Implications of climate targets on oil production and fiscal revenues in Latin America and the Caribbean

Baltazar Solano-Rodríguez[1]*, Steve Pye[1], Pei-Hao Li[1], Paul Ekins[2], Osmel Manzano[3] and Adrien Vogt-Schilb[3]

[1] UCL Energy Institute, University College London, 14 Upper Woburn Place, London WC1H 0NN, UK.
[2] UCL Institute of Sustainable Resources, University College London, 14 Upper Woburn Place, London WC1H 0NN, UK.
[3] Inter-American Development Bank, Climate Change Division, Washington, DC, USA.

E-mail: b.solano@ucl.ac.uk

Abstract

While many governments rely on oil production and exports for fiscal revenues, the global energy transition driven by climate policy and technological change makes future demand and prices uncertain. We propose a framework to explore prospects for oil production, public revenues from oil, and unexploited oil reserves under hundreds of future energy transitions scenarios, following robust decision making principles. We apply it to Latin American and the Caribbean, a developing region that exports half its oil production and faces fiscal constraints. We use the BUEGO (Bottom-Up Economic and Geological Oil field production) model to simulate field development and production decisions globally. We find that oil production in the region over the next 15 years is highly sensitive to the impact of global climate action on oil prices and to the strategies of large global producers, while choices around oil fiscal regimes have limited impact. Also, 66 to 81% of proved, probable and possible reserves will remain unused by 2035. Finally, cumulative fiscal and nonfiscal revenues from oil would be $1.3-2.6 trillion under strong global climate action, compared to $2.7-6.8 trillion if reserves were strongly exploited. Our findings confirm that governments need to diversify their fiscal revenues away from dependency on oil production.

Key policy insights

- In Latin America and the Caribbean, 66-81% of 3P reserves may not be exploitable if the Paris Agreement temperature targets are met.
- Global oil demand and the strategies of large global producers are the key drivers of exogenous uncertainty for production in the region.
- Oil fiscal regimes have a limited role in mitigating transition risks; a low carbon transition could reduce tax revenues from oil to $1.3-2.6 trn compared with $2.7-6.8 trn if oil reserves were fully exploited.
- Governments should reduce their dependency on oil production and explore how to diversify their fiscal revenues as they recover from the pandemic.

Keywords: oil production, fiscal revenues, climate transition risk, Latin America, Caribbean

---

1. Introduction

Latin America and the Caribbean faces common development challenges linked to the gloal energy transition. On the one hand, many countries in the region increasingly aspire to transition to a net-zero carbon economy, thus contributing to the achievement of the temperature targets in the Paris Agreement (IDB and DDPLAC, 2019). On the other hand, many also have large oil production sectors or prospects for generating future revenues from oil resources.

Many countries in the region depend on global oil demand for fiscal revenues. More than half of the oil produced there is exported globally (BP, 2020) (Supplementary Figure 3a). In 2018, 8% of fiscal revenues in Ecuador, 4.6% in Bolivia, 4.2% in Mexico, and 3.4% in Trinidad in Tobago depended on oil and gas exploitation (OECD, 2020). In Venezuela, oil represented 98% of export earnings in 2017 (OPEC, 2017). Looking forward, countries like Argentina, Brazil and Mexico have ambitious plans to increase their production, and others, like Guyana, to start exploitation at a transformative scale for their economies (IEA, 2017a). In contrast, the region is a significative but by no means dominant player on the global oil market. It holds one fifth of the global proven reserves, distributed in Venezuela (91% of regional reserves), Brazil (3.8%), Mexico (2.3%), Ecuador (1%), Argentina (0.7%), and Colombia (0.5%) (OLADE, 2018), and produces just above 8 million bbl/day (Supplementary Figure 3b), or nearly 10% of global oil demand (BP, 2020).

One key risk for oil exporting countries is that future demand is highly uncertain. As alternative technologies become cheaper and measures to address climate change and implement the Paris Agreement take hold, oil demand is expected to slow down dramatically (Carbon Tracker Initiative, 2018; IEA, 2019). Electricity generation is expected to increasingly switch to renewable and other low carbon sources, with increasing electrification of the road transport sector and other end use sectors (Audoly, Vogt-Schilb, Guivarch, & Pfeiffer, 2018; Bataille et al., 2016; Davis et al., 2018; Rogelj et al., 2018). Such shifts are already occurring, with some countries experiencing large renewable energy growth (IRENA, 2019), and others increasing sales of electric vehicles (IEA, 2018) whilst in parallel proposing the future banning of diesel and gasoline vehicle sales.

If global action is ratcheted, oil demand will decline sharply, leading to unburnable carbon, that is fossil fuels which cannot be extracted and used if the world is to adhere to a given carbon budget (Carbon Tracker Initiative, 2011; Leaton et al., 2015). (C. McGlade & Ekins, 2015) quantified this prospect, estimating that almost 40% of proven plus probable oil reserves in Latin America (33% globally) would remain unburnable in 2050 in a world where the global temperature increase was limited to 2°C. More recently, a United Nations-backed study has demonstrated that oil, gas and coal production plans from global producers are inconsistent with international climate goals, as by 2030, they would together generate more than twice as much carbon dioxide as what would be consistent with the 1.5°C target (SEI et al., 2019).

It is well known that climate policy, and other disruptive factors impacting the energy transition create a risk for the oil sector (Bradley, Lahn, & Pye, 2018, McGlade and Ekins, 2015). Many deep decarbonisation analyses at a national level take limited account of how this sector might be disrupted, often due to lack of global scope of the modelling tools used (Lefevre, Wills, & Hourcade, 2018; Pye et al., 2016). Some papers study what this risk to the oil sector mean for large private companies (e.g. Griffin et al, 2015 and CTI, 2017), but the transition risk also has an effect on public revenues. Yet, the impact of the transition on public finances has seldom been studied[1]. In this paper, our main aim is to assess the impacts on oil revenues for government budgets, as well as the resources not extracted, or left in the ground. To this purpose, we propose a framework to explore prospects for oil producers under uncertainty, using multiple exploratory scenarios. While our paper focuses on Latin American and the Caribbean[2], a similar approach could be applied in any oil producing country to inform their budgetary planning policy decisions. The paper is structured as follows; section 2 sets out the method used to undertake the uncertainty analysis, including the model for generating scenarios. Section 3 highlights the key results, focusing on the production and revenue ranges at the country level, and the level of unburnable oil. Section 4 concludes with discussion of the key policy insights, and wider insights on the need to consider these transition risks in climate policy analysis.

2. Methods

2.1 Problem scoping

We use the XLRM scenario-based approach (Lempert, 2003), to explore the implications of uncertainty on Latin American and Caribbean oil producers out to 2035. The *XLRM framework* helps scope the problem and organize the relevant data, assumptions and modelling, as follows –

[1] Two exceptions published while this paper was under review are Carbon Tracker, 2021. Beyond Petrostates: The burning need to cut oil dependence in the energy transition and Huxham, M., Anwar, M., Nelson, D., 2019. Understanding the impact of a low carbon transition on South Africa. Climate Policy Initiative.

[2] This paper stems from a research project executed on behalf of the Inter-American Development Bank, which focuses on Latin America and the Caribbean.

- Exogenous uncertainties (X). These are uncertainties outside of the control of decision makers that may have an impact on oil production.
- Policy levers (L). These are the policy actions that can be explored to influence future impacts on oil producers.
- Relationships (R). These describe the ways in which the uncertainties explored through scenarios relate to one another and influence future impacts.
- Metrics for outcomes (M). These are the performance standards that decision makers can use to rank the desirability of various scenarios.

