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ORIGINAL RESEARCH PAPER

Extended Optimization Approach to Oil Production Portfolio Planning: An Empirical Study

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ABSTRACT

A fundamental activity in the energy sectors of oil- and gas-producing countries is strategic planning to determine the optimal level of hydrocarbon production. According to the International Energy Agency (IEA), oil and natural gas are expected to remain the world's primary energy sources in the long term, highlighting the importance of efficient investment and production decisions in this sector. In this context, selecting an appropriate portfolio of oil and gas production projects is a critical challenge for policymakers and energy planners. This paper aims to identify an optimal subset of oil and gas production projects, referred to as a "portfolio," by proposing a comprehensive mathematical optimization model. The model is designed to maximize the Net Present Value (NPV) of selected projects while considering key economic and operational constraints relevant to upstream energy development. To demonstrate the applicability and effectiveness of the proposed framework, the model is implemented in an empirical case study based on Iran's oil and gas sector. The results indicate that the use of quantitative optimization models can significantly improve decision-making quality by enabling a more productive allocation of financial and technical resources. The findings suggest that portfolio optimization approaches provide valuable support for long-term energy planning and can help energy-producing countries enhance economic performance and investment efficiency in the oil and gas secto



1. Introduction

One central decision-making context for countries is energy management [1]. The IEA [2] has announced that liquid fuels such as oil and gas will remain the most important energy sources in the long term due to the growing body of research in the energy field. Factual reports of consumption and demand rates emphasize this fact. Since 2014, global oil demand has been on a constant rise, from 96 million barrels per day in 2014 to 100 million barrels in 2018 [3]. According to the WEC, in 2017 [4], one-third of the global energy demand was supplied by oil. Oil, coal, and natural gas, with 29 and 24 percent of global demand, are the top sources of energy supply, respectively [5]. According to Artemkina et al. [6], oil demand has increased by approximately six percent in the four years ending in 2019. Therefore, it should be acknowledged that despite the unprecedented increase in the global demand for renewable energy, including wind and solar energy, fossil fuels are still the primary source of energy supply in many countries worldwide [7].

Oil and gas are key commodities in the global energy market, worth more than two trillion dollars annually, and have an annual investment of more than 300 billion dollars in exploration and production. Although oil and gas production industries are very

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dynamic, their fields have limited lifespans (this figure is, on average, between 15 and 20 years for oil fields and 20 and 30 years for gas fields). Therefore, major oil companies need more than seven percent annual growth to maintain their market share. In addition, significant oil and gas sectors require substantial and long-term investments [8]. The ratio of capital cost to income for big international oil companies is about 17%, while the global ratio of capital cost to income is around 6% to 7% [9]. Despite advancements in technology, exploring and producing oil remain risky professions. Consequently, optimal planning of oil and gas projects due to the limited resources as well as the irreversibility of decisions in this field because of the enormous financial obligations in the long-term horizon is of special importance [10,11].

Big oil companies must devise long-term portfolios to profit from low prices [12]. The portfolio selection is vital for oil and gas organizations to sustain and develop their businesses and enhance profitability [13,14]. A portfolio is a collection of projects, programs, or operations managed as a group in order to attain strategic organizational objectives and to take into account resource limitations [15,16]. A portfolio is a collection of products selected by the management for production and how they are combined to ensure optimal returns over a specific time period [17]. Planning and preparing companies' investment portfolios allows carrying out projects with higher capital returns, so preparing investment portfolios is essential for oil-producing companies [18,19]. Since the acceleration of the energy transfer stage, oil and gas companies must form their production and investment portfolios to ensure the sustainability of their profits in the long term [12]. Portfolio preparation is a tool for optimization, and although a long time has passed since this method was used, its application in the oil industry is still limited [20]. The risk theory and Markowitz portfolio selection theory are the most common tools for solving the problem of forming a portfolio [21].

Considering the important role of production planning in Iran's oil industry, the necessity of developing long-term and short-term oil plans has become increasingly important in various ways. Now the question arises: How is the optimal amount of crude oil production determined, considering its economic, social, and political consequences? Also, is this amount currently optimal in Iran? Therefore, this study aims to find the optimal oil production planning for one of the important companies in the country and then generalize it to other regions. In other words, the main goal of this article is to propose an optimization model for long-term production planning and investment in one of the important Iranian companies through which a long-term integrated plan for oil production can be achieved.

Optimization problems usually involve maximizing or minimizing one or more objective functions while constrained [22,23,24]. An optimization or mathematical programming problem involves finding the values of variables that maximize or minimize the value of one or more objective functions, provided that the values of these variables satisfy several equal or unequal constraints.

The optimization literature in the oil and gas industry was first concerned with the classification of planning tools, production optimization, and field development. Nygreen et al. [25] have classified the tools for oil production planning into three levels: operational, tactical, and strategic. Atkinson & Aysangulav [26] developed a model for optimization of oil and gas field development, well completion, and production rates, while Nygreen & Haugen [27] studied the application of linear programming models for field and pipeline development. A model has been developed by Dzubur & Langvik [28] to optimize the oil production with respect to the gas injection rates, oil, water, and gas production, and system pressure. Rahmawati et al. [29] proposed an integrated model to assess optimal production strategies considering control variables, operational constraints, and economic factors. Shakhsi-Niaei et al. [30] classified oil optimization problems into three levels, i.e., strategic, tactical, and operational. Shakhsi-Niaei et al. [22] reviewed the research on oil and gas optimization in upstream and suggested an integrated linear programming model for long-term strategic decision-making.

Then, studies were directed to investment portfolio selection, risk management, uncertainty analysis, and multi-criteria decision-making. Xue et al. [31] proposed a model for selecting oil and gas investment portfolios taking into account risk–return trade-offs, capital costs, and operating expenses. Mehrgan et al. [32] proposed a nonlinear multi-objective model for oil production optimization and gas consumption minimization. Vashkevich et al. [20] have studied 45 exploration projects. They considered the role of portfolio formation in risk management. Huang et al. [33] used the real option model to determine the optimal timing and scale of investment in oil markets with uncertainty. Artemkina et al. [6] have combined linear programming with multi-criteria selection; Molchanov and Romasheva [34] studied tools for benchmarking in portfolio management. Shafiei et al. [5] classified DSS into three stages: exploration, development, and production. Furthermore, decision-analytic frameworks were stressed by Fasth et al. [35], MADM by Karbassi-Yazdi et al. [36], IFMOLP by Yu et al. [37], software tools for project portfolios by Bilgin et al. [38], and a hybrid data-driven framework for project selection and management by Forouzeshnejad [39].

More recent studies also indicate that the field has moved towards multi-period, scenario-based, multi-objective and operational flexibility-based models. Yusuf et al. [40] developed a multi-period MILP model to investigate the optimal allocation of natural gas in the energy production and conversion network. Kruk & Shabalina [41] studied the optimisation of investment portfolios for oil and gas projects under risk and uncertainty, using the Markowitz portfolio theory. Liu and Zhang [42] proposed a multi-objective decision-making model for green shale gas development. Fedorov et al. [43] studied the marginal field portfolio allocation problem under uncertainty of oil and reservoir prices within a compound real options framework. Xiong et al. [44] integrated system dynamics and multi-objective optimisation for the analysis of the production, investment and financial plans of a "natural gas+" company. Mohamad Zaki et al. [45, 46] proposed a hybrid approach based on MILP and pinch analysis for technology selection. Therefore, the current study is in line with optimisation-based portfolio planning and scenario-based decision-making and contributes to the development of quantitative decision-making frameworks by focusing on oil and gas project selection, maximising NPV and taking economic and operational constraints into account.

