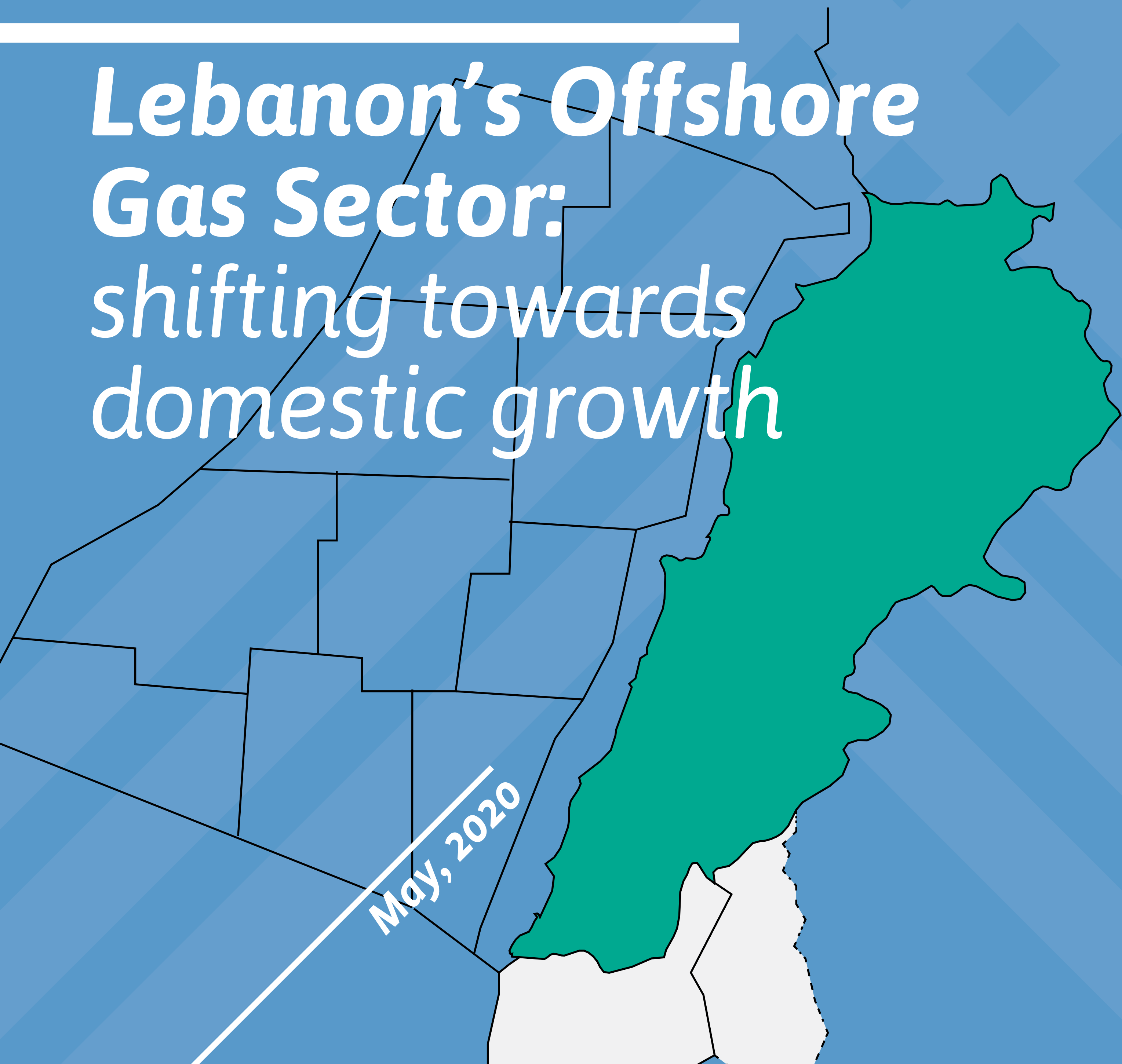
Lebanese Oil & Gas Initiative

المبادرة اللبنانية للنفط والغاز

# Lebanon's Offshore Gas Sector: *shifting towards domestic growth*



May, 2020

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# Lebanon's Offshore Gas Sector:
## *shifting towards domestic growth*

**Disclaimer:**

This model developed for LOGI and Kulluna Irada by OpenOil in cooperation with the Heinrich Boell Foundation, Beirut Office (HBS), and is meant to be used to help citizens assess the fiscal terms included in the Exploration and Production Agreements for 1st and 2nd licensing rounds.

Any conclusions, recommendations developed by citizens from using this model, reflect his/her opinion(s) and do not represent LOGI and HBS's positions.

LOGI's recommendations are expressed in the policy brief developed by LOGI and based on the findings presented by Open Oil in the following narrative published by them.

*Commissioned by:*
Lebanese Oil and Gas Initiative (LOGI) and Kulluna Irada (KI)

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HEINRICH BÖLL STIFTUNG
BEIRUT
Middle East

*Prepared by:*
Johnny West, Open Oil

# Executive Summary

Lebanon's hopes to develop an offshore gas sector were delivered a blow in April 2020 when the first offshore exploration well, drilled by Total and its partners, came up dry. The country is still hoping to join the club of East Mediterranean gas producers, despite the collapse of gas prices alongside crude oil prices in early 2020, the devastation wrought to the global economy by Covid19, and an oversupply of LNG, together with a long pipeline of new projects due to come on stream in the next few years.

OpenOil has carried out financial analysis of the potential of the sector for the Lebanese Oil and Gas Initiative (LOGI), which yields the following main findings:

- The deals negotiated in the first bid round, signed in 2017, show an average government take (undiscounted) of 56% across Blocks 4 and 9. This is roughly in line with the results reported by the government (using a real discount rate of 5%), and fall in the middle of the curve of government take metrics for similar circumstances.

- Tax contributions from the offshore gas sector cannot be transformative for Lebanon's distressed public finances. Even taxes from a large field might peak at only 3% of the annual budget for a couple of years in the 2030s. Gas is not a silver bullet.

- Likewise, the sector is unlikely to provide a basis for further sovereign debt. The net present value of the government's share of a large (10 trillion cubic feet) field might represent one year's servicing of current debt of $80 billion. The question of extra debt required to fund direct state participation should also be carefully considered.

