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# Development of Shale Gas Supply Chain Network under Market Uncertainties

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**Abstract:** The increasing demand of energy has turned the shale gas and shale oil into one of the most promising sources of energy in the United States. In this article, a model is proposed to address the long-term planning problem of the shale gas supply chain under uncertain conditions. A two-stage stochastic programming model is proposed to describe and optimize the shale gas supply chain network. Inherent uncertainty in final products' prices, such as natural gas and natural gas liquids (NGL), is treated through the utilization of a scenario-based method. A binomial option pricing model is utilized to approximate the stochastic process through the generation of scenario trees. The aim of the proposed model is to generate an appropriate and realistic supply chain network configuration as well as scheduling of different operations throughout the planning horizon of a shale gas development project.

**Keywords:** shale gas supply chain; market uncertainty; two-stage stochastic programming; binomial option pricing model

## 1. Introduction

In recent years, technological advances have provided necessary tools for the exploitation of new sources of fossil fuels in the United States. Particularly, the development of horizontal drilling and hydraulic fracturing technologies has turned the shale gas into one of the most rapidly growing businesses in the energy sector. The United States is ranked fourth in technically recoverable shale gas resources when compared with the 41 countries assessed in the world [1]. Shale gas is found in its source rock, the organic-rich shale that formed from the sedimentary deposition of mud, silt, clay, and organic matters in shallow seas. Large-scale natural gas production from shale began around 2000, when Mitchell Energy turned shale gas production into a commercial reality in the Barnett shale located in north-central Texas. By 2005, Barnett formation was producing half trillion cubic feet of natural gas per year [2]. The successful experience of the Barnett shale stimulated the development of other shale basins around the country and led to a dramatic shift in domestic natural gas production. Shale gas production, as a percentage of total natural gas production, has experienced a rapid increase from 6% to 47% from 2005 to 2013, and it is expected to increase to 55% by 2040 [3]. Given this enormous potential, the focus has shifted from recognizing available natural gas resources toward coordinating the necessary operations to allocate these resources into production and delivery of subsequent products to different types of markets while maximizing profitability. This objective turns the problem of optimal design and management of the shale gas supply chain network considering practical limitations of extreme relevance.

A supply chain may be defined as an integrated process wherein a number of various business entities work together in an effort to acquire raw materials, convert these raw materials into specific final products, and deliver these final products to markets [4]. Typical elements of supply chains can involve suppliers, manufacturers, and distributors. Considering the physical dimension, these elements translate to processing facilities, factories, trucks, trains, sea-faring vessels, and warehouses [5]. In the specific case of shale gas production, the supply chain represents a complex network that encompasses shale sites where wells are drilled and hydro-fractured, water management sections to ensure supply of required fracking water to wells and treatment of wastewater generated during hydraulic fracturing treatments, processing facilities to separate different products of shale gas, storage of final products, and different markets where final products are supplied including power generation plants, petrochemical plants, and residential and commercial establishments. Since shale reserves are frequently located in undeveloped and/or remote geographies, pipeline infrastructure to link different entities throughout the supply chain also has to be taken into account in the development of a shale gas project. Of course, from an economical point of view, all this offers major challenges and opportunities of improvement for design and coordination of different activities.

A number of contributions have addressed the complexity involved in the decision-making process of developing and planning a shale gas supply chain. Cafaro and Grossmann [6] presented a mixed-integer nonlinear programming (MINLP) model for the strategic planning and design of the shale gas supply chain. In this work, the role of optimal drilling and production strategy was highlighted in maximizing the utilization of gas processing and transportation infrastructure and enhancing the use of water resources. The water management problem for shale gas production was addressed by Gao and You [7], who developed a mixed-integer linear fractioning programming (MILFP) model to determine the optimal design and operations of the water supply chain. The approach considered multiple water management options including disposal, centralized wastewater treatment (CWT) facilities, and onsite treatment facilities. An optimal design of the shale gas supply chain combined with the water supply network was first developed by Gao and You [8]. A multi-objective nonconvex MINLP model was proposed for the economic and environmental optimization of the comprehensive network.

The aforementioned works were based on deterministic approaches and all the input parameters in the model were known in advance. However, most of the supply chain systems are characterized by lack of precise information about numerous technical and commercial parameters. The presence of uncertainty introduces a high degree of variability throughout the supply chain that can jeopardize the performance of an enterprise. Ignoring the impact of different types of uncertainties along a supply chain may result in a model incapable of adapting to future events. Therefore, incorporating uncertain parameters in the optimization framework represents an important extension of previous deterministic approaches and provides valuable insight about the design and operation of the supply chain.

More recently, different publications have addressed stochastic problems of designing and coordinating activities in supply chains under uncertainty. Gupta and Maranas [9,10] implemented a two-stage stochastic model to incorporate demand uncertainty for midterm planning problems. In this approach, manufacturing decisions were made before the realization of uncertain demands while logistic decisions were postponed until having certainty about each realization. A two-stage stochastic model was also developed by Guillen et al. [11] for the design of a three echelon (production-storage-market) supply chain with uncertain customer demands. In this case, the proposed formulation took into account not only the maximization of profitability and customer satisfaction but also the minimization of financial risks due to the inherent inaccuracy of the demand forecasts. You et al. [12] developed a two-stage stochastic model to address the optimization problem of a large scale supply chain under demand and freight rate uncertainties. In this work, Monte Carlo sampling and associated statistical methods were applied and incorporated into the model to reduce the number of possible scenarios. Moreover, a financial risk analysis of the enterprise was implemented through the utilization of different risk management models.

In shale gas production, there are few studies suggested in literature that incorporate the possibility of uncertainty throughout the supply chain. Yang et al. [13] formulated a two-stage stochastic model to develop the optimal drilling and fracturing water management for shale gas production. Uncertainty in water availability of different sources was considered through the utilization of data for each calendar year as a scenario. Gao and You [14] also developed a two-stage stochastic model to determine an optimal design and operation of the shale gas supply chain under uncertain estimated ultimate recovery (EUR). To tackle the challenge of generating different scenarios required by the stochastic model, a sample average approximation (SAA) method was implemented based on the real-world EUR distribution data. However, to the best of our knowledge, market uncertainties have not been considered for the resolution of the design and management of the shale gas supply chain. Product prices and demands are exogenous parameters established in an open market, which represents an enormous challenge to control their evolution throughout the planning horizon of a shale gas enterprise [15]. Therefore, the incorporation of randomness into the proposed model may have a significant impact on determining a more efficient and flexible shale gas supply chain.

In this article, the relevant problem of determining the optimal design and operations of a shale gas supply chain network in presence of market uncertainties is investigated. Market uncertainty is represented by the fluctuation of final products' prices including natural gas and NGL. The optimization problem is formulated, for the first time for this type of objective, through utilization of a two-stage stochastic model. The decision variables are partitioned into two categories based on whether the corresponding activities have to be performed before or after final products' prices realization. A scenario-based approach is implemented to represent the uncertainty in the proposed model. This approach is based on a set of discrete scenarios to describe the possible outcomes or events in the future with a specific probability of occurrence for each of them. The aim of this work is to incorporate and analyze the influence of the market price variations in the design and operations of the shale gas supply chain.

## 2. Mathematical Formulation

In this study, the optimization problem for the long-term planning, development, design, and operations of the shale gas supply chain under fluctuation of final products' prices is formulated as a two-stage stochastic programming model. The scenario-based method is utilized to represent the uncertain parameters of the model. This method is an approximation approach implemented to transform an intractable stochastic problem into a tractable one. The main idea is to address only a finite number of selected realizations in the optimization. Each possible realization represents a scenario with a unique probability of occurrence. This allows the transformation of the proposed model into a deterministic equivalent model with different possible scenarios for the uncertain prices. More detailed information about the determination of each possible scenario is given in the following section.

In the proposed model, production as well as design variables are modelled as first stage here-and-now decisions. These decision variables, which are taken by considering the price expectations at the beginning of the time period, include the determination of the number of wells to be drilled and fractured, shale gas production at each shale site, amount of water required in each shale site, amount of wastewater generated, treated, and reused, capacity of processing plants, and capacity of different pipelines throughout the supply chain. The second-stage decisions or logistic operations can be performed much faster. These decision variables can be fine-tuned in a wait-and-see setting after the prices of final products are revealed at the beginning of the time periods. The second stage variables to be determined by the proposed optimization model correspond to the activities related to transportation of shale gas and inventory/supply of final products. These variables include the amounts of shale gas transported from each shale site to processing plant, amounts of natural gas transported and stored in each underground reservoir, amounts of NGL stored, and amounts of natural and NGL supplied to different markets. Therefore, the model is partitioned into first stage and second stage equations with an objective function combining terms that captures the effects of decisions taken in both stages.

### 2.1. Assumptions

The main assumptions considered for the proposed model can be summarize as follows:

(1) The composition of the shale gas is a known constant and independent of the wells' location. This assumption differs from some previous approaches, which considered variability of composition in different shale sites [6,16,17];
(2) The number of wells that can be drilled and hydro-fracture in a shale site in each time period is bounded. Moreover, the maximum number of wells that can be drilled in each shale site throughout the planning horizon is also known beforehand;
(3) Multiple wells in the same shale site can be drilled, hydro-fractured, and completed in the same period;
(4) A quarterly discretization is considered for the planning horizon of the shale gas project;
(5) Well productivity rate is formulated based on the well age;
(6) Flowback water represents a fraction of the fracking water utilized during the hydraulic operations in each shale site;
(7) Produced water in different shale sites is proportional to the shale gas production in that site;
(8) Different management options can be utilized to handle the wastewater generated in each shale site due to the hydro-fracturing activities;
(9) Shale sites are located in a region without the necessary pipeline and processing infrastructure. Therefore, gas producer is not only responsible for exploiting the shale reservoir but also for providing the sufficient processing capacity;
(10) Processing plant separates natural gas from NGL considering certain efficiency. Storage capacity for NGL is considered in the processing plant;
(11) Only one processing plant is contemplated for processing the shale gas due to the limited number of shale sites considered in the case study;
(12) Power functions are utilized for the determination of the capital cost for the shale and natural gas pipeline infrastructure and processing plant infrastructure;
(13) Natural gas and NGL prices follow the trend of crude oil price. Fixed relationships are utilized to relate these commodities' prices. Randomness of prices is represented by a continuous-time stochastic process. More detailed explanation is given in the next section;
(14) Maximum and minimum demands of natural gas and NGL are constant throughout the planning horizon of the shale gas project.

### 2.2. Mathematical Model

The mathematical formulation for the shale gas supply chain network and operations is presented next. Information about the model is given including first and second stage equations and objective function. Detailed explanation of the parameters and variables are also presented in the Nomenclature section.

#### 2.2.1. Number of Wells to be Drilled and Hydro-Fractured at Shale Sites

The determination of the number of wells drilled, hydro-fractured, and completed at each shale site $i$ in each time period $t$ is obtained through the implementation of Equations (1)–(3) [6,8].

$$\sum_{n=0}^{nt_i} YW_{i,n,t} = 1 \ \forall \ i \in I, t \in T \tag{1}$$

$$NW_{i,t} = \sum_{n=0}^{nt_i} n \cdot YW_{i,n,t} \ \forall \ i \in I, t \in T \tag{2}$$

$$\sum_{t \in T} NW_{i,t} \leq Nmax_i \; \forall \, i \in I \tag{3}$$

Equation (1) establishes that only a specific number of wells can be drilled in each time period $t$. $nt_i$ denotes the maximum number of wells that can be drilled and hydro-fractured at shale site $i$ per time period. $YW_{i,n,t}$ is a binary variable that equals 1 when a number $n$ of wells is selected to be drilled at shale site $i$ in time period $t$. Equation (2) determines the total number of wells drilled and hydro-fractured at shale site $i$ in time period $t$. Equation (3) bounds the total number of wells to be drilled and hydro-fractured in a shale site $i$ over the planning horizon. $Nmax_i$ is the maximum number of wells that can be drilled at each shale site $i$ throughout the planning horizon.

2.2.2. Shale Gas Production and Flows to Processing Plants

The gas production of the different shale sites is given by Equation (4). In this equation, gas production at shale site $i$ in each time period $t$ equals the sum of that from different wells. Index $\theta$ is the age of a shale well such that $\theta = t - \hat{t}$, and $\hat{t}$ is the time period when a specific well is drilled and hydro-fractured. $ps_{i,t-\hat{t}}$ is the production profile of a well drilled in time period $\hat{t}$ at shale site $i$ in time period $t$.

$$SP_{i,t} = \sum_{\hat{t}=1}^{t-1} NW_{i,\hat{t}} \cdot ps_{i,t-\hat{t}} \; \forall \, i \in I, t \geq 2 \tag{4}$$

The amount of gas produced in different shale sites equals the total amount of gas transported to processing plants, as stated by:

$$SP_{i,t} = \sum_{p \in P} TSP_{i,p,t,s} \; \forall \, i \in I, t \in T, s \in S \tag{5}$$

where $TSP_{i,p,t,s}$ is the shale gas transported from shale site $i$ to processing plant $p$ in each time period $t$ for the scenario $s$.