2. Method

2.1. Components and symbols of the proposed model

The problem and main traits are explained first. We consider several oil production projects in specific fields. A portfolio of the best projects is the goal. Nodes represent producing fields and refineries, and edges represent pipelines that transport products or feed from refineries to fields. A mathematical programming model finds the highest net present value projects in the investment plan, which includes cash flows. Project implementation is determined by this model's decision variables. Definitions of model symbols:

Table 1. Indices

h, i, j	Network nodes
p	Projects
s	Upstream products
t, t'	Years of the planning horizon
r	Resources needed to implement projects

Table 2. sets

Exp	Issuing nodes
$IntMark$	Internal market nodes
$Supp$	Supplier nodes
Dem	Nodes requesting the product
$Pump$	Inter-route communication nodes including inter-route pump houses
$PrjNod_i$	Development projects related to node i
$PrjArc_{ij}$	Development projects related to arc ij
Alt-set-p	Projects corresponding to different states of p project development
Pre-set-l	Pair of projects with prerequisite relationships with a specified time interval between their starts
Pre-set-nl	Pair of projects with prerequisite relationships without a specified time interval between their starts
Sim-set	Pairs of projects with co-requirement relationships (selecting/not selecting both)
Obl-set-t	Set of mandatory projects with specified start time
Obl-set-nt	Set of mandatory projects without specific start time
Obl-set-b	Set of mandatory projects with a specified time limit to start

Table 3. parameters

B_{it}	Amount of planned production/demand at node i in year t (without implementing any field development projects)
$NB_{pt't}$	Amount of product produced/required in the tth year of the planning horizon by project p if it starts in year t
AI	Ratio allowed to increase production compared to normal profile
AD	Ratio allowed to reduce production compared to the normal profile
TP_i	Total amount that can be taken from field i
U_{ij}	Available capacity for transmission between two nodes i and j at the time of planning start (without implementing any line development projects)
$PU_{pt't}$	Capacity that is added to the product transfer capacity in year t between two nodes related to project p due to the start of project P in year t
$L_{p,p'}$	Minimum time interval required to start project p' after the start of project p
$PK_{prt't}$	Amount required from resource r in year t to implement project p if this project was started in year t
TK_{rt}	Maximum amount that can be allocated from resource r in the tth year of the planning horizon
MC_{ij}	Cost of moving a product unit from node i to node j at the price of the year of planning
$UCCI_t$	Index of capital costs of the upstream sector in year t
$UOCI_t$	Index of production costs of the upstream sector in year t
$MARR$	Minimum RoR (Rate of Return) on investment
PR_t	Base price of sales in year t
RPR_i	Ratio of selling price in node i to its base price
VC_i	Variable cost of producing each unit at node i
FC_i	Annual fixed cost of production at node i (regardless of production more than the normal profile)
AFC_i	Overhead cost imposed due to producing more than the normal profile in node i
M	A big number
UIN_t	Target income ceiling in year t according to the macro financial policies of the country

LIN_t	Desired income floor in year t according to the macro financial policies of the country

Table 4. variables

y_{pt}	A binary (1 or 0) indicating the start time of the project (1: start of project p in year t; 0: otherwise)
yy_p	A binary (1 or 0) indicating selection/not selection of project p in the selection portfolio
e_p	The year the project started p
a_{it}	Amount of production increase/decrease in node i in year t compared to the normal profile (free in sign)
q_{it}	Cumulative value of the total production at node i during the first to t years
b'_{it}	Final amount of production/demand in year t and at node i after the implementation of the development projects selected in the basket
u'_{ijt}	Capacity that is added to the product transfer capacity in year t Transmission capacity between two nodes i and j in the tth year of the planning horizon after the implementation of the line development projects selected in the portfolio
f_{ijt}	Transfer value in year t from node i to node j
k_{rt}	Amount required from source r for all active projects in year t
z_{it}	A binary (1 or 0) indicating the presence/absence of additional production on the normal profile at node i in the tth year of planning
fz_{it}	A binary (1 or 0) indicating the occurrence of the first period of production increase compared to the normal profile at node i
tc_t	Sum of all annual costs related to the portfolio of selected projects
tb_t	Sum of all the annual revenues from the portfolio of selected projects
NPV	The NPV of the portfolio of selected projects

2.2. Methodological workflow

The model transparency is increased by implementing the research methodology in a stepwise framework. First, the operational and project data of the Iranian Offshore Oil Company are collected and converted to model inputs such as projects, products, investment needs, production profile, costs, prices and resource constraints within this framework. Then, the model components, objective function, and main constraints are described, and oil price, gas price, and investment capacity scenarios are introduced in the model: Finally, the MILP model is solved in GAMS software and outputs such as optimal portfolio, production level, investment path, costs, revenues and NPV are extracted and compared in different scenarios.

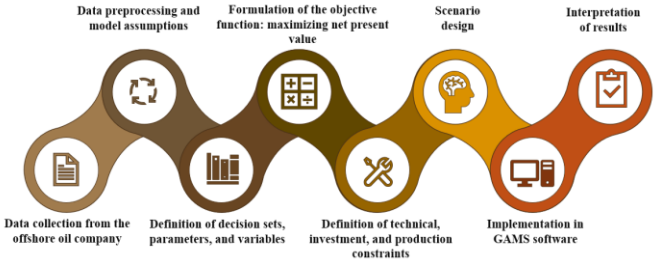


Figure 1. Methodological framework of the proposed optimization model

2.3 Objective function of the proposed model

The model's objective function, the NPV of investment, consists of two parts: revenue components (incomes) and cost components (outcomes). By discounting all incomes and expenses to the beginning of the year, the NPV is obtained as Equation (1).

$$\text{Max } NPV = \Sigma_t (1 + MARR)^{-t} \left(Tb_t - PV(Tc_t)\right) \quad (1)$$

Where:

$\boldsymbol{Tc_t}$: Total annual costs related to the portfolio in year t,

$\boldsymbol{Tb_t}$: Total annual revenues related to the portfolio in year t,

$\boldsymbol{MARR}$: Minimum Acceptable Rate of Return.

2.3.1 Costs in the objective function

The costs fall into five categories. The alpha category, as Equation (2), includes the cost of transferring products/feeds in the network.

$$\alpha_t = \Sigma_i \Sigma_j MC_{ij} f_{ijt} \quad (2)$$

Where:

$\boldsymbol{MC_{ij}}$: The average cost of transferring product/feed from node i to node j,

$\boldsymbol{f_{ijt}}$: Transfer amount in year t from node i to node j.

The beta category, as Equation (3), specifies the sum of fixed costs of node i.

$$\beta_t = \Sigma_i FC_i \quad (3)$$

Where:

$\boldsymbol{FC_i}$: Annual fixed cost of production at node i (regardless of production more than the normal profile).

The gamma category, as Equation (4) shows, includes the sum of the variable cost of the net production of the products for all the reservoirs. Notably, to obtain net production, the inventory of reservoirs in the last year is deducted from the current inventory of reservoirs.

$$\gamma_t = \Sigma_i VC_i \left(q_{it} - q_{i(t-1)}\right) \quad (4)$$

Where:

$\boldsymbol{VC_i}$: The average cost of product production at node i,

$\boldsymbol{q_{it}}$: The inventory of node i in year t, i.e., cumulative amount of the total production at node i during the first year to year t.

