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Using Natural Gas Resources to De-Risk Renewable Energy Investments in Lower-Income Countries

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Abstract: Combatting climate change necessitates a substantial global increase in renewable electricity capacity. Many low-income and lower-middle-income countries suffer from unfavorable green financing conditions. Fifteen of these countries possess substantial natural gas reserves. To overcome green financing constraints in such countries, we propose an integrated energy contract that awards a renewable energy project in parallel with an upstream natural gas project to interested energy companies. The state returns from the natural gas project provide a guarantee for renewable energy investments, reducing their associated risks. We conduct Monte Carlo simulations for each of the targeted countries after populating the input parameters for the upstream natural gas and renewable energy projects, including forecasting country-specific natural gas prices. When accounting for 10% of their existing natural gas reserves in the proposed contract, Nigeria, Myanmar, and Indonesia can achieve more than 60% of their 2030 renewable energy target capacity additions while countries with low access to electricity can significantly upscale their installed capacities. The guarantee mechanism provides protection levels exceeding 96% on renewable energy investments. The proposed contract enables the considered countries to increase their renewable energy capacities while inducing economic development.

Keywords: natural gas; renewable energy; upstream oil and gas; developing countries; climate change; investment risks; guarantee mechanism; Monte Carlo simulation; forecasting

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Citation: Olleik, M.; Hamie, H.; Auer, H. Using Natural Gas Resources to De-Risk Renewable Energy Investments in Lower-Income Countries. *Energies* **2022**, *15*, 1651. https://doi.org/10.3390/en15051651

Academic Editor: David Carter

Received: 23 January 2022
Accepted: 16 February 2022
Published: 23 February 2022

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1. Introduction

Climate change is a global challenge that humanity faces and that necessitates a rapid transition to low-carbon energy systems [1]. When approaching the topic from the point of view of developing economies, especially those classified by the United Nations as lower-middle-income and low-income countries (referred to as lower-income countries in the rest of this paper), different considerations should be kept in mind. First, these countries are not the inducers of climate change [2]. Therefore, if a global response should take place in the form of energy transition, among others, it should not cause additional burdens for their strained economies [3]. Second, while environmental concerns are essential in shaping the response to climate change, lower-income countries have other pressing priorities related to economic development and social inclusion [4]. Third, at the energy systems level, increasing electricity production capacity and affordable access are on top of the energy agenda of these countries [5,6]. This particularly favors the usage of fossil fuel-based solutions when these fuels are produced locally [6,7].

While all these concerns are legitimate, lower-income countries cannot remain idle in the face of climate change. Their geography, their overdependence on sensitive sectors, and their limited infrastructure and financial resources make them more prone to the devastating effects of climate change [8,9]. Therefore, achieving energy transition and inducing economic development should be regarded as two non-conflicting objectives [4]. Solutions that achieve both objectives should be prioritized.

Lower-income countries have limited financial capabilities [5] and tend to undertake energy planning based on the theory of scarcity [10] rather than optimally. They possess large untapped renewable energy investment potential [11] that remains unattractive to private sector investors [12]. Private investors adopt a risk-return perspective to investments [13]; a project with higher perceived risk is either dismissed or is only chosen if it promises high returns that compensate for the risk taken. Developing countries in general, and lower-income countries specifically, face a series of political, regulatory, commercial, technical, and informational barriers to the dissemination of renewable energy technologies [14,15]. These barriers result in an increased perception of risks for such investments and accordingly make access to finance either impossible or very costly [16]. Lower-income countries can therefore easily get stuck in "a climate investment trap" [17]. High-risk perceptions induce a high weighted average cost of capital (WACC), which delays green investments. The delayed green investments exacerbate the negative effects of climate change on the overall socio-economic situation and therefore increase further investment risks.

Breaking this trap necessitates reducing the investment risks by ensuring the ability of investors to monetize their returns for years in the future [11,18,19]. In the context of lower-income countries, the state maintains a main role in the electricity sector. The state or a state-owned entity acts as the off-taker of the produced electricity sold based on feed-in tariffs or power purchase agreements (Section S1 of the Supplementary Materials provides more details). One of the most important risks from the investor's point of view is that of the off-taker defaulting on their electricity payments [18,20]. Investment guarantee mechanisms provided by credible international institutions are a common approach to provide investors with the necessary assurance and coverage in case of the inability of the off-taker to pay its contractual duties. This results in lowering the country's risk and the investment WACC [18]. Yet, the guarantee schemes available, among other sustainable finance frameworks, fall short of the needs of developing economies [17]. Matthäus and Mehling propose a new global guarantee mechanism to reduce risk premia for renewable energy investments in regions with adverse financing conditions and estimate savings reaching 1.5 trillion USD until 2030 [20]. While the proposed guarantee might indeed accelerate the dissemination of renewable energy technologies in developing countries, it is still in the ideation phase and requires global alignment for its implementation.

In this paper, we focus on the subset of the lower-income countries that possess natural gas reserves. These countries typically aim to use their reserves to induce economic development especially since natural gas is perceived as the least polluting [21] and the most resilient fossil fuel during the ongoing energy transition [22]. However, they risk getting trapped in carbon lock-in as they increase the gasification of their economies.

The question that this paper aims to address is: How can these countries develop portions of their natural gas resources in a way that supports the good cause of a greener future with less reliance on fossil fuels and more dissemination of renewable energy technologies? This question becomes timely and relevant with the current observed trend where many international oil companies, especially with headquarters in Europe, are undertaking a transition to becoming integrated energy companies interested in investing in both oil and gas and the renewable energy sectors [23–25].

Succeeding in their quest for a greener future supported by the development of natural gas resources, the considered lower-income countries can open wide doors for the hydrogen economy. These countries can produce hydrogen either from natural gas or through water electrolysis powered by renewable energy sources [26] and then consume it locally [27] or export it at low cost using existing natural gas export pipelines [28].

In a previous paper for two of us, we introduced an upstream oil and gas production sharing contract that includes renewable energy elements where companies interested in oil and gas and renewable energy commit to re-investing a share of their oil and gas returns in renewable energy projects in the country [25]. Yet, these re-investments come later in the future, only when the production phase starts and require several years to materialize.

This constitutes a hurdle for lower-income countries in urgent need of green financing, especially in the wake of the COVID-19 pandemic.

