An Integrated Approach to State Decision-Making in Upstream Hydrocarbon Operations With Application to Lebanon

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***Abstract*—In the exploration, development, and production of hydrocarbons, a sovereign state faces conflicting challenges: maximizing its welfare while maintaining an attractive investment environment for developers. The terms and conditions of a production sharing contract (PSC) between the government and international oil companies (IOC) are usually finalized prior to the commencement of operations and with partial knowledge of the reserve level. In addition, hydrocarbons have several potential uses. This paper formulates an optimization model that assists the government in these challenges. Given an initial estimated reserve volume and hydrocarbon price, the model determines values for both the PSC's key parameters and the allocation of the government share into different uses to generate the maximum benefit to the state while providing an acceptable rate of return for the IOC. The model is applied to Lebanon. We find that an optimal PSC for Lebanon involves no royalty for all reasonable values of potential reserves, and a high cost recovery and profit share for low reserve volumes. In addition, sensitivity analysis indicates that the preferred export mode is via the Arab pipeline, due to the low level of the current gas price and high cost of the alternative liquefied natural gas export mode.**

***Index Terms*—Lebanon, offshore oil and gas, optimization, production sharing contracts.**

I. Introduction and Motivation

THE FINANCIAL evaluation of offshore petroleum assets is plagued with several problems that make traditional methods of analysis inadequate [1]. The volatility of hydrocarbon prices, costs, and demands coupled with the long project-life of these ventures and inherent geological uncertainties of field characteristics lead to a wide range of possible scenarios. For these reasons, risk analysis plays a key role in the decision-making process, economic evaluation, and assessment of exploration and production (E&P) procedures in upstream projects [2]. Real and compound options analysis, decision analysis, simulation, and several other valuation methods have been applied to financial analysis of hydrocarbon operations in search of more realistic results [3]–[5]. Additional complexities arise when considering the contractual framework between the sovereign state and international oil companies (IOC) due to the divergent objectives of the two parties. The investing company seeks to achieve a rate of return that is in-line with the perceived risk through maximizing its profits while the state has a more open-ended objective of maximizing its citizens' welfare taking into account economic, social, and developmental considerations.

The purpose of this paper is to define a decision-making process that would aid states in maximizing their welfare in upstream hydrocarbon operations and develop a tool that applies the proposed methodology. This is achieved by formulating an optimization model that allocates the government's share of reserves for the entire life of a production-sharing venture. Given technical (reservoir volume, decline properties, production rates) and commercial (hydrocarbon price, required investor IRR, costs, demands) information, the model jointly specifies the production sharing contract (PSC) parameters and the allocation of revenue into the different uses to generate the maximum benefit to the state while providing an acceptable rate of return to the IOC. Since several inputs are not known with certainty (gas price, project costs, reserve volume), the optimization is performed over the expected parameter ranges and the consequent change in strategy is analyzed (i.e., infrastructure investments, optimal use allocation, PSC contract parameters).

Our proposed optimization model is applied to the case of Lebanon. There has been growing interest in oil and gas exploration offshore Lebanon following recent discoveries off the Levantine margin. Results of recent studies indicate that the sedimentary succession offshore Lebanon may include source and reservoirs rocks similar to those in neighboring countries that have yielded confirmed gas discoveries [6]. Accordingly, the Lebanese government has shown great interest in this subject since 2000, and has employed several companies to carry out 2-D and 3-D seismic surveys. Preliminary data has confirmed that there is sufficient evidence to allow companies to drill. Lebanon's newly established potential has instigated the assignment of a state petroleum board and the Lebanese government has recently passed a petroleum law [7]. However, there exists a persistent lack of managerial and regulatory studies allowing the implementation of this law and policy. This translates to a strong need for further research in support of policy and lawmakers entrusted with the management of Lebanon's hydrocarbon resources. Therefore, our optimization model is applied

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to the case of Lebanon to illustrate the proposed methodology and to provide some insights which may aid in the Lebanese oil and gas policy.

The remainder of this paper is organized as follows. Section II briefly reviews the related literature. Section III presents the optimization model and assumptions. Section IV discusses the case of Lebanon and provides a thorough estimate of the parameters of the model in Section III. Section V presents numerical results and scenario analysis for Lebanon based on the parameters estimated in Section IV. Section VI concludes this paper and presents ideas for future research.

II. Literature Review

Different applications of decision-making in the petroleum industry are reviewed in Section II-A. Section II-B discusses the contractual structures that are used when commissioning a third party to develop hydrocarbon assets, with a special focus on PSCs. Since Lebanon is likely to have natural gas reserves, the literature pertaining to the uses of natural gas is outlined in Section II-C, citing examples from different countries.

A. Approaches to Decision-Making in the Upstream Petroleum Industry

Suslick and Schoizer [2] review the different applications of risk analysis in petroleum exploration. The domains investigated include decision analysis [8], portfolio management [9], [10], optimization [3], and real-option approaches [11]–[14]. Suslick and Schozier [2] conclude that most organizations use similar risk analysis procedures to assess E&P projects; some develop in-house tools while others rely on independent investigators and consultants. Dyner [15] and Olaya and Dyner [16] use system dynamics to provide a platform for integrated energy analysis and policy where upstream hydrocarbon activities, natural gas demand and transportation, urban transportation and environmental considerations are accounted for. Lund [4] approaches the problem of offshore oil development projects using real options, by developing a dynamic programming model to handle the inherent uncertainties. Maddah *et al*. [17] also utilize dynamic programming to develop a decision support system for the management of a portfolio of hydrocarbon assets under price and reserve risks. The model takes the point of view of the oil company and assists on exploration, production, and decommissioning decisions of the various assets over time. Together with the formulation of Maddah *et al*., the model proposed in this paper proffers the government useful negotiation tools with the IOCs. Finally, Pindyck [18] uses the capital asset pricing model to propose a tax scheme that would maximize the government's return while keeping the project attractive to investors (IOCs). Focusing on hydrocarbon developments off the shores of Haifa, he proposes a suitable rate of return for IOCs. In this paper, we adopt Pindyck's idea and require that a certain rate of return be realized by the IOC.

B. Contractual Systems for Hydrocarbon Exploitation and PSC Detail

In the following, we provide some background on PSCs and hydrocarbon contracts in general. Alomair and Al-Attar [19] investigate the different agreements that governments and IOCs can reach. They find that as E&P costs rise, the operator is granted more control of the reserves; with the structure changing from a risk service agreement (low E&P costs) to a PSC (medium E&P costs) to a royalty/tax contract (high E&P costs). It is worth noting that they find PSCs to be the most commonly used contract structure. Adenikinju and Oderinde [20] carry out a detailed analysis of production sharing agreements and their effects on the economics of offshore oil production in Nigeria. Using regression analysis and citing econometric evidence, they conclude that the variable with the most significant effect is the oil price. Bindemann [21] reviews several PSCs where she finds that operators have two main concerns: repaying their investment as soon as possible and having flexibility with contract parameters in order to ward off some of the commercial risks. Furthermore, Bindemann [21] reports typical values for contract parameters where she finds that low royalties and high cost recovery (CR) factors are common despite operational differences. Along similar lines, Yassine *et al*. [22] collect several PSCs and statistically analyze the contract parameters to arrive at recommendations for governments in general, Lebanon in particular. The results show a low range for royalty (0–23%), a high range for CR (62–100%), and the widest range for profit share (28–96%). Another approach for determining PSC parameters analytically, based on the auction theory ideas of Riley and Samuelson [23], is presented in Younes [24] where somewhat unrealistic assumptions were made (such as prior government knowledge of the average reserve valuation as well uncertainties in these valuations). While Yassine *et al*. [22] propose plausible PSC structures for Lebanon by benchmarking, this paper follows a more analytical approach based on value maximization for the government, while integrating PSC decisions with revenue management ones on the use of natural gas.