The delta category , as Equation (5), includes the annual cost to run project p, depending on which year t', it started.

$$\delta_t = \Sigma_p \Sigma_{t'} y_{pt'} PK_{p(devbudge)t't} \quad (5)$$

Where:

$\boldsymbol{y_{pt}}$: A binary (1 or 0) indicating the start time of project p (1: start of project p in year t; 0: otherwise),

$\boldsymbol{K_{p(devbudge)t't}}$: The cost of all required resources and the $devbudge$ index collects these costs according to the resources required for development.

The zeta category, as in Equation (6), represents the fluctuation of the field production compared to the standard profile.

$$\zeta_t = \Sigma_i fz_{it} AFC_i \quad (6)$$

Where:

$\boldsymbol{fz_{it}}$: A binary (1 or 0), which takes 1 when the production at node i in year t changes compared to the normal profile, and zero otherwise,

$\boldsymbol{AFC_i}$: Overhead cost imposed due to producing more than the normal profile in node i.

To adjust fz_{it}, we define constraints (7), (8), and (9), in which M is a big number. It is necessary to consider both negative and positive changes. Therefore, we first assume that the value of a_{it} is known in the first period, where a_{it} is amount of production increase/decrease in node i in year t compared to the normal profile (free in sign). Then the variable z_{it} is defined for which the following Equation (7) and Equation (8) is applied, where z_{it} is a binary (1 or 0) indicating the presence/absence of additional production on the normal profile at node i in year t of planning. We see that if a_{it} has a positive value, z_{it} will equal 1. Moreover, if $z_{it} = 1$ and a_{it} is a negative value, it would be possible to make the binary variable of fluctuation (both positive and negative). It should be noted that by having the initial value of a_{it}, this equation can be solved recursively.

$$a_{it} \leq M z_{it} \quad (7)$$

$$a_{it} \geq -M(1 - z_{it}) \quad (8)$$

$$fz_{it} \geq 2z_{it} - \Sigma_1^t z_{it'} \quad (9)$$

The total annual cost can be written as Equation (10).

$$Tc_t = \alpha_t + \beta_t + \gamma_t + \delta_t + \zeta_t \quad (10)$$

Since the general level of prices is not the same in different years of the calculation process, it is necessary to adjust the figures of each year according to inflation. However, the use of general inflation rates, despite the simplicity of calculation, does not give favorable results because the fluctuations and growth of oil industry's product prices are subject to different patterns compared to the consumer or producer price index. However, with the use of two indicators of (1) capital costs that are calculated by considering capital costs such as the cost of facilities, materials, personnel, and equipment and (2) the index of high production costs that calculates the changes in production costs; the problem of adjusting the annual figures to inflation are solved. Here, to adjust the price, the trend of cost changes in the available data is used as an estimate of the prediction periods' price index. Depending on whether the costs are capital or productive, a different index is defined. With the price adjustment

index obtained, the adjusted cost per year can be determined. Values $\alpha_t, \beta_t, \gamma_t$ are related to operating costs and statistics δ_t, ζ_t are related to capital costs. Therefore, to adjust the cost in relation to the price index and discount it to time $t = 1$, it is necessary to consider the following Equation (11).

$$\mathrm{PV}(Tc_{\mathrm{t}}) = \frac{\mathrm{UOCI_t}}{\mathrm{UOCI_1}}(\alpha_{\mathrm{t}} + \beta_{\mathrm{t}} + \gamma_{\mathrm{t}}) + \frac{\mathrm{UCCI_t}}{\mathrm{UCCI_1}}(\delta_{\mathrm{t}} + \zeta_{\mathrm{t}}) \quad (11)$$

Where:

$\boldsymbol{UCCI_t}$: Index of capital costs of the upstream sector in year t,

$\boldsymbol{UOCI_t}$: Index of production costs of the upstream sector in year t.

2.3.2 Revenues in the objective function

The total revenue is obtained by Equation (12).

$$Tb_t = \Sigma_j RPR_j PR_t \Sigma_i f_{ijt} \quad (12)$$

Where:

$\boldsymbol{f_{ijt}}$: Transfer amount in year t from node i to node j,

$\boldsymbol{PR_t}$: Base price of sales in year t (due to the price difference of the desired product in different markets, we need a base price to compare the prices),

$\boldsymbol{RPR_i}$: Ratio of selling price in node i to its base price.

As a matter of fact, the revenue from the sale of the product at year t is a function of the sales amount f_{ijt} in the export node or the domestic market $\forall j \in Exp$ (set of issuing nodes) or $\forall j \in IntMark$ (set of internal market nodes), which is the sum of inputs from other nodes i (because in the export terminal, sales can exceed the amount programmed, b'_{it} cannot be used, where b'_{it} is the final amount of production/demand in year t and at node i after the implementation of the portfolio projects); PR_t price of the product at time t in reference markets; and the ratio of the price of RPR_j in market j to the price in the reference market.

Minimum or maximum exogenous constraint can also be given for income. For example, the government's budget deficit may require that oil revenues in a year exceed a certain limit, or the government may prefer not to hand over oil foreign exchange revenues to the central bank to control liquidity. In the first case, there is a minimum constraint of LIN_t (that is target income ceiling in year t according to the macro financial policies of the country) and in the second case, there is a maximum constraint of UIN_t (that is desired income floor in year t according to the macro financial policies of the country), which are respectively shown in the model as the following Equation (13) and Equation (14).

$$Tb_t \geq LIN_t \quad (13)$$

$$Tb_t \leq UIN_t \quad (14)$$

Since conventional price indices can be used to discount earnings, we include average inflation in the discount rate of the $MARR$ model and modify it in the calculation of $UOCI$ and $UCCI$.

2.4. Constraints of the proposed model

2.4.1. Field development profile

The production profile, which shows the field's production in different years, is one of the main criteria for evaluating new fields or field development plans. To calculate the amount of annual production or the production profile, we consider the amount of annual production without planning and implementing the development project, and the amount of additional production of the current year, according to the starting year of the development project. In addition, production fluctuations should be included in the calculation of the annual production amount. The curve of the production profile in the early years of exploitation of the field is ascending. However, over time, with the continuation of the exploitation of the desired field, the graph is first stabilized and then begins to decline. Considering that the annual demand of a field can fluctuate, when evaluating the production profile of a field to increase the flexibility of the production plan, the amount of oil production in all the years in the planning is not considered equal to the production profile. In this model, the variable shows the fluctuation of production from the production profile at the node in the year.

2.4.2. Increasing production in production nodes

To increase production capacity in node i, it is necessary to implement project p. The start of project p in year t' is shown by a binary variable $y'_{pt} = 1$. If this project starts in year t', and completes in year t, the amount of $NB_{pt't}$ will be added to the product's normal capacity, where $B_{pt't}$ is that amount of product produced/required in year t of the planning horizon by project p, if it starts in year t'. The available capacity (without expansion) in node i in year t is denoted by B_{it}, in fact, B_{it} is the amount of planned production/demand at node i in year t (without implementing any field development projects). If a_{it} is less/greater than the capacity of node i in year t, the supply quantity after deciding on the expansion plan (i.e., the final amount of production/demand in year t and at node i after the implementation of the portfolio projects) will be equal to the following Equation (15).

$$b'_{it} = B_{it} + \Sigma_{t'}\, y_{pt'} NB_{pt't} + a_{it} \quad (15)$$

This equation is correct each node belonging to category $\forall i \in Supp$ (set of supplier nodes) and each project in this node, $\forall p \in PrjNod_i$ (set of development projects related to node i), in any time t.