To the best of our knowledge, this paper proposes, for the first time, a novel integrated energy contract that aims at overcoming green financing constraints by awarding a renewable energy project in parallel to an upstream natural gas project to an interested energy company. The company commits to undertaking renewable energy investments in the electricity sector in parallel to investing in the upstream gas project, such that the forecasted future state returns from the upstream gas project act as a guarantee for the renewable energy project, reducing its associated risks. We assess the implications of such a scheme on the decarbonization efforts in lower-income countries that possess natural gas reserves and the viability of this guarantee mechanism. Since most of the lower-income countries with natural gas reserves possess a great potential for solar energy, we assume that solar photovoltaics (PVs) are the renewable energy technology of choice. We conduct Monte Carlo simulations that consider the main uncertain elements of upstream natural gas field development and solar PV projects after generating forecasts for country-level future natural gas prices. We map the implications of the proposed energy contract and guarantee scheme for each of the analyzed countries when a limited portion of 10% of their proven natural gas reserves is considered.

The following section presents, at a conceptual level, the proposed integrated energy contract that includes the "cross-guarantee" between natural gas and renewable energy projects. The Section 3 describes the mathematical formulation of the proposed contract along with the details of the Monte Carlo simulations. The Section 4 describes the main findings of the analysis and highlights the implications of the proposed integrated energy contract on the efforts of lower-income countries to decarbonize their energy systems while developing a portion of their natural gas reserves. We conclude by re-iterating the novelty of our work and discussing limitations and areas of future research. The Supplementary Materials complement the paper and fully describe the input data used and the assumptions made.

2. The Integrated Energy Contract

This section presents the reasoning behind the proposed integrated energy contract, then highlights its conceptual structure.

2.1. Rationale

In 2020, the United Nations classified 77 countries as low income or low-middle income [29]. Fifteen of these countries possess considerable unassociated natural gas reserves exceeding five trillion cubic feet (Tcf) each [30]. Table 1 provides an overview of the current electricity sector status and the 2030 renewable energy targets of these countries in addition to their existing natural gas reserves. The renewable energy targets are mainly based on the announcements that these countries made as part of their Nationally Determined Contributions (NDCs) to reduce their emissions in line with the Paris agreement. More than half of these countries have not yet achieved 90% access to electricity. While the share of renewable electricity generation is sometimes very high, as is the case for Mozambique, Angola, Myanmar, and Papua New Guinea, the low access to electricity in these countries indicates that the installed capacities are not enough to meet the available demand. Considering the currently installed capacities, the share of non-hydro renewable electricity capacity is below 10% for 11 out of the 15 countries. The large differences between the renewable electricity status in 2020 and the 2030 targets are apparent across almost all the considered countries indicating the level of effort and investments required in the ongoing decade.

Table 1. Overview of the current status and future renewable energy targets in the electricity sector of lower-income countries possessing natural gas reserves.

Country	Natural Gas Reserves (Tcf) [a]	Access to Electricity [b]	Total Electricity Capacity (MW) [b]	Renewable Electricity Capacity (MW) [b]		Share of Renewable Electricity Generation [b]	Renewable Energy Targets in 2030 (MW or Share of Total Generation) [c]
				Hydro	Non-Hydro		
Angola	12.1	45%	5931	3729	64	72%	Hydro: 6310 Non-Hydro: 1740
Bolivia	10.7	93%	3537	736	321	36%	81%
Egypt	63	100%	59,420	2832	3139	9%	42%
India	48.8	95%	452,308	45,955	88,302	17%	500,000
Indonesia	49.7	99%	70,387	6210	4344	16%	21,650
Mozambique	100	31%	2915	2204	109	95%	NA
Myanmar	22.5	66%	7336	3304	144	52%	Hydro: 5676 Non-Hydro: 3070
Nigeria	203.4	57%	13,154	2153	41	25%	Hydro: 17,653 Non-Hydro: 22,741
Pakistan	20.9	73%	39,428	10,002	2404	31%	60%
PNG [d]	6.5	59%	1037	258	75	63%	78%
Syria	8.5	86%	8625	1490	10	3%	10%
Ukraine	39	100%	57,643	4819	8945	8%	13.2%
Uzbekistan	65	100%	16,041	2005	4	11%	25%
Viet Nam	24.7	100%	69,355	18,165	17,484	43%	NA
Yemen	16.9	62%	1947	0	253	14%	NA

[a] Based on the U.S. Energy Information Administration [30]; [b] Based-on IRENA country energy profiles [31]; [c] Based on their latest Nationally Determined Contributions (NDCs) as published on the UNFCCC website [32], except for Egypt [33], India [34], and Ukraine [35]; [d] Papua New Guinea.

The academic literature discusses different barriers that hinder the successful deployment of renewable energy technologies in developing countries [14–16,36,37]. The considered lower-income countries explicitly highlight many of these barriers in their NDCs [32]: (1) institutional and regulatory barriers in the form of weak public institutions, limited cross-institutional coordination, and lacking regulations; (2) informational barriers due to the absence of detailed assessments of renewable energy potential; (3) technical and technological barriers due to the limited availability of the specialized human resources and the required technologies. Yet, across the considered NDCs, the lack of sufficient green financing and the failure to attract private investments are recurring major concerns for the successful achievements of the desired climate goals, including the dissemination of renewable energy technologies. It is therefore crucial for these countries to de-risk renewable energy investments to succeed in decarbonizing their power systems.

The 15 lower-income countries possess considerable proven natural gas reserves. They all managed to attract investments from international oil and gas companies. Except for Syria, Ukraine, and Yemen (three countries that currently suffer from devastating wars that resulted in the execution of force majeure clauses in upstream gas contracts [35,38,39]), the remaining countries witness maintained upstream oil and gas operations by international companies (Section S2 of the Supplementary Materials describes the upstream investment climate in each of the considered countries.).

Therefore, it is beneficial for the countries considered to expand the interest of oil and gas companies into the renewable energy sector. This idea is not alien anymore, as many

oil and gas companies are undergoing the transition to becoming energy companies [25]. European oil and gas (now energy) companies are leading the way in this transformation and are declaring aggressive renewable energy targets for 2030 in their bid for carbon neutrality by 2050 (Table 2).

Table 2. Renewable energy targets for European energy companies.

Energy Company	Renewable Energy Capacity Target in 2030 (GW)
TotalEnergies [40]	100
BP [41]	50
Eni [42]	15
Repsol [43]	15
Equinor [44]	12 to 16

Given this logic, the goal of lower-income countries would be to attract renewable energy investments from oil and gas companies at reduced WACC. This enables them to break the "climate investment trap" [17] and helps them achieve their renewable energy targets. The presence of major energy companies familiar with the lower-income countries and with previous experience in capacity building, knowledge transfer, and institutional support also contributes to overcoming the other barriers typically faced by lower-income countries.

An energy contract that spans the upstream gas and the renewable energy sectors can also be attractive for oil and gas companies in the transformation to becoming energy companies. If this energy contract provides solid guarantees for renewable energy investments, then this opens lucrative investment opportunities with limited competition from companies specialized in only renewable energy, as these will not be able to obtain similar guarantees. Such a contract is in line with the strategies of the energy companies to diversify their investments and reduce their carbon footprint. Their main concern would be related to the robustness of the guarantee mechanism.