In this analysis, the XLRM categories are considered as follows -

***Metrics for outcomes** (M).* The performance indicators used to assess the range of oil production scenarios include total production, fraction of reserves that are left unused in the ground, and oil revenues generated for public budgets. We assess these three indicators by country, for all major oil exporting countries in the region.

***Exogenous uncertainties** (X).* Multiple uncertainties are likely to impact future oil production, including economic growth, demographic change, policy targets, including GHG emission reduction targets, and geo-political factors influencing oil markets[3]. We capture these uncertainties by varying global oil demand, and the behaviour of the OPEC group in setting production quotas.

Global oil demand trajectories are taken from large ensemble of scenarios from a peer-reviewed scenario database (Huppmann, Rogelj, Kriegler, Krey, & Riahi, 2018), used to inform the IPCC special report of global warming of 1.5°C (IPCC, 2018). The scenarios are from integrated assessment modelling, focused on exploring the implications of different future socioeconomic narratives on global temperatures, including assumptions on demographic change, economic growth, and technological change (O'Neill et al., 2017).

For this assessment, we have taken the median oil production trajectory (Table 1) for four groups of scenario defined by the temperature increase they lead to in 2100: i) Above 2°C, ii) Higher 2°C, iii) Lower 2°C, and iv) 1.5°C. (Supplementary Figure 1). The *Higher 2°C* scenarios lead to greenhouse gas emissions concentrations that are more likely to overshoot the 2°C limit than the *Lower 2°C* scenarios (Huppmann et al., 2018).

Table 1. Median oil demand projection by scenario (mbd)

Scenario	2010	2015	2020	2025	2030	2035	2040
1.5°C Median	83.7	82.5	81.3	79.6	77.9	75.2	72.6
Lower 2°C	82.7	87.4	92.1	91.9	91.6	84.5	77.4
Higher 2°C	82.4	87.2	91.9	93.4	94.9	94.2	93.5
Above 2°C	82.2	88.9	95.6	99.9	104.1	105.6	107.2

A second driver of prospects for oil production in Latin America and the Caribbean is how other key global producers act. To explore this, we focus on the role the OPEC, whose producers hold 82% of the world's proven oil reserves (OPEC, 2017). OPEC uses production quotas to ensure revenue stability for its members by controlling oil price, therefore impacting on the attractiveness of regional oil fields to investors. We consider two contrasting cases by either imposing a cap on annual production for each OPEC member (including Venezuela and Ecuador[4]), which we set based on the maximum historical annual production level since 2000 (Table 2), or imposing no caps at all.

Table 2. OPEC production constraints assumed over the period 2017-2035

Country	Maximum daily production rate (mbbl/d)
Algeria	1.7
Angola	2.0

[3] Some petroleum refineries favour certain crude oils based on their quality and that of their oil products, hence influencing demand and supply flows. This paper does not use a global refinery model and does not capture these inflexibilities in the oil supply chain.

[4] We have assumed that OPEC members at the time of our modelling (2019) would continue to belong to this organisation throughout the time horizon of our study (to 2035). Ecuador has left OPEC in January 2020; however, their cumulative oil production is relatively low (see Supplementary Figure 7). We consider that their membership of OPEC is not meaningful to global oil market dynamics or the regional insights from our results.

Libya	1.7
Nigeria	3.0
Ecuador	0.5
Venezuela	3.1
Kuwait	2.3
Iran	4.0
Iraq[2]	5-10.0
Qatar	1.0
Saudi Arabia[1]	11.1
UAE	2.9
Total	38-43

[1] Production from the Neutral Zone is split equally between Kuwait and Saudi Arabia
[2] Iraq is subject to a 4.5 mbbl/d cap up to 2019; and a 7 mbbl/d from 2020.

Policy levers *(L).* The policy levers that could be considered to influence the above metrics include incentives to make production more profitable, and the oil fiscal regime that determines the share of profits returned to government. Other policies may relate to diversification away from oil, or indeed a moratorium on exploration (as in Costa Rica and Belize), with a focus on driving foreign investment and growth through other sectors of the economy. Here, we focus on oil fiscal regime, including the impact of varying the type of regime and the level of tax rate. By oil fiscal regimes we refer to the instruments and regulations that govern the relationship between host governments and investors for sharing oil wealth and determine how the financial benefits and risks of extractive projects will be divided[5].

Oil fiscal regimes impact profitability for investors and producers, influencing which oil field development projects they decide to fund. Most Latin American and Caribbean countries currently use either production-sharing contracts or concessions, with different levels of fiscal pressure on producers (Supplementary Table 3). We model the current oil fiscal regimes, and systematically test the impact of switching from one scheme to the other, and the level of fiscal pressure. We focus these oil fiscal regime variations to assess the extent on which the competitiveness of countries in the region might change under different regional scenarios. Further information on the oil fiscal regimes used in this analysis, and how they have been represented in BUEGO, is provided in the Supplementary Information (SI4).

Relationships *(R).* This reflects the link between outcomes of the uncertainties (X) and policy interventions (L) on the outcome metrics (M). These relationships are represented in and simulated using the BUEGO model.

2.2 The BUEGO model

The Bottom Up Economic and Geological Oil field production model (BUEGO) is a medium-term model that incorporates economic and geological characteristics of oil production (C. McGlade, 2013; Christophe McGlade & Ekins, 2014). Characteristics include reserve levels, decline rates, capacity expansion potential, water depths, and capital and operating costs for over 7,000 producing, undiscovered and discovered but undeveloped oil fields globally. In addition, the oil fiscal regime of the country in which a field is located is represented. For a given, exogenous, global demand for oil, the model simulates the production capacity required to meet the production level for each future year iteratively. This is modelled by increasing the global price until sufficient existing production capacity is used and new capacity invested in, based on the economics of different field level project (including oil fiscal regime). Projects come online where a positive net present value is realized. Equation 1 presents the NPV calculation used in BUEGO.

$$NPV = \sum_{t=0}^{N} \frac{p_t q_t - tax_t(p) - cost_t}{(1+\delta)^t} \qquad (1)$$

where N is the lifetime of the project (assumed to be 30 years), p_t is the oil price, q_t is the grow number of barrels produced in that year, tax_t the taxes paid in that year, δ is the project specific discount rate and $cost_t$ the capital and operational costs at

[5] Natural Resource Governance Institute (NRGI). 2015. Oil, Gas, and Mining Fiscal Terms. Available at: https://resourcegovernance.org/analysis-tools/publications/oil-gas-and-mining-fiscal-terms (accessed on 22/02/2021)

time t. Discount rates (δ)[6] in BUEGO are sourced from (Della Vigna et al., 2012), using rates of 11-15% ranging from OECD countries to higher risk non-OECD countries; an exception is Canada with 15% to account for capital intensive projects. Therefore, for each year out to 2035, the model provides the minimum oil price required to meet global demand. It also provides estimates of production at a field and country level, total reserves made available by investments to develop fields at the country level, and the oil tax take by national governments.

The oilfield database in BUEGO is largely based on the model by Miller, as described in (C. McGlade, 2013). BUEGO includes all existing and prospective national producers in Latin America and the Caribbean, as listed in Supplementary Information Table 2. A range of updates have been made to BUEGO for this work compared to (Christophe McGlade & Ekins, 2014), including recalibration of current production to 2016 (from 2009), and a review of the oil fiscal regimes in each country. A recalibration effort has aimed at matching country production totals to (IEA, 2017b) estimates, and updating production and reserves for Latin America and Caribbean countries based on national statistics (Agência Nacional do Petróleo, 2017; Comisión Nacional de Hidrocarburos, 2019; Ministerio de Energía y Minas, 2017; Ministerio de Energía y Minería, 2016; Ministerio de Hidrocarburos, 2017; Ministerio de Minas y Energía, 2018).