2.4.3. Increasing demand in applicant nodes

With the increase in production capacity, the demand for the product also increases. As on the supply side, if project p is started in year t' $(y_{pt'} = 1)$, then $NB_{pt't}$ is added to the normal demand in year t. We denote the existing demand (without expansion) at node i in year t by B_{it}. If a_{it} is less/greater than the capacity of node i in year t, the amount of demand after deciding on the expansion plan would be as Equation (16).

$$b'_{it} = -B_{it} - \Sigma_{t'}\, y_{pt'} NB_{pt't} \quad (16)$$

This equation is true for every supply node that $\forall i \in Dem$ (set of nodes requesting the product) and every project in that node which $\forall p \in PrjNod_i$ (set of development projects related to node i) and every year t. If a node is both a supplier and user of products, both these equations are considered.

2.4.4. Communication nodes

Communication nodes, such as inter-road pump houses, are points whose net supply and demand are zero at any year, that is, no product is produced or consumed in them. So, the following Equation (17) must be true for each communication node of $\forall i \in Pump$ (set of inter-route communication nodes including inter-route pump houses) at any year t.

$$b'_{it} = 0 \quad \forall i \in Pump, t \quad (17)$$

2.4.5. Supplementary equations

Each project starts only once, so sum of y_{pt} for each project p must be equal to zero or one. Therefore Equation (18) is built.

$$\Sigma_t y_{pt} \leq 1 \quad (18)$$

For a project p to be selected (i.e. $yy_p = 1$, a binary variable indicating selection/not selection of project p) is the same as for at least one of the years to be selected. Because each project is available only once, as a result, the value of yy_p for each project p is the same as the left side of the above relation, therefore Equation (19) is written.

$$yy_p = \Sigma_t y_{pt} \quad (19)$$

To obtain the starting year of each project p, we use the following Equation (20), where e_p is the year that the project p starts.

$$e_p = \Sigma_t\, t.\, y_{pt} \quad (20)$$

2.4.6. Crude oil swap

In crude oil swap, the country is actually the transit point of the product, and as a result, the input and output must be the same. Therefore, for each product swap contract in year t, the value of $B_{it} > 0$ is added to the input terminal and the value of $-B_{it}$ subtracted from the export terminal. In this way, the swap contract for passing the desired product has been added to the conditions of the model.

2.4.7. Mutual fields

The challenge faced in planning for mutual fields is that the decisions of neighbors affect the profitability of the investment. In the years under review, sanctions against Iran have caused other countries to extract more from mutual hydrocarbon resources (such as the North Dome/South Pars). To model the collection of mutual resources, two general approaches can be taken: first, using game theory, developing the mathematical method of planning and adding the other party's decision making method to the model; second, exogenously include the possible scenario(s) of the neighboring country in the model. For the sake of simplicity, as well as the lack of information about how neighbors make decisions, the second method is used. In this situation, assuming a certain volume of harvest of the neighbors in each year and from each field, the cost-effectiveness of the development of the field is checked. In

this method, the capacity of node capacity that changes in each year ($NB_{pt't}$) is related to the remaining volume of the mutual field and the harvest of the neighboring country.

2.4.8. Production of variable

Some mathematical modeling answers are unacceptable due to technical limitations such as the capacity of pipelines or the limitation of market demand at the final nodes (Nigrin et al., 1998). To resolve this problem, the fluctuation percentage compared to the normal profile for the input and output of each node is assumed to have a certain limit. In other words, in each time interval from t' to $t, p \in PrjNod_i$ and in each production node $i \in Supp$, the change in production from AD (ratio allowed to reduce production compared to the normal profile) cannot be less than AI (ratio allowed to increase production compared to normal profile). In this regard, Equation (21) and Equation (22) are used.

$$\Sigma_{t'}\, y_{pt'} NB_{pt't} + a_{it} \le AI \Sigma_{t'}\, y_{pt'} NB_{pt't} \tag{21}$$

$$\Sigma_{t'}\, y_{pt'} NB_{pt't} + a_{it} \ge AD \Sigma_{t'}\, y_{pt'} NB_{pt't} \tag{22}$$

Since it is assumed that the production only changes when the development project is implemented for simplicity, the following Equation (23) is added so that the right side of the equation becomes zero without carrying out the development project.

$$a_{it} \le M y y_p \tag{23}$$

Another constraint is the capacity of the reservoirs of each production node $i \in Supp$ in any year t. As Equation (24), the inventory of each reservoir is the total inventory of the product from the first year to the year t.

$$q_{it} = \Sigma_{t'} b'_{it'} \tag{24}$$

It is assumed that the inventory in the first year of planning is insignificant and can be ignored, but q_{i0} can also be assumed to be positive. The value of q_{it} must not exceed the maximum capacity of TP_i (total amount that can be taken from field i) at any year t, therefore Equation (25) is built.

$$q_{it} \le \Sigma_t TP_i \tag{25}$$

2.4.9. Transfer capacity increase by developing of pipelines

In addition to moving several products in the upper area of an oil and gas reservoir, due to the high volume of products, not only pipelines are shared between moving products, but often several groups of pipelines must be utilized to transfer only one product. For representing the product transfer capacity at time t between nodes i and j, variable u'_{ijt} is defined, i.e., transmission capacity between two nodes i and j in year t of the planning horizon after implementation of the line portfolio projects. According to Equation (26), if at the beginning of the planning period, the product transfer capacity between nodes i and j is equal to U_{ij} (i.e., available capacity for transmission between nodes i and j at the time of planning start, without implementing any project), and as the result of implementing project $\forall p \in PrjArc_{ij}$ (set of projects related to arc ij), the capacity at time t', will be equal to the capacity at time t increased by $PU_{pt't}$, where $PU_{pt't}$ is the capacity that is added to the product transfer capacity in year t between two nodes related to project p due to the start of project p in year t.

$$u'_{ijt} = U_{it} + \Sigma_{t'} y_{pt'} PU_{pt't} \tag{26}$$

It should be noted that in all projects, the transfer capacity is permanently increased. Therefore, $PU_{pt't}$ is zero before $y_{pt'} = 1$ and equal to a constant afterwards.

