}$  denotes the storage amount of NGL in NGL storage units at shale gas processing plant p during time period t,  $uc_u^{under-i}$  and  $uc_u^{under-w}$  denote, respectively, the unit costs for the injection and withdrawal of wastewater at underground reservoir u, and  $uc^{NGLsto}$  is the unit NGL storage cost at NGL storage unit.

#### 3.1.8. Generation cost of electricity

The electricity produced by burning natural gas from the SGSCN is sold on the market. The total cost  $TC^{power}$  of generating electricity is

$$TC^{power} = \sum_{m} \sum_{t} \left( \frac{uc_{m}^{power}}{(1 + disr)^{t}} \left( \sum_{p} NTPM_{p,m,t} + \sum_{u} NTUM_{u,m,t} \right) \right)$$
(35)

where  $uc_m^{power}$  is the unit generation cost of electricity at power plant m.

#### 3.2. Constraints

Constraints on freshwater supply, was tewater management, shale gas production, and  $\mbox{CO}_2$  capture and injection are described.

#### 3.2.1. Freshwater supply

The freshwater requirement  $FWD_{i,t}$  at shale site i during time period t is calculated from the number of hydraulic fracturing jobs as:

$$FWD_{i,t} = acdw_i NHF_{i,t} \quad \forall i, t$$
 (36)

where  $acdw_i$  is the freshwater consumption for each hydraulic fracturing job at shale site i, and  $NHF_{i,t}$  is the number of hydraulic fracturing jobs at shale site i during time period t.

 $FWD_{i,t}$  is supplied by the freshwater supply from freshwater sites and by reusing wastewater treated by OT facilities:

$$FWD_{i,t} = \sum_{s} \sum_{k} FWR_{s,i,k,t} + \sum_{o} rr_o^{ot} WTIO_{i,o,t} \quad \forall i, t$$
(37)

where  $FWR_{s,i,k,t}$  is the transportation amount of freshwater by mode k between freshwater site s and shale site i during time period t,  $WTIO_{i,o,t}$  is the wastewater treatment amount by OT facility o at shale site i during time period t, and  $rr_o^{ot}$  is the recovery ratio of treated wastewater by facility o.

# 3.2.2. Wastewater generation

For shale gas production, water consumption is important in unconventional reservoirs because two types of wastewater are recovered. After hydraulic fracturing has been completed, the amount  $WP^h_{i,t}$  of recovered wastewater is calculated from the number  $NHF_{i,t}$  of hydraulic fracturing jobs at shale site i during time period t, and the recovery ratio  $r_i^h$  of wastewater at shale site i:

$$WP^{h}_{i,t} = acdw_{i}rr_{i}^{h}NHF_{i,t} \quad \forall i, t$$
(38)

Also, the amount  $WP_{i,t}^s$  of recovered wastewater is calculated from the ratio that is recovered from the total production amount of shale gas:

$$WP^{s}_{i,t} = ccsw_{i}PS_{i,t} \quad \forall i, t$$
(39)

where  $PS_{i,t}$  is the shale gas production amount at shale site i during time period t, and  $ccsw_i$  is the correlation coefficient between the amounts of produced shale gas and recovered wastewater at shale site i. To process two types of wastewater recovered after hydraulic fracturing has been completed, three wastewater management technologies are applied:

$$WP^{h}_{i,t} + WP^{s}_{i,t}$$

$$= \sum_{c} \sum_{k} WTIC_{i,c,k,t} + \sum_{d} \sum_{k} WTID_{i,d,k,t} + \sum_{o} \sum_{k} WTIO_{i,o,t} \quad \forall i, t$$

$$(40)$$

where  $WTID_{i,d,k,t}$  and  $WTIC_{i,c,k,t}$  are, respectively, the transportation amount of wastewater by mode k between shale site i and CWT facility c, and between shale site i and disposal well d during time period t.