2.2.3. Production and Flow Balances of Products at Processing Plants

The total amount of natural gas and NGL produced at processing plants ($TSG_{p,t,s}$ and $TSL_{p,t,s}$, respectively) are represented by Equations (6) and (7) [8,14]. The total methane produced is equal to the methane composition $cg_i$ multiplied by the total shale gas transported from different shale sites. The amount of NGL produced is equal to the NGL composition $cl_i$ multiplied by the total shale gas transported from different shale sites. The parameter $ppeff$ in the equations accounts for the efficiency of the processing plant.

$$\sum_{i \in I} TSP_{i,p,t,s} \cdot ppeff \cdot cg_i = TSG_{p,t,s} \; \forall \, p \in P, t \in T, s \in S \tag{6}$$

$$\sum_{i \in I} TSP_{i,p,t,s} \cdot ppeff \cdot cl_i = TSL_{p,t,s} \; \forall \, p \in P, t \in T, s \in S \tag{7}$$

The relationship between the total amounts of NGL produced, stored, and sold at processing plant is described by the following equation:

$$TSL_{p,t,s} + TLS_{p,t-1,s} = TPS_{p,t,s} + TLS_{p,t,s} \; \forall \, p \in P, t \geq 2, s \in S \tag{8}$$

Here, $TLS_{p,t,s}$ is the amount of NGL stored at processing plant $p$ in each time period $t$ for the scenario $s$. $TPS_{p,t,s}$ represents the amount of NGL sold at processing plant $p$ in each time period $t$ for the scenario $s$.

The flows of natural gas from processing plants to customer markets and underground reservoirs are given by Equation (9). The total amount of natural gas separated at processing plant must equal the amounts sold at different markets and sent to underground reservoirs.

$$TSG_{p,t,s} = \sum_{m \in M} STGM_{p,m,t,s} + \sum_{u \in U} STGU_{p,u,t,s} \ \forall\ p \in P, t \in T, s \in S \tag{9}$$

Here, $STGM_{p,m,t,s}$ is the amount of natural gas transported from processing plant $p$ to customer market $m$ in each time period $t$ for each possible scenario $s$. $STGU_{p,u,t,s}$ is the amount of natural gas transported from processing plant $p$ to underground reservoir $u$ in each time period $t$ for each possible scenario $s$.

#### 2.2.4. Flow Balances of Natural Gas and Storage Capacities at Each Underground Reservoir

At each underground reservoir, the relationship between the amount of natural gas received, stored, and sold to different customer markets is given by the following equation:

$$\sum_{p \in P} STGU_{p,u,t,s} + USG_{u,t-1,s} = \sum_{m \in M} STUM_{u,m,t,s} + USG_{u,t,s} \ \forall\ u \in U, t \geq 2, s \in S \tag{10}$$

where $USG_{u,t,s}$ is the amount of natural gas stored at underground reservoir $u$ in each time period $t$ for each possible scenario $s$. $STUM_{u,m,t,s}$ is the amount of natural gas transported from underground reservoir $u$ to customer market $m$ in each time period $t$ for each possible scenario $s$.

For different underground reservoirs, Equations (11)–(13) [8] describe the constraints for the amounts of natural gas stored, injected, and withdrawn, respectively.

$$USG_{u,t,s} \leq wcapur_u \ \forall\ u \in U, t \in T, s \in S \tag{11}$$

$$\sum_{p \in P} STGU_{p,u,t,s} \leq icapur_u \ \forall\ u \in U, t \in T, s \in S \tag{12}$$

$$\sum_{m \in M} STUM_{u,m,t,s} \leq wicapur_u \ \forall\ u \in U, t \in T, s \in S \tag{13}$$

where $wcapur_u$, $icapur_u$, and $wicapur$ are the working, injection, and withdrawal capacities, respectively.

#### 2.2.5. Production and Storage Capacities at Processing Plants

The amount of shale gas processed is bounded by the production capacity of processing plants as expressed by Equation (14).

$$\sum_{i \in I} TSP_{i,p,t,s} \leq PP_p \ \forall\ p \in P, t \in T \tag{14}$$

where $PP_p$ is the processing plant capacity for each processing plant $p$. This capacity is also constrained as follows:

$$ppcapl \cdot XPP_p \leq PP_p \leq ppcapu \cdot XPP_p \ \forall\ p \in P, t \in T \tag{15}$$

where $ppcapl$ and $ppcapu$ are the minimum and maximum capacity of processing plants. $XPP_p$ is a binary variable that equals 1 if processing plant $p$ is selected.

A single processing plant condition, which is stated by Equation (16), is incorporated in the model in order to force the optimizer to select only one location. This constraint allows the optimal configuration of shale gas network to be much closer to real industrial practices.

$$\sum_{p \in P} XPP_p \leq 1 \tag{16}$$

The amount of NGL stored at processing plant cannot exceed the storage capacity, which is given as:

$$TLS_{p,t,s} \leq XPP_p \cdot lscap_p \ \forall\ p \in P, t \in T, s \in S \tag{17}$$

where $lscap_p$ is the storage capacity of NGL at processing plant $p$.

#### 2.2.6. Transportation Capacity of Shale Gas and Natural Gas

In the case of transportation of gas from shale sites to processing plants, the amount transported is bounded by the pipeline capacity as stated by Equation (18).

$$TSP_{i,p,t,s} \leq TCP_{i,p} \ \forall \ i \in I, p \in P, t \in T \tag{18}$$

where $TCP_{i,p}$ is the capacity of pipeline transporting shale gas from shale site $i$ to processing plant $p$. This shale gas pipeline capacity is also constrained as follows:

$$tsgcapl \cdot XSG_{i,p} \leq TCP_{i,p} \leq tsgcapu \cdot XSG_{i,p} \ \forall \ i \in I, p \in P \tag{19}$$

where $tsgcapl$ and $tsgcapu$ are the minimum and maximum capacity of shale gas pipeline. $XSG_{i,p}$ is a binary variable that equals 1 if a pipeline is installed.

In the case of transportation of natural gas from processing plants to customer markets and underground reservoirs and from underground reservoirs to customer markets, the amount transported is bounded by the capacity of the pipelines as follows:

$$STGM_{p,m,t,s} \leq TCGM_{p,m} \ \forall \ p \in P, m \in M, t \in T, s \in S \tag{20}$$

$$STGU_{p,u,t,s} \leq TCGU_{p,u} \ \forall \ p \in P, u \in U, t \in T, s \in S \tag{21}$$

$$STUM_{u,m,t,s} \leq TCUM_{u,m} \ \forall \ u \in U, m \in M, t \in T, s \in S \tag{22}$$

where $TCGM_{p,m}$, $TCGU_{p,u}$, and $TCUM_{u,m}$ are the capacities for the transportation of natural gas from processing plant $p$ to customer market $m$, from processing plant $p$ to underground reservoir $u$, and from underground reservoir $u$ to customer market $m$, respectively. At the same time, these capacities are constrained as follows:

$$tgcapl \cdot XGM_{p,m} \leq TCGM_{p,m} \leq tgcapu \cdot XGM_{p,m} \ \forall \ p \in P, m \in M \tag{23}$$

$$tgcapl \cdot XGU_{p,u} \leq TCGU_{p,u} \leq tgcapu \cdot XGU_{p,u} \ \forall \ p \in P, u \in U \tag{24}$$

$$tgcapl \cdot XUM_{u,m} \leq TCUM_{u,m} \leq tgcapu \cdot XUM_{u,m} \ \forall \ u \in U, m \in M \tag{25}$$

where $tgcapl$ and $tgcapu$ are the minimum and maximum capacity of natural gas pipeline. $XGM_{p,m}$, $XGU_{p,u}$, and $XUM_{u,m}$ are binary variables that equal 1 if pipelines are installed.

#### 2.2.7. Flow Balances of Freshwater, Freshwater Requirement, and Water Reuse at Each Shale Site

The amount of freshwater required at each shale site is satisfied by the total amount of water acquired at different freshwater sources (nearby rivers, lakes, and underground water among others) plus the water recovered onsite through the implementation of different technologies including multistage flash (MSF), multi-effect distillation (MED), and reverse osmosis (RO) [18]. This flow balance of freshwater is described by Equation (26).

$$\sum_{f \in F} \sum_{k \in K} FWA_{f,i,k,t} + \sum_{o \in O} rfo_o \cdot WWO_{i,o,t-1} = FWR_{i,t} \ \forall \ i \in I, t \in T \tag{26}$$

where total water required at each shale site $i$ in each time period $t$ ($FWR_{i,t}$) is satisfied by the total water acquired in the different freshwater sources $f$ transported to shale site $i$ by the transportation mode $k$ in each time period $t$ ($FWA_{f,i,k,t}$) and the water treated at shale site $i$ by onsite treatment unit $o$ in the previous period $t-1$ ($WWO_{i,o,t-1}$). Parameter $rfo_o$ is the recovery factor, which represents how much of the wastewater is recovered as freshwater in the onsite treatment unit $o$.

Equation (27) determines that the total amount of water required at each shale site. It equals to the standard amount of water required to drill and fracture a single well multiplied by the number of wells developed at each shale site.

$$FWR_{i,t} = tfw_i \cdot NW_{i,t} \; \forall \; i \in I, t \in T \tag{27}$$

where $tfw_i$ is the standard value of water required to drill and hydro-fracture each single well.

To satisfy the reuse specification of water, the blending ratio of freshwater and treated water from onsite treatment is given by Equation (28) [8].

$$\sum_{o \in O} rfw_o \cdot rfo_o \cdot WWO_{i,o,t-1} \leq \sum_{f \in F} \sum_{k \in K} FWA_{f,i,k,t} \; \forall \; i \in I, t \in T \tag{28}$$

2.2.8. Flowback, Produced Water, and Flow Balances of Wastewater at Each Shale Site

The wastewater that comes back out of shale wells after fracturing activities is made of fluids from two different sources: flowback and produced water. Flowback is a water based solution that flows back to the surface during and relatively quickly after the hydraulic fracturing treatments. Most of the flowback occurs in the first seven to ten days while the rest can occur over a three to four-week time period. It consists of the fluid used for fracturing the shale formation [19,20]. In contrast, produced water is the water found in shale formations that flows to the surface throughout the entire lifespan of the gas well [18,21,22]. In this article, the determination of the amounts of wastewater generated from different sources is given by the following equations:

$$FBW_{i,t} = rdf_i \cdot tfw_i \cdot NW_{i,t} \; \forall \; i \in I, t \in T \tag{29}$$

$$PW_{i,t} = csgw_i \cdot SP_{i,t} \; \forall \; i \in I, t \in T \tag{30}$$

Equation (29) determines the amount of wastewater produced as flowback due to hydro-fracturing operations. Equation (30) describes the amount of produced water during the shale gas production, which is the water that was already present in the shale formation. $rdf_i$ and $csgw_i$ are the fraction of water recovered from fracturing and the correlation factor between water produced and gas production at shale site $i$.

Wastewater from different sources including flowback and produced water must equal the total amount of water treated onsite or transported to the different wastewater management options located offsite, as stated by:

$$FBW_{i,t} + PW_{i,t} = \sum_{c \in C} \sum_{k \in K} WWC_{i,c,k,t} + \sum_{d \in D} \sum_{k \in K} WWD_{i,d,k,t} + \sum_{o \in O} WWO_{i,o,t} \; \forall \; i \in I, t \in T \tag{31}$$

where $WWC_{i,c,k,t}$ is the amount of wastewater transported with transportation mode $k$ from shale site $i$ to CWT facility $c$ in each time period $t$. $WWD_{i,d,k,t}$ is the amount of wastewater transported with transportation mode $k$ from shale site $i$ to disposal well $d$ in each time period $t$. $WWO_{i,o,t}$ is the amount of wastewater treated at shale site $i$ by onsite treatment unit $o$ in each time period $t$.

2.2.9. Availability and Transportation Capacities of Freshwater

Freshwater resources normally have a maximum amount of water that can provide for all the operations related to development of wells at shale sites [6]. As a result, Equation (32) establishes that the transportation of freshwater from freshwater sources $f$ to different shale sites $i$ utilizing different transportation modes $k$ in each time period $t$ must not exceed the available water in those sources.

$$\sum_{i \in I} \sum_{k \in K} FWA_{f,i,k,t} \leq fwcap_{f,t} \; \forall \; f \in F, t \in T \tag{32}$$

where $fwcap_{f,t}$ is the supply capacity at freshwater source $f$ in each time period $t$.

For the case of transportation of freshwater to different shale sites, capacity constraints for each transportation mode are established by Equation (35).

$$FWA_{f,i,k,t} \leq tcapf_{f,i,k} \cdot XFI_{f,i,k} \; \forall \; f \in F, i \in I, k \in K, t \in T \tag{33}$$

where $tcapf_{f,i,k}$ is the transportation capacity for transportation mode $k$ from freshwater source $f$ to shale site $i$. $XFI_{f,i,k}$ is a binary variable that equals 1 when transportation mode $k$ is selected to transport freshwater from freshwater source $f$ to shale site $i$.

2.2.10. Treatment and Transportation Capacities of Wastewater

Equations (34)–(36) stand for the capacity constraints of each of the options for managing the wastewater including CWT facilities, disposal wells, and onsite treatment units, respectively. In the specific case of disposal wells, there might be limitations in terms of maximum allowable injection rate or maximum allowable build-up pressure depending on local regulations to avoid seismicity issues and its consequences [23].

$$\sum_{i \in I} \sum_{k \in K} WWC_{i,c,k,t} \leq cwtcap_{c,t} \; \forall \; c \in C, t \in T \tag{34}$$

$$\sum_{i \in I} \sum_{k \in K} WWD_{i,d,k,t} \leq dcap_{d,t} \; \forall \; d \in D, t \in T \tag{35}$$

$$WWO_{i,o,t} \leq YO_{i,o} \cdot ocap_o \; \forall \; i \in I, o \in O, t \in T \tag{36}$$

Here, $cwtcap_{c,t}$, $dcap_{d,t}$ are the capacities of CWT facility $c$ and disposal well $d$, respectively, in each time period $t$. $YO_{i,o}$ is a binary variable that equals to 1 when a specific onsite treatment unit $o$ is selected at shale site $i$. $ocap_o$ is the maximum capacity of onsite treatment unit $o$.