- With prospects closing of an export pipeline to Europe, even for a significant discovery, and geopolitics dogging regional project possibilities, development of any discovery is more likely to be led by LNG and / or the domestic market.

- International investors are unlikely to commit to developing a field unless they believe they can secure an average price at least $5 / mmBTU (in real terms) – more than twice the price of LNG today in all three traditional regional markets.

- Nevertheless, given the critical state of Lebanon's power sector, a national gas project could have significant impact on the economy, particularly as the sector is currently heavily subsidised and expensive because it relies on fuel imports to generate electricity. But investors would likely need a lot of reassurance to develop a project that was locked into the domestic market, and there would be a natural cap on demand, possibly of between 10 tcf and 15 tcf.

- Bidders in any second round will likely bid lower now compared to the offers of the first round. This could lead to difficult choices for the government.

1 *https://www.reuters.com/article/us-lebanon-economy-oil/lebanon-to-restart-oil-gas-licensing-round-after-three-year-delay-idUSKBN14Q049*

2 *https://www.executive-magazine.com/economics-policy/the-saga-of-lebanons-first-licensing-round*

3 *https://logi-lebanon.org/KeyIssue/lebanon-oil-gas-decrees*

4 *https://www.reuters.com/article/us-lebanon-economy-electricity/fixing-lebanons-ruinous-electricity-crisis-idUSKCN1RA24Z*

5 *https://monthlymagazine.com/article-desc_4752*

6 *https://www.thenational.ae/world/mena/lebanon-minister-hopeful-about-plan-for-24-7-electricity-by-next-year-1.848562*

# Background

## Development of the Eastern Mediterranean

Lebanon's efforts to explore its offshore potential go back as early as 1993 when the first two-dimensional seismic surveys were undertaken. However, Lebanon has been battling to put required legislation in place and – almost as important – getting its offshore borders defined with its neighbours.

The country's offshore is located in the formation of the Levant Basin, which stretches across Lebanon, Israel, Syria, and Cyprus. In its first offshore bid round in 2017, three of the five blocks Lebanon opened for bidding were in disputed zones with Israel. It was only in 2007 when Lebanon reached an agreement with Cyprus, while the border with Israel is still in dispute.

The country has taken a decade to put in place the governmental structure and legal framework to properly open it's offshore blocks to bidding. As a milestone, Lebanon Offshore Petroleum Resources Law (OPRL) was ratified in 2010, determining important aspects as prequalification criteria, and the bidding and evaluation process.

However, the Lebanese Petroleum Administration – in charge of licensing – was only established in December 2012. Companies were soon called to participate in the pre-qualification round in 2013 but the political context[1] - the country stayed without a president for more than two years- put the brakes to the process for almost four years[2].

Finally, by January 2017 the two decrees the industry was waiting for were passed: one pertaining to block delineation and the other to the Tender Protocol and model Exploration and Production Agreement (EPA), without which no company could bid for rights to explore for oil and gas in Lebanese waters[3] . From there on the bidding processes were fully launched and Lebanon awarded its first two blocks in late 2017.

**7**

*https://en.annahar.com/article/850746-analysis-electricity-in-lebanon-understanding-the-real-problem*

**8**

*https://www.energyandwater.gov.lb/mediafiles/articles/doc-100515-2019_05_21_04_27_25.pdf*

**9**

*http://www.mdpi.com/1996-1073/9/8/583/pdf*

**10**

*https://oec.world/en/profile/country/lbn/*

## Lebanon's Electricity Crisis

The Lebanon electricity crisis is a mixture of old infrastructures, prices stuck on values from the 1990s, and constant increase in demand. The main power plants have an average capacity of just over 2,000 megawatts (MW), while peak demand reaches 3,400 MW[4]. Different sources[5] of data points[6] at a shortfall of at least 1500MW- 1800MW[7-8].

The electricity is solely provided by the state-owned Electricite du Liban (EDL) and consumer prices for electricity have been frozen since 1994[9]. Attempts to reform pricing have been hindered by the sensitive political nature of the topic. Some regions report only 14 hours electricity supply a day, and the power crisis was one of the catalysts that triggered the country's street protests in late 2019.

The development of Lebanon's oil and gas industry has the potential to mitigate its electricity crisis and change its high dependence on hydrocarbons imports. In 2017, petroleum represented 18% of total imports and costed the country $3.77 billion[10], around 7% of Lebanon total GDP[11].

**11**

*Own calculation based on https://countryeconomy.com/gdp/lebanon numbers for 2017*

According to the IMF[12], the electricity sector in Lebanon is a major drain on the country's budget. The accumulated cost of subsidising EDL amounts reaches 40 percent of Lebanon's public debt, or over $30 billion.

The use of gas in the feedstock is minimal, in contrast with the region. Lebanon's main electricity source is still liquid fuel products, and some hydro, while in 2017, natural gas provided all the electricity generated in Bahrain and Qatar, and more than 95% in the United Arab Emirates and Oman. In Iran and Jordan, natural gas's share in electricity generation reached over 80% in 2017, according to data from The International Energy Agency[13] report published in 2018. [14]

12

*https://www.imf.org/~/media/Files/Publications/CR/2017/cr1719.ashx*

13

*https://webstore.iea.org/download/direct/2710?fileName=World_Energy_Balances_2019_Overview.pdf*

14

*IEA data*

15

*Article 24*

# Lebanon's Bid Rounds

## First Bid Round 2017

The emerging petroleum and gas sector in offshore Lebanon reached a milestone in February 2018 when by the first time in history - and amid struggles to attract investment and numerous delays- the country awarded two of its discovered block fields ( 4 and 9 ) to a consortium composed by three main industry players: Total S.A, ENI, and Novatek.

On its first offshore bid round, Lebanon opened five blocks for bidding (1,4,8,9 and 10) three of them stretched in disputed zones with Israel, and carried out two pre qualification rounds, one in 2013 and one in 2017. In total, more than 60 companies submitted requests, 54 of those succeeded in pre qualifying. However, to the disappointment of the government, only the winning consortium submitted a formal bid.