C. Possible Uses of Natural Gas

The optimization model also assists in identifying different hydrocarbon usages. With Lebanon's case in mind, where natural gas is most likely to be discovered, the following natural gas usages in different countries are reviewed. Table I summarizes the uses of natural gas in a number of producing countries: Turkey [25], Algeria [26], the Commonwealth of Independent States (CIS) [27], and China [28], [29]. Table I indicates that power generation is the most common end use of natural gas, found in all four countries. Heavy industrial and domestic uses are found in the CIS and China where an abundance of natural gas resources and existing infrastructure investments are evident. Algeria is presented as an example of an unconventional use of natural gas, where reserves are used to bolster solar energy resources through the use of hybrid natural gas/solar plants.

III. Model, Assumptions, and Solution Method

In this section, we present our model and assumptions. Section III-A describes our decision environment and the key assumptions. Section III-B presents the optimization model. Section III-C describes our solution methodology of the optimization model. Table II presents our notation.

TABLE I
MOST COMMON USES OF NATURAL GAS

	Energy			Industry					Domestic		Transportation	
	Power	Heat	Other	Iron & steel	Non-metallic	Petro-chemical	Chemical	Fertilizer	Heating	Cooking	Road	Aviation
Algeria [26]	■		■									
China [28,29]	■	■		■	■		■	■	■	■	■	
CIS [27]	■	■		■	■	■	■	■	■	■	■	■
Turkey [25]	■										■	

TABLE II
NOTATION, MODEL INPUTS, MAIN AND AUXILIARY DECISION VARIABLES

Parameters	
Initial volume	V_0
Production rate in year *t*	p_t
Initial investment (fixed cost) in year *t*	C_{it}
Operating (variable) cost	C_u
Pipeline cost	C_P
LNG plant cost	C_{LNG}
Required operator IRR	R
Annual electricity demand	d_t
Unit Saving in power generation	π
Gas price	P
Risk-free rate	r_f
Maximum number of contracts	C
Minimum contract duration	d_{min}
Minimum contract value	v_{min}
Maximum contract value	v_{max}
Main Decision Variables	
Royalty (PSC parameter)	ρ
CR (PSC parameter)	CR
Profit share (PSC)	PS
Tax rate (PSC)	τ
Contract *j* value	v_j
Contract *j* start time	s_j
Volume allocate to electricity	V_{et}
Binary operator defining whether contract *j* is active at time *t*	b_{jt}
Auxiliary Decision Variables	
Annual production in year *t*	V_t
Government share in year *t*	GS_t
CR volume in year *t*	CR_t
Export amount in year *t* via contract *j*	E_{jt}
Export amount in year *t*	E_t
Auxiliary variable for linearization	a_{jt}
Auxiliary variable for infrastructure cost	b

A. Decision Environment and Key Assumptions

Consider a state with natural gas reserves that wishes to structure a PSC with an IOC taking into account potential future usages of gas. The government's objective is to maximize the total profit while keeping the PSC attractive to the IOC. It is estimated that the gas reserve under consideration is V_0, which is assumed to be known with certainty. Furthermore, V_0 is assumed to be significant enough and has a commercial value justifying its development. The gas price is *P*, and is assumed to remain the same throughout the project life. The project life, consisting of developing and producing the gas, is *T* years.

While these assumptions of certainty and stability of reserve and price are admittedly restrictive, we account for the variability of price and reserve through extensive sensitivity analysis.

The government wishes to decide on the key parameters of the PSC, namely, the royalty ρ, the *CR*, the profit share *PS*, and the tax rate τ, jointly with allocating its share from the gas among different uses. Royalty determines the percentage of production allocated directly to the state and is applied first. CR determines the maximum percentage of postroyalty production that can be given to the operator to reimburse expenses. It is important to note that if the operator's expenses are below this limit, then that is all that is reimbursed. The remaining production is split according to the profit share percentage, and finally the operator's share of profit is taxed. Any of the government revenue streams can be taken in cash or kind, depending on the national petroleum law. The PSC parameters will be used to split the annual production V_t in year *t*, $t = 1, 2, \ldots, T$, between the government and the IOC. The annual production V_t is assumed to be obtained from the overall reserve V_0 based on annual production rates, p_{t}, i.e., $V_t = p_t V_0$. The model assumes that any production received by the operator is valued at the input gas price. It is this value that is constrained to provide the investor with a minimum prespecified rate of return.

This approach is typical in the literature (e.g., [30], [31]). The approach for estimating p_t based on the project duration *T* is described in Appendix A.

Based on the discussion in Section II-C, we limit the hydrocarbon usages into two categories, power generation and export. Assuming the required infrastructure is already in place, power generation is assumed to generate a benefit to the state of π \$/unit. This is typically the savings from using the produced hydrocarbon instead of other modes to produce electricity, as illustrated in Section IV for the case of Lebanon. It is also assumed that power generation usage in year *t*, $t = 1, \ldots, T$, cannot exceed the power demand in year *t*, d_t.

Export can be done via two modes: 1) as gas through a pipeline; and 2) as liquefied natural gas (LNG). The pipeline option has an infrastructure cost of C_P, typically encompassing the cost of linking to major pipelines, while the LNG option has an infrastructure cost of C_{LNG}, which is typically the cost of establishing a liquefaction plant. In both modes, the sales price of gas is *P*, the known gas price. However, we assume that sales through a pipeline can only be done through contracts. This is justified by the fact that there is no spot market for gas, and a pipeline typically allows reaching a limited number of customers. LNG exporting, on the other hand, allows selling to the global market with a large number of customers. In addition, natural gas contracts, to be meaningful, are restricted to having

a minimum duration $d_{\min}$ years and have bounds on their annual value, $v_{\min}$ and $v_{\max}$. It is further assumed that a maximum of *C* contracts are active at any given time. The parameter *C* can be determined based on the pipeline capacity and $v_{\min}$.

We assume that either pipeline or LNG export mode are used in a given situation. This implies two different model formulations, one of which is presented in the next section (pipeline) while details of the other model (LNG), which are very similar to the formulation presented next, can be found in Appendix B and the research done by Wahab [32].

Finally, the IOC interest is accounted for by assuming that it requires a minimum rate of return *r*. This rate of return reflects the revenue based on the IOC share from the project over time and the production costs. The production costs are assumed to be composed of fixed production costs of C_{it} in year *t*, and a cost of C_u per unit, assumed to be fixed over time. This linear cost structure is supported by recent research (e.g., [33]).

B. Mathematical Formulation: Pipeline Model

When a pipeline is used for export, and export contracts are necessary, the mathematical formulation for the proposed model is given below. Contracts are defined by their start times and values (s_j and v_j for contract *j*). Using these auxiliary variables allows contracts to be modeled effectively and constraints can be imposed on their value and duration as shown in the following mathematical program:

$$\max \sum_{\mathrm{t}=1}^{\mathrm{T}} \frac{\pi^{*}\mathrm{V}_{et} + \mathrm{P}^{*}\sum_{\mathrm{j}=1}^{\mathrm{C}} E_{\mathrm{jt}}}{(1+\mathrm{r_f})^{\mathrm{t}}} - bC_P \tag{1}$$

$$v_{\min} \le v_j \le v_{\max}, \quad j = 1, \ldots, C \tag{2}$$

$$d_{\min} \le \sum_{t=1}^{T} b_{jt}, \quad j = 1, \ldots, C \tag{3}$$

$$E_{jt} = v_j b_{jt}, \quad j = 1, \ldots, C;\ t = 1, \ldots, T \tag{4}$$

$$s_j b_{jt} \le t, \quad j = 1, \ldots, C;\ t = 1, \ldots, T \tag{5}$$

$$b_{jt} \le \frac{s_j + \sum_{t=1}^{T} b_{jt}}{t}, \quad j = 1, \ldots, C;\ t = 1, \ldots, T \tag{6}$$

$$V_{et} \le d_t, \quad t = 1, \ldots, T \tag{7}$$

$$V_{et} + \sum_{j=1}^{C} E_{jt} \le GS_t, \quad t = 1, \ldots, T \tag{8}$$

$$V_t = V_0 p_t, \quad t = 1, \ldots, T \tag{9}$$

$$CR_t = \min\left[V_t^{*}CR, \frac{\sum_{k=1}^{t} C_{ik} + C_u V_k}{P} - \sum_{k=1}^{t-1} CR_k\right] \tag{10}$$

$$GS_t = (\rho^{*}V_t) + ((1-\rho)^{*}V_t - CR_t)^{*}(PS + \tau(1-PS)) \tag{11}$$

$$\sum_{t=1}^{T} \frac{(V_t - GS_t)^{*}P}{(1+r)^{t}} \ge \sum_{t=1}^{T} \frac{C_{it} + C_u V_t}{(1+r)^{t}} \tag{12}$$

$$b \ge \frac{\sum_{t=1}^{T}\sum_{j=1}^{C} E_{jt}}{V_0} \tag{13}$$

$$0 \le \rho \le 1, 0 \le CR \le 1, 0 \le PS \le 1, 0 \le \tau \le 1 \tag{14}$$

$$v_j \ge 0, s_j \text{integer}, b_{jt} \text{ binary}, b \text{ binary}, E_{jt} \ge 0, CR_t \ge 0,\ GS_t \ge 0. \tag{15}$$