Only one type of onsite wastewater treatment unit can be selected in each shale site, which is given by the following constraint:

$$\sum_{o \in O} YO_{i,o} \leq 1 \; \forall \; i \in I \tag{37}$$

For the case of transportation of wastewater to CWT facilities and disposal wells, capacity constraints for each transportation mode are established by Equations (38) and (39).

$$WWC_{i,c,k,t} \leq tcapic_{i,c,k} \cdot XWC_{,i,c,k} \; \forall \; i \in I, c \in C, k \in K, t \in T \tag{38}$$

$$WWD_{i,d,k,t} \leq tcapid_{i,d,k} \cdot XWD_{i,d,k} \; \forall \; i \in I, d \in D, k \in K, t \in T \tag{39}$$

where $tcapic_{i,c,k}$ denotes the transportation capacity for transportation mode $k$ from shale site $i$ to CWT facility $c$. $XWC_{,i,c,k}$ is a binary variable that equals 1 if transportation mode $k$ is selected to transport wastewater from shale site $i$ to CWT facility $c$. $tcapid_{i,d,k}$ denotes the transportation capacity for transportation mode $k$ from shale site $i$ to disposal well $d$. $XWD_{i,d,k}$ is a binary variable that equals 1 if transportation mode $k$ is selected to transport wastewater from shale site $i$ to disposal well $d$.

2.2.11. Maximum and Minimum Demands of Products

The amounts of natural gas and NGL sold must be within the minimum and maximum demands existing in different customer markets. Equations (40) and (41) describe the constraints for the amounts of natural gas and NGL sold, respectively.

$$dgmin_{m,t} \leq \sum_{p \in P} STGM_{p,m,t,s} + \sum_{u \in U} STUM_{u,m,t,s} \leq dgmax_{m,t} \; \forall \; m \in M, t \in T, s \in S \tag{40}$$

$$dlmin_t \leq \sum_{p \in P} TPS_{p,t,s} \leq dlmax_t \; \forall \; t \in T, s \in S \tag{41}$$

where $dgmin_{m,t}$ and $dgmax_{m,t}$ are the minimum and maximum demands of natural gas, respectively, at customer market $m$ in each time period $t$. $dlmin_t$ and $dlmax_t$ are the minimum and maximum demands of NGL, respectively, in each time period $t$.

### 2.2.12. Supply Chain Costs

The objective function of this optimization problem is profit maximization. This function is constituted by terms that represent costs involved throughout the shale gas supply chain and incomes generated by final products' sales.

The cost involved in the shale gas operations such as drilling and fracturing of different shale wells, $Cprod$, can be calculated as follows:

$$Cprod = \sum_{i \in I} \sum_{t \in T} \frac{csgd_{i,t} \cdot NW_{i,t}}{(1+dr)^t} + \sum_{i \in I} \sum_{t \in T} \frac{csgp_{i,t} \cdot SP_{i,t}}{(1+dr)^t} \tag{42}$$

where $csgd_{i,t}$ and $csgp_{i,t}$ are the drilling/fracturing and production costs, respectively, at shale site $i$ in each time period $t$.

The cost of freshwater, $Cf$, includes the costs related to the acquisition from the different freshwater sources, $Cacq$, and transportation to the different shale sites $Ctf$.

$$Cf = Cacq + Ctf \tag{43}$$

The cost of acquisition of freshwater from different sources is given by:

$$Cacq = \sum_{f \in F} \sum_{i \in I} \sum_{k \in K} \sum_{t \in T} \frac{cw_{f,t} \cdot FWA_{f,i,k,t}}{(1+dr)^t} \tag{44}$$

where $cw_{f,t}$ is the unit cost of freshwater acquisition at freshwater source $f$ in each time period $t$.

The cost of transportation of freshwater from different sources to shale sites is given as follows:

$$Ctfw = \sum_{f \in F} \sum_{i \in I} \sum_{k \in K} \sum_{t \in T} \left( clif_{f,i,k} \cdot lfi_{f,i} \cdot XFI_{f,i,k} + \frac{cfwt_k \cdot lfi_{f,i} \cdot FWA_{f,i,k,t}}{(1+dr)^t} \right) \tag{45}$$

where $clif_{f,i,k}$ is the capital cost of transporting freshwater from freshwater source $f$ to shale site $i$ by transportation mode $k$. $lfi_{f,i}$ is the distance between freshwater source $f$ and shale site $i$. $cfwt_k$ is the unit transportation cost of freshwater at freshwater source $f$ in each time period $t$.

The cost involved in the management of the wastewater generated in different shale sites, $Cw$, is the result of the confluence of the costs related to the wastewater transportation and the operation of the different management option.

$$Cw = C_{cwt}^{transp} + C_{cwt}^{treat} + C_{disp}^{transp} + C_{disp}^{inj} + C_{onsite}^{treat} \tag{46}$$

The transportation cost when wastewater is transported to CWT facility, $C_{cwt}^{transp}$, can be determined as:

$$C_{cwt}^{transp} = \sum_{i \in I} \sum_{c \in C} \sum_{k \in K} \sum_{t \in T} \left( clic_{i,c,k} \cdot lic_{i,c} \cdot XWC_{i,c,k} + \frac{cwwt_k \cdot lic_{i,c} \cdot WWC_{i,c,k,t}}{(1+dr)^t} \right) \tag{47}$$

where $clic_{i,c,k}$ is the capital cost of transporting wastewater from shale site $i$ to CWT facility $c$ by transportation mode $k$. $lic_{i,c}$ is the distance between CWT facility $c$ and shale site $i$. $cwwt_k$ is the transportation cost of transportation mode $k$.

The treatment cost in CWT facilities, $C_{cwt}^{treat}$, is given as follows:

$$C_{cwt}^{treat} = \sum_{i \in I} \sum_{c \in C} \sum_{k \in K} \sum_{t \in T} \frac{ccwt_c \cdot WWC_{i,c,k,t}}{(1+dr)^t} \tag{48}$$

where $ccwt_c$ is the unit cost of wastewater treatment at CWT facility $c$.

The transportation cost involved in the movement of wastewater from the shale sites to the different disposal wells, $C_{disp}^{transp}$, is determined as:

$$C_{disp}^{transp} = \sum_{i \in I} \sum_{d \in D} \sum_{k \in K} \sum_{t \in T} \left( clid_{i,d,k} \cdot lid_{i,d} \cdot XWD_{i,d,k} + \frac{cwwt_k \cdot lid_{i,d} \cdot WWD_{i,d,k,t}}{(1+dr)^t} \right) \tag{49}$$

where $clid_{i,d,k}$ is the capital cost of transporting wastewater from shale site $i$ to disposal well $d$ by transportation mode $k$. $lid_{i,d}$ is the distance between disposal well $d$ and shale site $i$.

The cost of injecting wastewater in the different disposal wells, $C_{disp}^{inj}$, is

$$C_{disp}^{inj} = \sum_{i \in I} \sum_{d \in D} \sum_{k \in K} \sum_{t \in T} \frac{cd_d \cdot WWD_{i,d,k,t}}{(1+dr)^t} \tag{50}$$

where $cd_d$ is the unit cost for the injection of waste water at disposal well $d$.

The cost of the wastewater treatment, $C_{onsite}^{treat}$, is determined as:

$$C_{onsite}^{treat} = \sum_{i \in I} \sum_{o \in O} \sum_{t \in T} \frac{cot_o \cdot WWO_{i,o,t}}{(1+dr)^t} \tag{51}$$

where $cot_o$ is the unit cost of wastewater treatment at onsite treatment unit $o$.

For both freshwater and wastewater, the transportation costs (Equations (45), (47) and (49)) are constituted by capital and operating costs. Capacities of different transportation modes $k$ (trucks and pipelines) are established based on maximum values that are defined as parameters ($tcapf_{f,i,k}$, $tcapic_{i,c,k}$, and $tcapid_{i,d,k}$) in the model. Therefore, capital costs are only function of distance between nodes [24] and the type of transportation. Equations (48), (50) and (51), are only based on operational costs since the facilities are already established.

The cost related to the processing plants $Cproc_s$ is described by the following equation.

$$Cproc_s = Ccproc + Csproc_s + Csgtp_s \tag{52}$$

The capital cost $C^{cproc}$ is given as:

$$Ccproc = \sum_{p \in P} rcp \cdot \left( \frac{PP_p}{rpc} \right)^{sfp} \cdot \left( \frac{pcipp}{rpcipp} \right) \tag{53}$$

The operating cost, $Csproc_s$, is:

$$Csproc_s = \sum_{i \in I} \sum_{p \in P} \sum_{t \in T} \frac{pcsg \cdot TSP_{i,p,t,s}}{(1+dr)^t} \tag{54}$$

where $pcsg$ is the unit processing cost of shale gas.

The shale gas transportation cost, $Csgtp_s$, can be determined as follows:

$$Csgtp_s = \sum_{i \in I} \sum_{p \in P} rccpsg \cdot \left( \frac{TCP_{i,p}}{rcpsg} \right)^{sft} \cdot \left( \frac{pcipl}{rpcipl} \right) \cdot lip_{i,p} + \sum_{i \in I} \sum_{p \in P} \sum_{t \in T} \frac{tcpsg \cdot lip_{i,p} \cdot TSP_{i,p,t,s}}{(1+dr)^t} \tag{55}$$

where the different parameters of this power function for the capital and operating costs are detailed in Appendix A. $lip_{i,p}$ is the distance between shale site $i$ and processing plant $p$.

In transportation cost of natural gas, $Ctg_s$, the capital and transportation cost for each possible scenario $s$ are considered for the pipeline infrastructure.

$$Ctg_s = Ctg_s^{pm} + Ctg_s^{pu} + Ctg_s^{um} \tag{56}$$

Equations (57)–(59) describe the costs involved in the transportation of natural gas from processing plants to different customer markets, $Ctg_s^{pm}$, from processing plants to different underground reservoirs, $Ctg_s^{pu}$, and from underground reservoirs to different customer markets, $Ctg_s^{um}$, respectively.

$$Ctg_s^{pm} = \sum_{p\in P}\sum_{m\in M} rccpsg\cdot\left(\frac{TCGM_{p,m}}{rcpsg}\right)^{sft}\cdot\left(\frac{pcipl}{rpcipl}\right)\cdot lpm_{p,m} + \sum_{p\in P}\sum_{m\in M}\sum_{t\in T}\frac{tcpsg\cdot lpm_{p,m}\cdot STGM_{p,m,t,s}}{(1+dr)^t} \tag{57}$$

$$Ctg_s^{pu} = \sum_{p\in P}\sum_{u\in U} rccpsg\cdot\left(\frac{TCGU_{p,u}}{rcpsg}\right)^{sft}\cdot\left(\frac{pcipl}{rpcipl}\right)\cdot lpu_{p,u} + \sum_{p\in P}\sum_{u\in U}\sum_{t\in T}\frac{tcpsg\cdot lpu_{p,u}\cdot STGU_{p,u,t,s}}{(1+dr)^t} \tag{58}$$

$$Ctg_s^{um} = \sum_{u\in U}\sum_{m\in M} rccpsg\cdot\left(\frac{TCUM_{u,m}}{rcpsg}\right)^{sft}\cdot\left(\frac{pcipl}{rpcipl}\right)\cdot lum_{u,m} + \sum_{u\in U}\sum_{m\in M}\sum_{t\in T}\frac{tcpsg\cdot lum_{u,m}\cdot STUM_{u,m,t,s}}{(1+dr)^t} \tag{59}$$

where the different parameters for the capital and operating costs are detailed in Appendix A. $lpm_{p,m}$, $lpu_{p,u}$, and $lum_{u,m}$ are the distances between processing plant $p$ and customer market $m$, processing plant $p$ and underground reservoir $u$, and underground reservoir $u$ and customer market $m$, respectively.

Non-linearities in Equations (53), (55) and (57)–(59) introduce a high degree of complexity in the optimization problem. In order to simplify the resolution of the proposed model, a linearization of different capital cost functions is required. A quite common technique implemented in oil and gas production and infrastructure planning models is the piecewise linearization method [25,26]. This is the approach implemented in our proposed model.

Considering that we have the tabular data of a scalar function $y = f(x)$ for an interval $x \in \left[x^{lo}, x^{up}\right]$, the piecewise linear approximation of the function is given by:

$$X = \sum_j \lambda_j\cdot\overline{x_j} \tag{60}$$

$$Y = \sum_j \lambda_j\cdot\overline{y_j} \tag{61}$$

$$\sum_j \lambda_j = 1 \tag{62}$$

$$\lambda_j \geq 0 \tag{63}$$

$$x^{lo} \leq X \leq x^{up} \tag{64}$$

where the set of grid points is indexed by $j$. $\left(\overline{x_j}, \overline{y_j}\right)$ is the tabular data corresponding to pre-specified grid points. $\lambda_j$ are variables that form a Special Order Set of Type 2 (SOS2). In a SOS2 set only two adjacent variables of the set can assume non-zero values. Equation (60) is known as the reference row. Equation (61) is known as the function row, and Equation (62) is the convexity row.