In the country's first signed Exploration and Production Agreements (EPA) a stability clause was present, however market obligations were somewhat open to discussion. As for fiscal regime:

| *Topic Major Fiscal Terms, Biddable and non-biddable, in the First Licensing Round 2017* | |
|---|---|
| Royalties | Not biddable. Equal to 4% of the gas produced, and a varying percentage (between 5% and 12%) of the oil produced. |
| Profit split | Biddable within R factor[15]. The minimum share of the State starts at 30% and then rises to a maximum of 55% (Block 4) and 40% Block 9 when the R Factor (the total of all income in the project over all outgoing payments) reaches 2.5. |
| CIT | 20%[16] |
| Cost Recovery Limits | Biddable, ceiling is 60% in Block 4 and 65% in Block 9[17] |

To mention unlimited carry forward losses[18], and stability clause are part of the contract, withholding tax on interests, taxed at a rate of 10%[19].

16

*as law 57/2017: Tax Provisions related to petroleum activities http://www.databank.com.lb/docs/Briefing%20of%20Lebanese%20Petroleum%20Activities'%20Tax%20Law%20No.%2057.pdf*

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*14.6. TP*

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*https://www.lpa.gov.lb/Library/Assets//Gallery/asdasdas/Brochures/Lebanon%20second%20offshore%20licensing%20round%20leaflet.pdf*

19

https://uk.practicallaw.thomsonreuters.com/1-630-4231?transitionType=*Default&contextData=(sc.Default)&firstPage=true&bhcp=1*

## Second Bid Round – 2020?

The second bid round, originally scheduled to close in January 2020, was extended until April 2020, and then postponed without date in the wake of the outbreak of the coronavirus pandemic. Three in the south (Blocks 5, 8 and 10) and two in the north, near the border with Syria (Blocks 1 and 2). Block 8 lies mainly in waters disputed with Israel[20].

20

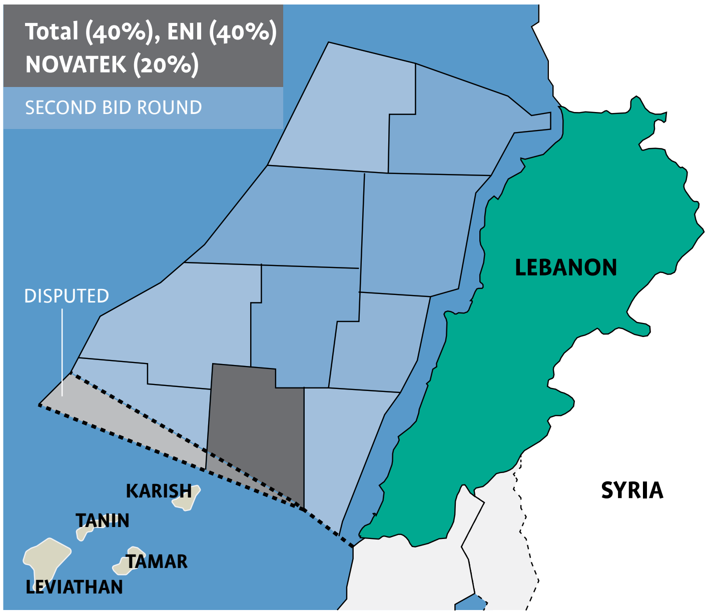
https://www.mees.com/2019/3/1/oil-gas/lebanon-nears-gas-exploration-kickoff/253e4060-3c3e-11e9-82fe-9fc40ce77fd0

Unlike the first bid round, prequalification of companies and bidding will be done at the same time. While the first bid evaluation round took around 10 months (February-October 2017)[21] the plan is for the second round evaluation will be wrapped up in five months from the deadline for submission.

The evaluation of prequalification applications and the consequent results publication are expected to take place in the first weeks of May 2020. The Council of Ministers would be expected to approve the licensing by mid-July 2020.

For pre-qualification criteria for the second round, operators are now required to have operated on petroleum developments at water depths exceeding 300m, not 500m as was previously requested.

It also appears that the loophole that was inserted in the initial pre-qualification decree – which allowed companies with no prior experience in the sector to qualify by partnering with companies that meet the criteria – was removed[22].




The Model Exploration and Production agreement (EPA) published as the basis for bids in the second round was slightly modified from the first round. Articles 5, 6, 7, 8, 9, 20, 21, 25, 27, 30, 36, 44 and Annex D (Accounting and Financial Procedures) were amended.

One significant change is in state participation. While in the first bid round, the government openly claimed no-state participating interest was expected, for the second bid round that statement was removed. Although there is no clear mention of what state participation will be expected this time. The Offshore Petroleum Resources law leaves the door open for a State Participation to be added in the EPA[23].

**21**

*and concluded with a ceremony on February 2018 awarding the Consortium Total-Eni-Novatek of block 4 and 9.*

**22**

*https://www.mesp.me/2019/04/05/lebanon-launches-its-second-offshore-oil-gas-licensing-round/*

**23**

*https://www.lpa.gov.lb/Library/Assets/Gallery/asdasdas/Laws/OPRL%20-%20English.pdf Article 6. State Participation.*

# Modelling Methodology

The accompanying model to this report is a static, deterministic Discounted Cash Flow model that follows the FAST methodology[24]. The provenance of all inputs and assumptions which have been taken from primary sources where possible, are marked and linked to a source sheet in the Excel workbook with citations.

Lebanon published the two production signed agreements it signed with the consortium led by Total in 2018, so the full text has been available for fiscal interpretation. Data for project economics, such as capital and operating expenditure, is more speculative in two senses. First, there are almost no data about Lebanon's offshore, since only one well has been drilled and no commercial discoveries developed. This means, from a modelling perspective, that the public statements of the companies have to be parsed for general indications, and projections made using generic industry approaches and projections. Second, any production lies several years in the future in a market which, even without the extraordinary turbulence of early 2020, is always marked by volatility. So even if project-level data and estimates were available in public domain, they would almost certainly have changed significantly, in some way, by the time a field was developed and went into production. Results from the model should therefore be considered indicative rather than predictive.

Nevertheless, sensitivity analysis within the model allows us to determine that broad conclusions of this report are somewhat robust to changing parameters.