The supply cost curves used in BUEGO characterize resource available at different cost for a given country, region, resource category, or any combination of these (C. McGlade, 2013). Middle Eastern OPEC countries dominate the low-cost resource, holding nearly 50% of the resource available below $40/bbl. Canada and Venezuela control 25% and 20% respectively of the resource available at $40-70/bbl while the US controls nearly 45% of the resource available over $70/bbl.

Price elasticities of demand are used in BUEGO, including a short-term elasticity of -0.05 and a medium and long-term elasticity of -0.15, to simulate the impact of prices on demand. This explains why the oil production profile in our Above 2°C scenarios is not higher and declines post-2030, in response to rising oil prices, in particular under OPEC-constrained scenarios (Supplementary Figure 2). Some categories of oil are not included within BUEGO, namely natural gas liquids (NGL), biofuels, kerogen oil and other Fischer-Tropsch liquids. While this is a limitation of the model, these oil categories are expected to play a relatively small role to 2035.

The project economics in BUEGO are impacted by the oil fiscal regime of each country (Supplementary Information section 4-6), updated based on (EY, 2017)[7]. Most of the countries in Latin America and the Caribbean fit into one of two main types of oil fiscal regime: concessions and production sharing contracts (see Supplementary Table 3). Concession regimes involve taking a certain percentage of gross revenues (the royalty), and then levying a tax on profits. Other important factors in the regime design include the depreciation scale (capital allowance) for offsetting capital costs against future profits, and the number of years for which a tax loss can be carried forward.

Production sharing contracts incorporate the features of a concession regime but also include additional terms. The first is 'cost oil', a volume of production initially allocated to an oil company to cover its capital and operating expenditure, and is generally permitted to a maximum percentage of gross revenues, termed the 'cost recovery limit'. Cost oil allows for repayment of the costs associated with the project and is usually levied after any royalties have been subtracted ('royalty oil'). Oil remaining after royalty and cost oil is subtracted is termed 'profit oil', which is split between company and Government, and then typically taxed. Payments may be differentiated (using a sliding scale) based on the level of production or an R-factor. The R-factor is the ratio of revenue to expenses; revenues earned by International Oil Companies (IOCs) from cost recovery and profit oil are divided by the cumulative expenses incurred during a specified period.

Service-based contracts are less prevalent in the region. Such contracts pay a fee to the international oil companies for each barrel of oil produced above the total costs of the project, meaning the national oil company retains the ownership of the oil production. This differs to the concessionary model, where the international oil company has ownership, or the production-sharing model, where joint ownership is in place (Ghandi & Lin, 2014).

(C. McGlade, 2013) shows how oil fiscal regimes and global oil prices impact on the tax take. For the same illustrative project, the tax take in China increases by 15% as the oil price increases by $40/bbl, while India's tax take for example decreases by

[6] Some oil companies might accept lower discount rates and profitability in order to maintain production, particularly under low oil price conditions. In BUEGO discount rates are fixed through to 2035, so this is not considered in our modelling.
[7] Tax regimes in BUEGO are fixed throughout the time horizon. Fiscal terms do not change and incentives are not offered to producers under specific oil market conditions, such as low oil prices. However, our uncertainty analysis approach includes scenarios with fiscal terms that may be more favourable to companies under low oil prices.

6% as the project's capital costs increase. This shows the huge variability in tax take depending on regime set-up – and then exogenous price uncertainty.

2.3 Scenario definition

To explore how exogenous uncertainty and endogenous policy choices affect the prospect for oil production and revenues, we run 480 scenarios with the BUEGO model. We vary parameters that represent two uncertainty dimensions; i) global oil demand, which is sensitive to climate policy and technological change, and ii) geo-political uncertainty, reflected in changes of production by the OPEC; and two policy levers, the type and the stringency of oil fiscal regimes by country in the region, as shown in Table 3.

Table 3. Scenario dimensions

Scenario dimension	Variable
Global oil demand under different climate targets	Oil demand trajectories from IAM scenario database used to inform the IPCC SR1.5 report under the following climate ambition categories – i) Above 2°C, ii) Higher 2°C, iii) Lower 2°C, and iv) 1.5°C.
Producer behaviour based on OPEC limits	OPEC countries either have limits imposed or do not. Caps have been imposed on annual production, and are set at the maximum historical annual production levels since 2000 (see Table 1).
Oil fiscal regime choice	Variants include current regime in place today (SI Table 4), and regimes that are concession-based or on a production sharing contract basis. These types have been selected due to their current widespread use in the region.
Oil fiscal regime rate level	Two tax rate levels, low and high, under each of the regime variants, estimated by multiplying the current regime level by a factor of 0.5 (low) or 1.5 (high). For those countries without a PSC regime in place, a fixed contractor share of 25% has been assumed for a high tax take rate and 75% for the low case. For those producers without a concession regime, a royalty of 30% and a tax rate of 37.5% has been assumed for the high rates case, while a royalty of 10% and a tax rate of 12.5% has been assumed for the low rates case. This value range has been considered to be representative of what other countries in the region have in place.

To derive our uncertainty combinations, we use Latin hypercube sampling, which allows us to minimise the number of runs necessary to represent the variability of our uncertainty space (McKay, Beckman, & Conover, 2000). Each scenario consists of the choice of one global oil demand pathway (from 1.5˚C to above 2˚C), one OPEC production variant (with / without cap), one oil fiscal regime type (current, concession, production sharing) and rate (current, low, high) for each country in the region. While larger producing countries (Argentina, Bolivia, Brazil, Colombia, Ecuador, Mexico, Peru, Trinidad and Tobago, and Venezuela) are considered individually in respect of regime type and rate, smaller producers take the same oil fiscal regime type and level in each scenario to keep the scenario number manageable.

3. Results

This section on scenario results is split into four parts; regional oil production outlook (3.1), implications of outlooks for government revenue generation (3.2), the influence of oil fiscal regimes (3.3), and the level of 3P reserves unused in 2035 (3.4). We focus on this year as a middle of the road milestone between 2020 and 2050, when global greenhouse gas emissions must be reduced to nearly zero in order to limit warming to 1.5°C. The results sections map to the metrics of outcomes that are outlined in section 2.1, on which the scenarios are being assessed.

3.1 Oil production prospects

Figure 1 shows the oil production profiles in Latin America and the Caribbean from the scenarios generated, illustrating the wide range of outputs (3-11 mbd in 2035), based on the uncertainties explored. Across all scenarios, production intially declines out to 2021, reflecting increasing production levels in USA and by some Middle Eastern producers, and recent declines in Venezuelan and Mexican production that more than compensate increases in Brazilian output. After 2025, the widening range highlights the risk that climate policy and technological change casts on producers and investors. The main driver of future production turns out to be global demand. Under the Above 2°C demand scenarios (red trend group), production increases during the mid-2020s. For demands consistent with more stringent temperature limits, regional production continues to decline to 35-70% of 2016 levels by 2035, with the median global price at 50 USD/bbl (Supplementary Table 1). A 1.5°C outlook suggests cumulative regional production of 47-56 billion barrels by 2035 compared to 57-70 billion barrels in an Above 2°C world, based on the interquartile range (Supplementary Figure 4a).