The cost of storing natural gas in underground reservoirs and NGL in the different processing plants for each scenario $s$, $Cst_s$, is given by:

$$Cst_s = \sum_{u\in U}\sum_{t\in T}\frac{\sum_{p\in P} icur_u\cdot STGU_{p,u,t,s} + \sum_{m\in M} wcur_u\cdot STUM_{u,m,t,s}}{(1+dr)^t} + \sum_{p\in P}\sum_{t\in T}\frac{scl\cdot TLS_{p,t,s}}{(1+dr)^t} \tag{65}$$

where $icur_u$ and $wcur_u$ are the unit costs of natural gas injection and withdrawal, respectively. $scl$ is the unit cost of storage of NGL.

#### 2.2.13. Income Resulting from the Sale of Products

The income resulting from sales of natural gas and NGL for each possible scenario $s$, $I_s$, is given as follows:

$$I_s = \sum_{p\in P}\sum_{t\in T}\frac{pl_{t,s}\cdot cf\cdot TPS_{p,t,s}}{(1+dr)^t} + \sum_{m\in M}\sum_{t\in T}\frac{pg_{t,s}\cdot\left(\sum_{p\in P} STGM_{p,m,t,s} + \sum_{u\in U} STUM_{u,m,t,s}\right)}{(1+dr)^t} \quad (66)$$

where $pl_{t,s}$ and $pg_{t,s}$ are the NGL and natural gas prices, respectively, in each time period $t$ for each possible scenario $s$. $cf$ is a conversion factor for the amount of NGL.

#### 2.2.14. Objective Function

The expected net present value, $E[NPV]$, is considered as the objective function of the strategic optimization model to be maximized, which is given as follows:

$$E[NPV] = \sum_{s\in S}(prob_s\cdot I_s) + \sum_{s\in S}(prob_s\cdot Cst_s) + \sum_{s\in S}(prob_s\cdot Ctg_s) + \sum_{s\in S}(prob_s\cdot Cproc_s) + Cprod + Cf + Cw \quad (67)$$

where certain terms are independent of the different possible scenario realizations and other terms are represented by the average of all the possible scenario outcomes.

## 3. Uncertainty in Final Products' Prices

In a problem where time and uncertainty play an important role, the decision model should be designed to allow the user to adapt a decision policy that can respond to events as they unfold [27]. To describe the inherent randomness of the natural gas and NGL prices or even regulations throughout the planning horizon of the shale gas enterprise, it is assumed that the crude oil price variation has a determinant impact on the fluctuation of these exogenous parameters. In the case of natural gas, the price movements generally track those of crude oil. A possible justification for this trend is that crude oil refined products and natural gas are close substitutes. Advances in technology nowadays allow industry and power generators to switch between fuels. If the price of one energy source rises, there is a movement to the other source of energy. This generates an increase of demand and the consequent rise of price. Due to the existent relationship between these commodities, market behavior suggests that crude oil is the dominant factor. The main reason of this is that crude oil prices are determined by the world market while natural gas remains confined to regional segments [28]. This means that the crude oil price can be assumed as the driven force of the natural gas price variations during the shale gas project. In the case of NGL, their price has also been closely linked to crude oil price [29]. Since many products made from NGL are closely tied to the crude oil price, the movements of the NGL price normally follow the movements of the crude oil price. Therefore, as in the case of the natural gas price, NGL price movements can also be considered to be shaped by the crude oil price throughout the life cycle of the shale gas project.

Because both natural gas and NGL prices are assumed to be primarily impacted by the movements of the crude oil price, it is first necessary to describe the possible variation of crude oil price during the course of the shale gas enterprise. In this article, the crude oil price trend or movements are presented by a Geometric Brownian Motion (GBM) or exponential Brownian Motion. A GBM is a continuous-time stochastic process in which the logarithm of the randomly varying quantity follows a Brownian Motion or Wiener process. Two main properties are characteristic of a Brownian Motion process, firstly commodity price changes in each time period follow a similar distribution in comparison to other periods, and secondly prices change in each time period are independent over the previous periods [30]. Therefore, the past trend or movement of stock price cannot be utilized to predict its future movement, and they follow a Markovian process.

A stochastic process is said to follow a GBM if it satisfies the following stochastic differential equation:

$$dP_t = \mu P_t dt + \sigma P_t dW_t \tag{68}$$

The analytical solution of the stochastic differential equation is given as follows:

$$P_t = P_{t-1}\, e^{(\mu - \frac{\sigma^2}{2})\Delta t + \sigma\sqrt{\Delta t} w_t} \tag{69}$$

where $P_t$ represents the random asset price at time $t$, $w_t$ is the underlying uncertainty driver as a random number with unit standard deviation and zero mean, $\mu$ is the drift coefficient, and σ is the volatility. Considering Equation (73), the sequential realization of random price of crude oil will lead to a multistage programming framework that could be solved by introducing the probabilistic scenarios or scenario-based approach [31].

The generation of each discrete scenario is possible by discretizing the GBM through the utilization of the Cox et al. [32] option pricing method. The resulting binomial tree can be thought as a time varying probability tree with binary nodes that result from discrete, known movements of the crude oil price [33]. The crude oil price moves up ($u$) and down ($d$) sequentially over time with an estimated probability ($p^{up}$ and $p^{down}$). These movements and their corresponding probabilities are determined by the following equations:

$$u = e^{\sigma\sqrt{\Delta t}},\ d = 1/u \tag{70}$$

$$p^{up} = \frac{e^{\mu\Delta t} - d}{u - d} \tag{71}$$

$$p^{down} = 1 - p^{up} \tag{72}$$

where the coefficient $\mu$ of the stock price is the risk-free rate considering a risk-neutral world. The coefficient $\mu$ and the volatility of the crude oil are obtained through the utilization of market information such as the historical data of crude oil prices included in the Appendix B.

Having the values of crude oil price and probability of any node at any time period $t$, the following upward and downward values of price and probability, respectively, are determined as:

$$P_{t+1}^{up} = P_t u \text{ with probability } p^{up} \tag{73}$$

$$P_{t+1}^{down} = P_t d \text{ with probability } p^{down} \tag{74}$$

A qualitative representation of the binomial tree obtained for the discretized stochastic process is given in Figure 1. Beginning with the initial value or base price $P$ of crude oil, all the possible movements can be defined and consequently all the realizations of the stochastic price, which are represented by certain number of potential scenarios.

Historically, it was thought that the prices of West Texas Intermediate (WTI) crude oil and natural gas delivered at the Henry Hub (HH) maintained a 10-1 relationship, so that one barrel of WTI crude oil priced at roughly 10 times 1 million British thermal units (MMBtu) of natural gas. In recent years, this relation declined by about 40% to 6-1, which was close to thermal parity [34]. Although the energy industry has long used these types of simple rules of thumb, more complex relationships have been established between prices based on cointegration analysis. Different works including Villar and Joutz [28], Bachmeier and Griffin [35], Brown and Yücel [36], Hartley et al. [34], and Parson and Ramberg [37] among others have found evidence that natural gas and crude oil prices are cointegrated. This allows the determination of different pricing relationships to link the natural gas and crude oil prices. Based on those previous works, the fundamental relation between HH natural gas and WTI crude oil prices utilized in this article is given by:

$$P_{HH} = -0.0333 + 0.468 P_{WTI} \tag{75}$$

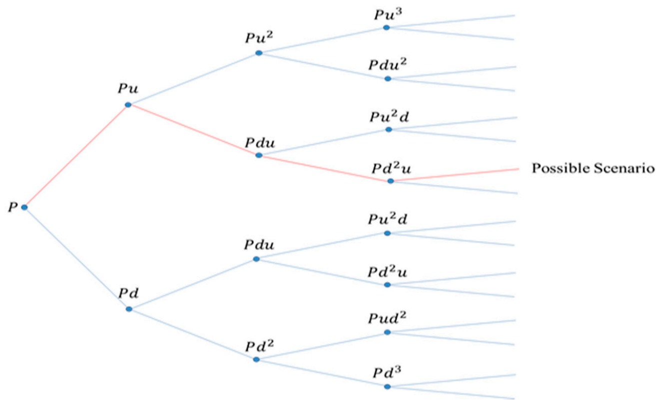


**Figure 1.** Binomial tree for determination of each possible scenario for crude oil price.

This logged linear equation allows the determination of the natural gas price for each node of crude oil price in the binomial tree. The prices of natural gas are given in U.S. dollars per millions of British thermal units (US$/MMBtu) while the crude oil price is given in U.S. dollars per barrel (US$/bbl).

As noticed in several of the mentioned works [38,39], the relationship between natural gas price and crude oil prices has shifted over time due to different factors including technological and economical among others. In the United States, many times the prices of crude oil and natural gas broke away for certain period and later recovered their link establishing a new relationship. Of course, the consideration of this possibility involves a degree of complexity that is not considered in this work. It is assumed that the fundamental tie between prices is maintained stable and does not suffer any type of shifting due to external forces during the life of the shale gas enterprise.

For the case of the NGL price, a much simpler relationship is utilized to establish its linkage with the crude oil price. Although NGL has been historically traded as 65%–70% of the crude oil price in US$/bbl, recently this relation has moved to approximately 45% of the crude oil price. A possible explanation for this shift in the NGL-crude oil relationship might be the production increase of ethane and propane, the primary constituents of NGL, generated by the shale gas boom e.g., in Marcellus and Eagle Ford areas. The higher production of these components has driven down their prices and consequently the NGL price [40]. For the proposed model, the value of 45% is assumed fixed for the NGL-crude oil relation during the life cycle of the shale gas project and utilized as a rule of thumb for the determination of the NGL price that correspond to each node of the binomial tree. Thus, the corresponding binomial tree of NGL prices is completely determined by the binomial tree of the crude oil prices.

The entire framework for the discretization of the stochastic problem is depicted by Figure 2.

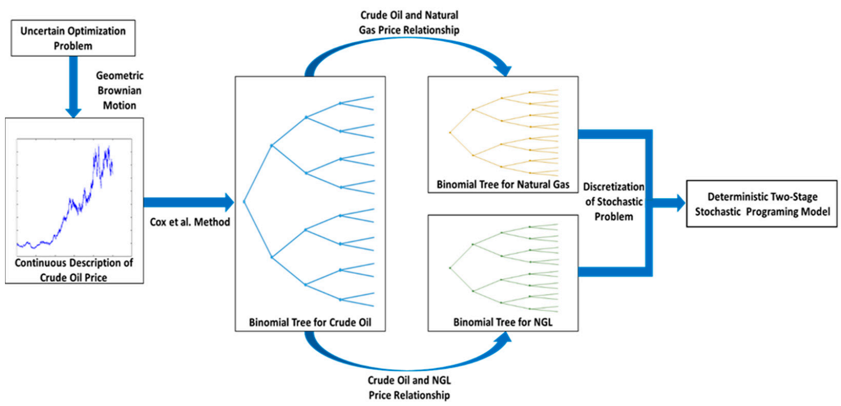


**Figure 2.** Framework for discretization of stochastic optimization problem.

## 4. Case Study

The case study under consideration involves three potential shale sites with the possibility of developing a maximum of two wells per time period. Moreover, a maximum of sixteen wells is assumed throughout the planning horizon of the project. Each well has a productivity that obeys a decreasing function of the well age $ps_{i,t} = \alpha\, t^{\beta}$. There are two possible locations for processing plants (only one is selected) with storage capacity for NGL. Two possible underground reservoirs to store natural gas, three potential sources of water, one possible onsite wastewater treatment unit per shale site, three possible CWT facilities, five potential Class II disposal wells, and two possible customer markets to deliver the natural gas are also assumed. All the distances between the different entities are fixed, represented in Cartesian coordinates in Table 1.

**Table 1.** Cartesian coordinates of different nodes in the network superstructure.

| $x$ (Miles) | $y$ (Miles) | | |
|---|---|---|---|
| 0.0 | 0.0 | i1 | Shale Sites |
| 0.0 | −18.6 | i2 | |
| 0.0 | −28.0 | i3 | |
| 18.6 | −12.4 | p1 | Processing Plants |
| 15.5 | −21.7 | p2 | |
| 62.1 | 31.1 | d1 | Disposal Wells |
| 43.5 | 31.1 | d2 | |
| 31.1 | −77.7 | d3 | |
| 62.1 | −62.1 | d4 | |
| 15.5 | 49.7 | d5 | |
| 9.3 | 15.5 | c1 | CWT Facilities |
| 9.3 | −24.9 | c2 | |
| −9.3 | −24.9 | c3 | |
| 21.7 | −3.1 | u1 | Underground Reservoirs |
| 20.5 | −24.9 | u2 | |
| 28.0 | −6.2 | m1 | Natural Gas Markets |
| 28.0 | −21.7 | m2 | |
| −6.2 | 0.0 | f1 | Freshwater Sources |
| −15.5 | −62.1 | f2 | |
| −12.4 | −9.3 | f3 | |

Pipeline infrastructure is required to transport shale gas from shale sites to processing plant, from processing plant to different markets, freshwater from different sources to shale sites, and wastewater from shale sites to different wastewater management options. Water transportation can also be performed through the use of the conventional trucking. The network superstructure comprising all the potential entities of the optimal shale gas supply chain is depicted by Figure 3. Due to the issue of space limitation, real distances cannot be shown in the figure, but it can offer a general picture of all the potential entities that could be involved in the optimal design of the shale gas supply chain.