#### 3.2.3. Shale gas production

After hydraulic fracturing has been completed, the amount of produced shale gas at each shale site is given by:

$$\sum_{tp} NHF_{i,t,tp}^{SP} p r_{tp}^{shale} = PS_{i,t} \quad \forall i, t$$
(41)

where  $p_{tp}^{shale}$  is the shale gas production rate at shale sites during time period tp, and  $NHF_{i,tp}^{SP}$  is the number of hydraulic fracturing jobs at shale site t between time periods t and tp. Details of other constraints and parameters used in SGSCN are presented in the ESI.

#### 3.2.4. CO<sub>2</sub> capture and injection

In the case of  $CO_2$  injection design for SGSCN model, the amount of shale gas produced at shale sites is equal to the increased amount of shale gas production at shale sites:

$$PS_{i,t} = total_{i,tp}^{SP-enhanced} \quad \forall i, t = tp$$
 (42)

where  $PS_{i,t}$  is the shale gas production amount at shale site i during time period t, and  $total_{i,tp}^{SP-enhanced}$  is the increased shale gas production amount at shale site i during time period tp. When natural gas is burned to produce electricity at power plants,  $CO_2$  is emitted; the amount is:

$$powerCO2_{m,t} = emp_{m,t}GE_{m,t} \quad \forall m, t$$
(43)

where  $powerCO2_{m,t}$  denotes the amounts of  $CO_2$  emitted at power plant m during time period t, and  $emp_{m,t}$  is the emission factor for the electricity generation at power plant m during time period t. The amount of captured  $CO_2$  cannot exceed the total amount of emitted  $CO_2$  at power plants:

$$capturedCO2_{m,t} \le powerCO2_{m,t} \quad \forall m, t$$
 (44)

where  $capturedCO2_{m,t}$  is the total amount of  $CO_2$  captured at power plant m during time period t. Captured  $CO_2$  is held in a storage unit for  $CO_2$ , then transported to shale sites. The total amount of  $CO_2$  stored at power plant m during time period t is determined by the captured  $CO_2$ , stored  $CO_2$ , and transported  $CO_2$ :

$$storedCO2_{m,t} = capturedCO2_{m,t} + storedCO2_{m,t-1} - \sum_{i} CTMI_{m,i,t}$$
  $\forall$ 

where  $storedCO2_{m,t}$  is the total amount of  $CO_2$  stored at power plant m during time period t. Finally, the total amount of  $CO_2$  required for the pulsed injection is:

$$requiredCO2_{i,t}^{pulse} = \sum_{m} CTMI_{m,i,t} \quad \forall i, t$$
(46)

where  $requiredCO2_{i,t}^{pulse}$  is the total  $CO_2$  requirement at shale site i during time period t.

# 4. Case study

To demonstrate the proposed model for the shale gas production considering enhanced gas productivity, three case studies where the Marcellus shale play is considered were adopted from [16,27]. The design parameters (Table 1) for SGSCN model are taken from the previous studies, and presented in Table 1.

Three cases (Fig. 4) are considered in this study as follows: Case 1 (SGSCN design with no  $CO_2$  injection); Case 2 (SGSCN design with EGR-

**Table 1**Design parameters for SGSCN model.

Papameter	Quantity	Reference
Freshwater sites	3	[23]
Shale sites	3	[58]
Maximum number of hydraulic fracturing jobs	6	[5]
Disposal wells	5	[59]
CWT facilities	3	[60,61]
OT technologies	MSF, MED, and RO	[60,61]
Shale gas processing plants	2	[62]
Power plants	2	[63,64]
Underground reservoirs	2	[65]
CO <sub>2</sub> capture plants	2	[40,45]
Transportation modes	Truck and pipeline	[16]
Total planning horizon	10 years	[22]

 $\mathrm{CO}_2$  from external markets); Case 3 (SGSCN design with EGR-CO $_2$  from  $\mathrm{CO}_2$  capture plants).