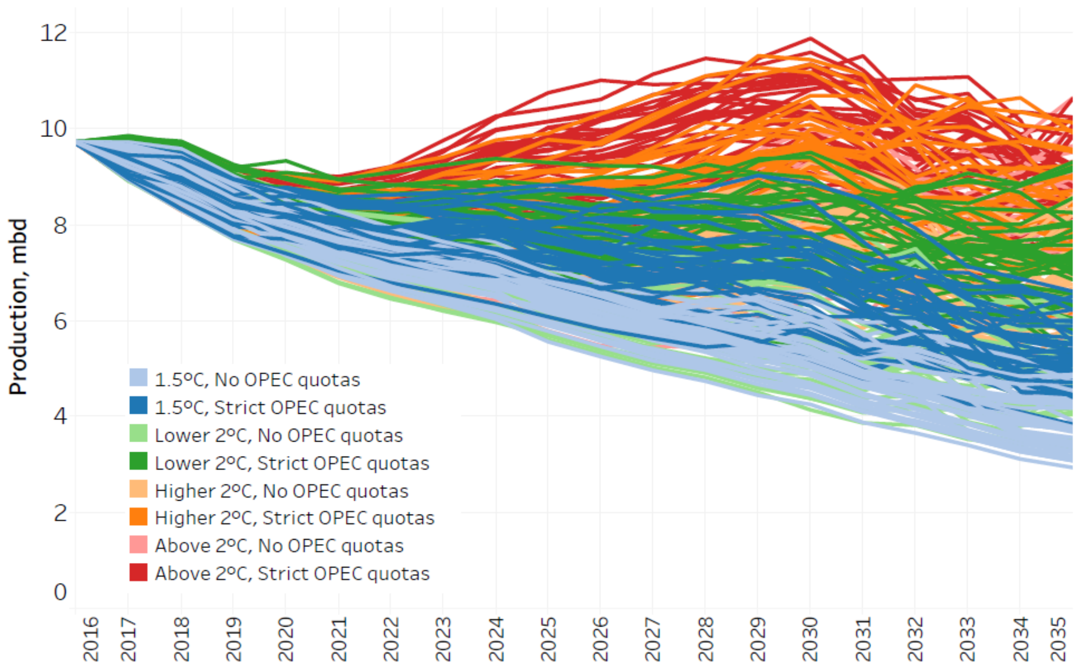

Figure 1. Oil production in Latin America and the Caribbean under different climate-driven global demand and OPEC production scenarios, 2016-2035. The legend identifies the global demand based on different global climate scenarios, combined with the OPEC variant, where production limits are or are not assumed for OPEC countries.

The role of OPEC quotas is also important. Constraints on OPEC producers leads to higher production by the major producers in the Latin America and Caribbean region across all the global demand variants. Figure 2 highlights this effect, showing higher production where quotas are implemented under both 1.5°C and 2°C cases (Figure 2a,b), compared to where they are not (Figure 2c,d). Production levels are shown in the same basis for non-Latin America and Caribbean producers, in Supplementary Figure 2, including the large OPEC producers. How OPEC operates in the future and the type of quotas assumed is highly uncertain, but something that other producing countries should be cognisant of.

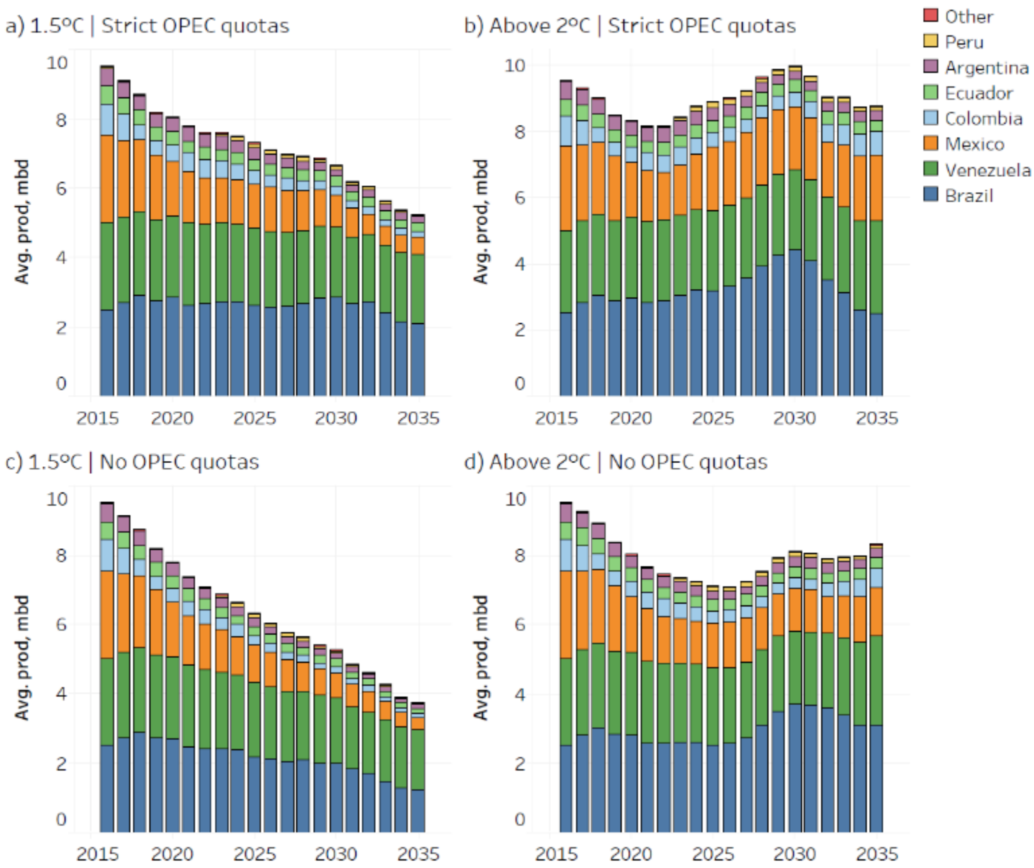

Figure 2. Average oil production in major Latin American and Caribbean producing countries under 1.5°C and Above 2°C cases, and OPEC quota variants, 2016-2035.

The production outlook varies considerably at the country level. Figure 3 shows production trajectories for the three top producers in the region: Brazil, Mexico and Venezuela. For all three countries, global oil demand and OPEC's production strategy are the most influential drivers of production, although the variability within a given combination of oil demand / OPEC strategy highlights the impact of different oil fiscal regimes. Despite Venezuela being part of OPEC, the cases with strict quotas result in higher oil prices globally and pushes production up to the domestic cap, while in the cases without quotas, Venezuelan production sits well below the capped level.

Brazil shows the highest variability in production; from nearly doubling its 2016 oil production (2.5 million barrels day, *mbd*) in the most optimistic Above 2°C scenario (red group), to almost halving production under the least optimistic 1.5°C scenario (light blue group). Production in Mexico declines from 2016 until the early- to mid-2020s, after which investment in oil field development increases, especially under Higher 2°C and Above 2°C demand scenarios. The impact of large global producers is also clearly shown for both countries by observing the different trajectories for the strict (dark blue) and no OPEC constraint (light blue) cases for 1.5°C scenario group. In Venezuela, the outlook appears less dependent on global oil demand variation than for other producers in the region, suggesting that choice of oil fiscal regime (not highlighted in Figure 3) and those of other producers in the region may have a more significant influence. For instance, under the most optimistic Lower 2°C scenario, Venezuela could produce 3.1 mbd by 2035; in the least optimistic case for the same global demand and OPEC behaviour, it only produces 1.4 mbd.