Required information about different parameters related to processing plants and their storage capacity, different wastewater treatment units, underground reservoirs, disposal wells, customer markets, and pipeline infrastructure and transportation are based on the data utilized by previous works [6,7]. The planning horizon considered for the shale gas enterprise is ten years with a time discretization of a quarter. Through the implementation of the binomial option pricing method mentioned in the previous section, 512 different paths or branches in the binomial trees are obtained for each different energy commodity. Figure 4 represents the scenario tree for crude oil with the prices obtained for different nodes and the scenarios distribution. Although depicting all the possible price nodes and scenarios of the binomial tree is not possible due to the space limitations, it is still possible to observe the wide range of prices obtained throughout the planning horizon.

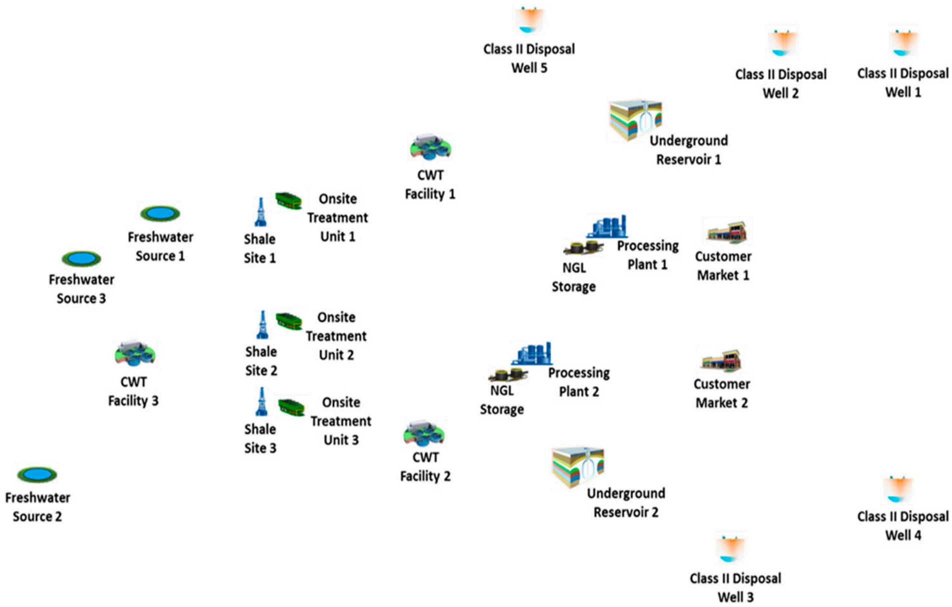


**Figure 3.** Shale gas network superstructure for optimization problem resolution.

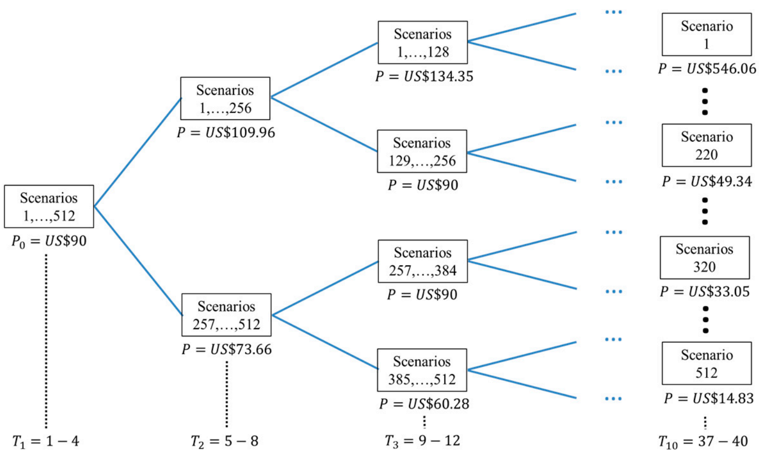


**Figure 4.** Number of scenarios and price (per bbl) variation in crude oil binomial tree.

The number of scenarios can be related to the number of stages T through the exponential relationship $2^{T-1}$. Of course, this represents a significant number of scenarios to be considered if it is assumed that each stage represents a time period of the model. Instead, the proposed approach assumes that each stochastic stage includes four time periods (quarters). For example, the first stage includes the time periods (quarters) 1, 2, 3, and 4. In other words, a yearly discretization is assumed to implement scenario-based approach, but a quarterly discretization is considered for the dynamics of shale gas production and operations throughout the supply chain. Therefore, each stochastic stage incorporates 4 time periods with the same possible realizations, which still enables working the present optimization problem with a manageable number of possible scenarios. More detailed information about input data required by the model is given in the Appendix A of the present article.

## 5. Results and Discussion

Results are determined by implementing the optimization model in the modelling system GAMS 24.4.6 utilizing CPLEX 12.6.2 linear solver on a PC with Intel Core i7-2600K CPU @3.40 GHz and 16 GB RAM, running Windows 7 Enterprise, 64-bit operating system.

## 5.1. Configuration of Shale Gas Supply Chain

Figure 5 represents the optimal configuration of the shale gas supply chain under the presence of uncertain market parameters. This network is constituted by three shale sites (Shale Sites 1, 2 and 3), which receive water from two of the three possible sources of freshwater (Freshwater Sources 1 and 3) for the drilling and primary fracturing operations. The corresponding configuration for the deterministic approach (base case) is depicted in Appendix C (Figure A2).

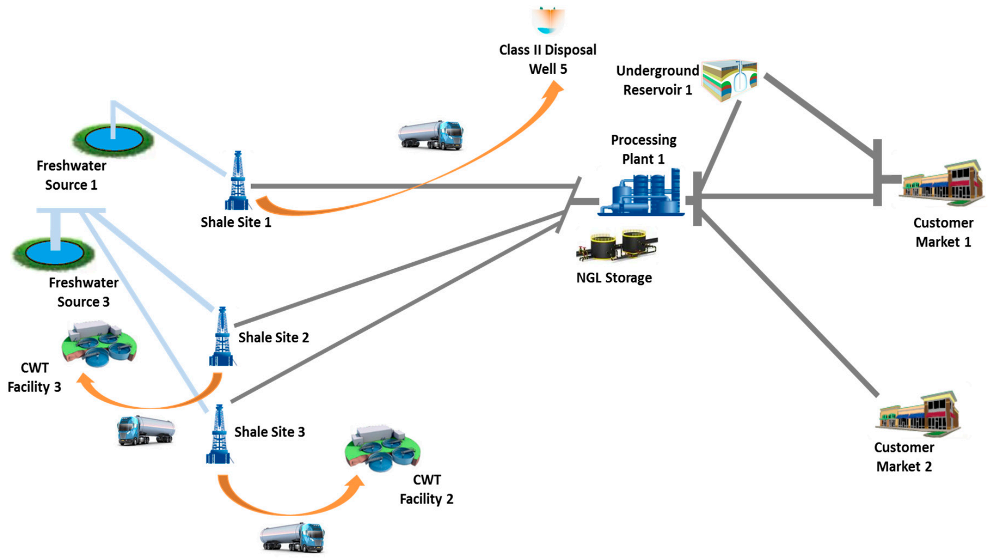


**Figure 5.** Optimal shale gas supply chain network under market uncertainty.

The criteria utilized by the optimizer for the selection of the freshwater sources is based on their distances to the different shale sites. The transportation of water to different shale sites is preferred to be performed through the utilization of a pipeline instead of conventional trucking. Although the use of trucks is the predominant method to transport water to well sites in shale gas projects, the gas drilling industry started to adopt the utilization of pipelines as a practice to reduce the heavy truck traffic [41,42]. So, the utilization of pipeline can be seen not only as a valid method for water transportation but also a recommendable practice to avoid the common land and wildlife disturbances produced by the continuous movement of trucks in this type of projects. Wastewater generated during the fracturing operations is transported to different management options outside the field. In the case of Shale Site 1, wastewater is transported to closest disposal well facility (Class II Disposal Well 5) for injection. For Shale Site 2 and Shale Site 3, the wastewater is transported to the closest CWT facilities for treatment (CWT facility 3 and CWT facility 2, respectively). Since the amount of water generated is not as important as the water required by the wells, it is preferred to utilize the traditional transportation method by trucks. Moreover, trucking has the main advantage of a lower capital investment required in comparison to pipelines. Then, shale gas produced in different sites is transported through pipeline infrastructure to Processing Plant 1 for its separation into natural gas and NGL. The location of the processing plant is selected taking into account the distance to both markets. Given the high fluctuation in the amounts of natural gas to take advantage of the price conditions (moving from high values to low values and vice versa), which requires high capacity of transportation, the optimizer tries to reduce the distance to decrease the infrastructure costs. NGL can be stored in the storage facility located in the processing plant or sold in a close customer market. Detailed results of the optimal combination of storage and amount of NGL is presented in the following section. Natural gas is transported through a pipeline infrastructure to the two possible customer markets. A portion of the production is directly delivered from Processing Plant 1 to Customer Markets 1 and 2. However, a significant part of the production is also sent to Underground Reservoirs 1 for its storage and later delivery to Customer

Markets 1. Several factors such as prices, amounts delivered, and distances play important roles in the strategy utilized for the distribution of natural gas. A more detailed explanation is provided when natural gas allocation is analyzed later in Section 5.4.

### 5.2. Drilling and Fracturing Strategy for Different Shale Sites

The optimal planning strategies for the drilling and fracturing operations for deterministic (base case) and stochastic cases are shown in Figure 6. For both cases, the necessary activities involved in the development of wells including the drilling and hydro-fracturing of shale formations are performed during the first time periods of the planning horizon, where an intense drilling process is observed. Results show a main difference between the deterministic and stochastic cases related to the time that wells are put online to produce. In the stochastic approach the wells are drilled and fractured sooner given the necessity of having enough product downstream to store and deliver when price conditions change. Of course, this provides more flexibility to allocate the different products and take advantage of the possible price scenarios.

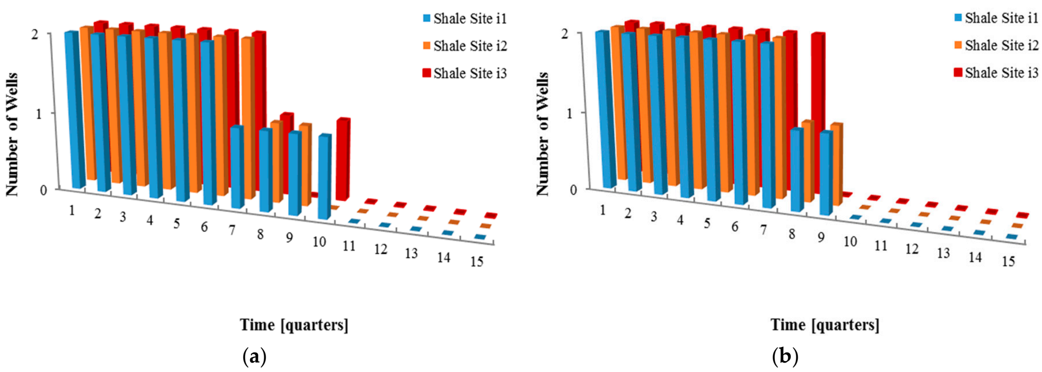


**Figure 6.** (**a**) Optimal drilling and fracturing plan for deterministic case; (**b**) Optimal drilling and fracturing plan for stochastic case.

Drilling and fracturing operations for shale gas production require significant amounts of water. Since there is a direct relationship between number of wells drilled and hydro-fractured and amount of water required, there is an intense utilization of water during the first time periods of the planning horizon for both deterministic and stochastic approaches (Figure 7). For the stochastic approach, the decrease in the utilization of water begins later and finalize sooner than in the deterministic case. This is again related to the necessity of putting the wells online to produce as soon as possible in order to provide more flexibility to allocate products in the downstream section of the supply chain.

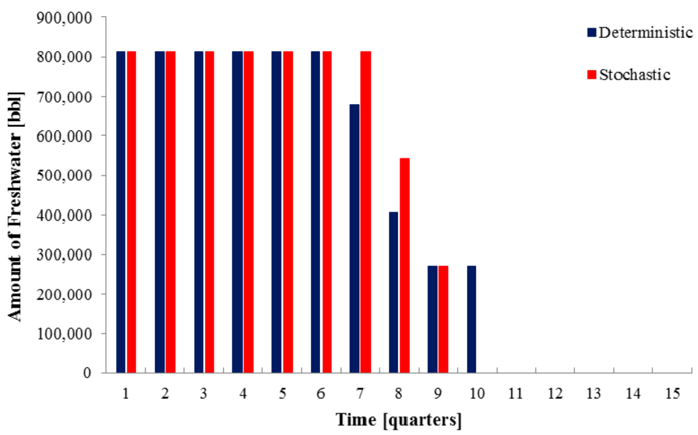


**Figure 7.** Amount of water required in shale sites for deterministic and stochastic cases.

### 5.3. Economic Analysis of Shale Gas Supply Chain

An economical comparative study between deterministic and stochastic cases is performed in order to demonstrate the potential of the developed approach. In Table 2, the profitability as well as the changes in comparison to the base case for the deterministic and the stochastic cases are presented.

**Table 2.** Comparison of deterministic and stochastic cases.

| | | Net Present Value (MMUS$) | % Change from Base Case |
|---|---|---|---|
| | High Price Case | 693.9 | 377.7 |
| Deterministic | Base Case | 145.2 | 0.0 |
| | Low Price Case | 26.9 | −81.4 |
| Stochastic | | 222.5 | 53.2 |

High Price and Low Price cases are based on the maximum and minimum prices of final products in the stochastic case throughout the planning horizon (Figure 8). As shown in Table 2, planning and design for maximum products' prices (High Price Case) would result in an significant increase of about 377.7% of profitability regarding the base case, whilst assuming the minimum products' prices (Low Price Case) would reduce the profitability by about −81.4%. Such important deviations in profitability demonstrate that planning and design under uncertain market pricing environment is extraordinary risky. In the case of the stochastic approach, there is an important improvement in the profitability of the supply chain (55.7%). Of course, this important improvement is obtained as a consequence of more intelligent decisions in the network design and coordination of operations, which are based on the consideration of possible fluctuations of prices throughout the planning horizon of the shale gas enterprise.