The objective is to maximize the benefit to the state; this is stated in (1), where the first part finds the savings generated from allocation to power generation while the second sums the volumes sold by all contracts. Export contract *j* is defined by three parameters: its value, v_j, the binary variables b_{jt} defining its duration, where $b_{jt} = 1$ if contract *j* is active at time *t* and $b_{jt} = 0$, otherwise, and starting time, s_j. Constraints (2) and (3) state the minimum and the maximum value, $v_{\min}$ and $v_{\max}$, and minimum duration, $d_{\min}$, of a contract. In these constraints, the maximum number of export contracts, *C*, can be found as the ratio of the infrastructure capacity (pipeline) divided by $v_{\min}$. Constraint (4) gives the volume exported by contract *j* at time *t*. Constraints (5) and (6) ensure that contract *j* extends continuously between its start time s_j and its end time $s_j + \sum_{t=1}^{T} b_{jt}$. Specifically, constraint (5) ensures that contract *j* starts at its designated time s_j as it is equivalent to $b_{jt} \le t/s_j$, which implies that $b_{jt} = 0$ whenever $t < s_j$. By a similar logic, constraint (6) ensures that contract *j* ends at the designated time, $s_j + \sum_{t=1}^{T} b_{jt}$; $b_{jt} = 0$ whenever $t > s_j + \sum_{t=1}^{T} b_{jt}$. Finally, the structure of the objective function in (1) and constraints (8)–(11) guarantee that $b_{jt} = 1$ for $s_j \le t \le s_j + \sum_{t=1}^{T} b_{jt}$. Constraint (7) states that no more volume can be allotted to power generation than the demand. Constraint (8) ensures that the annual sum of utilized reserves does not exceed the state's annual share of resources. Constraint (9) defines the relationship for the annual produced volume V_t as a function of the initial volume V_0 and the production vector p_t, where p_t is found as explained in the Appendix. Constraint (10) defines the CR in year *t* expressed in gas volume, where a maximum value of the cost recovery factor, *CR*, times the volume in year *t*, V_t, is allowed. Constraint (10) also reflects the assumption that when the cost exceeds the volume in a year, it is carried forward to future years. Specifically, the second term in the minimum expression in (10) can be written as the sum of the cost at time *t* expressed in gas volume, $\frac{C_{\mathrm{it}} + C_u V_t}{P}$, and the cost carried forward from previous time periods, $\sum_{k=1}^{t-1}\left(\frac{C_{ik} + C_u V_k}{P} - CR_k\right)$. This is consistent with the PSC literature (e.g., [21]). Constraint (11) gives the government share as the sum of revenues from royalty, profit sharing, and tax. Constraint (12) ensures that the IOC achieves a rate of return of *r*. Constraint (13) ensures that the export infrastructure cost (pipeline) is charged. Constraint (14) defines bounds on PSC parameters. Finally, constraint (15) defines the nature of our main and auxiliary decision variables.

C. Solution Methodology

First, we note that for a given problem instance, the optimal solutions for both the pipeline model discussed in Section II-B and the LNG model detailed in Appendix B can be found in [30]. Then, the solution from the model giving the highest objective value (government share) would be selected. Next, we discuss the solution methodology for the model. The model described

in the previous section is a nonlinear integer program which is typically difficult to solve, even with specialized nonlinear solvers. When attempting to solve this nonlinear model directly, Excel premium solver could not converge to a solution. Our solution methodology is based on solving a series of integer linear programs instead of one difficult nonlinear program. Specifically, our approach is to linearize nonlinear constraints, whenever possible, and to iterate over discrete values of the decision variables causing nonlinearity, when analytical linearization is not possible.

Specifically, there are two instances of nonlinearity in constraints (10) and (11) which are hard to resolve analytically. However, the involved decision variables, the PSC parameters ρ, CR, PS, and τ, are all bounded between 0 and 1. Furthermore, regulations often fix the values of some of these parameters; for example in Lebanon, as explained in Section IV, the tax rate τ is specified in the hydrocarbon law. This makes it easy to resolve the nonlinearity by iterating over discrete values of a set of parameters, while treating one parameter as a continuous variable. For example when the tax rate τ is specified by law (as is the case for Lebanon), we iterate over discrete values of the royalty, ρ, and *CR*, and solve a series of linear problems with the profit share *PS* treated as a continuous variable. We use a discretization step length of 1% for ρ and *CR*. With this approach, an "optimal" solution (rounded to two significant digits) is typically found in less than 10 min on a generic computer running Excel premium solver.

A further nonlinearity is also evident in constraints (4) and (5). Both of these constraints involve the product of a binary variable, b_{jt}, and a continuous variable, v_j in (4) and s_j in (5), these constraints can be linearized easily. Letting *M* be a sufficiently large number, constraint (4) can be linearized by replacing it with the following constraints:

$$E_{jt} \leq v_j, \quad j = 1, \ldots, C; \ t = 1, \ldots, T \tag{4a}$$

$$E_{jt} \leq M b_{jt}, \quad j = 1, \ldots, C; \ t = 1, \ldots, T \tag{4b}$$

$$E_{jt} \geq v_j + M\left(b_{jt} - 1\right), \quad j = 1, \ldots, C; \ t = 1, \ldots, T. \tag{4c}$$

Constraint (5) is handled similarly by introducing an auxiliary variable $a_{jt}(a_{jt} = s_j b_{jt})$, and replacing it with the following constraints:

$$a_{jt} \leq s_j, \quad j = 1, \ldots, C; t = 1, \ldots, T \tag{5a}$$

$$a_{jt} \leq M b_{jt}, \quad j = 1, \ldots, C; \ t = 1, \ldots, T \tag{5b}$$

$$a_{jt} \geq s_j + M\left(b_{jt} - 1\right), \quad j = 1, \ldots, C; \ t = 1, \ldots, T \tag{5c}$$

$$a_{jt} \leq t, \quad j = 1, \ldots, C; \ t = 1, \ldots, T. \tag{5d}$$

IV. Case of Lebanon

The emerging Lebanese hydrocarbon situation serves as an application of the proposed model. In the following, we present estimates of the parameters needed for the optimization models presented in Section III as they apply to the case of Lebanon. In Section V, we present results and insights based on applying the models in Section III with the Lebanese data described in this section.

In subsequent years, $t = 2, \ldots, 30$, demand $d_t = 1.0705\, d_{t-1}$.