2.4.10. Consideration of transfer capacity in pipelines

The amount of transferred product in year t through pipeline (i, j), which should not exceed the final capacity of the pipeline, u'_{ijt}, is modelled by variable f_{ijt} as Equation (27).

$$f_{ijt} \le u'_{ijt} \tag{27}$$

2.4.11. Balance in nodes

First, it must be considered that the amount of product transferred at time t between nodes i and j is nonnegative, so Equation (28) is written.

$$f_{ijt} \ge 0 \tag{28}$$

The net transfer of any product between nodes i and j at time t cannot be in both directions. Equation (29) depicts this requirement.

$$f_{ijt} \times f_{jit} = 0 \tag{29}$$

Now, it should be noted that in the upper network, market nodes are comprised of two types: (1) the internal markets where supply and demand must be in equilibrium. That is, in an internal market node, $i \in IntMark$, the sum of the produced amount of product at time t and the transferred product amount from other nodes, h, must be equal to the transferred product from this node to other nodes, j, therefore Equation (30) should be built, and (2) in external markets, although export obligations must be implemented, surplus product can be sold in the open market. Therefore, Equation (31) must be checked for each node $i \in Exp$.

$$\Sigma_{h:\, hi \in V} f_{ijt} + b'_{it} - \Sigma_{j:\, ij \in V} f_{ijt} = 0 \tag{30}$$

$$\Sigma_{h:\, hi \in V} f_{ijt} + b'_{it} - \Sigma_{j:\, ij \in V} f_{ijt} \ge 0 \tag{31}$$

2.4.12. Relations between projects

The time sequence of projects in this model falls into four general categories.

Category I: Project p' must be completed before start of project p. However, there is no specific order or priority among the projects, and there is no need for an explicit time interval between them. These projects are in the $pre-set-nl$ category (pair of projects with prerequisite relationships without a specified time interval between their starts). See Equation (32).

$$yy_{p'} \le yy_p \quad p \; and \; p' \in \; pre-set-nl \tag{32}$$

Category II: Project p' is only possible for just $L_{pp'}$ years after project p, where $L_{pp'}$ is the minimum time interval required to start project p' after start of project p. In this case, in addition to the above equation, the following condition must also be true in the $pre-set-l$ set (pair of projects with prerequisite relationships with a specified time interval between their starts). See Equation (33).

$$e_{p'} \ge e_p + L_{pp'} \tag{33}$$

Category III: Projects that must all be done to achieve the desired result. In this case, the following relationship should be established for each $\forall p$ and $p' \in Sim-set$ (set of pairs of projects with co-requirement relationships (selecting/not selecting both)), where $n(Sim-set)$ is the number of projects (cardinal) required to be completed together. See Equation (34).

$$yy_p \le \frac{\Sigma_{p'} yy_{p'}}{n(Sim-set)} \tag{34}$$

Category IV: Projects that are the substitute of each other and only one of them can be implemented. In this case, each project in the replacement set of $p \in ALt-set-p$ (set of projects corresponding to different states of project p), is limited by Equation (35).

$$\Sigma_p yy_p \le 1 \tag{35}$$

2.4.13. Need for different resources

For implementing any project p, that starts at the time of t', $PK_{prt't}$ is required from the r source in each time step t, where is the amount required from resource r in year t to implement project p if this project was started in year t. Therefore, the entire demand from the source r is obtained from the following Equation (36), in which k_{rt} is the demand of source r for all active projects in year t.

$$k_{rt} = \Sigma_p \Sigma_{t'} y_{pt'} PK_{prt't} \tag{36}$$

Moreover, the amount of consumption of each source r should be less than TK_{rt}, i.e., maximum amount that can be allocated from resource r in year t of the planning horizon. This constraint is displayed by Equation (37).

$$k_{rt} \le TK_{rt} \tag{37}$$

2.4.14. Specific requirements for some projects

If implementation of project $p' \in Obl-set-nt$ (set of mandatory projects with specified start time) is necessary due to non-economic reasons and outside the model, the following Equation (38) should be included.

$$yy_{p'} = 1 \quad (38)$$

If the execution time is specified for implementation of the project $p' \in Obl - set - t$ (set of mandatory projects without specific start time), the following Equation (39) is included.

$$y_{tp'} = 1 \quad (39)$$

If only the project's completion time $p' \in Obl - set - b$ (set of mandatory projects with a specified time limit to start) is specified, we consider the following Equation (40).

$$\Sigma_1^{t'} y_{tp'} = 1 \quad (40)$$

4. Results and Discussion

4.1. Case Description and Data Sources

The case study of this study is one of the largest offshore oil-producing companies in the world and is affiliated with Iran, whose main responsibility is the exploitation, maintenance, and development of offshore oil and gas resources in the Persian Gulf. The company produces more than 500,000 barrels of oil per day and operates in an operational area of about 1,800 km in length and 27 to 120 km in width. It was formed as a result of the merger of five oil companies: Sirip, Ipak, Lapco, Iminoko, and Sofiran.

In this study, eight development projects related to oil fields A and B are examined. These projects are in three main groups: production planning projects, buyback contracts, and new petroleum contracts or IPC, i.e., Iranian Petroleum Contracts. Production planning projects are designed with the aim of optimally allocating resources; scheduling implementation stages; reducing resource waste; increasing productivity; improving production forecasting; and also taking into account technical and operational constraints.

Buyback contracts have been used in Iran since 1974 as a common method of financing and attracting capital, especially foreign investment, in the upstream oil and gas sector. The IPC contracts are a kind of service purchase contract, similar to the production sharing contracts, which are designed to attract international oil companies, to preserve Iran's position in OPEC and the global oil and gas market, and to improve the process of exploration, development, and exploitation of fields. In IPC, the contractor has greater latitude in development and production than in buyback.

4.1.1. Oil projects

In this study, eight development projects related to oil fields A and B are examined. Projects 1, 2, and 3 are production planning projects. In Project 1, the investment is made during the third to sixth years of the 20-year horizon so that in the initial and final years of this period, an investment of $339 million is considered, and in the middle years, an investment of $508.5 million is considered. The total investment of this project is $1,695 million, and its daily production from the seventh to the twentieth year is estimated to be between 40,000 and 20,100 barrels of crude oil. Project 2 includes an investment of $76.2 million, of which $7.2 million is made in the third year and $23 million annually in the fourth through sixth years. This project will produce 37,000 barrels per day in the seventh year and 18,800 barrels per day in the final year. Project 3 is also a production planning project with an investment of $350 million in years four to seven.

Projects 4, 7, and 8 are IPC projects. In Project 4, $503 million will be invested in years three to six; Project 7 involves an investment of $104 million, and Project 8 is estimated to have an investment of $917.034 million. Projects 5 and 6 are buyback projects; in Project 5, $421 million will be invested in years two and three, and in Project 6, $94 million will be invested in years one and two.

To prepare the data, information on the type of project, implementation period, investment amount, capacity or production profile, and assumed product prices are organized in the form of a 20-year planning horizon. This information is then converted into optimization model parameters to input investment data; production; costs; oil, gas, and condensate prices; technical constraints; and investment absorption capacity into the objective function and model constraints. Since some input parameters, especially crude oil sales prices, are subject to uncertainty due to global market fluctuations, oil sanctions, and operational constraints, several valid scenarios for prices and investment conditions are defined. Finally, the prepared data along with the price scenarios are used in GAMS software to implement and solve the model.

4.2. Scenario Design

4.2.1. First scenario: Price Stability

In this scenario, based on data from the Iranian Offshore Oil Company, the investment absorption capacity for Oilfield A is assumed to be $250 million in the early years and gradually increases to $1 billion over a 20-year planning horizon. For Field B, the investment level is assumed to be $350 million; therefore, the main focus of investment is on the development of Field A. The price of fossil fuels, including crude oil, gas, and condensate, is determined based on the current price in the first year and then increases such that the price of crude oil reaches $70 per barrel in the first year to $77 in the final year.