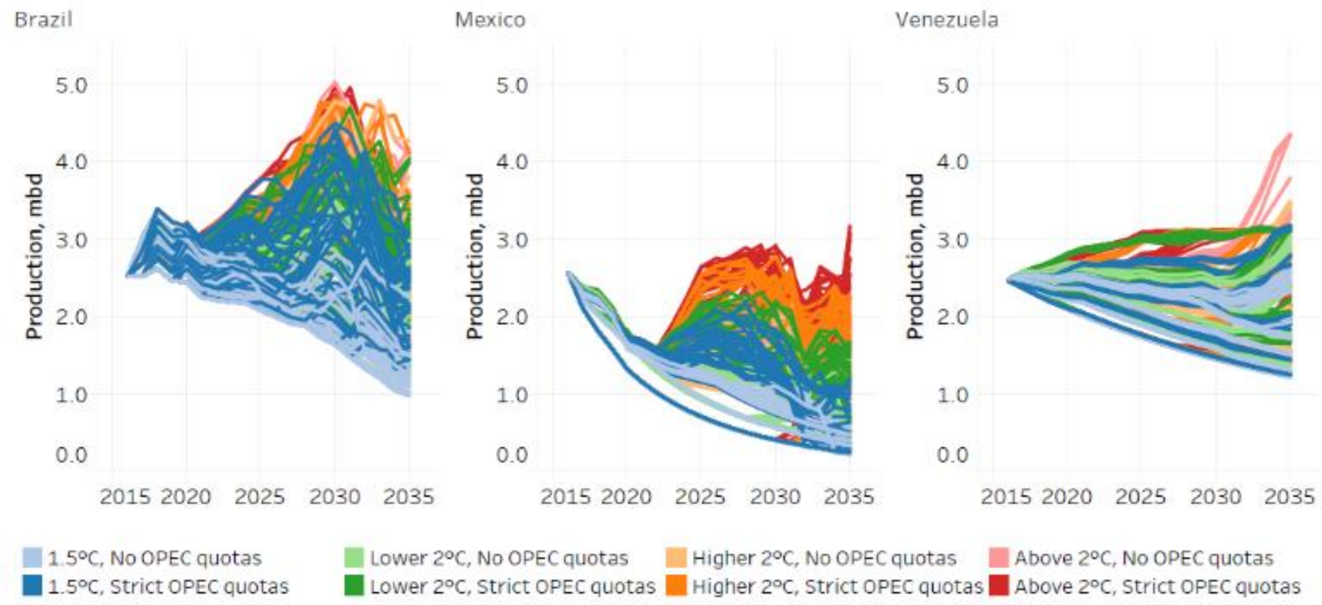

Figure 3. Oil production in Brazil, Mexico and Venezuela, by demand scenario, 2016-2035. Each line corresponds to one of our 480 scenarios. In the legend, the numbers refer to the global demand under different temperature targets.

3.2 Government revenues from oil production

The level of production, as described in section 3.1, has implications for government revenues. The revenue stream is dependent on the type of oil fiscal regimes in place across Latin America and the Caribbean, as described in Supplementary Information section SI4. Figure 4 shows cumulative tax take (over the period 2016-2035) by country for the main regional producers. The range in total oil revenues is large and, like production, is driven by global demand and OPEC production quotas (or lack thereof). For instance, the interquartile range of tax take for Brazil goes from $550bn to $1,250bn. The scenarios below the interquartile range primarily correspond to 1.5°C cases (blue coloured markers); these scenarios represent the highest transition risk for oil producers. Variability within the clusters (global demand / OPEC strategy combination) is driven by differences in oil fiscal regimes across countries in the region, as discussed later.

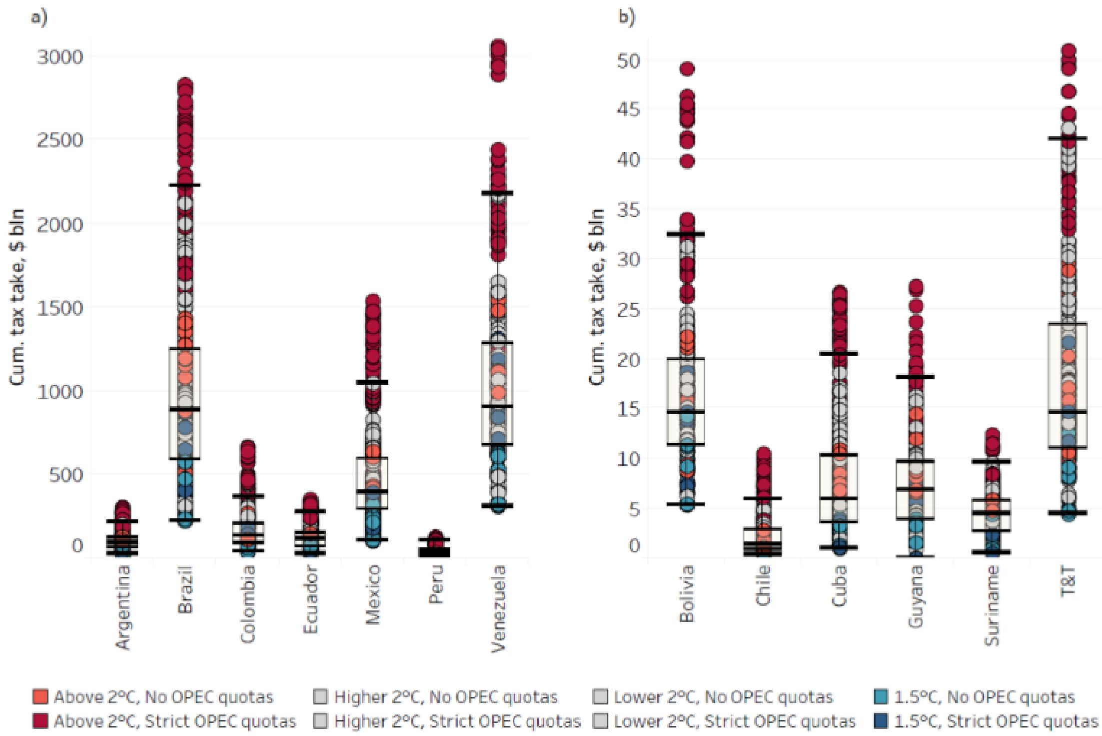

Figure 4. Cumulative government tax take by country and demand scenario (2016-2035). Each dot represents one of the 480 scenarios. In box-and-whiskers plot, median and interquartile (IQ) range are shown. Whiskers extend to 1.5 times the IQ range. a) Large oil producers in Latin America and the Caribbean; b) Small oil producers in Latin America and the Caribbean. The abbreviation T&T refers to Trinidad and Tobago.

Figure 5 aggregates the oil revenues to government in from Figure 4, to derive a plot of cumulative tax take versus cumulative production for the whole region. As expected a positive correlation is observed, with higher tax take associated with higher production. However, of particular interest is the variation; regional production ranges from 42 to 74 billion barrels while the oil revenues governments receive range from $1,000 and $9,000 bn. Wide variations in tax take at similar levels of production also illustrate the uncertainty around the global price of oil, driven by differences in global demand and OPEC behaviour. For example, 55 bln barrels could generate just over $1000 bln or around $4000 bln. This is a major uncertainty, with large implications for strategic decision making both by international oil companies investment in the region and governments exploring the future budgetary contribution the sector can make.

The Above 2°C OPEC-constrained scenarios (brown markers) see the highest tax take and production levels, whilst the 1.5°C OPEC-unconstrained (light blue) see the lowest. It is important to note that the prices for the OPEC-constrained Above 2°C scenarios hit high levels, up to 300$/barrel after 2030 (Supplementary Table 1). These are a product of heavily constraining the largest producers under a high global oil demand scenario, and should therefore be treated with caution. The difference in tax take between brown and yellow markers reflects the impact on oil price of constrained production from OPEC countries under the highest demand case. For any given combination of global demand and OPEC production (one colour in the plot), the variability is driven by the choices of oil fiscal regimes (see below). The box plots for the data shown in Figure 5 are in Supplementary Figure 4.