2.2. Structure

In a typical upstream gas project, the contractual arrangements between the state and the company define the rights and obligations of both parties including, their shares from the produced gas. In the context of developing countries, the most adopted contractual arrangement is the production sharing contract (PSC) [45] which consists, in its basic form, of placing all the investment requirements on the shoulders of the private company while the state and the company share the produced gas according to well-defined terms [45,46]. Typically, once production starts, and after deducting an optional royalty that goes to the state, a portion of the produced gas is allocated to cover the incurred capital costs and the ongoing operational costs. This portion is labeled Cost Gas and is allocated to the company. The remaining portion is labeled Profit Gas and is split between the state and the company according to fixed or variable shares. The state and company shares of the Profit Gas should be crafted in a way that incentivizes the company to undertake the investment, promising it enough returns while providing the state with a perceived fair split. It is therefore common for these terms to be renegotiated just before the final investment decision, to align them with the realities of the time, as by then many uncertainties, such as the size of the available reserves and the detailed engineering plans for building the infrastructure, would have been resolved.

To overcome green financing constraints, the proposed integrated energy contract builds on the typical upstream gas PSC and adds a second dimension to tackle the renewable energy electricity project (Figure 1). The energy company provides the necessary investments for both projects, is responsible for their successful execution, and assumes full liability for managing their operations. The company can outsource some of the managerial or operational roles, but will always be the accountable party to the state. In parallel, the state commits to purchasing all the renewable electricity that will be produced throughout the life of the renewable project at the contractually agreed price. To de-risk the renewable

energy project, the state offers its future Profit Gas share from the gas project as a guarantee that ensures that the company is paid for the renewable electricity it will be producing. At any point in time during the lives of both projects, the state is entitled to receive its Profit Gas share fully as long as the renewable electricity it is buying is paid for. If the state defaults on its payments at any point in time, then all the future state Profit Gas will be available to the company to collect its due payments. The mathematical definitions are provided in Section 3.

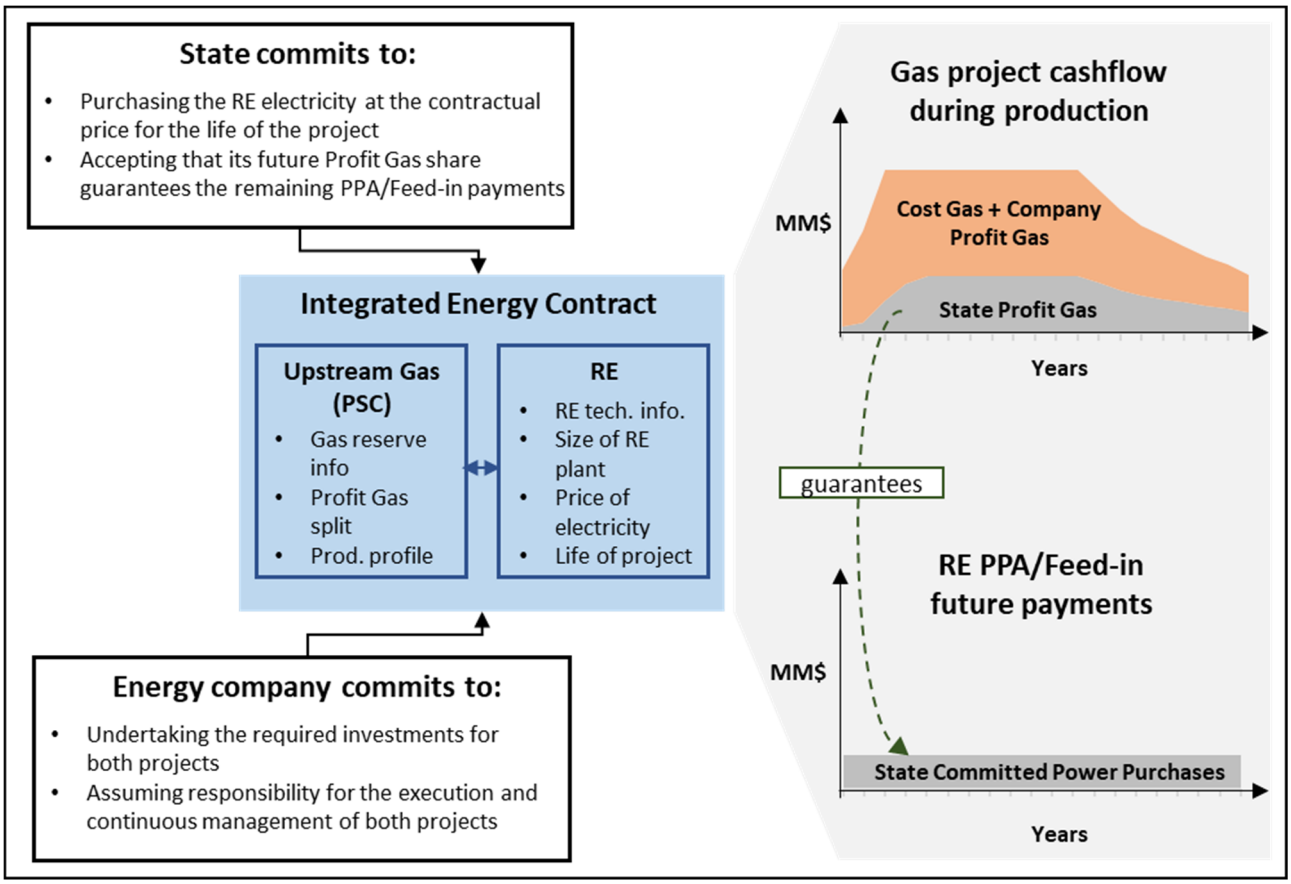

Figure 1. Structure of the proposed integrated energy contract.

For the upstream gas project, the gas reserves that will be developed along with the projected production profile and the details of the PSC are important elements of the contract. The commercial factors that are part of the PSC, including the Profit Gas split between the state and the company, are determined based on the economics of the upstream gas project and the return expectations of the company. These elements can be subject to direct negotiations or to bidding.

For the renewable energy project, within reasonable boundaries set by the state, the flexibility is left to the company to decide on the size of investments that it is willing to make and, accordingly, the capacity of the renewable energy plant. In parallel, the company should agree with the state on the price of electricity for the duration of the agreement. This is also determined based on the economics of the renewable energy project and the return expectations of the company. Given that the renewable energy returns are now guaranteed against the risk of the default of the off-taker, the WACC that the company uses to run the economics of the renewable energy project should be reduced to reflect the reduction in risk.