This scenario is based on the assumption of gradual realization of investment and a gentle increase in prices, but it still faces challenges such as uncertainty in capital absorption, price fluctuations, technological changes, the effects of technology on production costs and productivity, and geopolitical risks. To avoid these risks, it is necessary to diversify financial resources, to increase the flexibility of production planning, to use advanced technologies, and to manage political and market risks.

4.2.2. Second scenario: Moderate Decline

In the second scenario, unlike the first scenario, more pessimistic conditions are considered for the future of investment and the energy market. Due to production and exploration constraints, the prices of energy carriers decrease linearly over the planning horizon, such that the price of crude oil drops from $70 to $50 per barrel and the price of gas drops from 10 cents to 8 cents per cubic meter. The price reduction rate in this scenario is assumed to be 1.05. Also, due to investment constraints, the capital absorption capacity for Field A is considered to be $250 million and for Field B is considered to be $350 million. This reflects the relative stagnation in the global energy market, the limited capacity for capital absorption, and the increasing financial stress in development projects. Declining prices and capital constraints may slow the rate of field development, delay project implementation and limit profitability. In this case the risks of economic sanctions, volatile prices, and scarce financial resources become more important. Strategies like implementation, simplifying financial resources, reducing operating costs, concluding long-term contracts, implementing projects in phases, and strengthening regional cooperation are proposed to deal with this situation. The success of this scenario depends on cost control, attraction of alternative financial resources, and flexible project implementation.

4.2.3. Third scenario: Severe Decline

The third scenario is designed to examine the impact of existing restrictions on crude oil production, similar to the second scenario, except that it uses the most pessimistic assumptions about energy carrier prices. In this scenario, the investment restrictions are similar to the second scenario; the capital absorption capacity for Field A is assumed to be $250 million and for Field B to be $350 million. However, the severity of the price decline is greater, and by the end of the 20-year planning horizon, the price of crude oil reaches $30 per barrel and the price of gas reaches 5 cents per cubic meter. This sharp price decline seriously pressures the profitability of development projects and exacerbates financing problems. In such circumstances, revenue decline, severe market fluctuations, operational restrictions, and weakening of the company's position in the market are among the most important risks ahead. To manage this situation, it is essential to focus on high-yield projects, diversify revenue sources, build financial and energy reserves, conclude long-term domestic and regional contracts, and use innovative cost control methods. The success of this scenario depends on careful resource management, high flexibility, and the development of alternative plans to maintain the company's sustainability.

4.2.4. Fourth scenario: Optimistic Growth

The fourth scenario, unlike the previous three, takes an optimistic view. In this scenario, oil and gas prices increase over the 20-year planning horizon, with crude oil prices reaching $110 per barrel in the final year. The realization of such a situation could boost investment in the upstream oil and gas sector; however, given Iran's economic conditions, sanctions, and existing structural constraints, this scenario is considered highly unlikely, and even a sudden lifting of sanctions would not necessarily lead to its realization. The main risks of this scenario include the continuation of economic and sanctions restrictions, global energy market volatility, and the expansion of renewable energies, which could prevent a sustainable increase in oil prices. The possible outcomes are the price goes up and there is more capital. The price goes up temporarily and then goes back to the way things were. The price does not go up at all. In such conditions, diversification of products and markets, use of domestic sources of capital, raising productivity, signing long-term sales agreements, and building up strategic financial reserves are important. In this scenario, success In this scenario, creative resource management, increased productivity, and the development of long-term, flexible strategies lead to success. in creative resource management, increasing productivity and creating long-term and flexible strategies.

4.3. Computational Implementation of the Model

The proposed optimization model was implemented in GAMS software as a mixed integer linear programming (MILP) model. The model was designed based on the mathematical formulation presented in the previous sections, and the main decision-making components, including project selection, investment planning, production scheduling, product transfer flow, resource allocation, and scenario-based pricing assumptions, were included in an integrated framework. The model input data, including project production profiles, investment needs, operating costs, transfer capacities, available resources, and assumptions regarding oil, gas, and other product prices, were converted into parameters that can be used in the model. The model was then solved separately for each

scenario to examine the effect of oil and gas price changes and investment absorption capacity on the optimal portfolio structure of projects. The main outputs of the model include the selected portfolio, project start time, production level, investment path, costs, annual revenues, and the portfolio's net present value. These outputs were extracted and compared in different scenarios to evaluate the economic and operational performance of the model under different market and investment conditions.

4.4. Modeling results

The modeling was done according to data from the Iranian offshore oil company. Modeling each scenario introduced in the previous section has been done in two ways. First, the data are modeled only considering projects and investments related to oil fields and crude oil price fluctuations. Then, the results related to the current net worth, production, investment, and other research results will be presented in tables and graphs. In the following, we will compare the results obtained from modeling with those obtained from general modeling. Therefore, two tables and graphs will be provided for each scenario.

4.4.1. First scenario

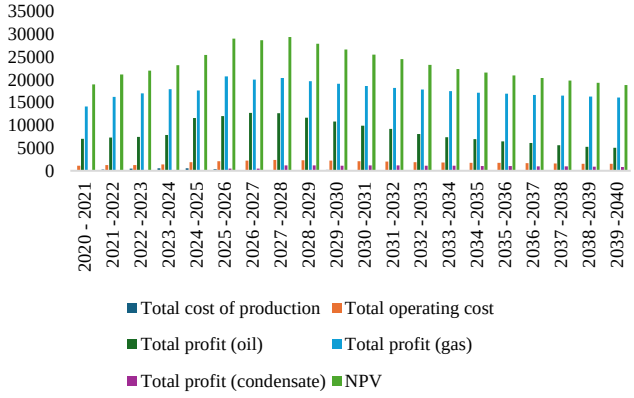


Figure 2. The results of optimization of crude oil production and investment

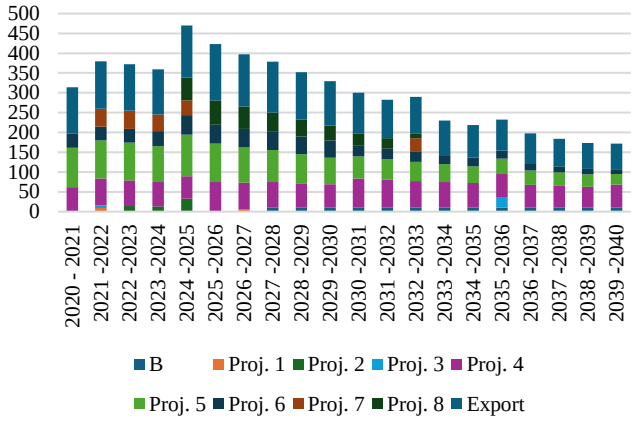


Figure 3. Final production/demand quantity of the product (oil)

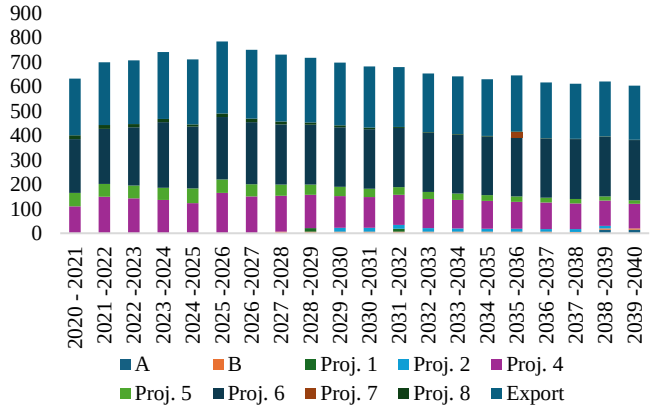


Figure 4. Final production/demand quantity of the product (gas)