1) *Project duration, T:* As stipulated in the Lebanese hydrocarbon law [7], a base project duration of 30 years is considered.
2) *Gas reserve volumes, V_0:* The U.S. Geological Survey [33] estimates that 83 000 square km of the eastern Mediterranean hold between 1400 and 6430 Bcm (billion cubic meter), 30% of which lie in Lebanese waters. Therefore, a rough estimate for potential natural gas reserves in Lebanon, taking into account inherent uncertainties, would be anywhere under 2100 Bcm, all in a deep offshore environment. Accordingly, we utilize a range of reserve volume between 140 and 2100 Bcm in our numerical results.
3) *Gas price, P:* The gas price of October 2012 of ¢9.76/m^3 is used as the base price value.
4) *Risk free rate, r_f:* The risk-free rate used for discounting the government's revenues is the one-year Lebanese treasury-bond rate of 5.35% [34].
5) *IOC required rate of return, r:* In his work on taxation for Israeli natural gas projects, Pindyck [18] identifies an investor rate of return of 9% as sufficient for maintaining project attractiveness for IOCs. Although the IOCs selected for Pindyck's appraisal all operate in risky deep offshore environments, the 9% rate was based on a portfolio with some less-risky onshore projects. Since all investment in Lebanon is expected to be in an expensive deep-offshore environment, and with the high political risk, a higher base value of 12.5% is utilized in this paper for IOC rate of return.
6) *Unit Saving in power generation, π:* In 2009, the cost to produce 1 kWh of electricity in Lebanon was ¢17.14, ¢10.77 of which was due to fuel cost [35]. Natural gas produces 35 300 Btu/cubic meter. Assuming an average heat rate of 7800 Btu/kWh and transmission losses of 15%, a rate of 0.26 cubic meter/kWh is obtained [35]. Accordingly, a value of ¢10.77/0.26 = ¢41.4/cubic meter is used for the unit saving in power generation.
7) *Power demand, d_t:* In 2009, the total power demand in Lebanon was approximately 18 400 GWh = 18.4 million kWh. Of this value, and due to the available infrastructure, only 50% of the demand can be met from fuel or gas [35]. Given the long-term scope of this investigation, demand growth must also be estimated. The World Bank uses gross domestic product (GDP) estimates to forecast future power demand in Lebanon with the GDP [36]. According to the World Bank website[1], the average growth rate of Lebanon's GDP over the last five years is 7.05%. Accordingly, we use this rate to estimate demand growth. As such, starting with 2009 demand for gas (50% of 18 400 GWh), assuming a 7.05% growth per year, and utilizing the 0.26 cubic meter/kWh conversion factor discussed above, we estimate the 2012 demand for gas that can be used to produce power as $d_1 = 2.93$ bcm.
8) *Export contract parameters, $v_{\min}$, $v_{\max}$, $d_{\min}$, and C:* A minimum contract duration of five years is adopted, i.e., $d_{\min} = 5$ years. In addition, minimum and maximum values

[1]http://www.worldbank.org/.

are set to $v_{\min} = 2$ bcm/year and $v_{\max} = 10$ bcm/year, respectively. These values are consistent with the practice in the gas market [37]. With these contract characteristics and taking into account the capacity of the Arab gas pipeline that Lebanon is connected to (which amounts to 10 Bcm [38]), we use a maximum number of $C = 5$ contracts.

9) *Infrastructure costs, C_P and C_{LNG}:* Since the Arab gas pipeline that Lebanon is connected to is already in-place, we assume that no additional infrastructure investment is needed for exporting via the pipeline option, i.e., $C_P = \$0$. As for exporting via the LNG option, we assume an infrastructure cost of $C_{LNG} = \$6$ billion, which is the cost to build a new liquefaction plant. This is consistent with the literature and practice where the total investment cost, which depends on several factors such as market needs, geographic location, number and size of trains, number of ships required, has been reported to be in the range of $1.5 - 10$ billion [39]–[41].

10) *Production costs, C_{it} and C_u:* Jablonowski and Strachan [42] analyze private and public data from 24 projects and generate cost functions for two technologies (spars and tension leg platforms), giving total project costs and the marginal costs from increases in production. They find a linear cost structure with the production cost increasing in the production volume. We adopt a similar linear approach for estimating production costs.

The main challenge is finding the initial investment cost. This is the cost required for drilling wells and increasing the production capacity up to its maximum level, $P_{\max}$. As discussed in the appendix, we assume that $P_{\max}$ is reached after one year if $V_0 < 281$ Bcm, after three years if $281 < V_0 < 701$ Bcm, and after five years if $V_0 > 701$ Bcm. We assume that the initial investment cost applies uniformly over the three and five years "ramp-up" periods of the medium and large projects. Using values published by Noble [43], [44], regarding well costs at \$150 M/well and Tamar well rates of 4.25 million cubic meter (Mcm)/day, the number of wells required to achieve the maximum production and their cost is found. Then, the marginal cost of production is found based on the number of barrels of oil equivalent (BOE)/day corresponding to $P_{\max.}$ We utilized a conversion rate of 166.66 BOE/Mcm. We utilized published estimates of marginal costs for local projects to subjectively estimate this cost. We find marginal rates between \$14.6 and \$16.3 million/ 1 000 BOE. Adding these two costs gives the total development cost for fields of various sizes produced over thirty years. Applying the above methodology to the identified range of volumes gives the initial investment costs shown in Table III. By analyzing the initial cost versus the maximum production volume $P_{\max}$ in Table III, we find that it varies linearly with $P_{\max}$. Accordingly to simplify the analysis, we utilize linear regression and find the initial cost (IC in million dollars) as a function of $P_{\max}$ as

$$\mathrm{IC} = 0.3485 P_{\max} + 200. \tag{16}$$

This investment cost will be split uniformly over the ramp-up period to obtain the fixed cost, C_{it}, during the ramp-up period.

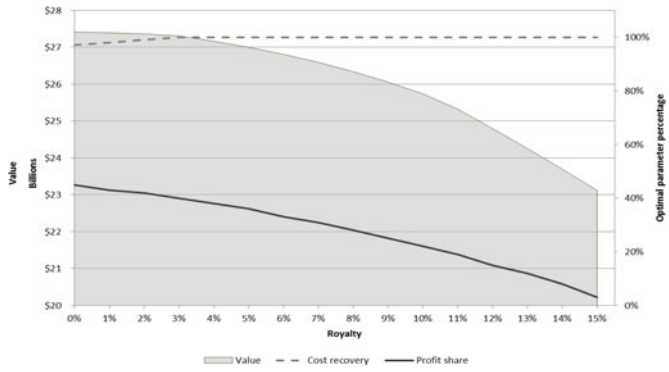

Fig. 1. Optimizing contracts while varying royalty.

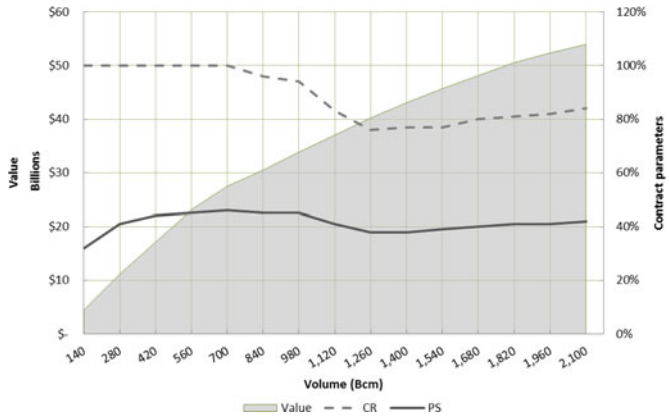

Fig. 2. Optimal solution across volume range.

The cost C_{it} is equal to zero in later years. For example, if $V_0 > 701$ Bcm, $C_{it} = IC/5$, if $1 \le t \le 5$, and $C_{it} = 0$ if $t > 6$.

As for the variable cost, an operating cost of $C_u = 2.85$/cubic meter, quoted from Noble [43], [44] on its expected expenditure on Tamar, is incurred by the operator throughout the project.

This method admittedly leads to some uncertainty in estimating C_{it}. However, the model optimal solution, i.e., optimal CR and profit share, appears to be robust to the estimates of the reserve volume V_0 upon which $P_{\max}$ is based (see for example Fig. 2). This makes sense as the PSC contract is essentially specifying a split mechanism of revenue which should not be too sensitive to reserve estimates. This implies, since C_{it} depends on V_0 and $P_{\max}$, that uncertainties in estimating the value of C_{it} should not have a major influence on the results.