This model follows an open source methodology, and is published under Creative Commons license[25], so that inputs can be freely updated as and when new information comes into public domain.

| *Base Scenario Economic Assumptions in the model* | |
|---|---|
| Exploration | $60 million assumed as cost of one well to meet exploration obligations, and form based of exploration economics calculations; developed field exploration $200 million pre-Final Investment Decision |
| Development Costs | Pipeline-led development $4 billion; FLNG: $1,440 per tonne of LNG pa |
| Operating Costs | Pipeline development: $0.50 per MMscf; LNG development $40 per tonne of LNG |
| Operational Parameters | Exploration three years; Conventional Pipeline development five years; LNG development four years. |
| Price | $6 per mmBTU for base scenario, set as constant in 2020 real terms – user adjustable parameter |

24 https://www.fast-standard.org/about-fso/

25 https://creativecommons.org/licenses/by-sa/4.0/deed.en

| Base Scenario Economic Assumptions in the model | |
|---|---|
| Finance | 2% inflation rate to convert real to nominal; 10% nominal discount rate for government take calculation; project finance not modelled. |
| Decommission | 15% of Capital Expenditure accrued from revenues once 50% of initial reserves are produced. |

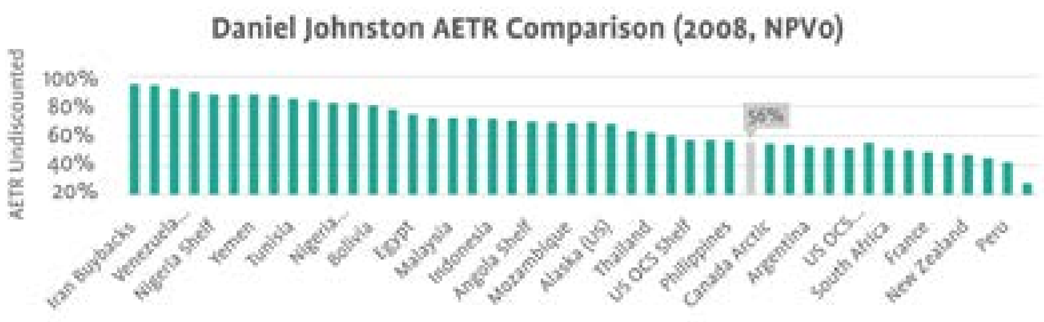
Significant uncertainty around potential costs is likely to endure for a number of reasons. The net impact of Covid19 and the likely global economic recession is hard to project as of mid-2020. In addition, costs for deep offshore projects such as those that would be developed in either Block 4 or 9 vary significantly depending on geology and engineering requirements, making it hard to predict capital costs in a frontier province with no comparable data. Sensitivity analysis within the model allows analysis of outcomes against variations in all major project economics components, including exploration, capital costs, operating costs, overall production, and price.

# Headline Results

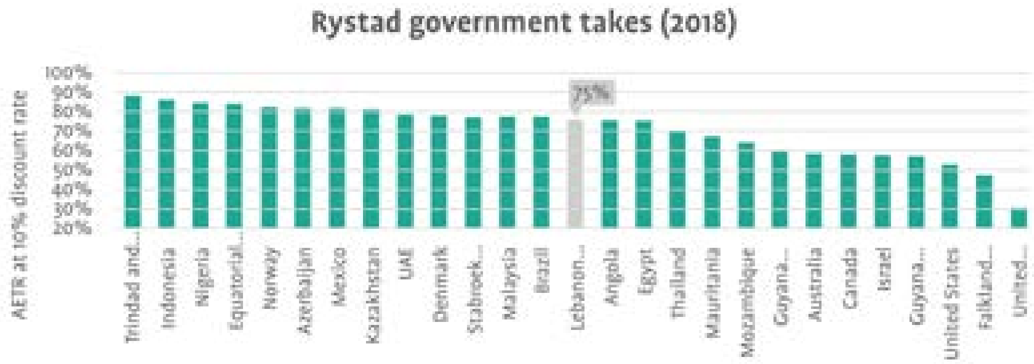
## The Fair Deal Question

One of the most significant questions in management of natural resources is the so-called "Fair Deal" question – did the government secure an agreement that assures an equitable distribution of potential profits in a project between the state and the commercial investors who bid for exploration and production rights. This is a complex area with many interacting factors, some of which are either not quantitative, such as state of development of the sector in the given country and long-term political risk, or not known at the time of negotiation, such as the precise nature of the resource and cost bases in each given project. Nevertheless, public interest drives towards direct apples-for-apples comparison of any agreement signed with the known terms of other agreements elsewhere.

Usually, this takes the form of analysis of "government take", or, as we label it in this research, the Average Effective Tax Rate (AETR)[26] – the percentage of profits the government gets against a base scenario of input assumptions around price, costs, and operational factors.




The model finds that across the two Production Sharing Agreements (PSAs) Lebanon signed in 2017 secure an averaged undiscounted AETR of 56%, which puts it in the middle of the pack of AETR metrics from other countries, as can be seen from the graph above[27]. Given the fact that Lebanon was a frontier province at the time, and the main interest in prospectivity is around natural gas rather than crude oil, this is a reasonable result. [28]




**26**
*AETR is the term of art used by the International Monetary Fund in its FARI analysis and elsewhere, broadly corresponding to what is known as "government take".*

**27**
*The government take metric is highly approximate, and should not be read in an overly deterministic way.*

**28**
*The methodology grouped Blocks 4 and Blocks 9 as one commercial package, given that the same consortium obtained PSAs in both fields in the same bid round and no block-level information on geological prospectivity was available. Some 32 separate government take figures were compiled for each of Blocks 4 and 9, under different field size and price scenarios, then those scenarios which yielded a less than commercial rate of return for the investor were excluded. The higher share of profit petroleum in the terms of the licenses leads to Block 4 averaging an AETR of 61% undiscounted, and Block 9 at 51%.*

*29*

*Governments normally obtain a higher take in discounted calculations than undiscounted for the technical reason that they have no outgoings early in the project to drag their life of project metric down.*

Using a 10% discount rate, the PSAs achieve a government take of 75%. This again, falls in the middle of similar projects, as can be seen by this comparison with government take figures from Rystad, also using a 10% discount rate.