To compare the optimal configurations among the three cases, we used ten assumptions:

- (1) Shale gas, which has a constant composition, is extracted when the hydraulic fracturing is completed.
- (2) Produced shale gas is an ideal gas mixture.
- (3) Hydraulic fracturing is completed within three months (one time period)
- (4) One time period denotes three months, and the total production period is ten years (forty time periods).
- (5) Shale gas production rate decreases with time in each well (Table S1, Figs. S1 and S2).
- (6) Wastewater with a constant composition is recovered during shale gas production.
- (7)  $CO_2$  is captured from flue gases for use in pulsed  $CO_2$  injection at shale sites.
- (8) The capacities of shale gas processing plants for the separation of shale gas and pipelines for material transportation must be determined considering presented data (Table S2).
- (9) NGL and electricity generated in power plants are sold.
- (10) The capacities of CO<sub>2</sub> capture plants must be determined considering presented data (Table S3).

Remark 1. In this case study, we have considered a Marcellus shale play to determine the optimal configuration of SGSCN considering the enhanced gas recovery by CO<sub>2</sub> injection. We have used the data obtained from a previous study to evaluate the economic feasibility of the proposed approach. There is the Brugge benchmarking case by Peters et al. (2010) [66], which is a publicly available dataset of a faulted reservoir with 20 producers and 10 injectors. However, to our best knowledge, no research has been performed to determine the optimal configuration of SGSCN while considering multiple CO<sub>2</sub>-injection and gas-production wells to increase the shale gas production rate. Furthermore, the optimization approach proposed in this study can be directly applicable to large-scale case studies provided that necessary optimization models and model parameters are available.

#### 5. Results and discussion

This section explains how to determine the optimal configuration of SGSCN by considering the effect of EGR-CO $_2$  technology to increase the shale gas production rates and decrease the net amount of CO $_2$  emission. The proposed SGSCN model was solved using GAMS 24.3.1 (CPLEX 12.6) with Intel® Core™ i5-7200 CPU @2.50 GHz and 16 GB RAM. The proposed problems include 1,166 discrete variables, 46,238 continuous variables, and 47,785 constraints.

#### 5.1. Optimal costs

After conducting three case studies, the overall profit of the proposed model (Fig. 5) over the 10-year operation was calculated considering the three profits (i.e., incomes by selling NGL and electricity, and benefit by reducing  $CO_2$  emission) and ten costs (i.e., gas production cost, gas transportation cost, gas processing cost, storage cost for shale gas and NGL, power plant cost, wastewater management cost, freshwater transportation cost,  $CO_2$  capture cost,  $CO_2$  injection cost, and  $CO_2$  purchasing cost).

Case 1 and Case 2. The overall profit of Case 2 (US\$240  $\times$  10<sup>6</sup>), which utilized the EGR-CO2 technology for improving gas productivity by pulsed injection using CO2 obtained from the external market, was 2.56% higher than that of Case 1 (US\$234  $\times~10^6$  ), which considered the original shale gas production rates without any technology to increase shale gas productivity. In Case 1 and Case 2, the profits obtained by income from selling electricity (Case 1: US\$415  $\times$  10<sup>6</sup>; Case 2: US\$433  $\times$  10<sup>6</sup>) on the external market at US\$ 0.1215 per kW·h [67] dominate the other costs. Sale of NGL separated from shale gas (Case 1: US\$28  $\times$  10<sup>6</sup>; Case 2: US\$29  $\times$  10<sup>6</sup>) is another major profit in the optimal costs in both cases. The total costs expect for profit from electricity and NGL were Case 1: US\$199 × 106; Case 2: US  $$220 \times 10^6$ . Specifically, in these cases, the costs of the shale gas processing (Case 1: US\$158  $\times$  10<sup>6</sup>; Case 2: US\$159  $\times$  10<sup>6</sup>) included the construction costs as well as the operating costs, and were therefore higher than the other costs. The power plant costs to generate electricity are the next highest costs (Case 1: US\$21  $\times$  10<sup>6</sup>; Case 2: US\$22  $\times$  10<sup>6</sup>); they include the costs to transport the natural gas to power plants for electricity generation.