V. Results

In the case of Lebanon, the tax is fixed at 23.5% [45]. As such, we fix the tax rate to $\tau = 0.235$ in all of our numerical results. This leaves us with three decision variables related to PSC parameters, royalty, ρ, *CR*, and profit split, *PS*. Since as discussed in Section IV, optimizing over these three decision variables directly requires solving complex integer nonlinear program, we adopt a simplified approach where we iterate over values of ρ and *CR* and solve the resulting integer *linear* programs, using Excel premium solver, over *PS* and other model decision variables discussed in Section III. Specifically, we use

TABLE III
COST ESTIMATION ACROSS THE RANGE OF EXPECTED VOLUMES

Initial volume (Bcm)	P_{max} (Mcm)	Equivalent production (1000BOE/day)	Production capacity costs ($1000)	Wells needed	Drilling costs ($1000)	Initial cost (IC) ($ million)
140	4726	78	$ 1 141 531	4	$ 600 000	**$ 1741.531**
280	9452	156	$ 2 433 062	7	$ 1 050 000	**$ 3483.062**
420	14 178	233	$ 3 724 593	10	$ 1 500 000	**$ 5224.593**
560	18 904	311	$ 5 016 124	13	$ 1 950 000	**$ 6966.124**
700	23 630	388	$ 6 307 655	16	$ 2 400 000	**$ 8707.655**
840	28 356	466	$ 7 599 186	19	$ 2 850 000	**$ 10 449.186**
980	33 082	543	$ 8 890 717	22	$ 3 300 000	**$ 12 190.717**
1120	37 808	621	$ 10 182 248	25	$ 3 750 000	**$ 13 932.248**
1260	42 534	698	$ 11 473 779	28	$ 4 200 000	**$ 15 673.779**
1400	47 260	776	$ 12 765 310	31	$ 4 650 000	**$ 17 415.310**
1540	51 986	853	$ 14 056 841	34	$ 5 100 000	**$ 19 156.841**
1680	56 712	931	$ 15 348 372	37	$ 5 550 000	**$ 20 898.372**
1820	61 438	1008	$ 16 639 903	40	$ 6 000 000	**$ 22 639.903**
1960	66 164	1086	$ 17 931 434	43	$ 6 450 000	**$ 24 381.434**
2100	70 890	1163	$ 19 222 965	46	$ 6 900 000	**$ 26 122.965**

a step size of 1% for both ρ and *CR* and do a grid search with search values derived from solving ILP over the remaining parameters. A sample of our results is shown in Fig. 1 for a reserve volume of $V_0 = 700$ Bcm for the case of a pipeline exporting option. All other model parameters are set at their base values which are presented in Section IV.

The optimal value to the state, i.e., the optimal solution, is generated for a royalty of zero, $\rho = 0\%$, a $CR = 100\%$, and a profit share $PS = 44\%$. We believe that this is related to the usage of gas to meet power demand. Since power demand increases with time, as discussed in Section IV, the government has benefit in allowing the IOC to recover its costs early on in the project life, via a $CR = 100\%$ and $\rho = 0\%$, where power demand is low. This early payment pattern also allows the IOC to meet its required IRR with the least amount of gas in later years, which is desired by the government. Our trials on several other reserve volume ranges give consistent results, with a high CR and, always, no royalty.

These results are in agreement with previous work which addresses recommended PSC parameters (e.g., [21], [22]). Accordingly, in the remainder of this section, we adopt a PSC with no royalty, $\rho = 0\%$. We find the two remaining contract parameters, *CR*, and profit share *PS*, by iterating over *CR*, with a step size of 1%, and solving the resulting ILP in *PS* and other decision variables. With this solution methodology, we proceed in the remainder of this section. We evaluate the current situation in Section V-A and then present a sensitivity analysis in Section V-B.

A. Current Situation

Fig. 2 shows the optimal PSC parameters and total state welfare for different reserve volumes, under the export via pipeline option. We note that the pipeline option is optimal (i.e., preferred to the LNG export option) in all the cases shown in Fig. 2. The changes in the PSC parameters and allocation strategy show three stages as the volume of reserves grows.

The first stage concerns fields with reserves up to 700 Bcm, the optimal strategy is to pay the investor back as soon as possible, with a *CR* of 100%, to maximize the amount of production left to the state afterwards and meet power demand. In this stage also, an increase in the reserve volume is coupled with an increase in the optimal profit share, *PS*. This is the case since with a fixed *CR* of 100%, higher reserves allow meeting the investor's IRR with a lower PS. The government share allocation results for a field of 420 Bcm are shown in Fig. 3 to illustrate the results. Fig. 3 indicates that the state's share of the production is constantly below the power demand. Accordingly, the entire government share is allocated to power, and no export contracts are used.

The second stage concerns fields with reserves between 700 and 1260 Bcm. Relative to the first stage, both *CR* and *PS* decrease. This is the case since, in this stage, lowering *CR* provides enough production for the state in the early years to meet most of the power demand. Specifically, *CR* decreases significantly below 100% reaching 78% for a reserve of 1260 Bcm. As *CR* decreases, the operator is compensated by a decrease in *PS*. However, since *PS* is applied, at the same level, at all time periods, it decreases at a lower rate than *CR*, which has a significant effect in the first few years of production. For example, *PS* decreases from 45 to 38% as the reserve increase from 700 to 1260 Bcm (while CR decreases from 100 to 78%).

The allocation strategy for a volume of 1260 Bcm is shown in Fig. 4 where it can be seen that a large proportion of the power demand is met in the earlier years of the project, specifically, up to Year 10. Fig. 4 also indicates that as the production rate stabilizes and most of the cost is recovered in Years 10 to 20, all of the power demand is met and the government has enough gas volume to export. In this case two contracts are used, together coming to a modest total of less than 5 Bcm per year. In later years, i.e., Years 21 to 30, the production volume starts declining and no exporting is possible.

The third stage concerns fields with reserves greater than 1 260 Bcm. As the volume grows during this stage, the annual production rises and can satisfy the early power demand more easily. The results for optimal PSC parameters show both CR and PS rising. This translates into a quicker repayment of the

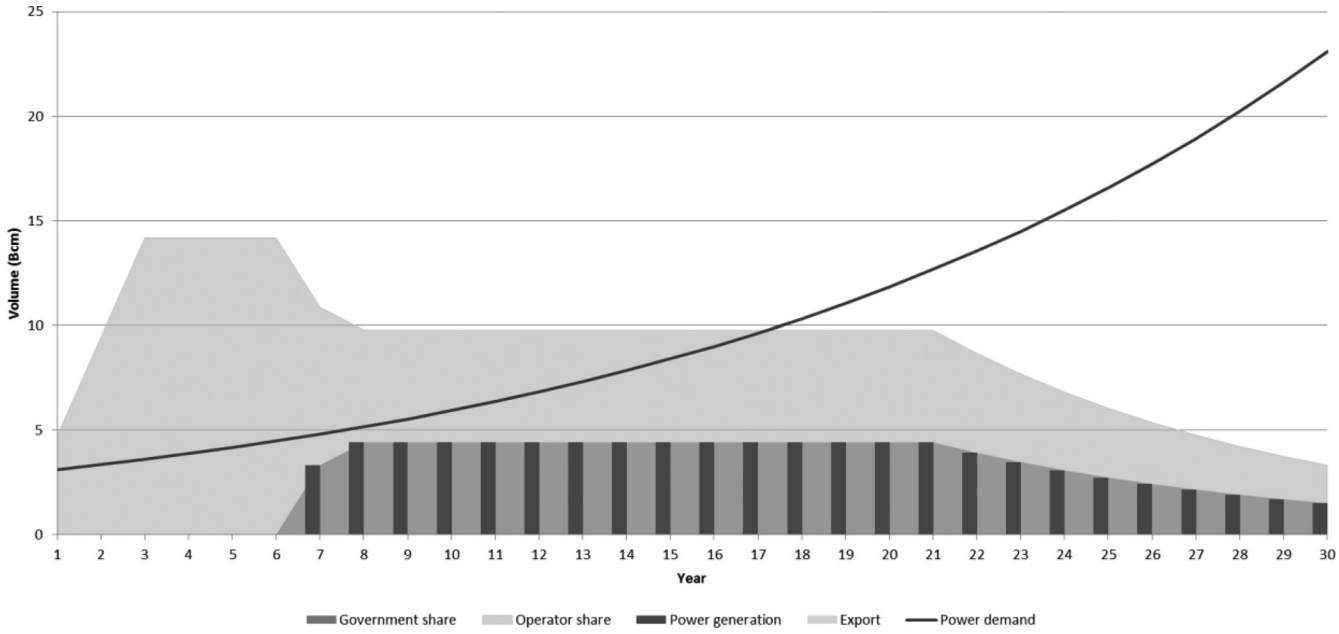

Fig. 3. Production split and optimal allocation of a 420-Bcm field.

