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# High and dry: Stranded natural gas reserves and fiscal revenues in Latin America and the Caribbean

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Inter-American Development Bank  
Climate Change and Sustainable Development Sector

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# High and dry: stranded natural gas reserves and fiscal revenues in Latin America and the Caribbean

Dan Welsby, Baltazar Solano Rodriguez, Steve Pye, Adrien Vogt-Schilb<sup>1</sup>

## Abstract

The global low-carbon energy transition driven by technological change and government plans to comply with the Paris Agreement makes future gas demand, prices, and associated public revenues uncertain. We assess the prospects for natural gas production and public revenues from royalties and taxation of gas production in Latin American and the Caribbean under different levels of climate policy. We derive demand from a global energy model, and supply from a global natural gas field model and a global oil field model – for associated gas.

We find that natural gas production and associated public revenue are strongly impacted by decarbonization efforts. The more stringent climate policy is, the lower the production of natural gas. Exporting natural gas from Latin America and the Caribbean does not help the rest of the world reduce greenhouse gas emissions. In scenarios consistent with limiting global warming well-below 2°C, incumbent producers and natural gas associated with oil dominate production, drastically limiting opportunities for new gas production in the region and increasing the amount of gas left in the ground. Reduced demand for gas produced from Latin America and the Caribbean is mainly driven by falling demand in the region itself, as energy demand in buildings, industry, and transportation shift towards electricity produced from zero-carbon sources.

Cumulative public revenues from natural gas extraction by 2035 range between 42 and 200 billion USD. The lower end of the range reflects scenarios consistent with below 2°C warming. In this case, up to 50% of proven, probable, and possible (3P) reserves in the region (excluding Venezuela) remain unburnable – the paper provides estimates by country. Our findings confirm that governments cannot rely on revenues from gas extraction if the objectives of the Paris Agreement are to be met. Instead, they need to diversify their fiscal and export strategy away from dependence on gas production. More generally, climate objectives, energy policies and fiscal strategies need to be consistent.

## 1. Introduction

Natural gas plays an important role in Latin America and the Caribbean. It accounted for 25% of primary energy consumption in 2019 (BP, 2021). Key producers in the region are Argentina, Mexico, Brazil, Bolivia, Trinidad & Tobago and Venezuela. Venezuela holds nearly 70% of proven gas reserves in the region, and Argentina holds huge unconventional resources, in particular the Vaca Muerta shale play. Natural gas also has an economic impact, whilst much lower than oil. In Bolivia and Trinidad and Tobago, natural gas rents, measured as the difference between domestic production costs and value and global prices, represent several points of GDP (Figure 1). In Trinidad and Tobago, gas also provides several points of GDP in tax revenues to the government (OECD et al., 2020).

The global energy transition driven by compliance with the Paris Agreement objectives and technological change makes future gas demand, and therefore prices, uncertain. Years ago, natural gas has been thought as a potential bridge fuel to a net-zero energy system, since it emits less carbon dioxide during combustion than coal, historically the dominant source for electricity production globally (Kerr, 2010; Brown et al., 2009). But recent research has shown that expanding supplies of natural gas may delay decarbonization (Davis et al., 2014; González-Mahecha et al., 2019), that climate benefits from gas depends on methane leakage rates, which tend to be underestimated (Howarth, 2014; Brandt et al., 2014; Shearer et al, 2020), and that the role of natural gas as a bridge to a low

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carbon energy system is subject to the replacement of more polluting fossil fuels and the availability of technologies such as carbon capture and storage (McGlade et al., 2014).