The findings are also broadly consistent with the estimates announced by the government shortly after the deal of 65% to 73% in Block 4, and 55% to 63% in Block 9. This is because the Lebanon Petroleum Authority model used a 5% discount in real dollar terms , which naturally results in a range that stands inbetween the undiscounted ("NPV0") rate and the 10% nominal discount rate ("NPV10"). [31]

Given also a normative degree of transparency in governance of the bid round, the model results in AETR give no reason to suppose that the deals negotiated by the government are inadequate in fiscal terms. [32]

## Differences between Block 4 and Block 9

*30*

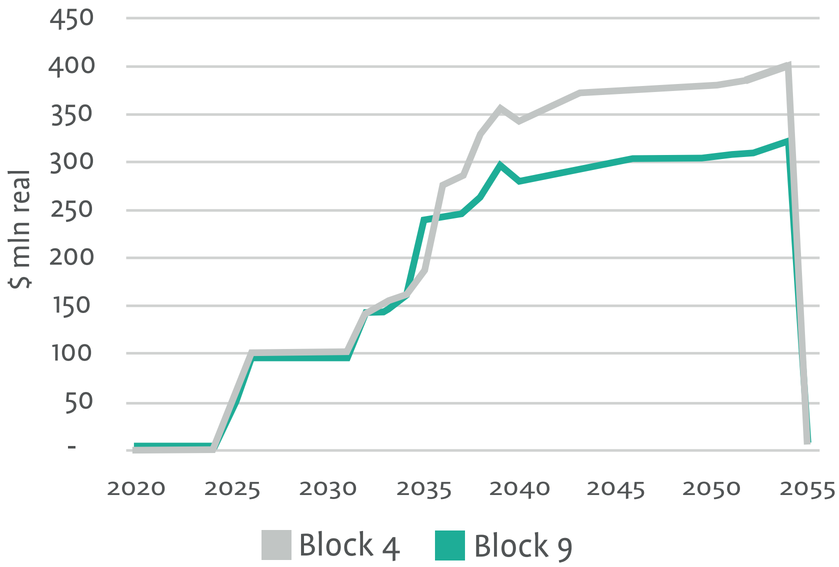
*Government take figures in the same project can vary by as much as 20% depending on project profitability, inclusion or exclusion of inflation (real or nominal dollars), discount rate, and time scoping (life of project or Final Investment Decision forward, for example).*

*31*

*Replicating the LPA's 5% real discount rate in the model yields an average of 61% to 67% for Block 4 and 52% to 57% in Block 9. Although this represents a difference of 4%-5% in each case from the ranges announced by the government, such a differential cannot be considered highly material to the basic conclusion that the deal offers reasonable terms given the NPV0 and NPV10 results, and also the unavailability of the LPA model to check consistency in other inputs and assumptions.*

The terms signed for Block 4 differed from Block 9 in two ways: the cost recovery ceiling agreed was lower (60% versus 65%) and the profit split mechanism had a greater maximum share to the government (55% compared to 40%). These differences lead to a higher yield from Block 4 compared to Block 9, using the same economic assumptions.

**Block 4 vs Block 9**
(From stored values, 3 tcf field $6 mmBTU)




The model shows how these factors lead to higher take at the beginning of the project (where a lower allowance for cost recovery increases the amount of profit oil available), and in the mature phase of the project (where the government achieves 55% profit share, compared to 40%) .

The differences are significant, but fall well within a normal range for different blocks, even within the same bid round. The biggest reason bid offers from investors might differ is normally that their analysis of block level prospectivity is different. There might also be a specific factor in this case, in that Block 9 lies along the southern edge of Lebanon's disputed maritime border with Israel, and a portion of the block lies in waters which are disputed. Regardless of any particular view of that border dispute, an investor would quite naturally accord a higher degree of political risk to a license which overlaid with a dispute between two countries who are still formally in a state of war. This would normally lead them to attach a higher discount rate to their own modelling, and cause them to seek concessions in the fiscal regime, to counteract the higher perceived risk.

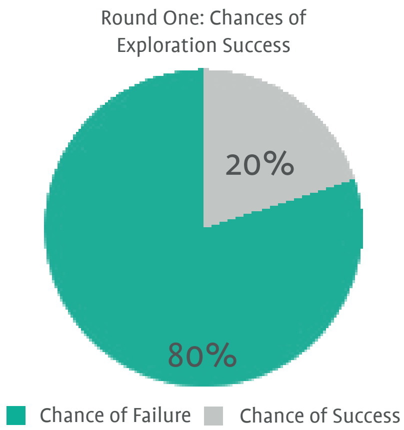
## Probability of Development

The dry hole registered by Total and its partners in Block 4 in April 2020 has dented expectations about development of a petroleum sector in Lebanon. While the PSA for Block 9 prescribes a well to be drilled there, the schedule for that has been pushed back until late 2020 or possibly 2021. Under normal lead time for offshore projects, this means that the earliest any discovery might reach first oil, under the best of conditions, would be after 2025, and significant revenues would not come until after 2030.

### Exploration Chance of Success

Globally, a well drilled in a frontier province like Lebanon (i.e. where there is no existing production) is usually not given more than a 20% "Chance of Success". [34]

It may be that there are reasons for thinking the chance of success in Block 9 is higher than the global average. The LPA for instances reported that geological data sales had reached a total of $43 million, indicating high interest. There is some indication also that the chance of success in the Egyptian offshore may be higher. But in the absence of specific information, it is prudent to assume the global ratio of 20%




Furthermore, the dry well will cause companies to predict a lower chance of success which in turn means potential bidders in a second round will lower their bids. It is only realistic to expect that bids in a second round will likely be similar to that made for Block 9, or perhaps lower, rather than the higher terms offered for Block 4. The government could then be faced with a difficult decision about whether to accept such bid terms, since the resulting deals would yield lower government takes than comparison with most historic contracts in peer group countries.

## Development Options: LNG or Pipeline

If offshore gas is found, it could be developed either by a pipeline running to shore, or by installing a floating liquefied natural gas plant (FLNG). The production profiles of each kind of development result in different profiles of revenue to the government, as can be seen from the graph. With an LNG development, production is geared to the maximum capacity of the processing plant, creating a flat production profile, whereas no such cap exists with a pipeline, meaning that the company will seek to produce and sell as much gas as early in the life of the project, to up the commercial rate of return.