In principle, when determining the size of the renewable energy investment, the company contemplates two conflicting objectives. Maximizing its investments maximizes the associated profit especially since the nature of the integrated energy contract offers

it easy access to largely untapped renewable energy resources, as is the case with lower-income countries. Yet, the uncertainties that the future brings, mainly in terms of natural gas prices, have a great effect on the size of the state Profit Gas and, accordingly, the guarantee available to compensate the company in case of the off-taker defaulting. Striking the right balance here can be achieved by estimating the guarantee available based on a conservative natural gas price estimate that the company feels safe with. The size of the renewable energy investment should therefore be equal to the size of the conservative guarantee estimate.

To illustrate the proposed integrated energy contract, we develop a stylized version and run Monte Carlo simulations for each of the 15 lower-income countries, accounting for their specificities. We consider that each country is willing to offer 10% of its existing proven natural gas reserves under the integrated energy contract. We develop probability distributions for the estimates of capital and operational costs of the upstream gas project based on the cost profile of each country. Based on historical natural gas prices at the three main markets that act as regional hubs (the United States, Europe, and Japan), we develop an autoregressive model to forecast future hub gas prices. We treat every forecast as a random variable where its mean is the point forecast generated from the autoregressive model. This allows the testing of different scenarios for future gas prices. We then link the sales price of natural gas in each of the considered countries to one of the three regional hubs and accordingly develop distinct natural gas prices by country. For the renewable energy project, we set PVs as the technology of choice. We develop country-specific probability distributions for capital and operational costs.

In terms of financing, we differentiate between upstream gas and renewable energy projects. For the former, we use the declared rates of returns of European energy companies for their upstream investments to estimate ranges for their upstream project discount rates. For the renewable energy project, we estimate ranges for the company WACC based on estimates of costs of debt and equity and tax rates in each country. We measure the effect of the guarantee mechanism by assuming that it reduces the renewable energy project WACC by the country default spread [20].

Section 3 describes the mathematical formulation of the integrated energy contract and the details of the Monte Carlo simulations.

3. Materials and Methods

This section starts by presenting the details of the integrated energy contract, then discusses the various elements of the Monte Carlo simulations. Sources to input data are provided whenever they are introduced. The Supplementary Materials present a complete description of the input parameters.

3.1. Details of the Integrated Energy Contracts

To simplify the presentation of the essence of the integrated energy contract, we consider a stylized PSC for the upstream gas project. The same conclusions can be reached with a more complex and realistic PSC design. We adopt the PSC design described in [45] and we restrict the state share to a single component: the state Profit Gas. We set the Cost Gas Ceiling (CGC) to 70%. The CGC defines the maximum share of the periodic revenues that can be allocated to cover ongoing or carried costs.

Using years as units of time, for every period t, let P_t be the price of natural gas per unit volume and V_t the volume of natural gas produced. The revenues generated account for $P_t \cdot V_t$. The Cost Gas, CG_t, is the minimum between the balance of unsettled costs to date and the maximum cost recovery possible:

$$CG_t = min\left(\sum_{n=1}^{t} C_n - \sum_{n=1}^{t-1} CG_n, CGC \cdot P_t \cdot V_t\right) \quad (1)$$

where C_n refers to the total upstream costs at period n.

The Profit Gas is the remaining revenue after deducting the Cost Gas. Given a state Profit Gas share, PGS_s, the state and company Profit Gas at period t, PG_{st} and PG_{ct}, are computed, respectively, as per the below equations:

$$PG_{st} = (P_t \cdot V_t - CG_t) \cdot PGS_s \tag{2}$$

$$PG_{ct} = (P_t \cdot V_t - CG_t) \cdot (1 - PGS_s) \tag{3}$$

The company upstream revenues at period t are composed of the Cost Gas and the company Profit Gas:

$$R_{ut} = CG_t + PG_{ct} \tag{4}$$

In this stylized PSC, the only item that is subject to negotiation or bidding is PGS_s. The company sets this item such that it manages to achieve a desired internal rate of return, i_u, on the upstream project, assuming a certain base case natural gas price, P_b [25]. Therefore, PGS_s is chosen such that the net present value (NPV) of costs (that are all paid by the company) equals the NPV of the company revenues when the periodic natural gas prices are set to P_b:

$$\sum_{t=1}^{T_u} \frac{C_t}{(1+i_u)^t} = \sum_{t=1}^{T_u} \frac{R_{ut}}{(1+i_u)^t} \tag{5}$$

where T_u is the upstream project life.

When the above equation cannot be satisfied even if PGS_s is reduced to values as low as 0%, then the upstream project does not generate the necessary rate of return for the company and is accordingly deemed infeasible and abandoned.

For feasible upstream projects, to determine the size of the renewable energy investments that will be guaranteed, the company is interested in quantifying the NPV of the state Profit Gas profile. The company should choose a gas price to compute it. A conservative approach that considers the possibility of future gas prices consistently dropping below the base case estimate, P_b, used to assess the upstream project, can be adopted to compute the desired NPV. A reduced gas price of P_r where $P_r = (1 - r) \cdot P_b$ and r refers to the reduction rate applied on the base case gas price can be used. Accordingly, given a renewable energy project discount rate (i_r), the NPV of the state Profit Gas from the company perspective, using P_r as the gas price, corresponds to the size of the total guarantee (TG) as perceived by the company.

$$TG = \sum_{t=1}^{T_u} \frac{PG_{st}}{(1+i_r)^t} \tag{6}$$

The company is therefore willing to invest an amount of TG at time zero to build the renewable energy plant. Using estimates of unit capital costs per renewable energy capacity C_c, the size of the renewable energy plant can be computed:

$$S_r = \frac{TG}{C_c} \tag{7}$$

The electricity price that the company will charge on the renewable energy project is set to the Levelized Cost of Energy ($LCOE$) of the renewable energy technology using estimates of unit capital, operational costs, and capacity factors. Based on Heck et al. [47], the $LCOE$ can be computed as:

$$LCOE = \frac{A}{8760 \cdot C_f} + O\&M \tag{8}$$

where A is the annualized equivalent of the unit capital costs, C_f is the capacity factor, $O\&M$ is the unit variable operational costs, and 8760 refers to the number of hours in a year. A can be computed as:

$$A = C_c \cdot \left(i_r + \frac{i_r}{(1+i_r)^{T_r} - 1} \right) \tag{9}$$

where T_r is the productive life of the renewable energy plant.