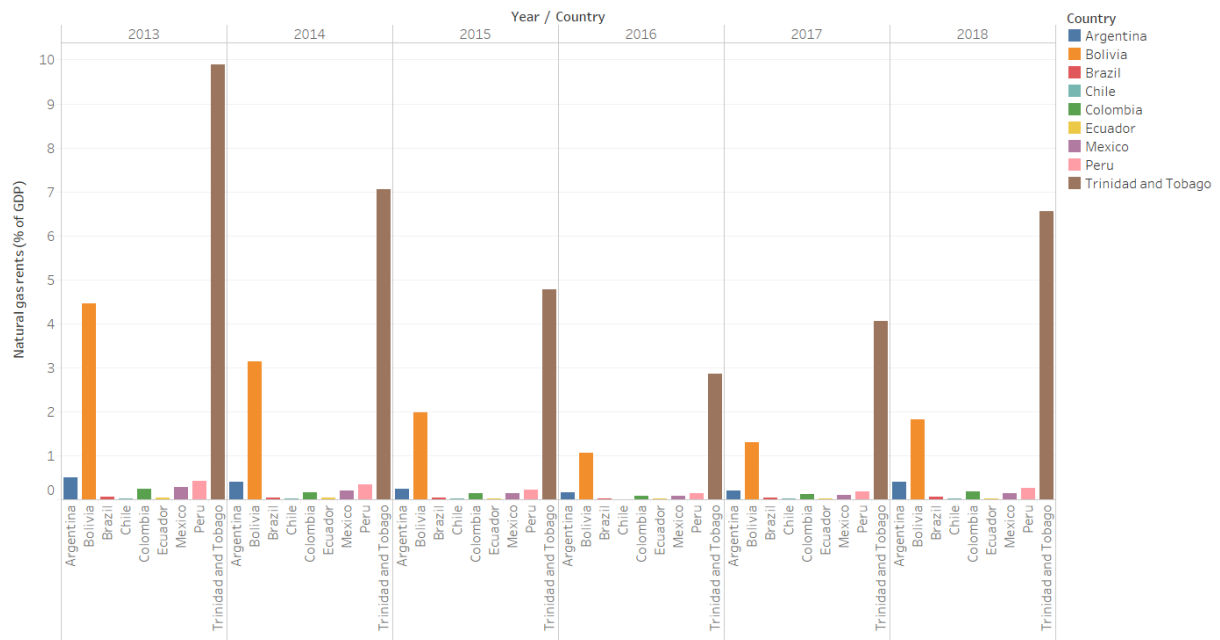


Figure 1. Natural gas rents across Latin America and the Caribbean (World Bank, 2020)

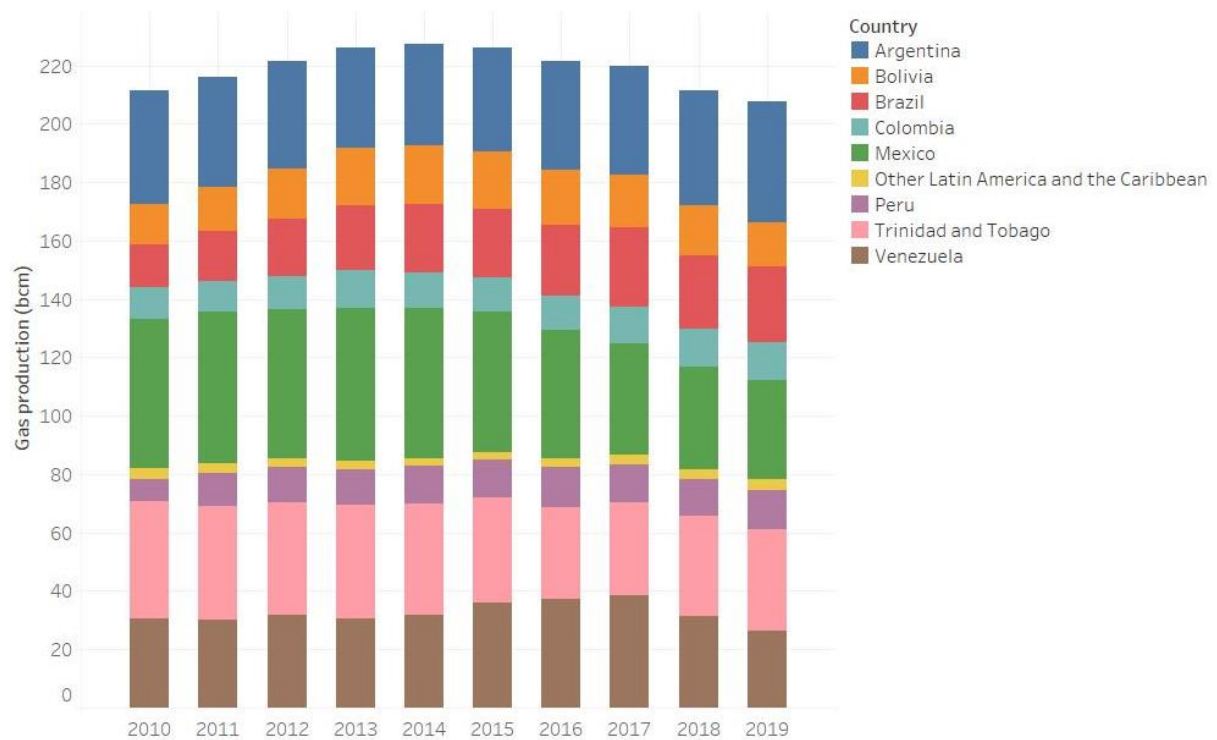


Figure 2. Production of natural gas by Latin American and Caribbean regions (BP, 2020)  
'bcm' on the y-axis stands for billion cubic meters

In the last years, renewable energy has emerged globally as the cheapest and fastest-growing source of energy in the world (IEA, 2021a). In addition, policymakers are increasingly focusing on net-zero-by-2050 goals (IDB and DDPLAC, 2019; IEA, 2021b). This calls into question the notion that any bridge to renewable energy is needed (McGlade et al 2018). Further, fossil fuels reserves are increasingly seen as assets exposed to *transition risk*, meaning that they could become *unburnable*, or *stranded* during the energy transition (McGlade and Ekins, 2015, Delgado et al, 2021). It has been pointed that government production plans or projections are inconsistent with their own emission-reduction goals under the Paris Agreement (SEI et al, 2021), and calls now abound for ministries of finance in fossil-fuel dependent countries to anticipate this risk and act to manage it (Delgado et al, 2021; Solano-Rodríguez et al., 2021, Coffin et al, 2021).