Case 3. The overall profit of Case 3 (US\$216  $\times$  10<sup>6</sup>), which utilized the EGR-CO<sub>2</sub> technology to increase gas productivity by pulsed injection using CO<sub>2</sub> obtained from CO<sub>2</sub> capture plant, was 7.69% and 10.00% lower than those of Case 1 and Case 2, respectively. The reason is that the construction cost of the CO<sub>2</sub>-capture plant is higher than the CO<sub>2</sub> benefit obtained by reducing net CO<sub>2</sub> emission by CO<sub>2</sub> injection at shale sites (CO<sub>2</sub> purchasing cost and CO<sub>2</sub> benefit are calculated using the same price; i.e., US\$2 per MCF [57]), so in Case 3, the total cost of CO<sub>2</sub> capture plants including CO<sub>2</sub> transportation is US\$43  $\times$  10<sup>6</sup>. These results were observed in the optimal configurations of the SGSCN model computed for all three cases.

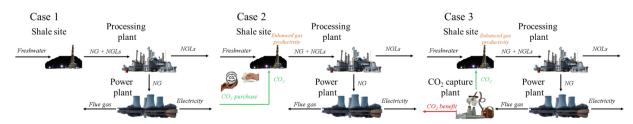


Fig. 4. Simplified SGSCN diagrams for the three case studies.

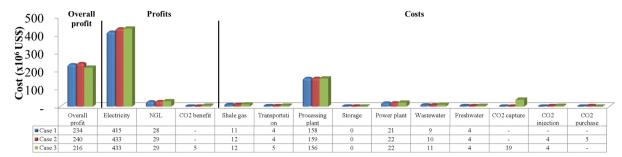


Fig. 5. Optimal SGSCN costs based on different cases.

#### 5.2. Optimal configuration

For Case 1, the optimal configuration of SGSCN model was: three freshwater sites (Fig. 6); two shale sites with ten hydraulic fracturing jobs; two processing plants with two NGL storage units; two underground reservoirs; two power plants, one DW; one OT; and one CWT facility.

All freshwater requirements in two shale sites were transported by trucks from freshwater sites. The amounts of freshwater supplied to Shale site 1 were transported from Freshwater sites 1 (405,000 bbl), 2 (405,000 bbl), and 3 (651,466 bbl). At Shale site 1, one CWT facility (wastewater treated to the shale state as surface water), one DW (injection to a deep well without any treatment), and one OT facility (treatment to reuse the treated water at other shale wells or shale sites) were selected to process the recovered wastewater during shale gas production. All wastewater and treated water were supplied by trucks. All recovered wastewater at Shale site 1 was handled by DW (1,113,214 bbl), CWT facility (444,296 bbl), and OT facility (15,000 bbl). The amounts of freshwater supplied to Shale site 2 were also transported from Freshwater sites 1 (270,000 bbl), 2 (270,000 bbl), and 3 (260,661

bbl) by trucks. At Shale site 2, the recovered wastewater was treated by one CWT facility (798,596 bbl) and was transported only by truck. In total, ten hydraulic fracturing jobs were completed over twelve time periods (36 months) in Shale sites 1 (six shale wells) and 2 (four shale wells).

Two processing plants were constructed to separate the extracted shale gas at the two shale sites; two processing plants 1 and 2 handled 28,502,240 and 74,001 MCF of natural gas and NGL per time period, respectively. The extracted shale gas was supplied to shale gas processing plants via pipelines to separate natural gas and NGL, and the natural gas separated at shale gas processing plants was transported via pipelines to the two power plants to be burned to generate electricity, or to the two underground reservoirs to wait until electricity price increased; the total amounts of produced electricity were 2,185,217,148 MW·h at Power plant 1, and 1,227,666,547 MW·h at Power plant 2.