The World Bank Global Solar Atlas [48] uses a measure called the specific photovoltaic power output (PV_{out}) that represents the average daily electric energy produced per installed PV capacity. Equation (8) can therefore be written as:

$$LCOE = \frac{A}{365 \cdot PV_{out}} + O\&M \tag{10}$$

The yearly revenues that the company receives from the electricity payments are:

$$R_{rt} = LCOE \cdot S_r \cdot PV_{out} \cdot 365 \tag{11}$$

In normal circumstances, the state is fulfilling its electricity payments as stipulated in the integrated energy contract and is entitled to fully receive its state Profit Gas PG_{st}. If at any time, n, the state defaults on its electricity payments, the company can use all the future PG_{st} to recover its due amounts.

Let OR_n be the NPV of the outstanding returns from the electricity project that the company is entitled to receive after the state defaults at time n:

$$OR_n = \sum_{t=n}^{T_r} \frac{R_{rt}}{(1+i_r)^t} \tag{12}$$

Let RG_n be the NPV of the remaining guarantee available which corresponds to the NPV of the future state Profit Gas:

$$RG_n = \sum_{t=n}^{T_u} \frac{PG_{st}}{(1+i_r)^t} \tag{13}$$

The company is able to recover its total due amounts if $RG_n \geq OR_n$. Otherwise, the company is only able to recover a share of its due amounts. We define the protection level, PL_n, as the share of the NPV of the total electricity payments that the company is able to recover if the state defaults at time n:

$$PL_n = \begin{cases} 1 & if \quad RG_n \geq OR_n \\ 1 - \left(\frac{OR_n - RG_n}{OR_1} \right) & otherwise \end{cases} \tag{14}$$

where OR_1 refers to the NPV of all the electricity payments.

We define PL as the minimum protection level achieved if the state defaults at any point in time:

$$PL = \min_n (PL_n) \tag{15}$$

PL is the lowest protection level among all years over the project time horizon. Therefore, reporting a high value for PL provides confidence that the guarantee mechanism is functioning well, whereas a low PL raises red flags.

3.2. Elements of the Monte Carlo Simulations

In this subsection, we describe the following details associated with the Monte Carlo simulations:

- The approach adopted to compute the country-specific gas price forecasts;

- The reasoning behind the assumed discount rates for the upstream and renewable energy projects;
- The parametrization of the various estimates used in the simulations.

3.2.1. Country-Specific Natural Gas Prices

To assess the implications of the proposed integrated energy contract, we should determine the prices at which the produced natural gas is sold. Forecasting natural gas prices directly for each of the considered countries based on market-specific historical data is very difficult, if not impossible, since the historical data is lacking for most, if not all, of the target countries. Instead, we develop a two-step approach to come up with reasonable forecasts. Natural gas prices are regionally set based on three major hubs: the United States (represented by the Henry Hub), Europe (represented by the Title Trading Facility virtual hub), and Japan (where natural gas prices are based on the Japanese Crude Cocktail price index) [49–51]. These three regions have well-documented historical data. Therefore, we forecast future natural gas prices for the three main hubs, then derive country-specific natural gas prices for each considered country based on its natural gas import and export activities.

Forecasting Hub Prices

Univariate regression models are generally used to forecast future natural gas prices based on historical prices [51,52]. We use the statistical software R and adopt the classical ARMA (auto-regressive moving average) method, which is simple, powerful, and widely used for forecasting and prediction [53]. We use nominal monthly natural gas prices from January 1992 to December 2020, as reported by the World Bank for the United States, Europe, and Japan [54]. The historical time series for all the three markets exhibit a non-stationarity behavior when tested using the Augmented Dickey–Fuller test. Knowing the importance of the stationarity concept in time series regression analysis, a set of mathematical techniques can be used to stabilize non-stationary data. We use first-order differencing for each of the three markets, such that:

$$y'_m = y_m - y_{m-1} \tag{16}$$

y_m being the gas price at month m. The Augmented Dickey-Fuller test indicates that the series of the first-order differences for the three markets are stationary at a 1% significance level.

We then apply the ARMA model on the first difference time series, with p lag-order for the autoregressive process and q lag-order for the moving average process. The linear equation of such a model is as follows:

$$y'_m = \alpha_0 + \sum_{j=1}^{p} \Phi_j \cdot y'_{m-j} + \sum_{j=1}^{q} \theta_j \cdot \varepsilon_{m-j} + \varepsilon_m \tag{17}$$

where α_0 is a constant, ε_m is the residual Gaussian white noise, and Φ_j and θ_j are the coefficients of the auto-regressive moving average lags, respectively.

It is common practice to enumerate the set of all possible candidate models (ARMA (p, q)) by considering significant lags based on the auto-correlation and partial auto-correlation functions (ACF and PACF). A grid search technique is then applied to come up with p and q values that minimize the Akaike Information Criterion (AIC) [55]. The values of p and q, the coefficients Φ_j and θ_j for the three markets, and a plot of the point-forecasted gas prices are provided in Section S4 of the Supplementary Materials. Instead of relying solely on these point forecasts, we treat each monthly forecast as a normally distributed random variable with the mean as the point forecast and the standard deviation as the standard error. This approach allows the generation of different gas price profiles across the Monte Carlo simulations.

Linking Country-Specific Prices to Hub Prices

We categorize the considered countries into net importers and net exporters of natural gas. These countries import or export natural gas either through pipelines or liquified natural gas (LNG) shipments. We address below how we treat each of the four possible categories.

For net exporters via LNG, the destination market is mainly one of the three main gas markets (US, Europe, Japan). To compute the price of natural gas that the producing country ends up collecting at the end of the upstream infrastructure, we deduct all the costs associated with bringing the gas from the producing country to the destination market. In simple terms, the price of the gas produced in the subject country is based on its value in the market it is destined for, minus the cost associated with moving it there. These costs are regasification in the destination market, LNG transport fees, and liquefaction costs in the country where it is produced. Almost all these countries sell their LNG primarily to East Asia, except for Egypt which sells mostly to Europe. The regasification costs are assumed to be the same for all countries, regardless of the location where the molecule is being regasified [56]. The liquefaction and transportation cost assumptions are computed by country [57]. The countries that belong to this category are Angola, Indonesia, Mozambique, Egypt, Nigeria, Papua New Guinea, and Yemen.

For net exporters via pipelines, the same netback approach is also adopted. In this case, cost estimates for pipeline transmission are deducted. These costs are a function of the pipeline length and diameter [58]. The countries that belong to this category are Bolivia, Myanmar, and Uzbekistan.

For net imports via LNG or via pipelines, it is assumed that the prices of the produced natural gas are set equal to the prices of the imported gas that will be substituted. A similar analysis to exporters is performed to compute the price of the imported gas based on one of the three regional hubs. The net importers are India, Pakistan, Syria, Ukraine, and Vietnam.

Across the Monte Carlo simulations, the unit of time used is a year. Therefore, yearly averages of the monthly forecasts are generated.

Section S5 of the Supplementary Materials discusses the country-level reasoning and provides the numerical data.