In the case of Latin America and the Caribbean, an additional issue is that competition from abroad jeopardizes domestic natural gas production. The region holds less than 5% of global reserves, and accounts for only 7% of production (OLADE, 2019). Before COVID, an increase in industrial activities and competition from the US has led to growing imports, particularly in Mexico. This has driven a decline in the aggregate gas production of the region between 2014 and 2019 (Figure 2).

This paper assesses the prospects for natural gas production and associate revenues in Latin American and Caribbean under emerging climate regimes over the next decade. It complements a previous study that assessed the prospects for *oil* production and associated revenues in the region, which found that more than two third of oil reserves and several trillions of dollars of oil royalties in the region are at risk (Solano-Rodríguez et al., 2021). We use a *robust decision-making* framework to explore a wide range of future energy transition scenarios.

We combine three models to quantify the uncertainties around future production and public revenue from natural gas. Future natural gas demand is taken from the TIMES Integrated Assessment Model at University College London (TIAM-UCL) in which we explore different levels of socioeconomic energy service demand drivers and different levels of climate policy globally. We use the Bottom-Up Geological and Economic Oil field model (BUEGO) to inform country-level production of associated natural gas (gas co-produced with oil). The Global GAs Production, Trade and Annual Pricing Model (GAPTAP) (Welsby, 2019, forthcoming), a new geological-economic model of global natural gas resources at field-level, is then used to determine how much can be produced at a country-level and the development of gas prices.

We simulate several scenarios of global energy production and demand. We combine assumptions about future energy demand drivers globally (from the shared socioeconomic pathway) with carbon budgets meant to represent climate policies consistent with current NDCs – which are known to be inconsistent with the achievement of long-term temperature targets of the Paris Agreement (Binsted et al., 2019; Olhoff et al., 2020; Bataille et al., 2020), a 2°C warming target, a 1.75°C target, or no climate policies at all. We also explore the impact of decreasing or increasing government take rates to 50 or 150% of current values.

We quantify the effects of the above-listed uncertainties on natural gas production, the share of proven, probable, and possible (3P) reserves in the region that remain underground, and total government take associated with natural gas production. We focus on Argentina, Bolivia, Brazil, Colombia, Mexico, Peru, Trinidad and Tobago and Venezuela, which account for over 98% of reserves and production in the region.

We find that the level of gas production in Latin America and the Caribbean depends chiefly on demand levels and the associated ambition of climate mitigation efforts. In well-below 2°C scenarios, gas production reaches 4-6 exajoules by 2035, compared to 9-13 EJ in the reference scenarios (that

reach 3°C or more). In our reference and NDC scenarios, gas demand in the region increases to 14-72% above 2018 levels by 2035. In contrast, in the scenarios that achieve global warming below 2°C, gas demand falls to 32-45% below 2018 levels. Natural gas is rapidly phased out of the power generation mix, and by 2035 gas demand is dominated by the industrial and transportation sectors.

We also find that 70% of proven, probable, and possible (3P) reserves in Latin America and the Caribbean remain unburnable due to reduced demand associated with high climate ambition. Removing Venezuela from the sample, unburnable natural gas reserves in the rest of the region range from 39-50%. We find significant volumes of unburnable gas reserves for key producers: Argentina (34-37%), Brazil (15-30%), Venezuela (89%), Mexico (69-72%). Trinidad and Tobago (6-8% unburnable) is an interesting case where production remains relatively static across all scenarios, due to production decline in the mature offshore fields and, whilst exports of LNG continue, struggle to compete against larger producers (Qatar, US, Nigeria, Australia). Trinidad exports of LNG have largely the same destination as current trade flows: Europe and within Latin America and the Caribbean.

We estimate cumulative fiscal revenues from natural gas extraction in the region to range between 42 and 200 billion USD in the period 2017-2035. The lower end of the range reflects the well-below 2°C cases. While some countries could hope to see increasing natural gas revenues in scenarios where climate change and the energy transition are ignored, public revenues from natural gas are poised to decline in scenarios consistent with 2°C or below-2°C targets.

Government efforts to maximize revenue from gas production and/or incentivize investment in the sector through lowering tax rates have a limited impact. Indeed, most of the Latin American and Caribbean production is consumed within the region. Most regional producers are not competitive against large global exporters, such as Qatar in the LNG markets. As a result, we do not find that producing natural gas in the region can help lower emissions in the rest of the world (e.g., by displacing coal). In the scenarios consistent with 2°C or below 2°C warming, reduced demand for natural gas is the dominant driver of both production and public revenue declines. Incumbent producers and associated gas dominate the production picture, leaving limited flexibility for any redistribution of production between countries.