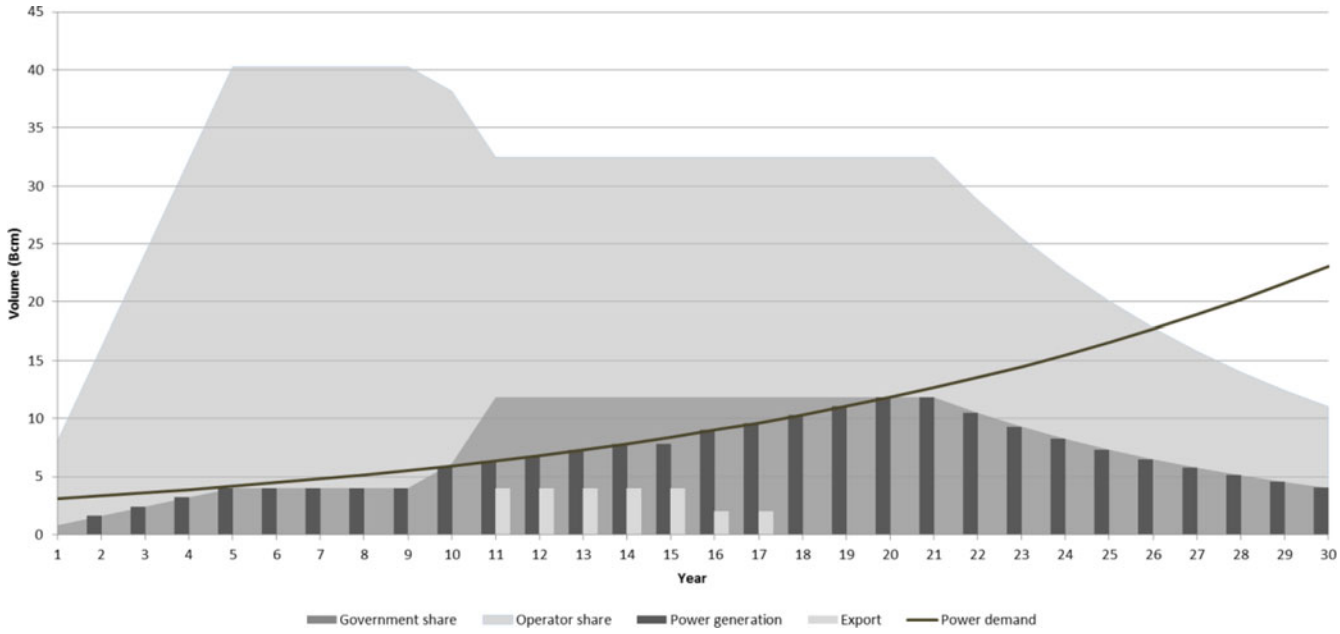

Fig. 4. Production split and optimal allocation of a 1260-Bcm field.

operator costs without compromising the value created by generating power from state production in the early years of the project. Fig. 5 shows the allocation results of a field with 2100 Bcm. It is clear that it is optimal for the state to structure a PSC that meets early power demand, in Years 1 to 9, exactly. Similar to Fig. 4 with a volume of 1260 Bcm, exporting happens in "middle" years, here between Years 9 and 23. However, in contrast to the smaller reserves case, the export amount in this case is much more significant with several contracts totaling 10 Bcm in most of the years.

Finally, we verify that the two problems of setting PSC parameters and allocation government share among different usages are closely coupled. To this end, we compare the optimal PSC structure for the two export modes, pipeline and LNG, for different reserve volumes. Even though the pipeline option is optimal for all volume ranges, the focus here is showing that variations in the allocation mode do affect the PSC structure. Fig. 6 shows significant differences in optimal contract parameters in the two scenarios across the volume range. For small volumes in which no export is done in either

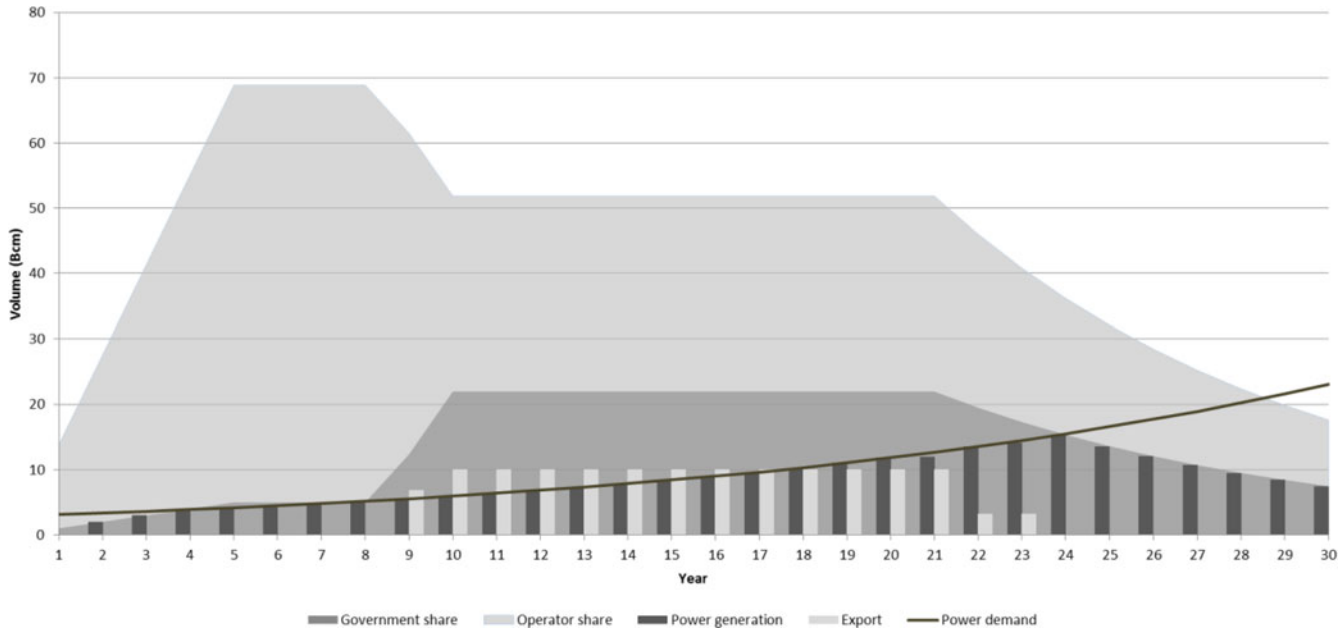

Fig. 5. Production split and optimal allocation of a 2100-Bcm field.