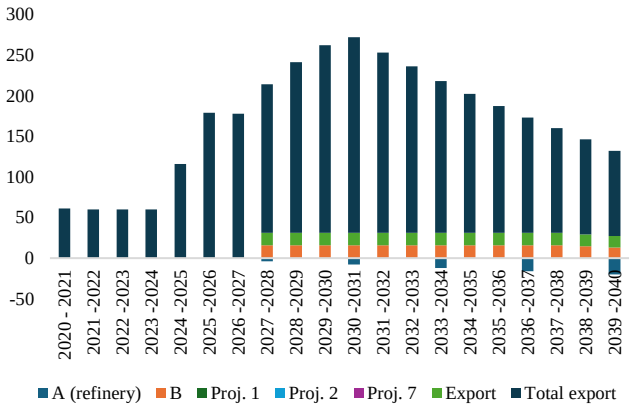


Figure 5. Final production/demand quantity of the product (condensate

The graphs presented examine the trend of optimizing production and investment in crude oil and other related products over a long period. Figure 3 shows the production costs, operating expenses, profits from oil, gas, and condensate, and the net present value (NPV), which indicates the relative stability of profitability in some years. From Figure 4, it can be seen the demand and oil production in the coming years are on a downward trend, which can be due to a reduction of resources or changes in investment. Figure 5 shows gas production and demand, which, unlike oil, is high in the early years but gradually declines. Gas condensate production and demand, shown in Figure 6, also grows exponentially from very low levels to a maximum around the middle of the time span and then declines again, perhaps due to decreased reservoir output or changed export policies. The analyses lead to the conclusion that the efficient production and investment activities in the energy sector can only be addressed from a comprehensive, long-term perspective.

4.4.2. Second scenario

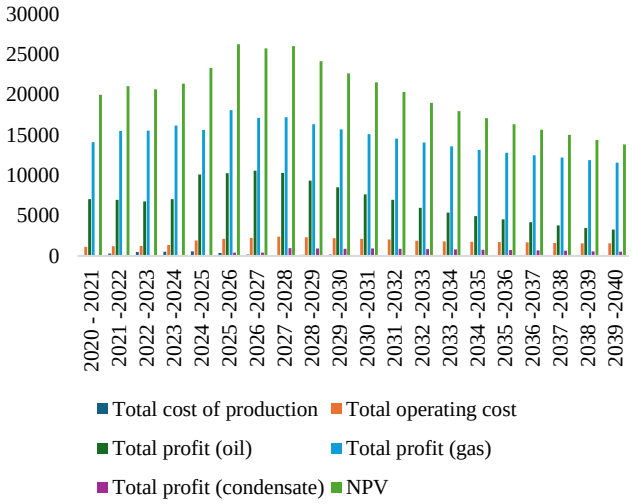


Figure 6. The results of optimization of crude oil production and investment

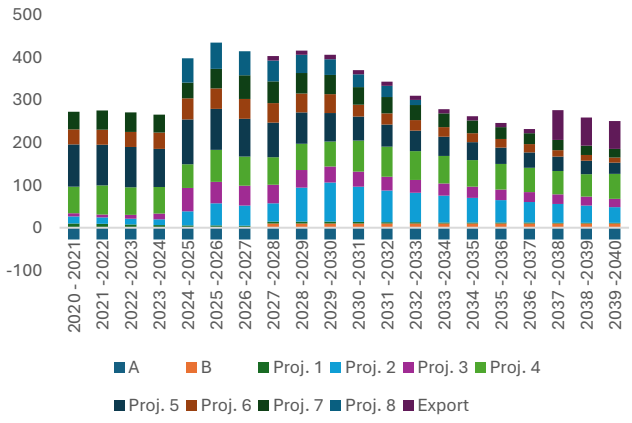


Figure 7. Final production/demand quantity of the product (oil)

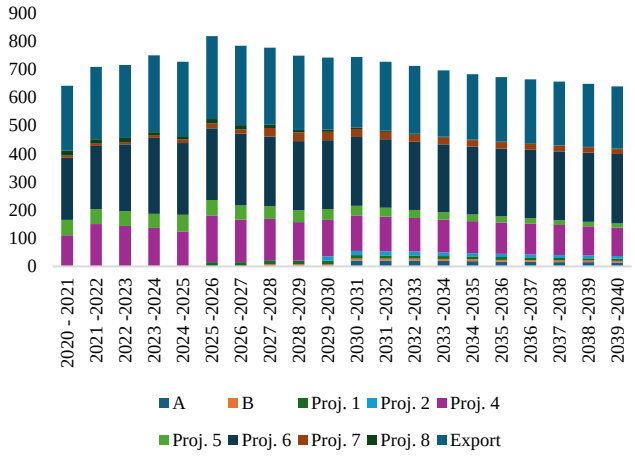


Figure 8. Final production/demand quantity of the produc (gas)

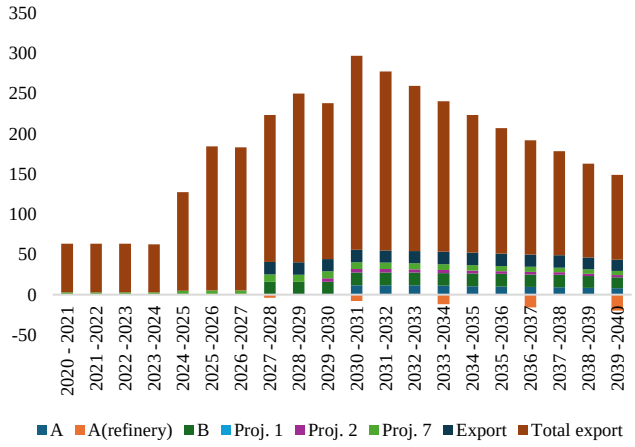


Figure 9. Final production/demand quantity of the product (condensate)

This series of charts analyzes the trend of production, investment optimization, and distribution of energy resources from 2020 to 2040. Chart 7 looks at the production costs, operating costs, profits from oil, gas, and condensate, and net present value (NPV) and shows a trend of relative sustainability of profitability in some years. Oil production and demand from various projects and the volume of its exports (Figure 8) increase in the middle years and then decline. The volume of gas production and demand is high in the initial years but slowly declines (figure 9). And we can see from Figure 10, looking at gas condensate production and demand, that it has an upward trend initially, peaking around 2030 and then gradually declining. These analyses point out the importance of long-term planning and strategic optimization in energy production and distribution.