In Case 2, the optimal configuration of SGSCN model was determined as follows (Fig. 7; Tables 2, 3): three freshwater sites; two shale sites with ten hydraulic fracturing jobs; two shale gas processing plants with two NGL storage units; one underground reservoir; two

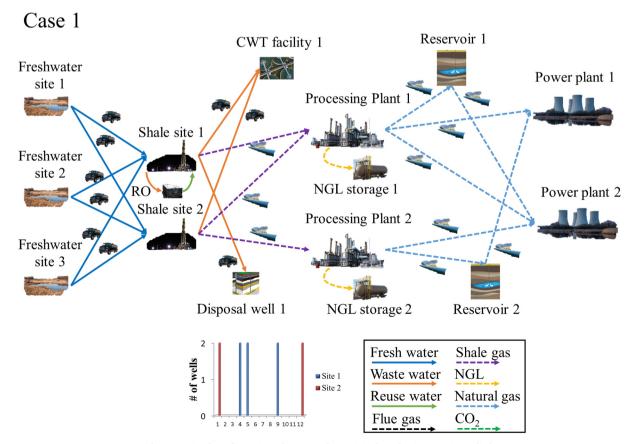


Fig. 6. Optimal configuration of SGSCN when original production rate is applied.

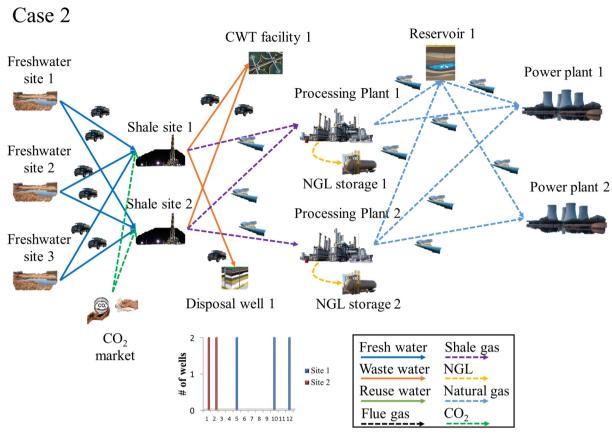


Fig. 7. Optimal configuration of SGSCN when EGR- $CO_2$  technology is applied using  $CO_2$  from external markets.

Table 2
Optimal design results when original gas production rates (Case 1) and EGR-CO<sub>2</sub> technology (Case 2 and Case 3) are used.

		Case 1	Case 2	Case 3	
Total amount of freshwater					bbl
Freshwater site 1	Truck	675,000	675,000	675,000	
	Pipeline	_	-	_	
Freshwater site 2	Truck	675,000	675,000	675,000	
	Pipeline	-	_	_	
Freshwater site 3	Truck	651,644	651,654	651,645	
	Pipeline	_	-	_	
Total amount of wastewater					bbl
Shale site 1	WTC (truck)	444,296	436,518	436,498	
	WTD (truck)	1,113,214	1,124,841	1,124,841	
	WTO	15,003	_	20,001	
Shale site 2	WTC (truck)	798,596	836,190	836,190	
	WTD	_	-	_	
	WTO	_	-	_	
Total amount of shale gas prod	uction				MCF
Shale site 1		17,740,342	17,817,020	17,817,020	
Shale site 2		11,719,700	12,972,809	12,972,809	
Total amount of natural gas and	d NGL				MCF
Processing plant 1	Natural gas	25,087,311	8,972,099	25,926,368	
	NGL	3,414,929	966,900	3,569,780	
Processing plant 2	Natural gas	62,900	17,278,240	323,971	
	NGL	11,100	2,618,895	46,014	
Total amount of natural gas tra	nsportation				MCF
Processing plant 1	Power plant	15,191,525	6,290,139	15,873,793	
	Reservoir	9,895,786	2,681,960	10,052,575	
Processing plant 2	Power plant	62,900	9,684,812	323,971	
	Reservoir	-	7,593,428	_	
Underground reservoir	Power plant	9,895,786	10,275,389	10,052,575	
Total amount of generated elec	tricity				MW·h
Power plant 1		2,185,217,148	2,230,268,781	1,994,200,244	
Power plant 2		1,227,666,547	1,331,902,234	1,567,970,770	

**Table 3**Optimal design results when EGR-CO<sub>2</sub> technology is used.

		Case 1	Case 2	Case 3	
Total amount of e	Total amount of emitted CO <sub>2</sub>				MCF
Power plant 1		11,575,858	11,814,512	10,563,975	
Power plant 2		9,078,973	9,849,829	11,595,628	
Total amount of ca	aptured CO <sub>2</sub>	-	_	2,378,955	MCF
Power plant 1		-	_	2,378,955	
Power plant 2		-	-	-	
Total amount of st	tored CO <sub>2</sub>	-	_		MCF
Power plant 1		-	_	1,863,141	
Power plant 2		-	-		
Total amount of injected CO <sub>2</sub>		_			MCF
External market	Shale site 1	_	1,350,721		
	Shale site 2	_	1,026,663		
Power plant 1	Shale site 1	_	_	1,350,721	
	Shale site 2	-	-	1,206,663	

power plants; one CWT facility; and one DW.