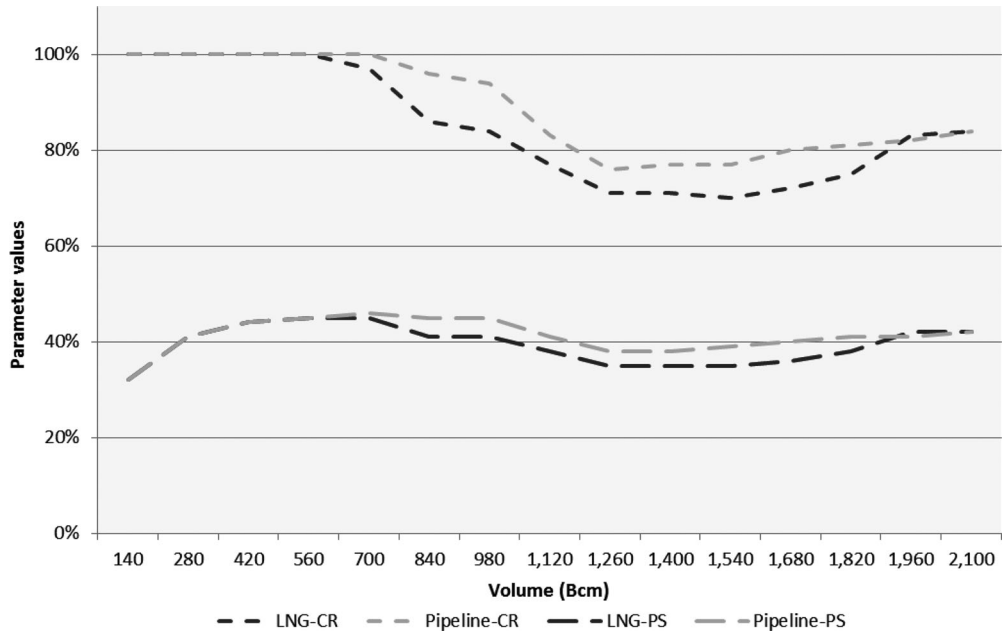

Fig. 6. Optimal contract parameter values for LNG and pipeline model formulations.

model, the contract parameters are identical. As the volume grows, the parameters in the LNG model drop more quickly than those of the pipeline model. This is the case since the LNG export mode allows exporting in smaller amounts at earlier years than the pipeline option where a minimum amount of 2 Bcm is needed for export. For larger volumes, both LNG and pipeline allow exporting in large amounts, the PSC parameters under both modes become identical again.

B. Sensitivity Analysis

In the following sections, we investigate the effects of changing the project duration, gas price and investor's IRR, respectively. In each section, only the parameter of interest is changed. All other parameter values are held at their base values as presented in Section IV.

1) Varying the Project Duration: A realistic range for the project duration, T, is between 10 and 30 years. Optimizing PSC parameters and government share allocation, for different

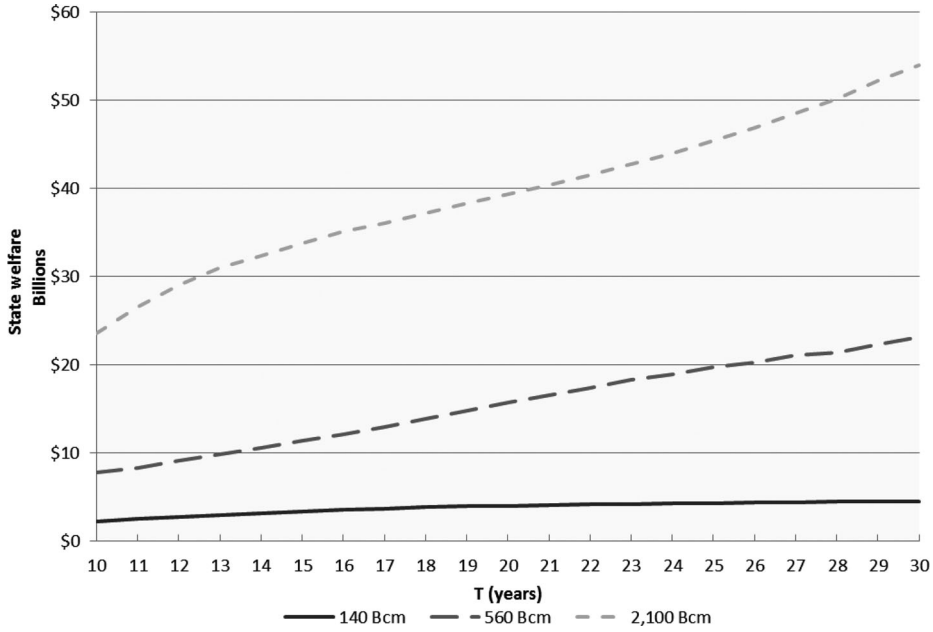

Fig. 7. Optimizing field of different volumes over the range of project lifetime.

T over this range, reveals the optimal production time of a field. This was performed for three different volumes (140, 560, and 2100 Bcm). The results are shown in Fig. 7, in terms of the optimal (maximum) state welfare (government share) for different project durations. The results are consistent for all three volumes, the value of the field increases with T and the maximum value is achieved at the maximum project duration, $T =$ 30 years. This has to do with the cost structure discussed in Section IV. Recall that the initial investment cost is proportional to the maximum production level $P_{\max}$. A shorter project duration implies a higher $P_{\max}$ and hence higher costs. Fig. 7 also reveals that larger fields suffer more of a loss when produced quickly because producing large this requires much greater production capacity, increasing development costs considerably. Note that for all the project durations in Fig. 7, it is always optimal to export via a pipeline.

2) Varying the Gas Price: At the current price of ¢9.76/ m^3, there is no volume that will justify Lebanon commissioning a $6 Billion LNG plant. The results from varying the gas price are presented in Table IV, where two higher price levels are investigated, ¢13.7/ m^3 and ¢17.66/ m^3. As the price of gas increases, the values of offshore fields increase considerably. At ¢13.7/cm, a 40% increase, the value of the fields grows by more than 60% on average. The higher price reimburses the operator costs using smaller volumes of natural gas, leaving more to the state. This new price makes building a LNG facility optimal for large fields having reserves exceeding 1260 Bcm, as shown in Table IV. Increasing the price further to ¢17.66/cubic meter causes the value to grow by only 30% and also lowers the threshold volume for investing in an LNG facility to 980 Bcm.

3) Varying the Investor's IRR: As discussed in Section IV, a rate of 12.5% was used by adjusting the value found by Pindyck [18] for international energy companies to account for the expensive offshore environment. Since this is a rough estimate, we investigate two different IRRs of 10% and 15%. The optimal state welfare for different volumes and IRRs is shown in Fig. 8. These results indicate that the total value of the project to the state is less sensitive to the operator's rate of return than the gas price. This is because the range in which the IRR can reasonably vary is narrow compared to the wide range of values for the gas price. In terms of the exporting strategy, commissioning an LNG plant is not optimal, even for the lowest investor IRR of 10%.

TABLE IV
RESULTING STATE WELFARE AND STRATEGY FOR OPTIMIZING OVER THE VOLUME RANGE AT DIFFERENT GAS PRICES

Volume (Bcm)	Gas price (¢/cubic meter) 9.76	13.71	17.66	Strategy
140	$ 4,488,899,133	$ 12,440,260,367	$ 16,126,064,418	
280	$ 11,168,435,430	$ 24,676,861,761	$ 30,185,046,430	
420	$ 17,143,476,142	$ 33,293,469,083	$ 39,926,377,665	Pipline
560	$ 23,098,619,710	$ 40,660,901,264	$ 47,887,841,686	
700	$ 27,471,922,025	$ 46,147,683,527	$ 55,299,923,089	
840	$ 30,476,385,242	$ 50,238,138,197	$ 59,281,551,326	
980	$ 33,857,258,450	$ 54,063,876,847	$ 65,727,700,279	
1,120	$ 37,028,471,576	$ 57,208 401,563	$ 73,158,007,599	
1,260	$ 40,225,698,995	$ 61,307,221,500	$ 80,479,867,471	
1,400	$ 43,064,486,055	$ 66,195,782,436	$ 87,702,955,295	
1,540	$ 45,706,216,201	$ 71,001,845,344	$ 94,879,535,534	LNG
1,680	$ 48,134,850,497	$ 75,725,570,523	$ 101,975,486,243	
1,820	$ 50,560,677,074	$ 80,408,446,677	$ 109,039,706,419	
1,960	$ 52,358,427,366	$ 85,029,526,786	$ 116,047,473,307	
2,100	$ 53,950,633,565	$ 89,646,212,698	$ 123,052,446,749	