3.2.2. Discount Rates

We adopt a bottom-up approach to compute the weighted average cost of capital ($WACC$) that is used as the discount rate, i_r, for the PV project. The $WACC$ is generally defined as:

$$WACC = W_D \cdot (1 - TR) \cdot CoD + W_E \cdot CoE \tag{18}$$

where W_D and W_E are the weights of debt and equity, respectively; TR is the tax rate; and CoD and CoE are the costs of debt and equity, respectively.

The cost of debt is computed as:

$$CoD = r_f + DS \tag{19}$$

where r_f is the risk-free rate and DS is the default spread [59].

In the context of renewable energy projects, project finance has recently been gaining increased popularity [60], where a special purpose vehicle (SPV) is established and the project is ring-fenced from its sponsors [61]. Such SPVs are generally unlisted entities and their default spreads cannot be computed based on traded securities [62]. To compute the SPV default spread, various elements of the project's risk should be assessed and incorporated [63]. One of the most important risks for renewable energy projects is the risk of the default of the off-taker [20]. In a lower-income country, the off-taker is the state or a state-owned entity. We assume that the risk of sovereign default is equivalent to the risk of default of the off-taker on its power purchase commitments [20]. Additionally, based on Angelopoulos et al. [64], we adopt a simplified representation of the SPV default spread

that assumes it is equal to the sovereign default spread of the state where the project is executed, DS_s, and a generic renewable energy project spread, DS_r:

$$DS = DS_s + DS_r \tag{20}$$

Damodaran from New York University maintains a consistent database for country default spreads [65]. We set DS_s based on this, and we assume $DS_r = 2\%$ [20].

Additionally, we assume that debt is raised in US Dollars (USD) and all cash flows are calculated in USD. Therefore, the risk-free rate, r_f, corresponds to that of the USD. We set it equal to the average of a 10 year US treasury bond in 2019.

In the context of the European energy companies, promised equity IRRs for renewable energy investments (IRR_e) are published. They range from 7% to 16% [41–44,66,67]. To compute the CoE, we consider these equity IRRs and adjust them by a country risk premium, CRP [59]. Damodaran provides a comprehensive list of country risk premia that we use to compute the CoE accordingly:

$$CoE = IRR_e + CRP \tag{21}$$

Using country-specific tax rates [68] and a $W_D = 80\%$ [69], the WACC of the PV project, i_r, can be computed.

The proposed guarantee mechanism, if successful, isolates the renewable energy project from the country's risk of default. Therefore, the CoD and CoE are assumed to be reduced by the state default risk spread, DS_s [20].

In contrast to the renewable energy project, the upstream project is not directly affected by the risk of default. In a typical PSC, the investor is responsible for all the investments and shares the revenues with the state [25]. Therefore, the investor is not expecting any payments from the state that will be foregone if the state defaults. Therefore, we use the declared internal rates of returns for upstream investments for the European energy companies as proxies for the upstream project investor discount rate i_u. These IRRs range from 14% to 20% [42,67].

3.2.3. Upstream Gas and Renewable Energy Estimates

We perform the Monte Carlo simulations using Python and making the following assumptions:

The lives of both the PV project and the upstream gas project are set to 25 years based on typical situations [70]. Both projects run in parallel, and we assume that at year 1, the final investment decision is made for both. By then, the main uncertainty that remains unresolved is the future natural gas prices. We assume that the first period in the simulation corresponds to the year 2023.

Country-specific yearly natural gas prices are randomly generated based on point forecasts and standard errors computed from the ARMA model. The base price used to determine the economics of the upstream project, P_b, is randomly chosen per simulation from the set of generated yearly prices.

The below table (Table 3) summarizes the parameters that are kept constant throughout the simulations and are assumed the same for all the countries considered.

Table 3. Parameters kept constant for all countries.

Parameter	Value
PV	
Years of construction	1
W_d (Weight of debt)	80%
DS_r (Default spread of RE projects)	2%
r_f (USD risk free rate)	2.14%
Upstream	
Years of construction	5
State	
State discount rate [a]	11%

[a] Based on the typical discount rates in developing countries [71].

For all countries, the IRR_e and i_u parameters are assumed to follow uniform distributions with the following ranges:

$$IRR_e \sim U(7\%, 16\%) \tag{22}$$

$$i_u \sim U(14\%, 20\%) \tag{23}$$

The remaining simulation parameters are specified at the country level and are fully described in Sections S3–S6 of the Supplementary Materials.

4. Results and Discussion

For each of the considered countries, we perform a Monte Carlo simulation with 10,000 runs and report the average values. We present below two categories of results:

- The effectiveness of the guarantee mechanism in protecting against the risk of off-taker default;
- The benefits that the considered countries achieve from the proposed integrated energy contract.

4.1. Guarantee Protection

When determining the size of the guarantee available, the company assumes a certain future natural gas price, P_r. As described in Section 3, this price can be set by applying a reduction rate r on the gas price used in assessing the upstream gas project, P_b such that $P_r = (1 - r) \cdot P_b$. With increasing r, the company reduces the probability that future gas prices drop below P_r and increases the probability that the future state Profit Gas is enough to compensate for the lost electricity payments in case of the default of the off-taker. To illustrate the effect of r on the protection that the guarantee mechanism provides, we run the Monte Carlo simulations across the 15 countries for $r = 0\%$ (assuming that the future natural gas markets will behave in line with the company view), $r = 25\%$ (accounting for limited disturbance to the future gas markets), and $r = 50\%$ (considering larger negative shocks to future natural gas prices that might be caused by accelerated reductions in renewable energy costs or stringent policy decisions on the usage of fossil fuels). Figure 2 displays the spread of the average protection level PL per country across the 15 countries considered for different values of r. As earlier described, PL refers to the share of the net present value of all the electricity payments stipulated in the agreement that the company ends up recovering through the guarantee mechanism if the off-taker defaults at the worst timing of default. In this case, the company gets, on average, a very high protection level exceeding 96% for all 15 countries when r is set to 50%. The protection levels drop considerably, to as low as 70%, when r is set to 0%.