Our findings confirm that countries need to diversify their revenues and energy strategy away from dependency on gas production (Coffin et al, 2021; SEI et al, 2021). Instead, investments should focus on the development of zero-carbon power generation capacity, such as wind, solar and hydro, and the use of electricity to displace fossil fuels in transportation, building and industry. For example, in our scenarios that achieve a temperature increase below 2°C, electricity generation reaches 4704-8160 TWh by 2050, a 2-to-4-fold increase of current generation, of which 88-96% is from solar, wind, or hydro. Wind and solar alone account for 76% of the generation mix in our below 2°C scenarios by 2050.

Our paper has several limitations. For instance, TIAM-UCL represents Central and South America as one single region and simplifies heterogeneities between different deployment potentials and energy systems at the country level. In addition our scenarios consistent with warming well below 2°C are centered around warming of 1.75°C, while many politicians currently use 1.5°C, or net-zero by 2050, as their preferred target. Studies at the country level, developed in collaboration with local energy and finance ministries, for instance following methods used by Huxham et al (2019, 2020) in South Africa and Uganda, could address some of these limitations.

Notwithstanding its limitations, this paper shows the necessity to shift away from natural gas production, decarbonise the power system and facilitate the electrification of energy services. The rest of the paper is structured as follows. Section 2 presents methods. Section 3 presents our results. Section 4 concludes.



## 2. Methods

### Approach to scenario assessment

We use a Robust Decision Making (RDM) approach (Lempert, 2003) to explore the implications of uncertainty for Latin American and Caribbean gas production and revenues to 2035. This analytical method uses data and models to stress test proposed strategies against a wide range of plausible futures. We evaluate clusters of future states of the world to understand the strengths and weaknesses of different strategies. This scenario-based approach uses the XLRM framework suggested by Lempert (2003) to guide stakeholder elicitation and organize the relevant data, assumptions, and modelling, as follows –

**Metrics for outcomes (M).** To assess whether future states of the world achieve decision makers' objectives, we quantify gas production and the consequent tax revenue generated for public budgets, for all major gas producing countries in the region. Additionally, we evaluate the fraction of reserves that remain unused by 2035.

**Policy levers (L).** These are the range of decisions that gas producers can make to influence the metrics. In our case, one decision that producers can make to influence outcomes are fiscal tax rates. We model the impact of halving or increasing by half the existing government take rates (50–150% of existing rates).

**Exogenous uncertainties (X).** This includes key uncertainties that impact global gas markets include economic growth, climate policies, demographic changes, and the role of gas in the low carbon transition. These are reflected in the evolution of global gas demand over the next two decades. In this study we use global gas demand trajectories resulting from a range of scenarios modelled in TIAM-UCL consistent with a temperature increase in 2100 leading to 2.9-3.8°C (Reference), 2.75-2.9°C (NDC), 1.85°C (2°C ), and 1.75°C (Below 2°C ). We also run individual sensitivities on the development costs of natural gas fields, using the Global GAs Production, Trade and Annual Pricing model (GAPTAP) (Welsby, n.d.). In this work we combine uncertainty of field development costs with tax rate policy levers (two of the key drivers of field development decisions) in order to assess and attempt to quantify the uncertainty in future production and government revenues from natural gas extraction in Latin America.

**Relationships (R).** We use the GAPTAP model, described in detail below, to quantify the implications of uncertainties and policy interventions on our metrics.

### The modelling framework

We use the new GAPTAP model (Welsby, 2019) in order to explore uncertainties surrounding future public revenue and unburnable gas reserves in Latin America and the Caribbean. GAPTAP is a new geological-economic model of global natural gas resources at field-level that determines how much can be produced and at what cost. The focus of this novel model is on upstream and midstream natural gas supply chain dynamics, considering future uncertainty in natural gas markets: demand, price formation mechanisms and levels, trade volumes, infrastructure costs, and inter-fuel competition (with details set out in the next section). Due to GAPTAP being constructed by Welsby (forthcoming) without an industrial database, the focus of the model is necessarily on larger producers with some fields in small producing countries missing. Here we present results for the largest producers in Latin America and the Caribbean, namely: Argentina, Bolivia, Brazil, Colombia, Mexico, Peru, Trinidad and Tobago and Venezuela. Given these countries account for more than 98% of current production and 99% of reserves, this forms the vast majority of both current, and projected future, gas production in Latin America and the Caribbean.

Regional demand shares of global natural gas demand are taken under different scenarios from the energy systems model TIAM-UCL (TIMES Integrated Assessment Model at University College London), as described in Pye et al. (2020a). TIAM-UCL (Pye et al., 2020b) is a 16-region, bottom-up linear optimisation model of the global energy system. It represents the production of energy resources, through to their conversion to other products, and to their use in end-use sectors. There are a total of eight sources of conventional and unconventional gas contained within TIAM-UCL: existing proved and probable reserves, reserve growth, undiscovered gas, arctic gas, tight gas, coalbed methane, shale gas, and associated gas. Each gas resource has individual availability and cost of production within each region. Production of associated natural gas is also taken from TIAM-UCL, with new investments in gathering and processing capacity taken into account (Welsby, forthcoming). A key strength of GAPTAP and TIAM-UCL is the soft-link consistency between the two models: the bottom-up databases constructed as part of GAPTAP's development were used to generate natural gas supply cost curves in TIAM-UCL, and therefore TIAM-UCL has a detailed techno-economic representation of the drivers of natural gas field supply costs (Welsby, forthcoming).