Government revenues are downstream of the production profile set by investors, so these different development paths naturally create different revenue profiles for the

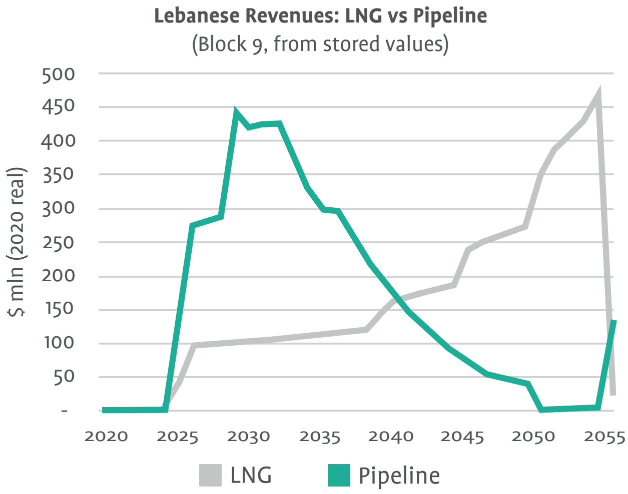
32 *Though the fact there is no public information about block-level prospectivity must remain a heavy qualification on this finding.*

33 *Interestingly, there is one year where Block 9 achieves higher take since the higher cost recovery allows completion of recuperation of expenses from the capital development phase earlier in Block 9, and a corresponding rise in the R-factor, on which the profit share is calculated.*

34 *Note that this refers not merely to the physical presence of hydrocarbons, but presence in enough quantity, and accessible enough geologically, to enable a commercial project to go ahead.*

35 *Investors generally measure the profitability of an investment in Net Present Value against a discount rate. The same amount of gas sales and production over the life of a project can yield very different results in the NPV metric, depending on how much is produced when. This is based on the "time is money" principle.*

state. The graphic demonstrates what would happen in Block 9 with a three trillion cubic feet field, if it is developed in either way. With LNG, the flat production profile means it takes longer for the investor to recover the initial costs of building the field, so in turn all government revenue streams other than royalties are pushed low until well into the life of the project. With "conventional" development, production is pushed to a plateau as soon as reservoir management allows it, to recoup costs and go into profit.




The LNG market has developed fast in the last decade, along with FLNG. Although the different production profile offers lower rates of return in larger fields and with high gas prices, development costs are coming down, and lead times are shortening globally[36] resulting in smaller viable field sizes. An LNG solution would also tie into proposed plans to build LNG regasification plants at power plants in Lebanon to increase the supply of feedstock gas into the electricity grid to help address chronic power shortages.

## 2020 Market Constraints

The discussion above handles the technical aspects of either development path, LNG or a more traditional pipeline. But the Total-led consortium have to consider those options against real market conditions. As of mid-2020, these are characterised by several elements:

- **Gas convergence:** the different regional markets for gas that have existed in Asia, Europe and the USA seem to be converging towards a spot market, at least for LNG, for the first time.

- **Price Collapse:** But this is happening at the same time as prices have fallen through the floor. Sharply higher prices in Asia have come down to levels close to the USA, and even there prices have collapsed below $2 per mmBTU. To put this in perspective in the East Mediterranean region, Egypt has been offering gas at $5 / mmBTU and finding no buyers.[37] There is thus a big gap between current spot prices and the levels needed to sustain gas projects long-term.

- **Structural Oversupply:** although the Covid19 pandemic has accentuated the gap between demand and supply, oversupply of LNG is structural and has been building up over the past few years. Many more LNG projects around the world are already being built, making it probable that supply will outstrip demand growth globally through the 2020s.

- **Pipeline to Europe is unlikely:** The possibility of an export pipeline to Europe, which could deliver high rates of return, is now remote for two reasons (even if there were a big enough discovery to justify commercial development). First, the politics of

36 *E.g. LNG Plant Cost reduction 2014-2018, Oxford Institute of Energy Studies https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/10/LNG-Plant-Cost-Reduction-2014–18-NG137.pdf*

37 *"Economic Implications of Low Oil and Gas Prices on East Med Gas Resources", presentation by Charles Ellinas in webinar, May 11, 2020*

the region have evolved in a way which makes it more rather than less challenging geo-politically. In early 2020 alone, Turkey declared it needed to be consulted on any pipeline route running to Europe, and Israel, Greece and Cyprus declared a rival pipeline project. Second, there is increasing evidence that the European Union has changed its approach to potential gas supply from the Middle East, reacting to the global glut, and also progressing energy transition policy to reduce reliance on all fossil fuels long-term, including gas.

• **Geopolitics clouds prospects for regional projects:** Turkey could constitute a potential export market in theory, with the Turkish coastline being only about 400 km north of Block 9. But the route of the pipeline would be challenging: it could not pass from Cypriot into Turkish waters, so would have to run through Syrian waters. Apart from the fact Lebanon and Syria have no agreed maritime border, Syria's ongoing civil war presents highly challenging conditions in which to build major infrastructure. The fast changing operational of the East Mediterranean should also be taken into account. In the last decade, as Lebanon prepared to bid out blocks, 60 tcf or proven reserves have come online from fields now producing in Egypt (Zohr) and Israel (Leviathan and Tamar).

• **A local pipeline could be challenging:** a local pipeline to Lebanon would cost less but likely be challenging to agree with international investors, since the state-owned Lebanese electricity company EDL would then be the main, perhaps even the only customer, and it, and the Lebanese state are currently bankrupt. Although there is a policy discussion about potential reform of the energy sector, Lebanon's high public debt, a large portion of which was directly incurred by EDL, would likely make investors cautious about committing to a large scale project whose revenues depended on the health of Lebanon's public finances.

• **Competition from Renewables:** scaled solar installations are increasing across the Middle East region and, as elsewhere, becoming more competitive with fossil fuels.

What these considerations add up to, then, is the idea that, one way or another, there is a natural ceiling to finding actual markets for any gas that was discovered, even in large quantities.[38] This will be significant in the discussion about the potential scale of contribution of a sector in Lebanon to public finances.

## Breakeven prices and field sizes

The breakeven price for any size field is high above LNG spot prices in the first half of 2020. For a 3 trillion cubic feet development, a minimum of $5.07 per mmBTU would be needed to hit a 10% rate of return, and even this would require appreciation of price in the years to come in nominal terms. Because of the flat nature of the LNG production profile, this breakeven price does not come down much even with bigger field sizes, because a larger corresponding capital investment to develop the field is being balanced out against production which is still capped at the maximum throughput of the LNG facility, albeit at a higher level. So breakeven drops only a few cents to $4.93 per mmBTU for a 5 tcf field and only to $4.82 for a giant 10 tcf field.