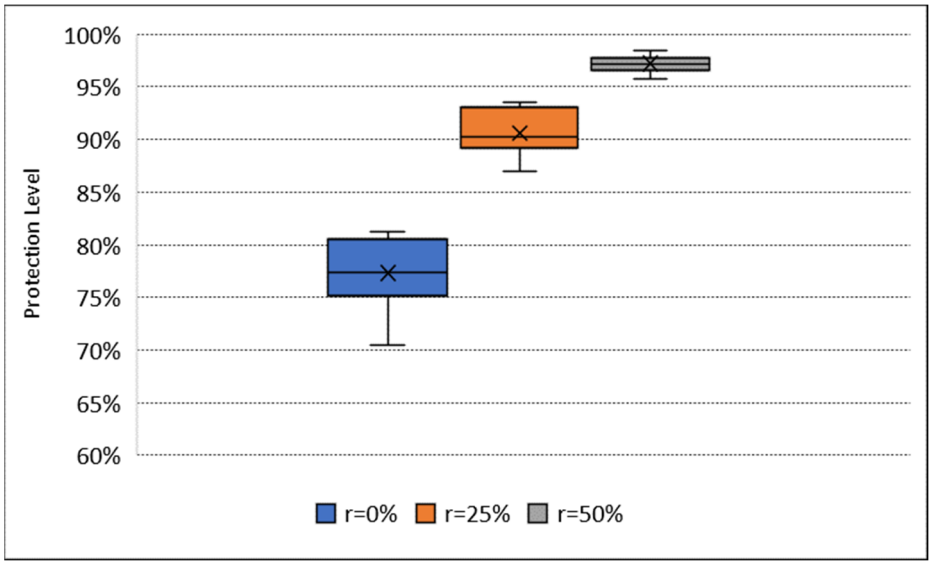

Figure 2. Protection levels for different values of r across the considered countries.

Given the importance of ensuring a high protection level to attract company investments, we report country-level results in the next sub-section based on $r = 50\%$.

4.2. Country Results of the Integrated Energy Contract

The proposed integrated energy contract can result in substantive additional renewable energy capacities at reduced levelized costs of energy (LCOE) (Figure 3).

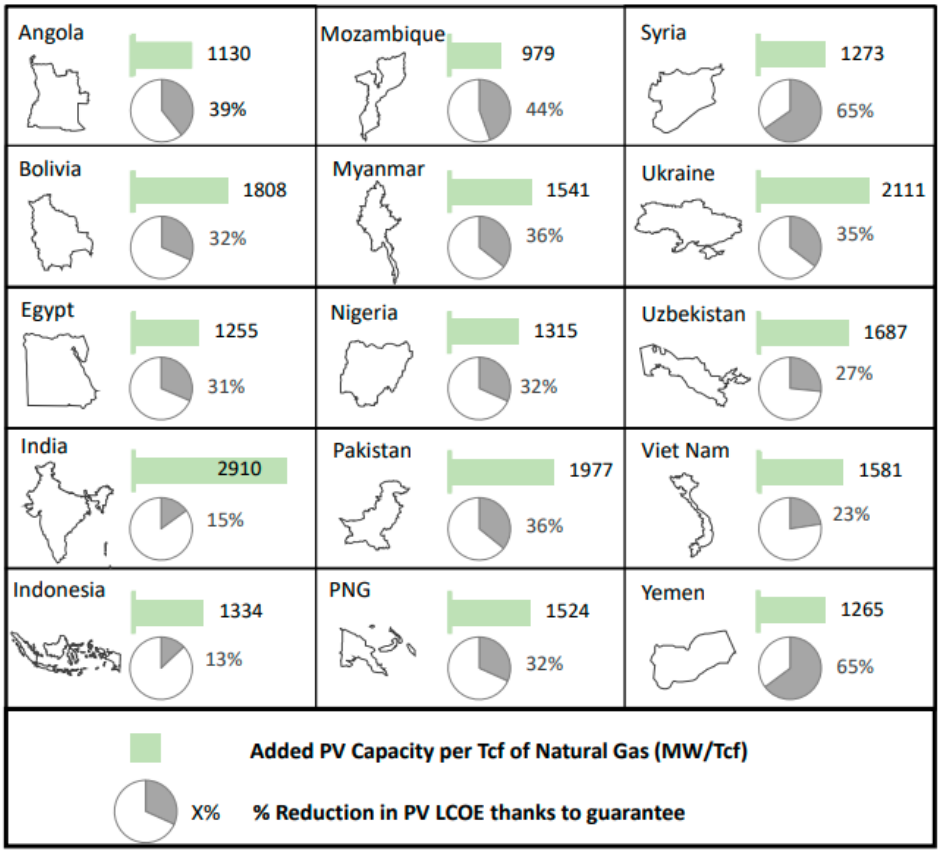

Figure 3. Added PV capacity per Tcf of natural gas and % reduction in PV LCOE across the 15 considered countries.

India leads the list in terms of added PV capacity per Tcf of natural gas developed through the integrated energy contract. The drivers of increased capacities are improved upstream conditions and reduced PV costs in the respective markets. Upstream conditions are dependent on the costs of laying down the gas infrastructure and the country-specific prices of natural gas at the end of the upstream infrastructure. The proposed guarantee mechanism is assumed to reduce the renewable energy WACC by the country default spread. The largest reductions in PV LCOE are observed in countries with high risks (and high default spreads), as is the case with Yemen and Syria. Indonesia and India sit on the other side of the spectrum with relatively limited cost reduction benefits of 13% and 15%, respectively (the absolute LCOEs with and without the guarantee mechanism are provided in Section S7 of the Supplementary Materials). The reductions in LCOE after de-risking the PV investments are generally consistent with previous findings [20]. The results also reinforce the established conclusion in the literature that the discount rate has a major impact on the economics of the PV investments [16,17,19].

When 10% of the proven natural gas reserves of each country are assumed to be awarded through the integrated energy contract, the effect on the national energy context is different by country (Table 4). Among countries that published renewable energy capacity targets for 2030, Nigeria, Myanmar, and Indonesia can achieve at least 60% of their target added capacities thanks to the integrated energy contract and to their considerable natural gas reserves. In contrast, despite being at the top of the list in terms of added PV capacity per Tcf of natural gas, India can barely achieve 4% of the target added capacity because of its relatively limited natural gas reserves compared to its renewable electricity capacity needs.

Table 4. Simulation results for added PV capacity and upstream investment success rate by country.

Country	Added PV Capacity (MW)	% of 2030 RE Target Capacity Additions Achieved	% Increase in Total Electricity Capacity	Positive FID Rate
Angola	1369	32%	23%	49%
Bolivia	1934	NA	55%	55%
Egypt	7904	NA	13%	48%
India	14,187	4%	3%	76%
Indonesia	6635	60%	9%	64%
Mozambique	9792	NA	336%	31%
Myanmar	3467	65%	47%	76%
Nigeria	26,762	70%	203%	61%
Pakistan	4135	NA	10%	85%
PNG	985	NA	95%	72%
Syria	1082	NA	13%	53%
Ukraine	8235	NA	14%	81%
Uzbekistan	10,965	NA	68%	66%
Viet Nam	3906	NA	6%	79%
Yemen	2138	NA	110%	55%

Focusing on countries with low access to electricity, major increases in total electricity capacity can be achieved for Mozambique (336%), Nigeria (203%), Yemen (110%), Papua New Guinea (95%), and Myanmar (47%). These additional capacities can majorly contribute to bridging the existing gap in electricity generation in these countries.