VI. SUMMARY AND CONCLUSION

This paper presents an optimization model that allocates the government's share of reserves for the entire life of a

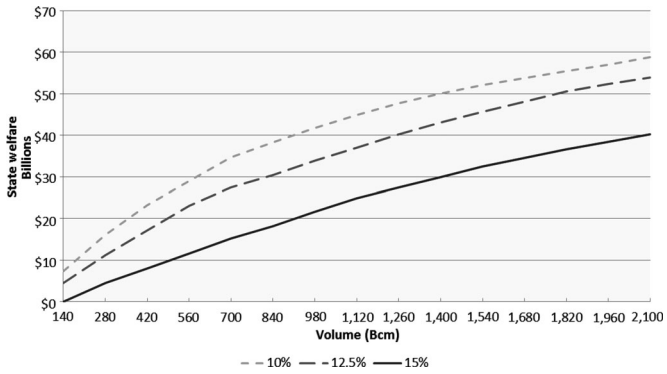

Fig. 8. Optimal state welfare for different investor rates of return.

production-sharing venture. The model determines values for both the PSC's key parameters and the allocation of the government share into different uses to generate the maximum benefit to the state while providing an acceptable rate of return for the IOC.

The proposed model was applied to the case of Lebanon—a country with a wide range of potential reserves—over two identified uses for natural gas, power generation, and export.

The main contribution of this paper is the integrated approach to policy-making that takes into account the infrastructure investments for monetizing natural gas, the allocation of the state's share of production and PSC parameter selection. Combining these aspects provides the state with a coherent framework for the formation of sound policy over the identified range of uncertainties. Specifically, the main insights that came out of the model analysis, as applied to the case of Lebanon are as follows.

1) It is optimal to have no royalty in the PSC contract in expensive offshore environments, regardless of the reserve volume, while CR and profit share vary with the reserves.
2) For small fields, the government should try repaying the operator's investment as fast as possible, with a CR of 100%, to allow meeting power demand effectively in later years through higher profit share. Larger fields permit lower values of CR (and of profit share), so that the state can meet its power demand in the early years of production.
3) It is optimal for the state to exploit projects for the maximum time possible of 30 years, as this allows reducing development costs.
4) Current gas prices, of ¢9.76/m^3, are too low to justify investing in an LNG plant for any reasonable field reserve. The existing Arab pipeline should be used for export. Higher gas prices significantly increase the state welfare, and justify LNG investment.
5) The effect of variation of investor RoR on the state welfare is less than that of the gas price.

The model can be improved in future work, especially with regards to its inputs. In addition, the gas price used in this paper was constant, which may not be reasonable for the investigated timeframe of 30 years. The presented model can easily be modified to have the gas price indexed over time and use long-term forecasts as input. Including uncertainty in modeling the price and reserve volumes could make the developed framework more realistic. Another improvement for the presented approach would be the modeling of operator gas utilization. The current model assumes that the operator collects the equivalent of the gas price for each unit of volume it receives and does not contribute to the identified state uses. Accounting for the operator usages of gas and potential collaboration schemes with the government could be useful.

APPENDIX A

Identifying the Annual Production Rate: The production rate is constrained by geophysical considerations (i.e., initial reserve volume, well rates, and decline rates). The required production capacity is the one that depletes the recoverable reserves in the field within the total project lifetime, *T*. In this paper, it is assumed that field development will take one year for fields up to 280 Bcm in volume, three years for fields with volumes in the range of 280–700 Bcm and five years for fields that are larger than 700 Bcm. In small fields the maximum production, $p_{\max}$, is achieved in the first year, whereas in larger fields it grows linearly until the field is fully developed.

Assuming the typical behavior of gas fields (as shown in Fig. 9), the field will produce at this capacity until two-thirds of its resources have been exhausted after which it will decline exponentially at 12% every year, with an ultimate recoverability of *U* of the initial reserve volume [30], [31]. In this paper, we use a recoverability of 85%. For example, the production profile of a medium field (3 year production ramp-up) is shown in Table V, where *c* is the last time period before the decline begins.

It is clear that $\sum_{t=1}^{T} p_t = (c-1)\, p_{\max}$ and $\sum_{t=c+1}^{T} p_t = p_{\max} \sum_{t=1}^{T-c} e^{-0.12t}$. Therefore, with a total production equal to a fraction *U* of the reserve, results in

$$p_{\max}\left(c - 1 + \sum_{t=1}^{T-c} e^{-0.12t}\right) = U. \tag{17}$$

In addition, with two third of the production reached at *c*, $\sum_{t=1}^{c} P_t = (c-1)\, p_{\max} = \frac{2}{3}$, which gives, with appropriate rounding

$$c = 1 + \frac{2}{3p_{\max}}. \tag{18}$$

Substituting equation (17) into (18) allows us to solve for $p_{\max}$. Then, the production profile, similar to that in Table V, gives p_t.

APPENDIX B

Mathematical Formulation: LNG Model: With an LNG export model, the pipeline model formulation is simplified, since as argued in Section III-A, export contracts are not needed in this setting. Essentially, gas can be exported in any volume, E_t in year *t*, provided it generates enough revenue to cover the infrastructure cost related to LNG. The mathematical formulation

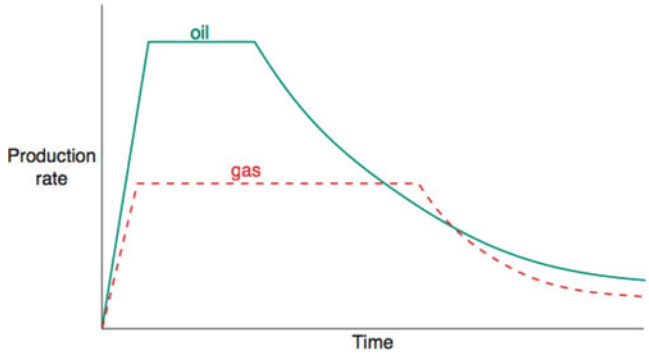

Fig. 9. Typical production profile of hydrocarbon fields.

TABLE V
PRODUCTION OVER TIME AS A FUNCTION OF THE MAXIMUM PRODUCTION RATE (P_{MAX})

Time Period	p_t
1	$p_{max}/3$
2	$2p_{max}/3$
3	p_{max}
...	...
c	p_{max}
$c+1$	$p_{max}\ e^{-0.12}$
$c+2$	$p_{max}\ e^{-0.12^*2}$

for the LNG export mode is as follows:

$$\max \sum_{t=1}^{T} \frac{\pi^* V_{et} + P^* E_t}{(1+r_f)^t} - bC_{LNG} \tag{19}$$

$$V_{et} \le d_t;\ \ t = 1, \ldots, T \tag{20}$$

$$V_{et} + E_t \le GS_t;\ \ t = 1, \ldots, T \tag{21}$$

$$V_t = V_0 p_t;\ \ t = 1, \ldots, T \tag{22}$$

$$CR_t = \min \left[CR^* V_t, \frac{\sum_{k=1}^{t} C_{ik} + C_u V_k}{P} - \sum_{k=1}^{t-1} CR_k \right] \tag{23}$$

$$GS_t = (\rho^* V_t) + ((1-\rho)^* V_t - CR_t)^* (PS + \tau(1-PS)) \tag{24}$$

$$\sum_{t=1}^{T} \frac{(V_t - GS_t)^* P}{(1+r)^t} \ge \sum_{t=1}^{T} \frac{C_{it} + C_u V_t}{(1+r)^t} \tag{25}$$

$$b \ge \frac{\sum_{t=1}^{T} E_t}{V_0} \tag{26}$$

$$0 \le \rho \le 1, 0 \le CR \le 1, 0 \le PS \le 1, 0 \le \tau \le 1 \tag{27}$$

$$b\,\text{binary}, E_t \ge 0, CR_t \ge 0,\ GS_t \ge 0. \tag{28}$$

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