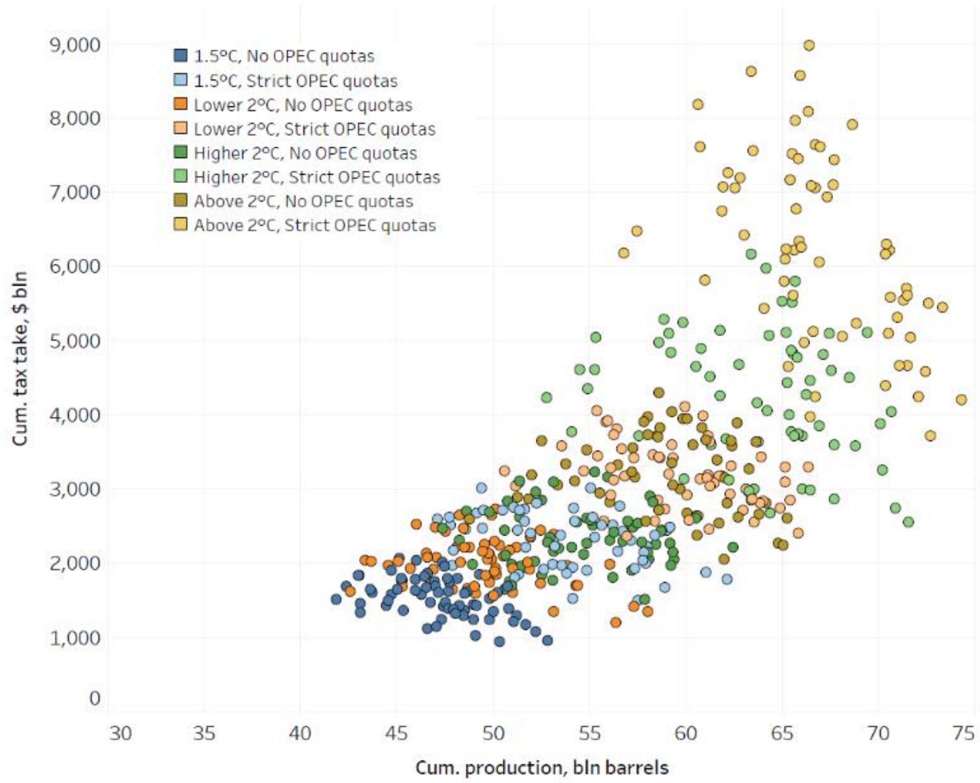

Figure 5. Cumulative production (billion barrels) versus cumulative tax take ($bn) for Latin America and the Caribbean, 2016-2035. Each dot represents one of the 480 scenarios. Colour denotes demand case, colour shade the OPEC production scenario.

For the largest producers, Brazil, Mexico and Venezuela, again global oil demand is a key driver for government tax take (Supplementary Figure 5a). The highest tax take and production are observed in Above 2°C scenarios, although not in all scenarios. In Brazil, tax take ranges from $500 bn to $3,000 bn and production from 14 to 25 billion barrels by 2035 in the Above 2°C scenarios; for Mexico, these demand scenarios range from $7 to $16 bn barrels of cumulative production in 2035, with a tax take range of $100-$2000 bn. Similarly, Above 2°C scenarios in Venezuela can lead to a tax take between $300 and $3,300 bn and production between 13 and 23 bn barrels. This variation for a given global demand is linked to oil fiscal regime sensitivities for these three producers, as well as to the tax configuration in the other countries considered in the rest of the region. Argentina, Ecuador and Colombia see a similar distribution to that observed for the top regional producers, showing a correlation between production, demand level, and oil fiscal regime and intensities; albeit at much lower levels of production and tax take (Supplementary Figure 5b).

3.3 The influence of oil fiscal regimes

Fiscal regimes determine how governments make money from oil, either when exploited by the private sector or state owned enterprises.[8] The regime matters; too high a rate and the field appears uneconomic, whilst lower rates stimulate investment but might not deliver potential oil revenues to government. To highlight the impact of oil fiscal regimes on production, Supplementary Figure 6 shows production versus government tax take in Brazil, Mexico, and Venezuela, in scenarios with no OPEC quotas, and for 1.5°C and Above 2°C demands. Although secondary to global oil demand and OPEC behaviour, the choice of tax rates and regime type may still have an impact on production and tax take, and therefore are a policy lever to maximise oil revenues, whilst ensuring investment.

[8] In this study our modelling of taxation regimes aims to estimate the relevance of taxation relative to global oil demand and OPEC quotas; further exploration of parameters and scenarios would be required to fully understand if a Laffer Curve exists in some countries under certain scenarios (Manzano M, Navajas, & Powell, 2017). That is, if a reduction in tax parameters could lead to an increase in tax revenues from oil; and vice versa, at what point would an increase in tax rates result in a reduced tax collection.

In the case of Brazil, a higher rate profit sharing regime (dark orange dots), in the Above 2°C demand case, could increase the revenue take up to 30% at a production level that is 20% lower than the low rate case (yellow dots); but an alternative low rate concessionary regime (pink dots) could potentially halve the current tax regime revenue (orange crosses). In the 1.5°C demand case, the difference in cumulative tax take between the current rate case and its low and high rate variants is smaller, but following a similar pattern to the Above 2°C demand case; higher tax rate scenarios show 15% less cumulative production than low rate ones, but with higher tax take. These policy levers cannot compensate the large uncertainties that are outside of decision makers control but may provide a lever to help manage a transition towards lower decline.

3.4 Cumulative production and unused reserves

The final metric of outcome (M) under the XLRM approach is the level of 3P reserves that would remain unexploited in 2035. This is an important metric, as an indicator of whether reserves held in country would be exploitable, informing decision makers on expectations under a range of futures. Supplementary Figure 7 shows cumulative production by country. The outlook is dominated by Brazil, Venezuela and Mexico with between a 10 to 22 billion cumulative barrels median production. A second set of mid-sized producers includes Argentina, Colombia, Ecuador and Peru, in the 1-3 billion barrels range. All see large ranges in potential cumulative production, reinforcing the earlier insights. Finally, smaller producers are those with a cumulative production of less than 500 million barrels. Interestingly, a few countries experience no or almost no production at all, including Barbados, Belize, Costa Rica, Guatemala, Nicaragua, Paraguay and Uruguay.

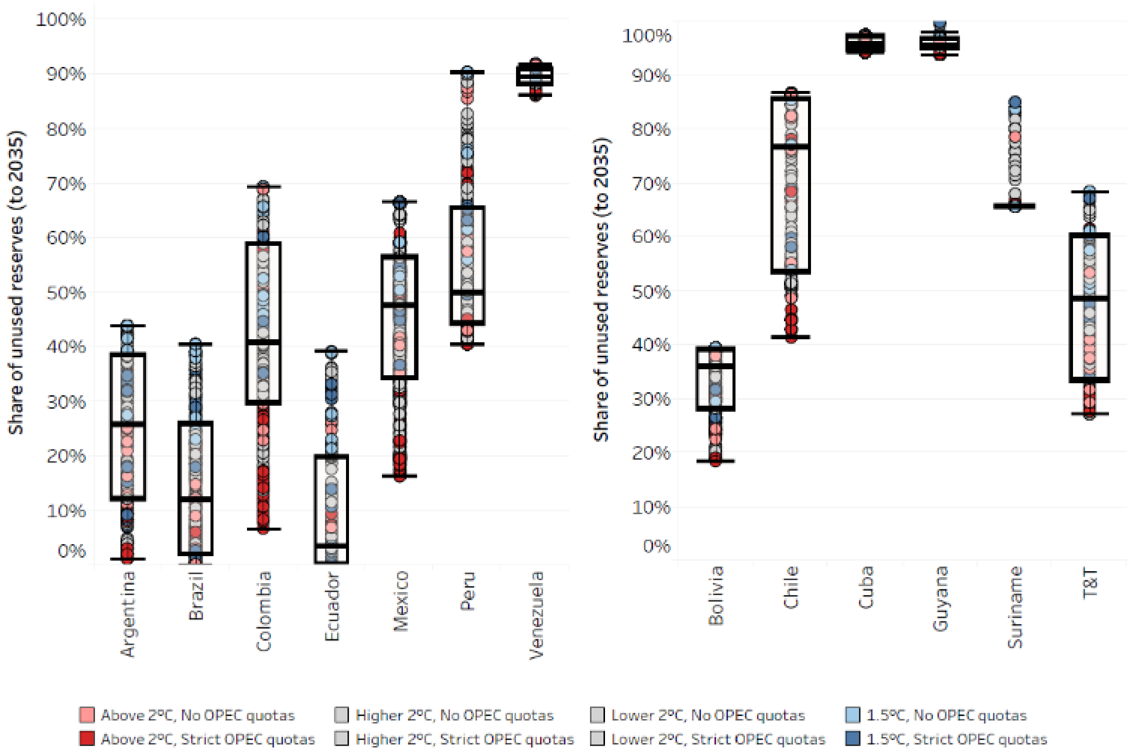

Figure 6. Unused reserve range by country for the period 2016-2035. Note that this plot estimates the shares of unused 3P reserves. Larger producers are in the left panel plots, and smaller producers in the right panel plots. The abbreviation T&T refers to Trinidad and Tobago.