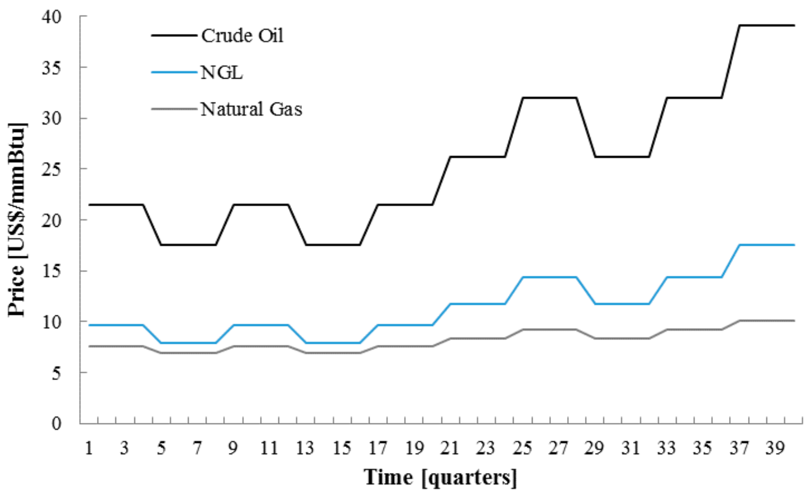


**Figure 8.** Variation of crude oil, NGL, and natural gas prices during the planning horizon.

In Table 3, it can be observed that the increase of profitability in the stochastic case is the consequence of an increase of revenues at the expense of an extra cost due to storage and pipeline infrastructure. An increment of 8.6% is observed in the total revenues of the enterprise, which has a determinant impact on the higher value created by the enterprise in the stochastic model. Of course, this is attached with a storage cost of MMUS$1.2. As will be explained in more detail later in the next section, it is required to pay the costs of storage to take advantage of final products' prices fluctuations in order to maximize sales' revenues. There is also an increase of natural gas transportation cost from MMUS$4.1 to MMUS$6.3. This is associated to the pipeline infrastructure with higher capacity required to allocate natural gas in underground reservoirs and markets according to the market conditions. In the case of processing and production costs, the slightly higher values obtained in the stochastic model are mainly related to the sooner drilling and fracturing of wells. Of course, this generates higher amounts of shale gas to be transported and processed during certain time periods. The remaining costs including freshwater and wastewater management are similar in both cases. Freshwater costs are practically the same given that the total number of wells drilled does not differ between the two cases. In the case of wastewater management, an increase of approximately 0.4% in the cost involved on transportation and treatment of water generated during drilling and fracturing operations is observed in the stochastic case. Given the fact that wells at Shale Site 1 and 3 are put online sooner in the stochastic case, there is an impact in the wastewater production. A slightly higher cumulative production of wastewater is obtained in the stochastic approach, which is reflected in the increase of wastewater management cost.

**Table 3.** Income and costs obtained in deterministic (base case) and stochastic cases.

| | Revenues (MMUS$) | Storage Cost (MMUS$) | Natural Gas Transportation Cost (MMUS$) | Processing Cost (MMUS$) | Shale Gas Production (MMUS$) | Freshwater Cost (MMUS$) | Wastewater Cost (MMUS$) |
|---|---|---|---|---|---|---|---|
| Base case | 994 | 0 | 4.1 | 507.1 | 321.6 | 5.4 | 10.3 |
| Stochastic | 1079.3 | 1.2 | 6.3 | 510.9 | 322.4 | 5.4 | 10.4 |

Figure 9 illustrates the wide range of net present values (NPVs) determined by different scenarios through the implementation of the binomial option pricing approach in the proposed model. Also, the cumulative probability distribution function is depicted in the figure, which can be used in financial risk management by determining the probability of occurrence of unfavorable scenarios (scenarios with NPVs less than a desired value defined by the decision maker).

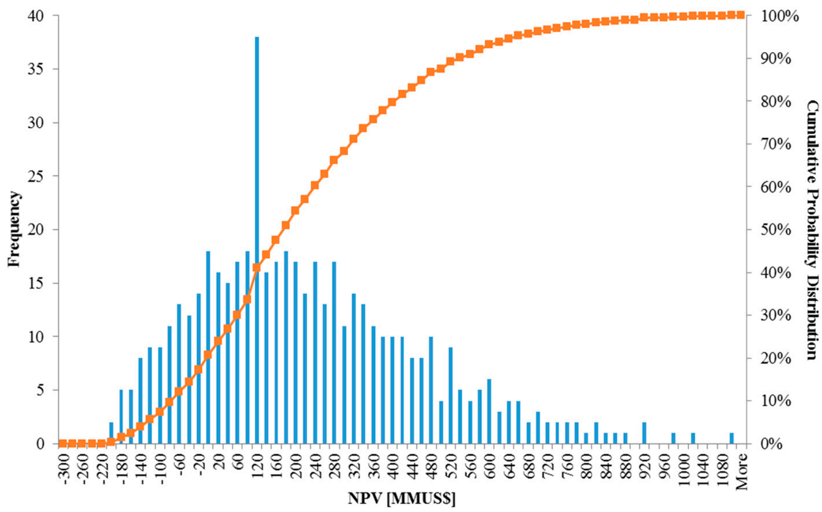


**Figure 9.** Histogram and cumulative probability function for two-stage stochastic model.

### *5.4. Comparative Analysis of Products' Sales and Storage in Deterministic and Stochastic Cases*

In addition to comparing the NPVs and different costs throughout the supply chain between the deterministic and stochastic cases, the variation of total amount of NGL sold during the planning horizon can also be analyzed as shown in Figure 10. Additionally, Figure 11 depicts the fluctuation of NGL stored, and Figure 12 shows the percentage of demand fulfilment for both approaches. In the case of the deterministic model (base case), the initial increase of the amount of NGL sold to the market is directly related with the initial increase of wells' production. During the first time periods, when the drilling and fracturing operations of wells are more intense, the amount of NGL sold achieves a peak in the eighth time period. Then, the amount of NGL sold decreases throughout the rest of the planning horizon following the decreasing pattern of productivity in the shale sites. This is also reflected in the continuous decrease of the percentage of demand fulfilment observed until the last time period (Figure 12). Since the price of NGL is assumed to be constant in the deterministic model, there is no storage of product due to speculation and the entire production from processing plant is sold at gate.

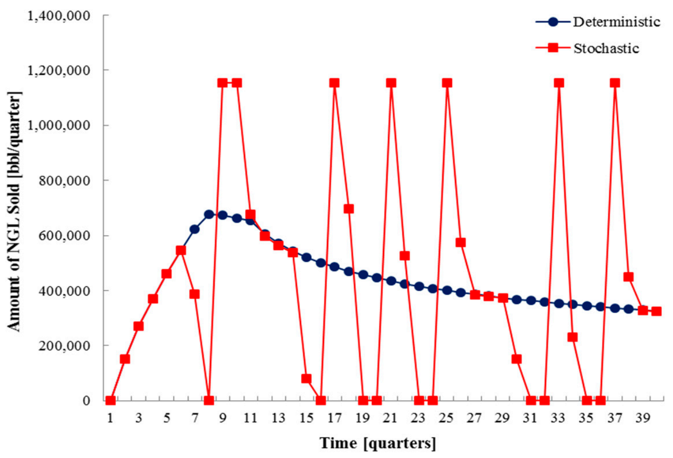


**Figure 10.** Comparison of sold NGL during the planning horizon for stochastic and deterministic cases studies.

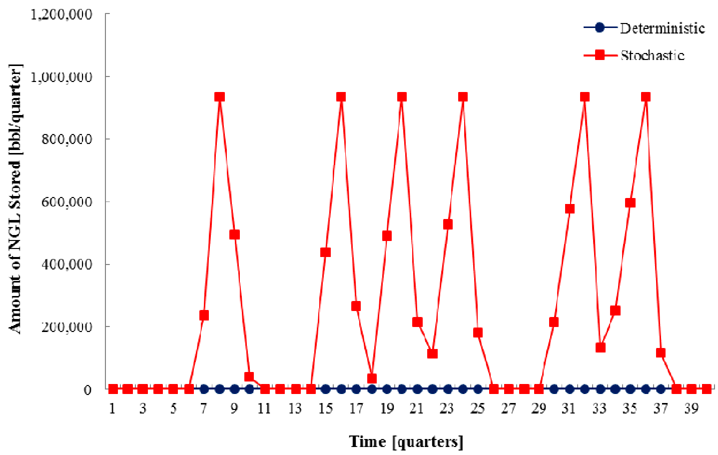


**Figure 11.** Variation of NGL stored for deterministic and stochastic cases.

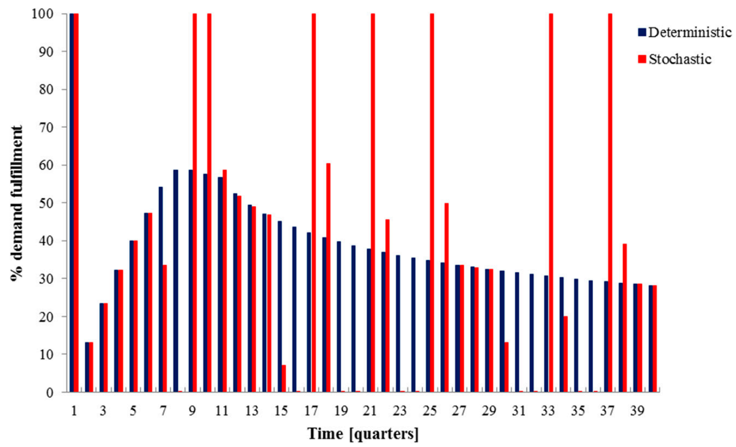


**Figure 12.** Variation of % of demand fulfilment for NGL for deterministic and stochastic cases.

In the case of the stochastic model, NGL price fluctuates over the planning horizon of the shale gas project (Figure 8). Results in this case show an increase in the amount of NGL sold during the first six time periods, which is again associated with the intense drilling and fracturing operations (Figure 10). However, during the seventh and eighth time periods a storage of NGL is generated in the processing plant (Figure 11) and the amount of NGL sold decreases. As can be observed in Figure 8, a lower value for NGL price is obtained during the second year (quarters 5–8) of the project. Because of that, part of the production is stored during the last two quarters of that year with a decrease of the demand fulfilment (Figure 12) in order to deliver the product when better price conditions emerge. This happens in the next year during the quarters 9 and 10, where a higher amount of NGL is sold by utilizing what was stored previously plus the current production. This pattern is observed throughout the rest of the planning horizon. Cleary, there is a trade-off between storage and delivery of NGL according to the revealed price. During the years of low prices, last quarters are utilized to store NGL (minimum percentage of demand fulfilment) in order to deliver the products at the first quarters of the years with better price conditions (maximum percentage of demand fulfilment). Moreover, as wells get aged and their production declines even more, this trade-off between storage and delivery trend to be even more important. Of course, lower production levels put a major emphasis on speculative tools in order to maintain the shale gas project over its economic threshold. Results show that speculative tools that take into account fluctuations of prices have a main role in maintaining a healthy economy of the shale gas enterprise. Consequently, a more flexible and effective decision process for operations is generated by considering the randomness of prices over the life cycle of the shale gas project.

A similar situation is observed when natural gas is delivered to different customer markets during the planning horizon of the shale gas project (Figures 13 and 14). In the deterministic case is possible to observe that the amount delivered to Market 1 is smaller during the entire planning horizon given the larger distance involved between the processing plant and the mentioned market. Given these lower amounts transported, the maximum percentage of demand fulfilment is never achieved (Figure 15). The amount of natural gas delivered to Market 2 follows the trend of production. A peak is achieved during the eighth and ninth time periods due to limitations in the total amount that can be transported to that market. Part of the production is stored at Underground Reservoir 2 to avoid an overstock in that market. This storage is not related to any type of price fluctuations' influence. The percentage of demand fulfilment achieves a peak when the production in the field is maximum and then decreases following the declining trend of production. Clearly, no speculation is observed in the deterministic case and the storage and delivery of products are driven by the production of wells and delivery limitations of the system.

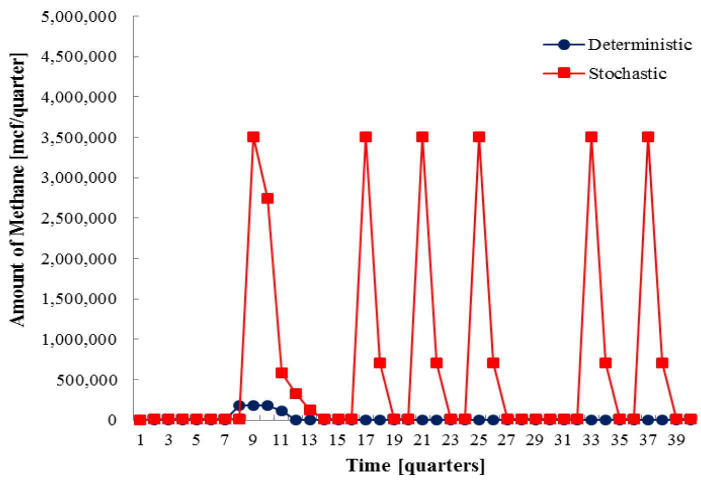


**Figure 13.** Total amount of natural gas sold in Market 1 for both deterministic (base case) and stochastic cases during the planning horizon.