### GAPTAP modelling mechanism

The GAPTAP model consists of three core modules that determine type of supply: long-term contracts with indexation if applicable, domestic production, and spot. For reference, Appendix 1 and 2 provide a detailed breakdown and description of the mathematical formulation of GAPTAP (Welsby, forthcoming), including the derivation of price and tax revenue outputs for each module.

1. The long-term contract module runs to satisfy the minimum contracted quantity for long-term contracts from each exporter to each importing regions; the long-term contract volumes are exogenously set based on annual contracted quantities and/or average historical bilateral gas trade over five years. These volumes are then extended for the duration of the natural gas contract and are summed across the importing countries in each region and subtracted from the total regional consumption demand; importing regions are assumed to be price-takers (i.e. have to take minimum contracted quantity regardless of price). An extension of the model accounts for the uncertainties over future annual contracted quantities in existing gas contracts that involves varying the take-up of contracted volumes above the minimum contracted quantity. Additionally, the model can also decide to extend gas contracts on a rolling annual basis if these are competitive against an indicated price for available spot volumes.
2. The domestic production module essentially splits producing regions into net importers from net exporters. Regional production from TIAM-UCL is divided by regional consumption to signal whether a region is a net importer (production divided by consumption is less than 1) or a net exporter (production divided by consumption is greater than 1). For example, if a region produces more than it consumes, then the regional demand taken from TIAM-UCL (net of any long-term contracts) is met by fields within that region. Conversely, if a region is a net-importer, then GAPTAP brings individual fields online up to a maximum of the regional production suggested by TIAM-UCL (i.e. TIAM provides an upper bound indication for indigenous production, with GAPTAP determining which countries in the region produce). The module determines the proportion of regional demand which must come from that region's natural gas fields, and therefore reflects political decision to develop certain fields, even at higher cost. These include field development decisions which are motivated more in the name of energy security and diversification of supply, rather than importing gas at potentially lower prices.

The module also ensures production from individual countries are taken into account to ensure that one country does not over- or under-represent its share of regional production. Additionally, domestic price formation mechanisms taken into account include fiscal regimes and any production subsidies. For this work, any subsidies on the demand side were removed from the NPV equation, therefore the breakeven price for each field is independent of any potential government intervention to artificially reduce prices. The domestic module also has an in-built function in the supply clearing algorithm whereby it can choose which fields to develop based on a lagged indicated price and the residual production capacity in that region. In regions with relatively tight gas supply, this is relatively unused.

3. Once the initial long-term contract and domestic modules have run, any residual demand is met by additional trade modules. Firstly, any residual volumes of natural gas available from the long-term contracts (i.e. the difference between the maximum and minimum contracted volumes) competes against an indicated spot trade price<sup>2</sup>, and if competitive, additional volumes of contracted gas are traded. Natural gas trade is constrained based on an underlying trade matrix (i.e. bilateral trade constraints based on distance, historical patterns, and geopolitical factors), and suppliers compete based on competitive costs and the prevailing gas price (once long-term contracts have been satisfied and production from domestic fields have been taken into account) in both the importing and exporting region. The spot module allows the model to reflect differing market structures and price formation mechanisms.

#### Long-term contracts

GAPTAP has long-term contracts in place, with prices indexed to oil prices in each year. Each contract has an assumed minimum quantity which has to be taken by an importing country. The contracts are run to their end date, but can be extended on a rolling basis depending on the output contract price generated by the model, and the competing price of spot supply. Therefore, 'take-or-pay' clauses which were the basis for most major bilateral gas trade contracts in Latin America and the Caribbean are represented in the model, requiring importers to take a certain amount of gas regardless of alternatives. However, once these contracts run out, GAPTAP can continue to send out volumes based on more short-term spot variability. This can be seen in some of the scenarios explored below where Bolivian gas contracts with Argentina and Brazil expire, but volumes of pipeline Bolivian gas come in and out of the energy mix depending on the scenario in place (and combinations of different field costs and taxes discussed subsequently).

For Latin America and the Caribbean, an example of a long-term contract in GAPTAP is between Brazil and Bolivia, where the initial assumption around the minimum contracted quantity was 350 PJ per annum. However, Bolivian export contracts with both Brazil and Argentina were due to expire at the end of 2019/2020, with Bolivian exports declining significantly. However, there is an inbuilt function in the model which allows Bolivian exports on a rolling basis up to the former minimum contracted quantity, if competitive (as described above).

The annual time-slices of GAPTAP do not allow for some of the more complicated elements of gas take-or-pay contracts, which can include take up clauses allowing monthly variations in demand, but it does represent the main element of take-or-pay in the sense that the importer has to take a

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<sup>2</sup> Depending on the market structure in exporting countries, this indicated spot trade price is either the weighted price from specific fields which are "export only" (e.g. Russian LNG fields), or the price at which LNG exporters can purchase natural gas from hubs and then export (e.g. US and Canada).