Ten hydraulic fracturing jobs were completed over twelve time periods in Shale sites 1 (six shale wells) and 2 (four shale wells). One DW and CWT facility were placed at two shale sites to treat the wastewater recovered at shale sites.  $\rm CO_2$  for injection was purchased from external markets; their amounts were 1,350,721 MCF at Shale site 1 and 1,026,663 MCF at Shale site 2.

In Case 3, the optimal configuration of SGSCN model was determined as follows (Fig. 8; Tables 2, 3): three freshwater sites; two shale sites with ten hydraulic fracturing jobs; two shale gas processing plants with two NGL storage units; one OT facility; one underground reservoir; one  ${\rm CO}_2$  capture plant; two power plants; one DW; and one CWT facility.

Ten hydraulic fracturing jobs were completed over twelve time periods in Shale sites 1 (six shale wells) and 2 (four shale wells), as in Case 1 and Case 2. In Case 3, MED technology was selected to treat the recovered wastewater, and then the treated wastewater was reused in other shale sites or shale wells. In this case,  $\rm CO_2$  was captured from flue gas emitted at power plants as they burned natural gas to generate electricity, then transported by trucks and injected at the two shale sites. Transport of the required  $\rm CO_2$  to the two shale sites required two trucks; the amounts from  $\rm CO_2$  capture plant 1 were 1,350,721 MCF to Shale site 1, and 1,206,663 MCF to Shale site 2.

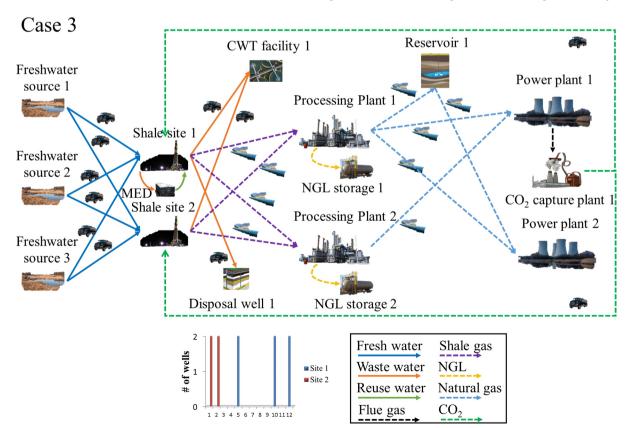
#### 5.3. Optimal production of shale gas

The task of break the rocks at shale sites required ten hydraulic fracturing jobs in all three cases; but the total amount of shale gas produced was different. Case 1 produced 29.5  $\times$  10 $^6$  MCF, whereas Case 2 and Case 3 both produced 30.8  $\times$  10 $^6$  MCF (Fig. 9), i.e., 4.41% more than by Case 1.

Optimal SGSCN configurations that maximize the overall profit with optimal schedules of hydraulic fracturing operations were determined for the three cases (Figs. 6–8). After fracking had been completed, most of the shale gas was produced within a year, and then the rates decreased rapidly over time. Synchronizing the presentation to have hydraulic fracturing jobs completed at the same time yielded the trends in the production profile of shale gas (Fig. 9). After the 12th time period, the trends in the gas production showed only decreases, because hydraulic fracturing operation should be completed within 36 months (twelve time periods; 3 years); otherwise, the gas production profile could increase without the constraint.