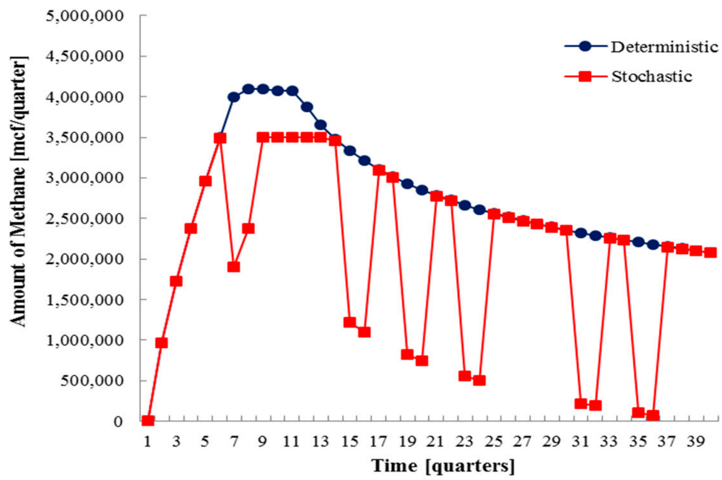


**Figure 14.** Total amount of natural gas sold in Market 2 for both deterministic (base case) and stochastic cases during the planning horizon.

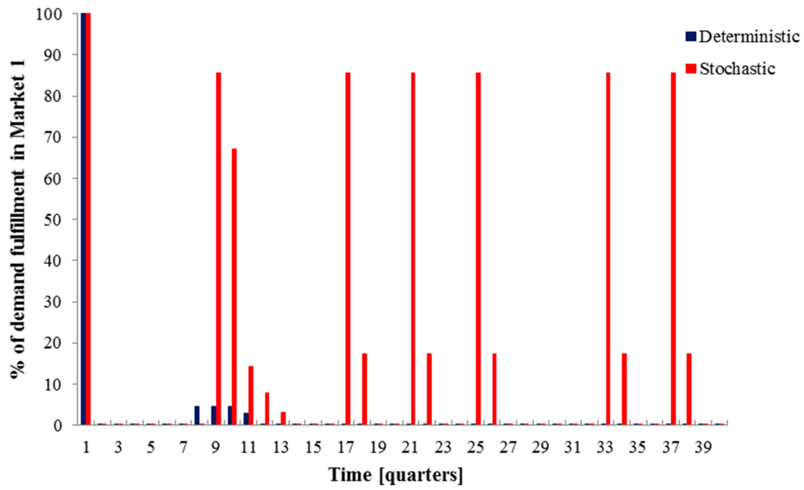


**Figure 15.** Variation of % of demand fulfilment in Market 1 for both deterministic (base case) and stochastic cases during the planning horizon.

In the stochastic approach, the price fluctuations play, like in the case of NGL, a key role in the determination of the optimal operations in the downstream section of the supply chain. The possibility of storing natural gas in underground reservoirs allows a more flexible schedule of operations in order to take advantage of market conditions. For years of low prices, storage of natural gas in Underground Reservoir 1 is produced during the last quarters of those years and the deliveries to Markets 1 and 2 decrease in the same periods. During the years of high prices the amounts stored in Underground Reservoirs 1 decrease during the first quarters of those years and the deliveries to Markets 1 and 2 increase (Figures 13 and 14). There is coordination of operations between the amounts allocated in Underground Reservoir 1 and the deliveries to Market 1 and 2. The delivery to Market 2 is generally higher than the one to Market 1. However, part of the production that should be sent to Market 2 is stored during unfavorable conditions and then utilized to increase the amount delivered in Market 1 when conditions improve. Again, there is a trade-off between storage and delivery during the planning horizon. Lower prices imply more storage and less delivery while higher prices involve less storage a more delivery. Moreover, this is also reflected in the percentage of demand fulfilment for each market (Figures 15 and 16). High percentages of demand fulfilment (approximately 85.5% for Market 1 and 50.6%–85.3% for Market 2) are achieved when the delivery of natural gas increase in the case of both markets while the percentage of demand fulfilment reaches extremely low values (as low as 0.22% in Market 1 and 1.78% in Market 2) during periods where storage increases. Therefore, speculative tools are also utilized in the case of natural gas to maximize the profitability of the shale gas project. Although natural gas has a lower value in comparison to NGL, it still exert a substantial role on the economic success of the shale gas project.

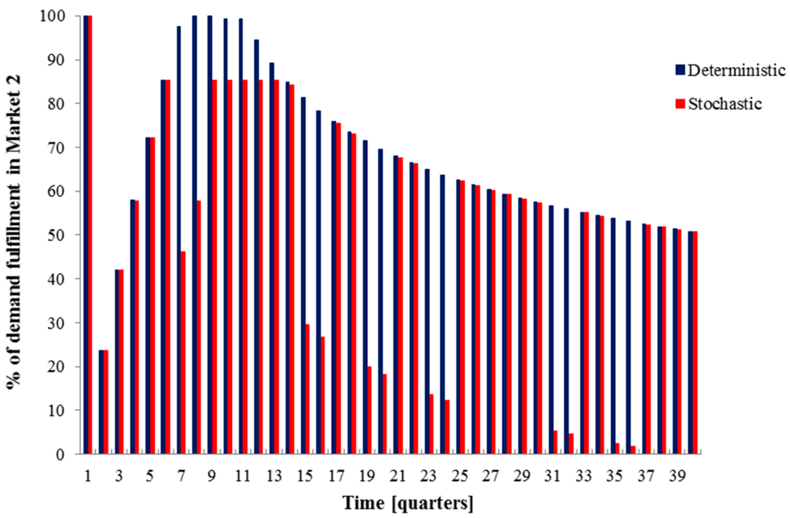


**Figure 16.** Variation of % of demand fulfilment in Market 2 for both deterministic (base case) and stochastic cases during the planning horizon.

## 6. Conclusions

In this article, a two-stage stochastic model is proposed and implemented to address the relevant problem of the optimal design and operation of a shale gas supply chain network under the presence of uncertain market parameters such as the prices of natural gas and NGL. The stochastic conditions of these parameters are captured through the utilization of a scenario-based approach, which attempts to represent the uncertainty by describing it in terms of a specific number of discrete realizations. In order to determine the possible realizations, a GBM is first implemented to simulate the stochastic characteristic of the crude oil price. Then, this continuous-time stochastic process is discretized by the implementation of an option pricing model, which allows the determination of the scenario tree for the crude oil price. Since the crude oil price and final products of shale gas production are assumed to fluctuate in tandem, different relationships between the prices of these commodities are utilized to determine the required scenario trees for the natural gas and NGL. Finally, the scenario trees are incorporated into the stochastic model to obtain a deterministic representation of the optimization problem. This work is intended to provide a decision-making support for the development of a shale gas supply chain. The mathematical framework presented in this article can represent a useful tool for economic development agencies as well as national and international oil and gas companies to evaluate and implement the necessary strategies to avoid the possible detrimental effects of uncertain market events and generate an economic plan for the development of a successful shale gas enterprise.

The analysis of results reveals that the stochastic case offers a more profitable design and operations for the shale gas supply chain when compared with the deterministic approach (base case). It is observed that the variability of the NGL and natural gas prices has a significant impact on the determination of the optimal design and, more specifically, the different operations in the shale gas supply chain network. The coordination of operations related to the supply of NGL and natural gas (post-production operations) such as storage and delivery to different markets can be of extreme importance for the improvement of the economics of a shale gas project. An increase of sales' revenues is produced at the expense of an increment of certain costs, which has a determining effect on the higher profitability obtained in the stochastic approach. Clearly, speculative tools have a key role in the development of a smarter and more profitable design and scheduling of activities of the shale gas supply chain.

Future work will focus on incorporating the uncertainty of other parameters including product demand, wells productivity, and different costs along the supply chain among others. Other direction for future research may be the implementation of a financial risk analysis for the shale gas enterprise through the utilization of different risk management methods. Moreover, the incorporation of other operations such as shutting in and re-fracturing of wells at different pads as well as certain characteristics of the horizontal wells including length, number of stages, and size of fractures are also part of the future research work. Considering the potentiality of the United States as a shale gas producer, another important feature that could be incorporated in the model is the possibility of external costumer markets in the supply chain for both natural gas and natural gas liquids.

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**Conflicts of Interest:** The authors declare no conflict of interest.

## Abbreviations

| | |
|---|---|
| *Sets* | |
| $T$ | time periods |
| $I$ | shale sites |
| $F$ | freshwater sources |
| $O$ | onsite treatment units, where $o1$ = MSF, $o2$ = MED, and $o3$ = RO |
| $C$ | CWT facilities |
| $D$ | disposal wells for wastewater |
| $P$ | processing plants |
| $U$ | underground reservoirs |
| $M$ | customer markets |
| $K$ | transportation modes, $k1$ = trucks and $k2$ = pipeline |
| $S$ | possible scenarios |
| *Continuous Variables* | |
| $NW_{i,t}$ | number of wells drilled and hydro-fractured at shale site $i$ in each time period $t$ |
| $FWR_{i,t}$ | freshwater required at shale site $i$ in each time period $t$ |
| $FWA_{f,i,k,t}$ | freshwater acquired at freshwater source $f$ transported to shale site $i$ by transportation mode $k$ in each time period $t$ |
| $FBW_{i,t}$ | flowback at shale site $i$ in each time period $t$ |
| $PW_{i,t}$ | produced water at shale site $i$ in each time period $t$ |
| $WWC_{i,c,k,t}$ | amount of wastewater transported from shale site $i$ to CWT facility $c$ by transportation mode k in each time period $t$ |
| $WWD_{i,d,k,t}$ | amount of wastewater transported from shale site $i$ to disposal well $d$ by transportation mode k in each time period $t$ |
| $WWO_{i,o,t}$ | amount of wastewater treated by onsite treatment unit $o$ at shale site $i$ in each time period $t$ |
| $SP_{i,t}$ | shale gas production at shale site $i$ in each time period $t$ |
| $TSP_{i,p,t}$ | amount of shale gas transported from shale site $i$ to processing plant $p$ in each time period $t$ |
| $TCP_{i,p}$ | pipeline capacity for transportation of shale gas from shale site $i$ to processing plant $p$ |
| $TSG_{p,t}$ | amount of natural gas produced at processing plant $p$ in each time period $t$ |
| $TSL_{p,t}$ | amount of NGL produced at processing plant $p$ in each time period $t$ |
| $PP_p$ | processing capacity for processing plant $p$ |

| | |
|---|---|
| $STGM_{p,m,t,s}$ | amount of natural gas transported from processing plant $p$ to customer market $m$ in each time period $t$ for scenario $s$ |
| $TCGM_{p,m}$ | transportation capacity of pipeline from processing $p$ to customer market $m$ |
| $STGU_{p,u,t,s}$ | amount of natural gas transported from processing plant $p$ to underground reservoir $u$ in each time period $t$ for scenario $s$ |
| $TCGU_{p,u}$ | transportation capacity of pipeline from processing $p$ to underground reservoir $u$ |
| $STUM_{u,m,t,s}$ | amount of natural gas transported from underground reservoir $u$ to customer market $m$ in each time period $t$ for scenario $s$ |
| $TCUM_{u,m}$ | transportation capacity of pipeline from underground reservoir $u$ to customer market $m$ |
| $USG_{u,t,s}$ | amount of natural gas stored at underground reservoir $u$ in each time period $t$ for scenario $s$ |
| $TLS_{p,t,s}$ | amount of NGL stored at processing plant $p$ in each time period $t$ for scenario $s$ |
| $TPS_{p,t,s}$ | amount of NGL sold at processing plant $p$ in each time period $t$ for scenario $s$ |
| $pl_{t,s}$ | forecasted price of NGL in each time period $t$ for scenario $s$ |
| $pg_{t,s}$ | forecasted price of natural gas in each time period $t$ for scenario $s$ |
| *Binary Variables* | |
| $YW_{i,n,t}$ | 1 if $n$ wells are drilled and hydro-fractured at shale site $i$ in each time period $t$ |
| $YO_{i,o}$ | 1 if onsite treatment $o$ is selected at shale site $i$ in each time period $t$ |
| $XFI_{f,i,k}$ | 1 if transportation mode $k$ is installed to transport freshwater from freshwater source $f$ to shale site $i$ |
| $XWC_{,i,c,k}$ | 1 if transportation mode $k$ is selected to transport wastewater from shale site $i$ to CWT facility $c$ |
| $XWD_{i,d,k}$ | 1 if transportation mode $k$ is selected to transport wastewater from shale site $i$ to disposal well $d$ |
| $XPP_p$ | 1 if processing plant is selected |
| $XSG_{i,p}$ | 1 if pipeline installed to transport shale gas from shale site $i$ to processing plant $p$ |
| $XGM_{p,m}$ | 1 if pipeline installed to transport natural gas from processing plant $p$ to customer market $m$ |
| $XGU_{p,u}$ | 1 if pipeline installed to transport natural gas from processing plant $p$ to underground reservoir $u$ |
| $XUM_{u,m}$ | 1 if pipeline installed to transport natural gas from underground reservoir $u$ to customer market $m$ |

## Appendix A

Additional information about the input data (Table A1).