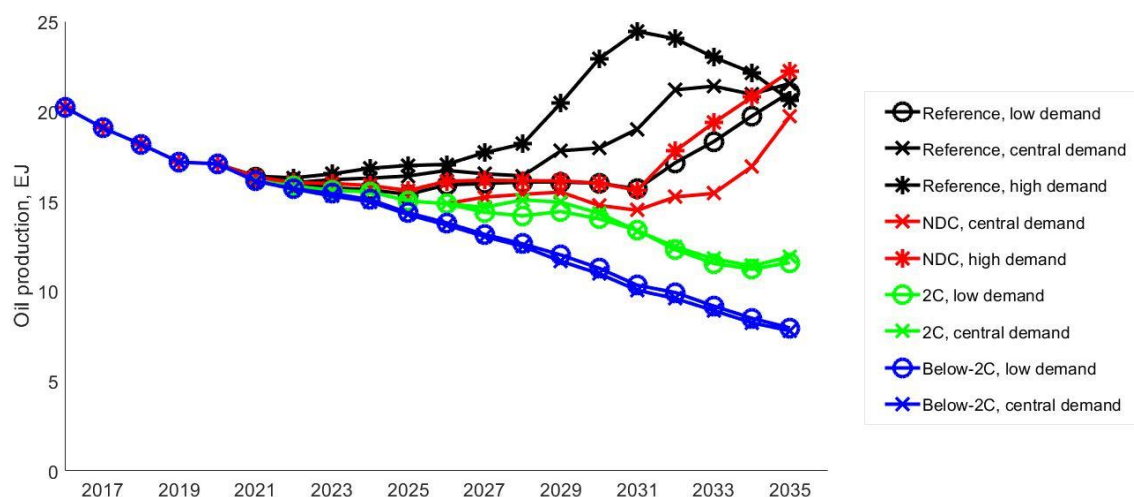
minimum amount of gas for the duration of the contract, regardless of potentially cheaper domestic production and/or LNG imports.

### Co-production of gas and oil

Gas production in some Latin American and Caribbean countries is dominated by associated natural gas, accounting for 74% of total gas production in Mexico and 79% in Brazil. Venezuelan production is also dominated by gas associated with oil, although there have been recent developments of offshore non-associated gas fields (e.g. Perla).

In this study, potential associated gas production levels are taken from each TIAM-UCL scenario. TIAM-UCL chooses whether to develop associated gas based on a range of parameters including the climate constraints, existing capacity, demand, and the availability of cheaper alternatives (it is an optimisation model). If associated gas is produced and requires additional capacity (gathering and processing), the model will have to build this capacity. If the associated gas is not ‘developed’, it is either flared or left unused (proxy for re-injection which the model cannot take into account).

The work conducted recently on unburnable oil (Solano-Rodríguez et al., 2021) has been the basis to conduct our oil production modelling at country level for Latin America and the Caribbean. Using BUEGO we have generated an outlook for oil producers in the region under a range of different climate-demand scenarios (discussed in the next Section). These oil production pathways have been used to estimate the percentage share of associated gas produced by countries under each scenario. The share from each country was then applied to the aggregated regional associated gas production outputs from TIAM-UCL (see Figure 8 in Section 3). The representation of associated gas in TIAM-UCL has been significantly improved by Welsby (forthcoming).



**Figure 3. Oil production in Latin America and the Caribbean (EJ)**

BUEGO is a medium-term model that incorporates economic and geological characteristics of oil (McGlade, 2013). 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 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 fiscal regime).

Figure 3 shows the oil production pathways for the Latin America and Caribbean region under a range of scenarios discussed in more detail in the next section.

### Pipelines and other distribution infrastructure

GAPTAP takes into account internationally traded gas infrastructure in the following ways:

- Existing pipelines, and under construction pipelines are considered in the model; under construction pipelines have a separate capital expenditure (CAPEX) figure which needs to be paid off over (currently) ten years including pre-production
- LNG infrastructure (existing) is included with a unit investment cost included in the trade costs. The unit investment cost is calculated using project specific CAPEX<sup>3</sup> divided by an assumed capacity output over a 20-year period. Project specific discount rates are also included. For LNG trade, if a unit investment cost was not used and a direct CAPEX figure was used instead as with pipelines, then it is not possible to apportion CAPEX to certain importers in the contract price (i.e. how much of the CAPEX is reflected in the contract price to trade to individual countries).
- The model can also invest in new LNG infrastructure given the following constraints:
  - Sufficient supply potential
  - Residual demand in importing regions
  - Competing spot supply prices amongst exporters, and prevailing price in importing region

### Field level supply costs

At present, there is a single supply cost applied to each field which includes capital expenditure (CAPEX) and operation expenditure (OPEX). This is due to data limitations – there is very limited publicly available cost information for individual gas fields, and therefore separating CAPEX and OPEX into individual cost parameters was not possible. A literature review therefore gathered data on a range of gas field cost data, which in many cases was already in a combined “supply cost” format. A regression model was then applied to key drivers of these field costs in order to apply costs to fields for which there was no data available and/or have not yet been developed. In this way the costs for undeveloped fields are based on statistically significant drivers. Additionally, cost of capital assumptions are inbuilt into this single supply cost figure. The model has dynamic field costs for offshore conventional non-associated gas fields derived from a linear regression model analysis of statistically significant drivers of gas field development costs (Welsby, forthcoming).