In theory, development of a big enough field using a pipeline could yield radically more profitable economics. But as discussed above, a combination of geopolitics and both short- and long-term global market conditions make it unlikely an export pipeline could now be developed for a larger field.

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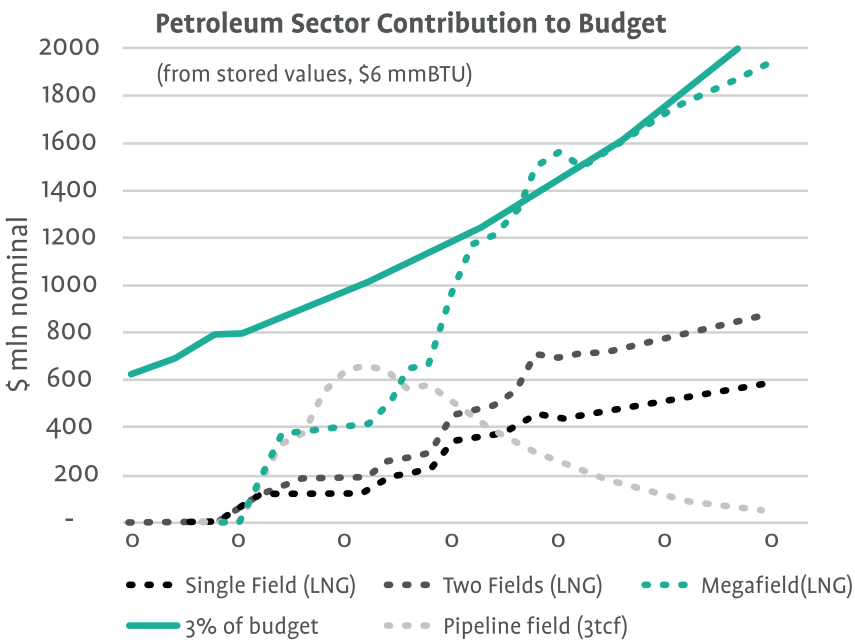
*Although the Egyptian gas field of Zohr, discovered in 2014, would seem to present an instance of a giant gas field in the region that has been developed, the difference in circumstances and context should be rercognised: the domestic market in Egypt, with a population of 100 million, is already 65 billion cubic metres of gas per year, and the Zohr field was developed fast because Egypt has had an oil industry operating at scale for over 50 years, complete with local service companies. These conditions do not apply in Lebanon.*

This leaves the possibility of a pipeline primarily to drive domestic consumption of gas. Because there is room to build a production plateau early in the project, there is potentially greater profitability, with breakeven price at around $3.72 on a 3 tcf field developed with a pipeline, assuming a 10% nominal discount rate. But it should be noted that this price would rely on no cost or time overruns, which could dramatically lower rates of return, and ignores the fact that investors would most likely increase the discount rate against the perceived greater risk of selling mainly into the Lebanese domestic market. Once these are taken into account, it would be more realistic to assume that for this kind of project also investors would be looking for a price, in 2020 terms, of at least $5 per mmBTU before even considering committing to a final investment decision.

## Impact of Development

Since Lebanon is trying to develop a petroleum sector, it makes sense to look at the potential contribution of the sector as a whole to public finances and macro-economic growth. The chart below provides four different scenarios for Lebanon's offshore sector as a whole (represented by the dashed lines) and tracks them against current and projected government expenditure (the solid line).

### Public Finances



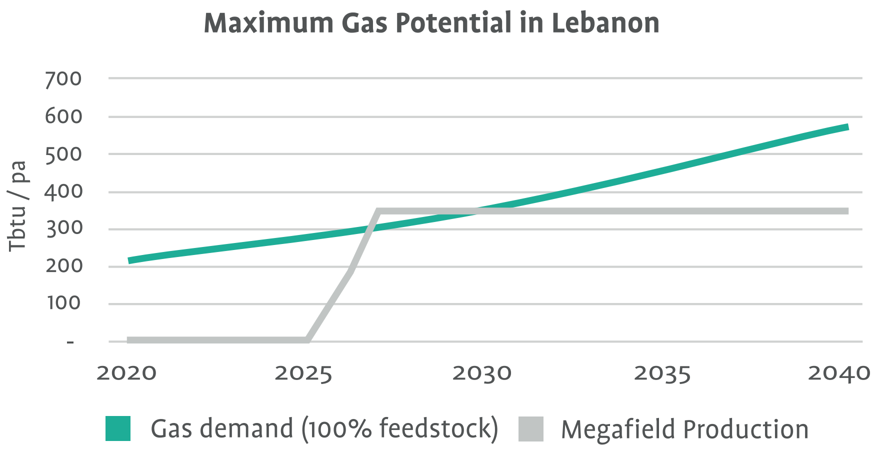

Three of the scenarios are based on the assumption of LNG development, folding in the analysis above which suggests that a pipeline export configuration for Lebanon is not currently realistic. "Single Field" assumes a 3 tcf discovery in Block 9 when it is drilled. "Two Fields" adds a smaller field, bid for in the postponed second round, and developed a couple of years later. The "Megafield" assumes a project in which 10 tcf is produced over the life of a project, via LNG. This would be used mainly to substitute in gas to Lebanon's power network, but export marginal extra production. Finally, a local pipeline solution is envisaged, in which a 3 tcf field is developed with a pipeline. All scenarios rely on price averaging a constant 2020 price of $6 / mmBTU, which would clearly be a radical improvement from current conditions.

One conclusion is clear: none of these scenarios come close to being transformational for Lebanon's distressed public finances. If public spending increases at 4% per year from its current level, the only scenario that even reaches 3% of the government budget is the 10 tcf scenario – and then only in the late 2030s. The entire petroleum sector in Lebanon is likely to improve public finances less than any strong domestic revenue mobilisation policy.

It should also be noted that potential revenues to the state are also a tiny fraction of Lebanon's current public debt, when expressed in Net Present Value (NPV) terms. Even a 10 tcf field, developed with prices at $6 / mmBTU, yields an NPV of about $3.7 billion against a 10% nominal discount rate. This is less than 5% of Lebanon's $80 billion public debt, and might account for just one year's servicing of that debt.