**Table A1.** Input data for case study utilized for the resolution of optimization model.

| Parameters | Value | Description |
|---|---|---|
| $\alpha$[mcf/quarter] | 186,249.6–256,172.6 [6] | Productivity function coefficient |
| $\beta$ | 0.37 [6] | Productivity function exponent |
| $ccwt_c$[US$/bbl] | 3.5 [8] | Unit cost for wastewater treatment at CWT Unit $c$ |
| $cd_c$[US$/bbl] | 1.2 [8] | Unit cost for underground injection at disposal at well $d$ |
| $cf[bbl_l/mcf_g]$ | 0.0035 | Conversion factor between $bbl_l$ and $mcf_g$ of NGL |
| $cfwt_k$[US$/(mile bbl)] | $k1$ = 0.02, $k2$ = 0.0004 [8] | Transportation cost of freshwater for transportation mode $k$ |
| $cg_i$ | 0.8 [8] | Natural gas composition in shale gas at Shale Site $i$ |
| $cl_i$ | 0.2 [8] | Natural gas liquids composition in shale gas at Shale Site $i$ |
| $clic_{i,c,k}$[US$/mile] | $k1$ = 800, $k2$ = 3500 [8] | Unit capital cost of transportation mode k for wastewater from Shale Site $i$ to CWT Unit $c$ |
| $clid_{i,d,k}$[US$/mile] | $k1$ = 800, $k2$ = 3500 [8] | Unit capital cost of transportation mode k for wastewater from Shale Site $i$ to Disposal Well $d$ |
| $clif_{ik}$[US$/mile] | $k1$ = 800, $k2$ = 3000 [8] | Unit capital cost of transportation mode $k$ for freshwater from Freshwater Source $f$ to Shale Site $i$ |
| $cot_c$[US$/bbl] | $o1$ = 6.5, $o2$ = 5.4, $o3$ = 4.7 [8] | Unit cost for wastewater treatment Onsite Treatment Unit $o$ |
| $csgd_{i,t}$[US$] | 6,400,000 [43] | Unit cost for shale well drilling at Shale Site $i$ in time period $t$ |
| $csgp_{i,t}$[US$/mcf] | 0.5 [8] | Unit cost for shale gas production at Shale Site $i$ in time period $t$ |
| $csgw_i$[bbl/mcf] | 0.01–0.02 [8] | Correlation coefficient between shale gas production and wastewater produced at Shale Site $i$ |
| $ctwcap_{c,t}$[bbl/quarter] | 600,000 [8] | Capacity for wastewater treatment at CWT Unit $c$ |
| $cw_{f,t}$[US$/bbl] | 0.01–0.02 [44] | Acquisition cost of freshwater at Freshwater Source $f$ in time period $t$ |

**Table A1.** *Cont.*

| Parameters | Value | Description |
|---|---|---|
| $cwwt_k$[US$/(mile bbl)] | $k1$ = 0.03, $k2$ = 0.0006 [8] | Transportation cost of wastewater for transportation mode $k$ |
| $dcap_{c,t}$[bbl/quarter] | 90,000 [8] | Capacity for underground disposal at well $d$ |
| $dgmax_{m,t}$[mcf/quarter] | 4,100,000 | Maximum demand of natural gas for Customer Market $m$ |
| $dgmin_{m,t}$[mcf/quarter] | 7200 | Minimum demand of natural gas for Customer Market $m$ |
| $dlmax_t$[mcf/quarter] | 1,850,000 | Maximum demand of NGL |
| $dlmin_t$[mcf/quarter] | 1800 | Minimum demand of NGL |
| $dr$ | 0.024 | Discount rate per time period |
| $fwcap_{f,t}$[bbl/quarter] | 1,500,000 [8] | Water capacity of Freshwater Source $f$ in time period $t$ |
| $icapur_u$[mcf/quarter] | 9,000,000 [8] | Injection capability Underground Reservoir $u$ |
| $icur_u$[US$/mcf] | 0.02 [8] | Unit injection cost at Underground Reservoir $u$ |
| $lfi_{f,i}$[miles] | * | Distance from Freshwater Source $f$ to Shale Site $i$ |
| $lic_{i,c}$[US$/mile] | * | Distance from Shale Site $i$ to CWT Unit $c$ |
| $lid_{i,d}$[US$/mile] | * | Distance from Shale Site $i$ to Disposal Well $d$ |
| $lip_{i,p}$[miles] | * | Distance from Shale Site $i$ to Processing Plant $p$ |
| $lpm_{p,m}$[miles] | * | Distance from Processing Plant $p$ to Customer Market $m$ |
| $lpu_{p,u}$[miles] | * | Distance from Processing Plant $p$ to Underground Reservoir $u$ |
| $lscap_p$[mcf/quarter] | 1,500,000 | Storage capacity of NGL for each time period at Processing Plant $p$ |
| $lum_{u,m}$[miles] | * | Distance from Underground Reservoir $u$ to Customer Market $m$ |
| $Nmaxi$ | 16 | Maximum number of wells that can be drilled at Shale Site $i$ during the planning horizon |
| $nt_i$ | 2 [8] | Maximum number of wells drilled and hydro-fractured per time period $t$ |
| $ocap_o$[bbl/quarter] | $o1$ = 60,000, $o2$ = 10,000, $o3$ = 6000 [8] | Maximum treatment capacity for Onsite Treatment Units $o$ |
| $P$ [US$/bbl] | 90 [45] | Base price for crude oil in the time period $t$ = 1 |
| $pcipl$ [US$] | 881.9 [8] | Chemical engineering plant cost index for pipeline |
| $pcipp$[US$] | 574 [8] | Chemical engineering plant cost index for processing plant |
| $pcsg$[US$/mcf] | 6.3 [8] | Unit processing cost for shale gas |
| $ppcapl$[mcf/quarter] | 30,000 | Minimum capacity of processing plant |
| $ppcapu$[mcf/quarter] | 50,000,000 | Maximum capacity of processing plant |
| $ppeff$ | 0.97 [8] | Processing plant efficiency for separation of shale gas |
| $rccpg$[US$/mile] | 64,144 [8] | Reference capital investment of pipeline transporting natural gas |
| $rccpsg$[US$/mile] | 64,144 [8] | Reference capital investment of pipeline transporting shale gas |
| $rcp$[US$] | 21,310,000 [8] | Reference capital cost for processing plant |
| $rcpg$[mcf/quarter] | 639,840 [8] | Reference capacity of pipeline transporting natural gas |
| $rcpsg$[mcf/quarter] | 639,840 [8] | Reference capacity of pipeline transporting shale gas |
| $rdf_i$ | 0.15 [38] | Recovery ratio of water for fracturing process at Shale Site $i$ |
| $rfo_o$ | $o1$ = 0.15, $o2$ = 0.45, $o3$ = 0.65 [8] | Recovery factor of wastewater treated in Onsite Treatment Unit $o$ |
| $rfw_o$ | $o1$ = 0.43 $o2$ = 0.40, $o3$ = 0.38 [8] | Ratio of freshwater to wastewater required after treatment at Onsite Treatment Unit $o$ |
| $rpc$[mcf/quarter] | 4,809,600 [8] | Reference capacity of processing plant |
| $rpcipl$[US$] | 887.6 [8] | Chemical engineering plant cost index of the reference year for pipeline |
| $rpcipp$[US$] | 567.3 [8] | Chemical engineering plant cost index of the reference year for processing plant |
| $scl$[US$/mcf] | 0.1 [8] | Unit storage cost for NGL |
| $sfp$ | 0.6 [8] | Size factor of processing plant |
| $sft$ | 0.6 [8] | Size factor of pipeline transporting shale gas and natural gas |
| $tcapfi_{f,i,t}$[bbl/quarter] | $k1$ = 135,000, $k2$ = 1,200,000 [8] | Transportation capacity for transportation mode $k$ from Freshwater Source $f$ to Shale Site $i$ |
| $tcapic_{i,c,t}$[bbl/quarter] | $k1$ = 135,000, $k2$ = 1,200,000 [8] | Transportation capacity for transportation mode $k$ from Shale Site $i$ to CWT Unit $c$ |
| $tcapid_{i,d,t}$[bbl/quarter] | $k1$ = 540,000, $k2$ = 4,800,000 [8] | Transportation capacity for transportation mode $k$ from Shale Site $i$ to Disposal Well $d$ |
| $tcpg$[US$/(mcf mile)] | 0.0015 [8] | Unit transportation cost for pipeline transporting natural gas |
| $tcpsg$[US$/(mcf mile)] | 0.0015 [8] | Unit transportation cost for pipeline transporting shale gas |
| $t_f$ | 3 [8] | First time period where no more shale wells are developed |
| $tfw$[bbl/well] | 135,714 [18] | Amount of freshwater required for drilling and hydro-fracturing each well |
| $tgcapl$[mcf/quarter] | 9000 [8] | Minimum capacity of pipeline transporting natural gas |
| $tgcapu$[mcf/quarter] | 210,000,000 [8] | Maximum capacity of pipeline transporting natural gas |
| $tsgcapl$[mcf/quarter] | 9000 [8] | Minimum capacity of pipeline transporting shale gas |
| $tsgcapu$[mcf/quarter] | 210,000,000 [8] | Maximum capacity of pipeline transporting shale gas |
| $wcapur_u$[mcf/quarter] | 32,400,000 [8] | Working gas capacity of Underground Reservoir $u$ |
| $wcur_u$[US$/mcf] | 0.01 [8] | Unit withdrawal cost at Underground Reservoir $u$ |
| $wicapur_u$[mcf/quarter] | 18,240,000 [8] | Withdrawal capability of Underground Reservoir $u$ |

* Distances determined utilizing Table 1 from Case Study section of this article.

## Appendix B

Historical data of crude oil price is given in this section (Figure A1). The day number one corresponds to the date 2 January 1986, and the last day corresponds to the date 30 April 2014.

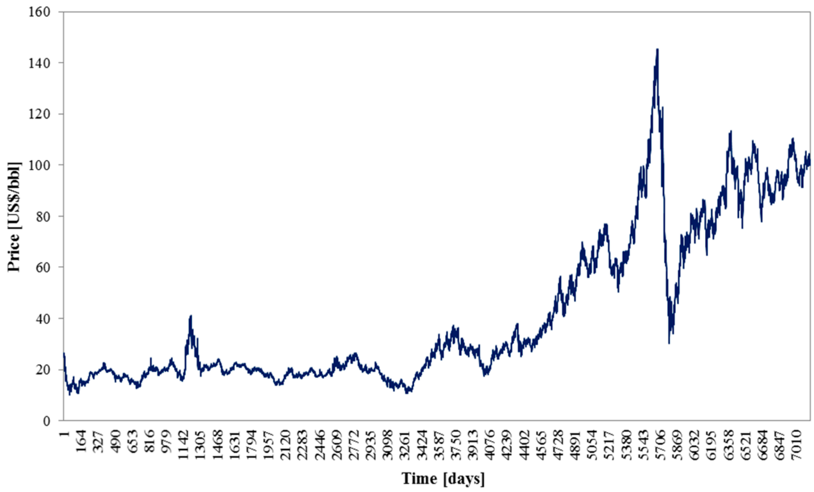


**Figure A1.** Historical data for crude oil price for approximately twenty-eight years [45].

## Appendix C

In this section, the configuration of shale gas network for the deterministic case is depicted.

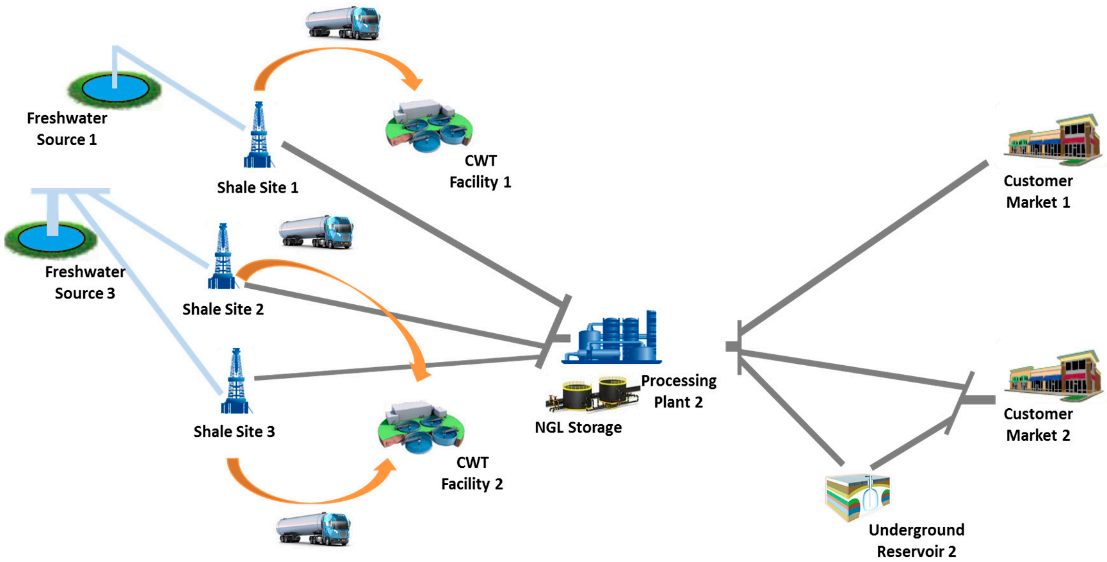


**Figure A2.** Optimal shale gas supply chain network for deterministic model (base case).

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