Figure 6 compares cumulative production with 3P reserves (proved, probable and possible as of 2016, Supplementary Table 2), to derive unused or unburned reserves in 2035. With the exception of Venezuela, most Latin American and Caribbean producers are exploiting most of their 2P reserves (proved and probable reserves) by 2035 in our modelled scenarios. We find that 66-81% of 3P reserves in Latin America and the Caribbean are unburnable; excluding Venezuela which dominates from the estimate, this range is 16-56%.

The range of estimates of unused 3P reserves reflects the high uncertainty of production over the next 20 years, and raises important questions about prospect for use after 2035, if and when climate targets will set stronger limits on oil demand. Some mid-range producing countries such as Argentina and Ecuador show a higher proportion of their reserves used while some of the countries with much larger reserves, notably Venezuela, have high shares of unused reserves. Some of the smaller producers, notably Chile, Peru, Guyana and Trinidad & Tobago, are particularly at risk given their relatively small reserve base, high production costs and apparent sensitivity to wider regional production patterns.

4. Discussion

This analysis highlights that oil producers face tremendous uncertainty on production and tax receipts returns over coming decades, driven by climate policy and technological change reducing demand for oil, and by the production output of major producers in OPEC. All reserves may not be bankable today; they do not necessarily translate into production nor into revenues to government. Although in this paper we do not quantitatively assess the impact of reduced oil revenues on the economies, we would expect to see a negative impact on net exports, GDP, and aggregate and sectoral employment. There is considerable uncertainty as to what future production levels might be and therefore planning taking account of this uncertainty is critical (Carbon Tracker Initiative, 2018).

After 2035, with oil demand dropping to very low levels under the most ambitious climate scenarios, the global price of oil will continue to fall and unused reserves will be more difficult to exploit. For some countries in Latin America and the Caribbean, the range of our production estimates is very wide (e.g. Colombia, Chile, Trinidad and Tobago), highlighting dependence to global prices and production levels in other countries. Some countries see much stronger use of reserves, notably Brazil, Argentina and Ecuador, implying a more cost-effective resource base, and/or a lower level of reserves. Other countries with expensive and extensive reserves, such as Guyana and Venezuela, see much higher unused shares.

The extent to which producers in the region will be able to compete after 2035 for a diminishing market will require further analysis. What is clear is that market conditions could become tighter, and higher cost projects may struggle to attract investment. In our 1.5°C scenarios, the price is around $50 in 2035, meaning many projects will remain uneconomical. The lack of control across these global sources of uncertainties suggests that a robust approach would be to ensure that public budgets were not heavily dependent on oil revenues, and that increasing diversification across the economy is critical; in particular for countries where the importance of oil has increased in recent years, such as Bolivia, Colombia or Ecuador. Their long-term economic strategies also need to be careful not to transition from oil extraction to other resources (such as gas[9]) that may not be resilient to a low carbon transition.

As governments consider investments in infrastructure and the broader economy for a post-COVID recovery, and then feed into the Paris Agreement process via reporting on long-term emission-reduction strategies, consideration of future oil demand and domestic production prospects will be crucial. Research has considered such prospects in a low carbon world, but more needs to be done to reflect the uncertainty, and the implications of different outlooks for government oil revenues.

In summary, this analysis highlights the need for consideration of uncertainty, to highlight not only the potential prospects for developing oil reserves, and the benefits to public revenues, but also the worst-case outcome. Its delivers insights that are relevant to many oil exporting countries globally. Its approach could be applied in any country to inform policy decisions on long-term budgetary planning, economic diversification, and the types of oil fiscal regimes governments might want to consider.

Acknowledgements

We acknowledge funding provided by the Inter-American Development Bank under the project "Stranded Assets in LAC: Implications of the Paris Agreement" (RG-K1447). We also thank Christophe McGlade for the development of BUEGO and for making the model available to us for this study.

Contributions

[9] The more stringent climate policies are, the lower the global production of natural gas is - as the world aims to reduce greenhouse gas emissions. Gas production in some large regional producers (e.g. Brazil and Mexico) is currently dominated by associated gas. Under below 2°C scenarios, oil production in Latin America and the Caribbean declines; as a result, associated gas production decreases. Additionally, under strict carbon budgets, there are limited opportunities for new gas production in the region.

A.V.S., S.P. and B.S.R. designed the research. B.S.R., S.P. and P.L. undertook the modelling. All authors contributed to analysing the results and writing the paper.

Declaration of interests

The authors declare no competing financial interests.

References

Agência Nacional do Petróleo. (2017). *Boletim de Recursos de Petróleo e Gás Natural 2017*. Brazil. Retrieved from http://www.anp.gov.br/images/DADOS_ESTATISTICOS/Reservas/Boletim_Reservas_2017.pdf

Audoly, R., Vogt-Schilb, A., Guivarch, C., & Pfeiffer, A. (2018). Pathways toward zero-carbon electricity required for climate stabilization. *Applied Energy*. https://doi.org/10.1016/j.apenergy.2018.05.026

Bataille, C., Waisman, H., Colombier, M., Segafredo, L., Williams, J., & Jotzo, F. (2016). The need for national deep decarbonization pathways for effective climate policy. *Climate Policy*, *16*(sup1), S7–S26. Retrieved from http://dx.doi.org/10.1080/14693062.2016.1173005%5Cnhttp://www.tandfonline.com.ezproxy.auckland.ac.nz/doi/abs/10.1080/14693062.2016.1173005%5Cnhttp://www.tandfonline.com.ezproxy.auckland.ac.nz/doi/pdf/10.1080/14693062.2016.1173005

BP. (2020). *BP Statistical Review of World Energy 2020*. *Statistical Review of World Energy*.

Bradley, S., Lahn, G., & Pye, S. (2018). *Carbon Risk and Resilience: How Energy Transition is Changing the Prospects for Developing Countries with Fossil Fuels*. Retrieved from https://www.chathamhouse.org/publication/carbon-risk-resilience-how-energy-transition-changing-prospects-countries-fossil

Carbon Tracker Initiative. (2011). Unburnable Carbon – Are the world's financial markets carrying a carbon bubble? *Carbon Tracker Initiative*.

Carbon Tracker Initiative. (2017). 2 Degrees of separation: Transition risk for oil and gas in a low carbon world. *Carbon Tracker Initiative*.

Carbon Tracker Initiative. (2018). *Mind the gap: The $1.6 trillion energy transition risk*. *accessed (18.02. 2019) at: https://www. carbontracker. org/reports/mind-the-gap*.