To undertake the renewable energy investments, the company must be convinced that the upstream project is economic. The last column in Table 4 shows the percentage

of total simulation runs where a positive final investment decision (FID) is reached on the upstream investment. This rate ranges from 31% in Mozambique to 85% in Pakistan.

4.3. Discussion

The simulations show that the integrated energy contract can provide specific benefits to specific countries and is not equally suitable or useful across the board. Countries such as Syria and Yemen have more serious problems related to the war situation that hinders investments. The integrated energy contract can become handy to these countries just after the security situation stabilizes and can play a role in heavily de-risking post-war development efforts in renewable energy. Large countries with relatively limited natural gas reserves (such as India and, to a lesser extent, Pakistan) can only marginally benefit from the integrated energy contract despite having the highest additions of PV capacities per Tcf of natural gas. This is the case because the total added PV capacities when 10% of their natural gas reserves are developed contribute little to their total electricity capacities or 2030 target renewable energy additions. In contrast, countries with large natural gas reserves relative to their population size (such as Indonesia and Nigeria) can offer a strong boost to their renewable energy sector using the integrated energy contract which can potentially be the main success enabler in reaching their green energy targets.

For countries with low access to electricity (such as Mozambique, Myanmar, and Papua New Guinea), the integrated energy contract can be the main enabler for bridging the electricity production gaps. Noting that overcoming the problem of low access to electricity also requires investments in transmission and distribution networks, and the scope of the integrated energy contract can be expanded to cover them whenever suitable.

The integrated energy contract can only succeed if the upstream investment environment is favorable. Upstream development costs and gas prices are key factors that determine whether the economics of the upstream projects match the company's expectations. In the simulations we conducted, positive FID rates are generally higher for countries in the East and South Asia regions since natural gas prices in these regions are relatively closer to the prices in Japan, which are, globally, the highest.

5. Conclusions

Despite not being the main inducers of climate change, lower-middle-income and low-income countries are among the most affected by its negative consequences. They possess limited mitigation capabilities as they generally suffer from unfavorable green investment conditions due to high perceived country risks. Fifteen of these countries possess considerable natural gas reserves that they aim to use to induce economic development. They, however, risk getting stuck in carbon lock-ins as they further gasify their economies, which conflicts with their declared commitments to carbon emission reductions and renewable energy additions.

To the best of our knowledge, this paper proposes, for the first time, an integrated energy contract that allows these countries to de-risk renewable energy investments by bundling them with upstream natural gas investments, such that the state future returns from the natural gas project guarantee the electricity payments of the renewable energy project. Integrated energy companies expanding their interest from oil and gas to the wider energy sector are the target audience for the proposed contract. To illustrate the use cases of the integrated energy contract, we design and conduct a series of Monte Carlo simulations for the considered countries, assuming that a limited portion of 10% of their natural gas reserves are developed and that the renewable energy technology of choice is PV.

The integrated energy contract provides companies with protection levels exceeding 96% on their future electricity payments if the electricity off-taker defaults. This high protection level reduces the risks of the renewable energy project and therefore the associated WACC. This, in turn, drives the LCOE of the PV electricity down to differing levels depending on the level of risk that each country is subject to. Setting the size of the PV investment based on the future cash flows of the upstream natural gas project results

in different additions of PV capacity by country, depending on the sizes of the natural gas reserves and the competitiveness of the produced natural gas. The integrated energy contract can constitute a strong de-risking tool for post-war investments in the renewable energy sector for countries such as Syria or Yemen, can boost the renewable energy sector and majorly contribute to achieving the 2030 renewable energy targets for countries such as Nigeria and Pakistan, and can be a main contributor to bridging the electricity access gap for countries such as Mozambique, Myanmar, and Papua New Guinea.

We believe that the introduced integrated energy contract contributes positively to the two objectives of the lower-income countries: inducing economic development and supporting the green energy transition. It also tackles the concerns of the energy companies and provides them with lucrative investment opportunities aligned with their low-carbon energy strategies.

The study has the following limitations. The feasibility of the proposed contract is based on the commerciality of the upstream natural gas investment. While for the considered countries, the continued presence and interest of international energy companies indicate positive prospects for their natural gas sectors, the future dynamics in light of the structural changes in the global energy sector remain unclear. This constitutes a limitation to our work that can only be addressed by considering the detailed upstream natural gas national context of each individual country. In our simulations, we use the same stylized PSC design across the 15 countries without accounting for the specific details of the fiscal regimes by country. Finally, we restrict the choice of renewable energy technology to PVs and we do not deal with other capital investments required in the transmission and distribution networks.

Our future work could resolve one or more of the limitations of this study. Particularly, incorporating country-specific upstream fiscal regimes and understanding their effects on the feasibility of the proposed integrated contract is worthy of consideration. Additionally, expanding the renewable energy technologies to wind and biomass could be important to align the integrated energy contract with the technology-specific plans set by the countries for their renewable energy targets. Addressing the important interlinkages between natural gas, renewable energy, and the hydrogen economy in the context of developing countries is also left for future considerations.

Supplementary Materials: The following supporting information can be downloaded at: https://www.mdpi.com/article/10.3390/en15051651/s1, The Supplementary Materials are organized as follows: Document S1. (Supplementary Materials) describes how all the simulation data was populated and provides additional references. It is composed of eight sections as follows: Section S1, Electricity Status; Section S2, Upstream Activities; Section S3, PV Parameters; Section S4, Natural Gas Hub Prices; Section S5, Natural Gas Country Prices and Upstream Costs; Section S6, Default Spreads, Country Risk Premia and Taxes; Section S7, Country LCOEs; Section S8, Upstream Country Descriptions; Section S9, References. References [72–133] are cited in the supplementary materials.

Author Contributions: Conceptualization: M.O. and H.A.; methodology: M.O. and H.H.; software: M.O. and H.H.; validation: M.O., H.H. and H.A.; formal analysis: M.O. and H.H.; investigation: M.O. and H.H.; data curation: M.O. and H.H.; writing—original draft: M.O. and H.H.; writing—review and editing: M.O., H.H. and H.A.; visualization: M.O. and H.H.; supervision: M.O. and H.A.; project administration: M.O. and H.A. All authors have read and agreed to the published version of the manuscript.

Funding: Open Access Funding by TU Wien Bibliothek.

Data Availability Statement: The Python and R codes along with their input data files are provided in the submitted zipped folder.

Acknowledgments: The authors acknowledge TU Wien Bibliothek for financial support through its Open Access Funding Program. The authors thank Anis Hoayek for his guidance and support.

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

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