Fields are developed based on an expected break-even price across the field lifetime. Taken on a year-by-year basis, this means that the output price required to yield a positive NPV will change and will be higher in the first few years as the CAPEX is paid off and then lower as only the OPEX is required. However the producer will not necessarily receive this higher price (i.e. they will expect a certain price to cover costs over the field lifetime), therefore a single price per field is used to cover the NPV over the project lifetime rather than in each year.

The market clearing algorithm for each module in GAPTAP yields the price which brings the required supply and sub-set of overall regional demand into equilibrium. As the price iterates upwards, the

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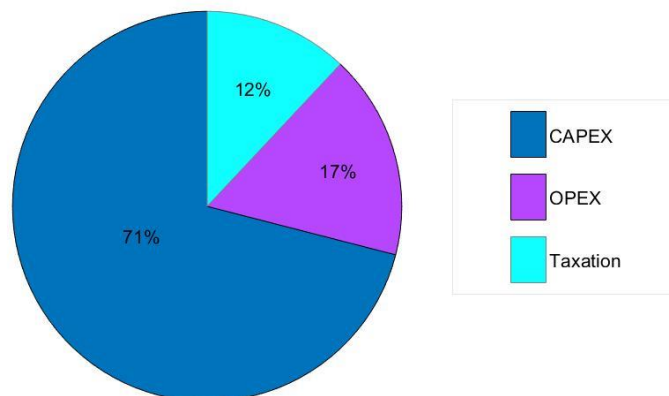
<sup>3</sup> The CAPEX is calculated including an assumed cost of capital, raised by the number of years assumed capital expenditure is amortised (standard assumed is five years (McGlade, 2013)), and divided by the plant/train capacity assuming output for 20 years. These are obviously simplifications as a liquefaction plant will generally last longer than 20 years, however, this period at full capacity is considered sufficient to cover a) it will unlikely run at full capacity, and b) some years output may well be below/significantly below capacity. Therefore:  $(CAPEX * CostofCapital^5) / (Capacity * 20)$

model can choose to develop (or alternatively not develop) a field based on the marginal price indication from the previous year.

Some indications of the composition of field costs are shown in Table 1 for some Latin American and Caribbean gas fields, and an example cost structure for the Margarita gas field in Bolivia is shown in Figure 4.

**Table 1. Indicative CAPEX for selected fields as percentage of total costs**

Field (Country)	% of costs from CAPEX
Margarita (Bolivia – onshore)	71
Perla (Venezuela – offshore)	55
Serrette (Trinidad – offshore)	80
Manati (Brazil – offshore)	77



**Figure 4. Cost structure of the Margarita gas field (Bolivia)**

#### Subsidies for natural gas supply and demand

Both production and consumption subsidies can be included in GAPTAP. Production subsidies included in GAPTAP across different countries include direct per unit production subsidies and tax breaks/tax rate reductions for certain geological categories/fields. However, as mentioned previously, consumption subsidies are not included in this work for the following reasons:

- There is a demand response function in GAPTAP which allows a small demand response to increasing prices. We decided to allow the full extent of this demand response, particularly in response to tax rate and field cost changes without the inclusion of artificially depreciated prices. This was done to allow the model to fully capture future dynamics where subsidised pricing is removed, rather than assume these continue out to the end of the modelling horizon. Additionally, consumption subsidies in Latin America and the Caribbean often involve discriminatory pricing depending on the end-use consumer which was beyond the scope of this study. An interesting extension to this work would therefore be an exploration into the downstream demand impact on end-use sectors of the scenarios we used;
- One of the main aims of this project is to estimate fiscal revenues of natural gas extraction in Latin America and the Caribbean under different global climate policy regimes. Therefore, we

focus on *gross revenues* rather than use limited public data to assume future levels of subsidies (which would provide *net revenues*). Our analysis therefore provides policy implications for any future subsidisation of fossil fuel consumption. In particular under the more ambitious global climate policy scenarios where fiscal revenues from natural gas are lower, a key policy takeaway is to shift expenditure to lower carbon energy vectors.

### Fiscal regime characterisation

An important element in the NPV calculation for each project is the taxes arising from the fiscal regime in place. In GAPTAP, this is represented as a percentage of revenue taken in royalties (i.e., proportion of production or revenue going to the government), profit and/or income taxes. In some countries, GAPTAP includes dynamic revenue taxes based on production levels. Additionally, each field has specific discount rates to reflect project risk. In its simplest form, distinctions are made between taxes on revenue and profit streams, which are subtracted from the revenue/profit stream of the producer and added to the public revenue of the country where the field/project is located. Further detail on the implementation of fiscal regimes can be found in Appendix 1.