Comisión Nacional de Hidrocarburos. (2019). *Reservas de Hidrocarburos*. Gobierno de México. Retrieved from https://reservas.hidrocarburos.gob.mx/

Davis, S. J., Lewis, N. S., Shaner, M., Aggarwal, S., Arent, D., Azevedo, I. L., … Caldeira, K. (2018). Net-zero emissions energy systems. *Science*. https://doi.org/10.1126/science.aas9793

Della Vigna, M., Jost, C., Rae, M., Colaco, N., Murti, A. N., Tarr, H., … Morris, H. (2012). *Goldman Sachs: 360 projects to change the world*. Goldman Sachs, London, UK.

EY. (2017). *Global oil and gas tax guide 2017*. Retrieved from https://www.ey.com/Publication/vwLUAssets/ey-oil-and-gas-tax-pdf/$File/ey-oil-and-gas-tax-pdf.pdf

Ghandi, A., & Lin, C. Y. C. (2014). Oil and gas service contracts around the world: A review. *Energy Strategy Reviews*. https://doi.org/10.1016/j.esr.2014.03.001

Griffin, P.A., Jaffe, A.M., Lont, D.H., Dominguez-Faus, R. (2015). Science and the stock market: Investors' recognition of unburnable carbon. Energy Economics 52, Part A, 1–12. https://doi.org/10.1016/j.eneco.2015.08.028

Huppmann, D., Rogelj, J., Kriegler, E., Krey, V., & Riahi, K. (2018). A new scenario resource for integrated 1.5 °C research. *Nature Climate Change*. https://doi.org/10.1038/s41558-018-0317-4

IDB and DDPLAC. (2019). *Getting to Net-Zero Emissions: Lessons from Latin America and the Caribbean*. Inter-American Development Bank, Washington D.C. Retrieved from https://publications.iadb.org/publications/english/document/Getting_to_Net-Zero_Emissions_Lessons_from_Latin_America_and_the_Caribbean.pdf

IEA. (2017a). *Oil 2017: Analysis and forecasts to 2022*. International Energy Agency, Paris. Retrieved from https://www.iea.org/publications/freepublications/publication/Market_Report_Series_Oil2017.pdf

IEA. (2017b). *Oil Information 2017*. International Energy Agency (IEA), Paris, France.

IEA. (2018). *Global EV Outlook 2018*. International Energy Agency, Paris. Retrieved from https://webstore.iea.org/global-ev-outlook-2018

IEA. (2019). *World Energy Outlook 2019*. *World Energy Outlook 2019*. International Energy Agency (IEA), Paris, France.

IPCC. (2018). Summary for Policymakers. In *Global warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change*, (p. World Meteorological Organization, Geneva, Switzer).

IRENA. (2019). *Renewable Energy Capacity Statistics 2019*. International Renewables Energy Agency, Abu Dhabi. Retrieved from https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Mar/IRENA_RE_Capacity_Statistics_2019.pdf

Leaton, J., Fulton, M., Spedding, P., Grant, A., Capalino, G., Sussams, L., & Gagliardi, M. (2015). *The $2 trillion stranded assets danger zone: How fossil fuel firms risk destroying investor returns*. *Carbon Tracker Initiative*.

Lefevre, J., Wills, W., & Hourcade, J.-C. (2018). Combining low-carbon economic development and oil exploration in Brazil? An energy–economy assessment. *Climate Policy*, 1–10.

Lempert, R. (2003). *Shaping the Next One Hundred Years: New Methods for Quantitative, Long-Term Policy Analysis*. https://doi.org/10.1016/j.techfore.2003.09.006

Manzano M, O. E., Navajas, F. H., & Powell, A. (2017). *The economics of natural resources in Latin America: Taxation and regulation of the extractive industries*. *The Economics of Natural Resources in Latin America: Taxation and Regulation of the Extractive Industries*. https://doi.org/10.4324/9781315111377
McGlade, C. (2013). *Uncertainties in the outlook for oil and gas*. *Doctoral thesis, UCL (University College London).*
McGlade, C., & Ekins, P. (2015). The geographical distribution of fossil fuels unused when limiting global warming to 2 °C. *Nature*, *517*(7533), 187–190. https://doi.org/10.1038/nature14016
McGlade, Christophe, & Ekins, P. (2014). Un-burnable oil: An examination of oil resource utilisation in a decarbonised energy system. *Energy Policy*, *64*, 102–112. https://doi.org/10.1016/j.enpol.2013.09.042
McKay, M. D., Beckman, R. J., & Conover, W. J. (2000). A comparison of three methods for selecting values of input variables in the analysis of output from a computer code. *Technometrics*. https://doi.org/10.1080/00401706.2000.10485979
Ministerio de Energía y Minas. (2017). *Libro Anual de Recursos de Hidrocarburos*. República del Perú. Retrieved from http://www.minem.gob.pe/minem/archivos/LARH_2017.pdf
Ministerio de Energía y Minería. (2016). *Síntesis de la evolución de las reservas de hidrocarburos al 31 de diciembre de cada año. Período 2007-2016.* República Argentina. Retrieved from http://www.energia.gob.ar/contenidos/archivos/Reorganizacion/informacion_del_mercado/mercado_hidrocarburos/informacion_estadistica/reservas/MINEM_Informe_Reservas_HFVU_2016.pdf
Ministerio de Hidrocarburos. (2017). *Informe Anual del Potencial Hidrocarburífero del Ecuador 2017*. Gobierno de Ecuador. Retrieved from http://www.secretariahidrocarburos.gob.ec/wp-content/uploads/downloads/2017/09/Revista-Informe-Anual-del-Potencial-Hidrocarburífero-2017.pdf
Ministerio de Minas y Energía. (2018). *Boletín Estadístico de Minas y Energía 2016-2018*. República de Colombia. Retrieved from http://www1.upme.gov.co/PromocionSector/SeccionesInteres/Documents/Boletines/Boletin_Estadistico_2018.pdf
O'Neill, B. C., Kriegler, E., Ebi, K. L., Kemp-Benedict, E., Riahi, K., Rothman, D. S., … Solecki, W. (2017). The roads ahead: Narratives for shared socioeconomic pathways describing world futures in the 21st century. *Global Environmental Change*. https://doi.org/10.1016/j.gloenvcha.2015.01.004
OECD. (2020). *Revenue Statistics in Latin America and the Caribbean*. Organisation for Economic Co-operation and Development (OECD) Centre for Tax Policy and Administration, the OECD Development Centre, the Economic Commission for Latin America and the Caribbean (ECLAC) and the Inter-American Centre of Tax Administrations (.
OLADE. (2018). *Energy Statistics Yearbook 2017*. Retrieved from http://www.olade.org/publicaciones/anuario-estadisticas-energeticas-2017/
OPEC. (2017). *OPEC Annual Statistical Bulletin*. Organization of the Petroleum Exporting Countries, Vienna. Retrieved from https://www.opec.org/opec_web/static_files_project/media/downloads/publications/ASB2017_13062017.pdf
Pye, S., McGlade, C., Bataille, C., Anandarajah, G., Denis-Ryan, A., & Potashnikov, V. (2016). Exploring national decarbonization pathways and global energy trade flows: a multi-scale analysis. *Climate Policy*, *16*. https://doi.org/10.1080/14693062.2016.1179619
Rogelj, J., Popp, A., Calvin, K. V, Luderer, G., Emmerling, J., Gernaat, D., … Tavoni, M. (2018). Scenarios towards limiting global mean temperature increase below 1.5 °C. *Nature Climate Change*, *8*(4), 325. https://doi.org/10.1038/s41558-018-0091-3
SEI, IISD, ODI, Climate Analytics, CICERO, & UNEP. (2019). *The Production Gap: The discrepancy between countries' planned fossil fuel production and global production levels consistent with limiting warming to 1.5°C or 2°C.*