## 5.4. Optimal schedule of CO2 injection

In both Case 2 and Case 3, pulsed injection of CO<sub>2</sub> is used to increase the shale gas production rates at all shale sites. To maximize the overall profit of the SGSCN, the optimal schedules of pulsed CO<sub>2</sub> injection were



 $\textbf{Fig. 8.} \ \textbf{Optimal configuration of SGSCN when EGR-CO}_2 \ \text{technology is applied using CO}_2 \ \text{from CO}_2 \ \text{capture plants}.$ 

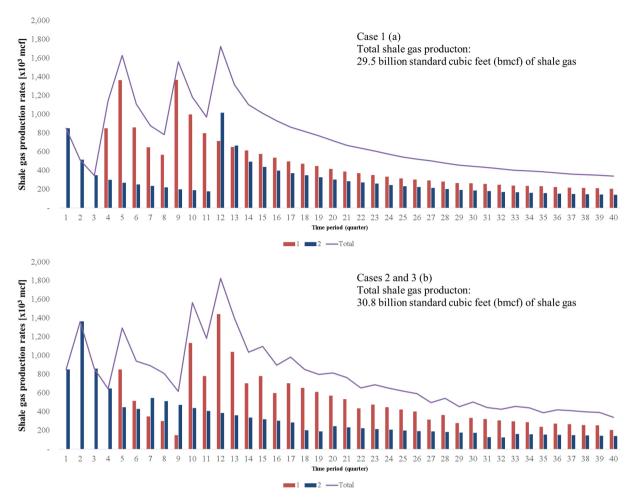


Fig. 9. Optimal shale gas production profiles for (a) Case 1 and (b) Case 2 and Case 3.

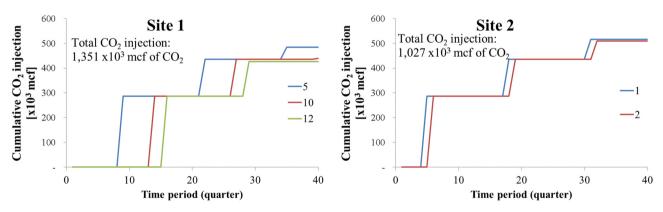


Fig. 10. Optimal schedules of pulsed  $CO_2$  injection in Case 2 and Case 3.

determined (Fig. 10).

The amounts of  $CO_2$  injected at each shale site are assumed to be the same as the increases in the amounts of gas production. The optimal schedules of hydraulic fracturing jobs (Figs. 7 and 8) at Shale site 1 determine that the first pulsed  $CO_2$  injection should occur during the 9th time period because the first hydraulic fracturing operation occurred at the 5th time period (four-time period difference; 1 year). At the two shale sites,  $CO_2$  were injected into the wellbore to increase the amount of produced shale gas by an amount equal to the amount of injected  $CO_2$ . This  $CO_2$  injection changed the shale gas production profiles at the both shale sites (Fig. 11).

At Shale site 1, the shale gas production increased by 10% compared to Case 1 (original method); after the 12th time period, all shale gas

production rates exceeded those in the original. However, at Shale site 2, the production rates were less than the original case; the decrease occurs because the hydraulic fracturing operations with EGR-CO<sub>2</sub> technology were completed during the 1st and 2nd time periods. However, the total shale gas production was 11.11% higher than that of the original method.

# 5.5. Sensitivity analysis

In this study, we focus on the EGR- $CO_2$  technology to increase the shale gas productivity at shale sites by pulsed injection of  $CO_2$  captured from flue gas emitted at power plants during electricity production by combustion of natural gas from the site. Comparison of the optimal

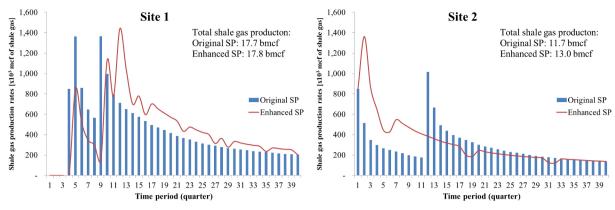


Fig. 11. Comparison of the shale gas production profiles based on the original gas production and enhanced gas production in Case 2 and Case 3.

Table 4 Sensitivity analysis results among the variation of  ${\rm CO_2}$  price for the overall profit of the SGSCN model in Case 2 and Case 3.