This means it would be hard to justify any increase in public debt based on projected gas revenues, no matter what the long-term scenario envisaged is.

## Macroeconomic Growth




The impact of development of a gas sector on Lebanon's macro-economy, however, could be significant if there were a sizeable discovery. The graph shows a highly stylised interaction between gas and the power sector.[39] If power generation of about 2 GwH could be switched to close to 100% generated by gas, and production increased to cover a shortfall currently estimated to be 1.5 GwH, Lebanon's domestic market could absorb a 10 tcf field developed by LNG. The undoubtedly cheaper costs of power generation using gas rather than imported fuel products would provide some budget envelope to reform subsidised electricity prices which have been such a burden on the state, as well as increasing productivity across all sectors of the economy.

Although the economics of a pipeline could look commercially stronger in theory, and so more encouraging to international investors, any field much above 5 tcf would not find a market in Lebanon for typical plateau production levels.[40]

The increasing constraints on finding a market for any gas discovered could create a difficult judgement call with regard to any bids submitted in a future second round.

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*Based on World Bank data showing 2,800 KwH electricity use per capita in Lebanon in 2016, projecting an additional 50% demand ("shortfall") because of the electricity crisis, assuming 5% growth in demand per year and a theoretical 100% conversion of the power sector to use of gas or LNG as feedstock.*

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*Modelled at 10% of recoverable reserves for each of Years 2 to 5 of production.*

Depressed prices and a long-term oversupply might lead potential investors to bid lower than either of the offers in the first bid round – with a lower profit share to the government, and a higher cost recovery ceiling. Lower terms would lead to a lower government take. On the other hand, such terms might be required by international investors to guarantee a commercial return in a bear market.

A distinctive feature of any project which was geared to domestic consumption would be that the government would effectively have some insurance against low gas prices since it also currently subsidises electricity. Losses to the exchequer from low gas prices and a concessional fiscal regime could be more than offset by extra fiscal headroom to reduce fossil fuel subsidies.

The question of how far developing gas resources for the Lebanese market could improve public finances deserves further study. There are large uncertainties over the timing and scale of potential reform of the energy sector: how far can electricity prices be liberalised how fast, for example, what other operational efficiencies are realistic, what the terms would be for capital investment to enable swapping in gas as the main feedstock not only for current grid production but to extend to cover a large part of the shortfall now addressed by the private generator market. These have proved beyond the scope of the current study.

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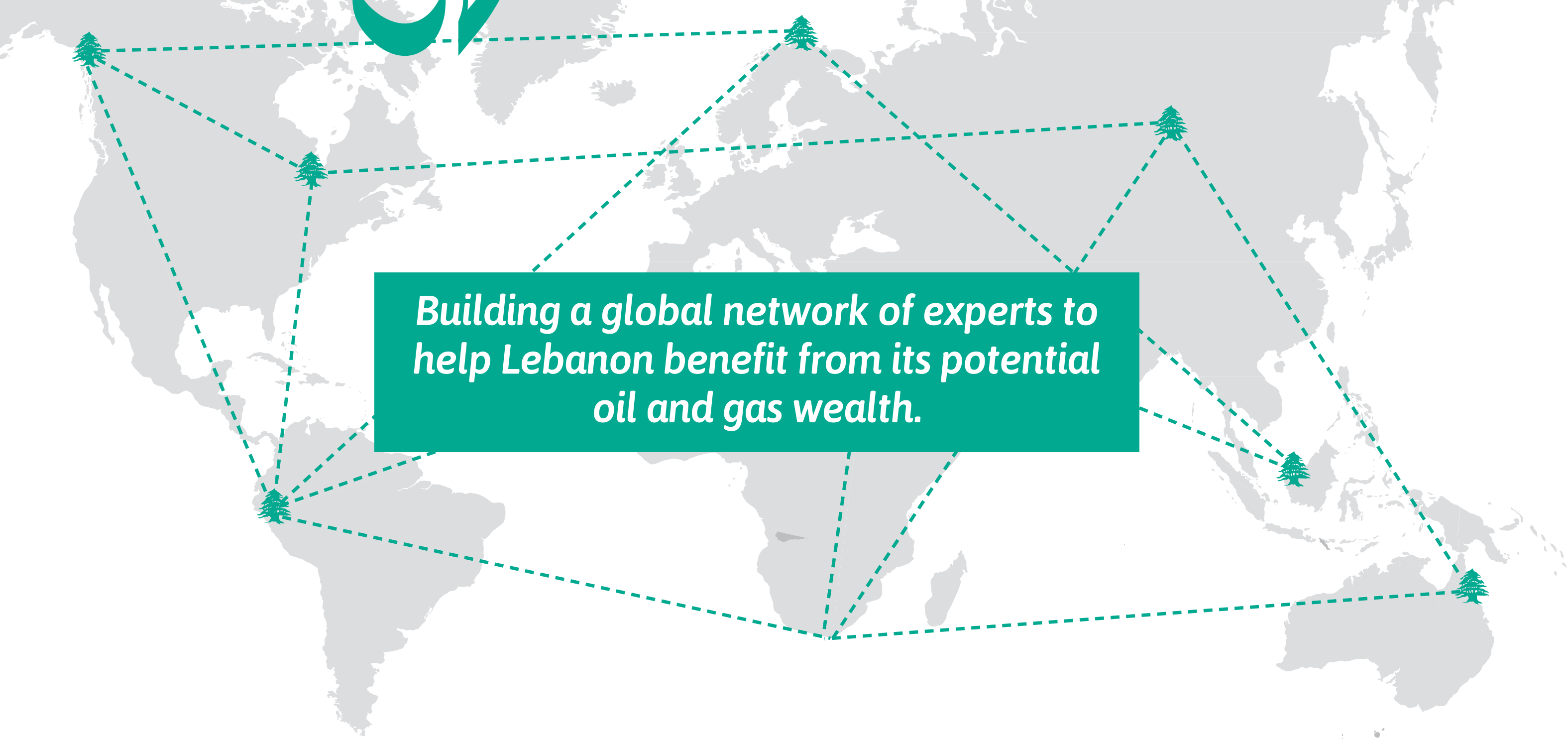


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