4.4.3. Third scenario

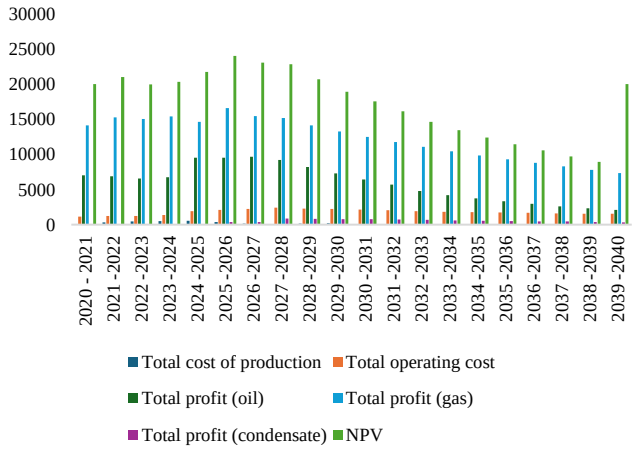


Figure 10. The results of optimization of crude oil production and investment

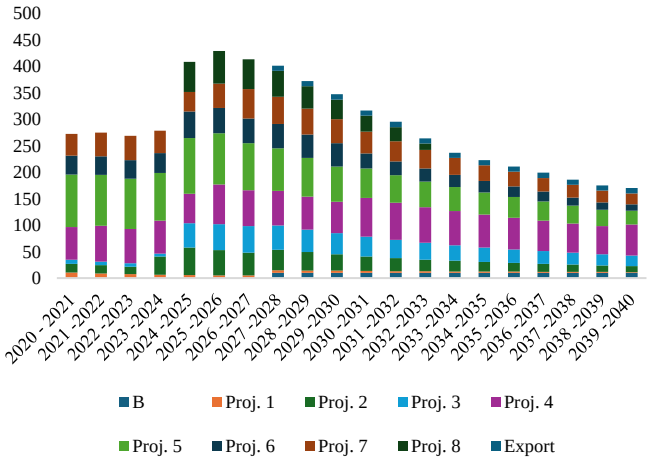


Figure 11. Final production/demand quantity of the product (oil)

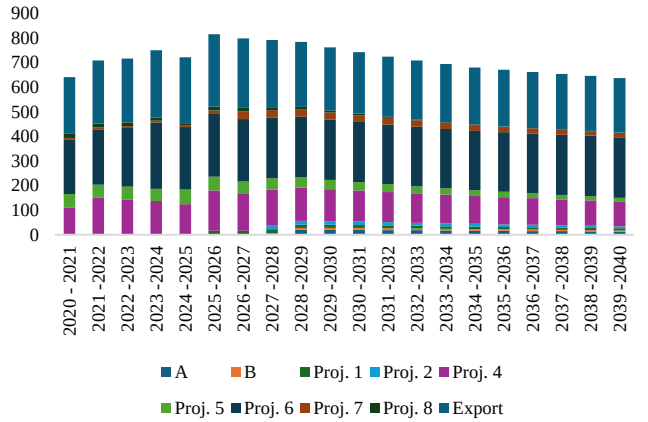


Figure 12. Final production/demand quantity of the product (gas)

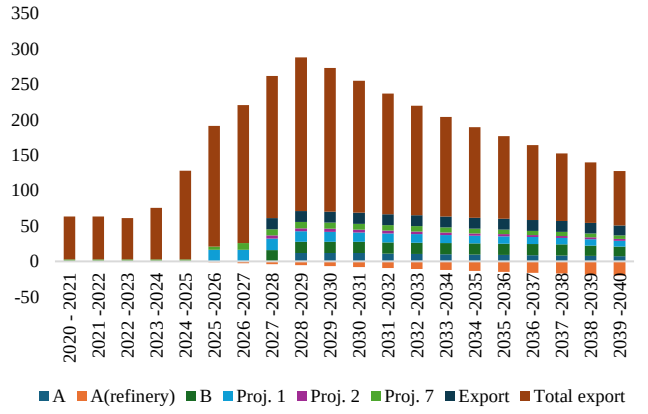


Figure 13. Final production/demand quantity of the product (condensate)

This chart set reviews oil, gas, and condensate production, demand, and investment trends, 2020-2040. The production costs, operating expenses, profits from oil, gas, and condensate, and net present value (NPV) with a balanced trend of investment and economic returns are shown in figure 10. Figure 11: Oil production and demand As we can see, the chart goes up and then slowly down. This trend may be a result of declining reservoir production or shifting energy policies. 12 shows gas production and demand. Gas production and demand remain flat in the early years before declining. Figure 13 shows the production and export of gas-condensate. Growth continues until 2030, then declines slowly. The analysis emphasizes the importance of efficient resource management and sustainable investment in the energy sector.

5.5. Scenario-based sensitivity and uncertainty analysis

What emerges from this modeling can be summarized as follows: in the second and third scenarios, the development projects are almost closed because the

development of fields and transmission lines will not be profitable with the decrease in oil prices. Production will not change much with the mild price reduction of oil products, gas, and condensate production. In the event of a sharp drop in oil prices, similar to what was observed during the corona crisis, maintaining the previous level of production will not be economically profitable. In such a situation, both costs and revenues will decrease, but the company's average profitability will also decline. The results show that for every 1% decrease in the price of petroleum products, regardless of whether the modeling is performed simultaneously for oil, gas, and condensates or focuses only on oil, the profitability of the offshore oil company is affected by less than 1%. This indicates that the company can to some extent use economies of scale to compensate for part of the decrease in profits. It should be noted that the first scenario is based on a time series analysis of oil prices up to 2016 and the third scenario is based on price changes up to the same year, while the second scenario is more of a hypothetical model of the Ministry of Oil and has not been observed in statistical forecasts or economic events in the last five years. Therefore, leaving aside the second scenario, the results show that modeling oil separately is not significantly different from modeling oil, gas, and condensate simultaneously in terms of cost and profit for the oil sector. Hence, using smaller, disaggregated models for different products or even fields can reduce the likelihood of error due to model overcomplexity while maintaining the validity of the results. The comparison of the four scenarios provides a scenario-based sensitivity and uncertainty analysis. The results show how changes in oil and gas prices and investment absorption capacity affect the optimal portfolio structure, profitability, production levels, and investment decisions.

4.6. Geopolitical and Crisis-Based Uncertainties

Besides price uncertainties, the proposed framework can be further extended to explore the geopolitical and crisis-based uncertainties. For the Iranian oil industry, oil sanctions, export restrictions, lack of investment attraction, regional crises, and the behavior of neighboring countries in shared fields may influence investment, production, project scheduling, and transmission capacity [46]. These factors can be introduced as exogenous scenarios in the model, e.g., limited investment capacity, export restrictions, project delays, or limited transmission capacity.

5. Conclusions

With oil and gas being the world's primary energy sources, petroleum companies and countries must specify their future production plans. A large marine oil-producing company in Iran with a daily production of over 500,000 barrels decided to establish its 20-year planning horizon. For this purpose, a programming model, MILP (Mixed Integer Linear Programming), was built to determine oil and gas portfolio projects to optimize overall NPV. We believe the proposed model is fairly comprehensive because it consists of many variables/parameters in the objective function, such as the cost of transferring products/feeds, fixed costs, variable cost of net production, annual cost to run projects, fluctuation of the field production, and revenue from the sale of the product. Moreover, many real-world limitations are taken into account, such as field development profile, increasing production in production nodes, increasing demand in applicant nodes, communication nodes, supplementary equations, crude oil swap, mutual fields, production of variables, transfer capacity increase by developing pipelines, balance in nodes, relations between projects, and the need for different resources. The model was employed for the aforementioned study case, with eight development projects related to two oil fields and four price scenarios. The results indicated that using the optimization model definitely guided selecting the right projects in the fields. The model also made separate plans for different products.

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Author Contribution

All authors contributed equally to the conception, preparation, and writing of this manuscript.

Conflict of Interest

S. A. Razavi as a member of editorial-board, while observing publication ethics in the referencing, declared the absence of interest of conflict.

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