US\$/MCF of CO <sub>2</sub>	Case 2 (×US\$ 10 <sup>6</sup> )	Case 3 (×US\$ 10 <sup>6</sup> )
2	240	216
3	239	217
4	238	220
5	233	232
6	230	234

costs (Fig. 5) confirms that the overall profit of SGSCN (Case 3) was lower than those in Case 1 and 2. An increase in the benefit obtained from reducing  $CO_2$  emission by  $CO_2$  injection may increase the economic feasibility of using recaptured  $CO_2$  gas (Case 3) compared to Case 1. To check the economics of  $CO_2$  capture plant in the SGSCN model, the proposed system evaluated the effects of  $CO_2$  prices between US\$2 and US\$6 per MCF (Table 4).

From the sensitivity analysis results for  $\mathrm{CO}_2$  price, the overall profit of the SGSCN model in Case 3 exceeds that of Case 2 when the  $\mathrm{CO}_2$  price exceeds US\$5 per MCF. This sensitivity analysis predicts that the EGR- $\mathrm{CO}_2$  technology using  $\mathrm{CO}_2$  obtained by  $\mathrm{CO}_2$  capture plant can be used to increase the shale gas production rates and decrease the net  $\mathrm{CO}_2$  emission that occurs by burning it. For EGR- $\mathrm{CO}_2$  that uses  $\mathrm{CO}_2$  from  $\mathrm{CO}_2$  capture plants to be profitable, the  $\mathrm{CO}_2$  price must be greater than US\$5 per MCF.

Remark 2. The proposed approach can be further extended to a multiperiod optimization model by taking into account actual locations of a variety of wastewater treatment and shale gas processing facilities as well as water sources and disposal wells. Specifically, these real field data can be integrated with our optimization model in the form of differences in model parameters and cost coefficients, which can significantly affect the optimal configuration of SGSCN. However, one of the key challenges is that to our best knowledge, a comprehensive review of these real field data has never been reported in the literature because either they are not publicly available or there data are distributed over multiple database sources.

# 6. Conclusions

In this study, we evaluated the effectiveness of enhanced gas recovery by carbon dioxide ( $CO_2$ ) injection' (EGR- $CO_2$ ) technology, which injects  $CO_2$  that is emitted when the shale gas is burned to produce electricity to simultaneously increase shale gas production and decrease net  $CO_2$  emissions. We used a mixed-integer linear programming problem, which determined the optimal configuration of supply chain network for shale gas production (SGSCN) that maximizes the overall profit by pulsed  $CO_2$  injection; the amounts of injected  $CO_2$ , the

increase in shale gas production rate, and the net  $CO_2$  reduction by injecting it into fractured wells were considered. The overall profit of Case 2, which uses EGR-CO $_2$  technology but buys  $CO_2$  externally, was 2.56% higher than that of Case 1, which considers only the normal production rates of shale gas in an SGSCN model. However, Case 3, which uses EGR-CO $_2$  using  $CO_2$  from  $CO_2$  capture plants, achieved lower overall profit by 7.69% compared to Case 1, and by 10.00% compared to Case 2, because the total additional cost of building and operating  $CO_2$ -capture plants was higher than the total benefit of  $CO_2$  injection at shale sites. For Case 3 to achieve profit that exceeds Case 2, the market price of  $CO_2$  must be greater than US\$5 per MCF (0.18 US\$ per m³). This study indicates that the total profit of shale gas extraction can be improved by applying the pulsed  $CO_2$  injection, because it increases shale gas productivity.

#### CRediT authorship contribution statement

Yuchan Ahn: Conceptualization, Methodology, Validation, Formal analysis, Investigation, Writing - original draft, Writing - review & editing, Visualization. Junghwan Kim: Writing - review & editing, Supervision, Project administration, Funding acquisition. Joseph Sang-Il Kwon: Conceptualization, Methodology, Formal analysis, Resources, Writing - review & editing, Supervision, Project administration, Funding acquisition.

#### **Declaration of Competing Interest**

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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# Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2020.115334.

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