## **Scenario definition and exploration**

### Definition

The role of gas in the global low carbon energy transition is subject to multiple uncertainties relating to economic growth, technological innovation, demographic drivers, political decisions, social acceptance and climate policies. According to OIES (2017), the key question is whether gas will become unaffordable and uncompetitive in Latin America and Caribbean countries where energy access is a critical concern, long before its emissions make it unburnable. This complex picture creates a wide variation in the outlook for gas in many markets across the globe, resulting in uncertain revenue for gas producers.

In order to understand how the combination of global gas demand uncertainty and fiscal regime impact on the production outlook for different producers in the Latin American and Caribbean region, we include variations across the following dimensions in our scenario design -

- Nine global demand levels based on the scenarios of gas production consistent with four global climate targets, and variations in energy service demands consistent with the shared socioeconomic pathways
- Fiscal rates by Latin American and Caribbean country

Each scenario consists of the choice of one global gas demand pathway and a fiscal rate for each country in the region. The exogenous drivers of energy service demands in TIAM-UCL are based on the shared socioeconomic pathways (SSPs), of which we have chosen three. The SSPs were constructed to form a narrative around the ability of society to adapt and mitigate the impacts of climate change (van Vuuren et al., 2014; O'Neill et al., 2014):

- SSP1 = 'sustainability, with lower population growth but high GDP growth, driven by consumer behaviour choices which emphasise sustainability and strong ability to mitigate and adapt to future climate change. SSP1 includes behavioural shifts such as lower meat and dairy consumption (and therefore lower emissions from land-use and land-use change), slower demand growth in aviation and lower demand reduction for pooled transportation over private vehicles compared to the middle-of-the-road SSP2 pathway
- SSP2 = 'middle of the road', a central pathway for energy service demand growth
- SSP5 = 'fossil fuel', very high per capita energy demand growth driven by high GDP growth and lower population than SSP2, with a focus on developing fossil fuels and high consumption of

meat and dairy, resulting in high land-use and land-use change emissions. However, income per capita is highest in SSP5 and institutions are assumed to be strong to adapt to the rapid growth in emissions. It should however be noted that when combined with representative concentration pathways (RCP's<sup>4</sup>) and carbon budgets in our 2-degree and below 2-degree scenarios in TIAM-UCL, an SSP5 demand growth pathways leads to an infeasible modelling result (i.e. the model cannot solve without the inclusion of a 'backstop' technology which removes CO<sub>2</sub> from the atmosphere at prohibitively high cost).

### Constructing scenarios to explore the uncertainty space for natural gas supply and demand in Latin America and the Caribbean

#### **Global gas supply and demand from TIAM-UCL**

In order to model varying levels of demand for natural gas under different decarbonisation pathways and socio-economic drivers of energy service demands, we use the energy system model TIAM-UCL. TIAM-UCL is a global energy system model which uses a bottom-up, technologically detailed energy reference system to equilibrate energy supply and demand. The demand for energy services in TIAM-UCL is driven by exogenous socio-economic drivers (e.g. GDP, population, urbanisation, etc.), with the model optimising (minimising the cost) the supply of the required energy, relative to numerous user constraints. The model can also run with an elastic demand function, whereby energy service demands react dynamically within the model run to any changes in the cost of energy feedstocks / changes to how 'tightly' the user constraints bind the objective function.

In this work, a range of demand pathways are developed in TIAM-UCL to reflect the inherent uncertainty in both future decarbonisation efforts and socio-economic drivers of energy service demands. Table 2 below describes each demand pathway and includes any climate parameter constraints, including carbon budgets used.

**Table 2: Scenarios developed using TIAM-UCL to generate a range of demand pathways for natural gas in Latin America and the Caribbean**

Scenario name	Shared socioeconomic pathway (SSP)	Temperature increase by 2100	Carbon budget applied, Y/N
Reference, low demand	1	2.9	N
Reference, central demand	2	3.2	N
Reference, high demand	5	3.8	N
NDC, central demand	2	2.8	Y
NDC, high demand	5	2.9	Y
2°C , low demand	1	1.9	Y
2°C , central demand	2	1.9	Y
Below-2°C , low demand	1	1.75	Y
Below-2°C , central demand	2	1.75	Y

For the "NDC" scenarios, regional greenhouse gas budgets are utilised based on Winning et. al (2019), with pledges under the Nationally Determined Contributions determined at COP21 extrapolated from 2030 at a constant rate of greenhouse gas (GHG) emissions per GDP/capita. For the "2°C" and "Below 2°C" scenarios, CO<sub>2</sub> budgets are used between 2018 and 2100 of 1170 Gt CO<sub>2</sub> and 800 Gt CO<sub>2</sub> (Rogelj

<sup>4</sup> The representative concentration pathways exhibit different narratives for the concentration of GHG's in the atmosphere (in TIAM-UCL these transform CO<sub>2</sub> emissions into concentrations using the relevant parameters for that RCP, and then constrain the model around the upper and lower bounds of the concentration pathway (van Vuuren et al., 2014)).

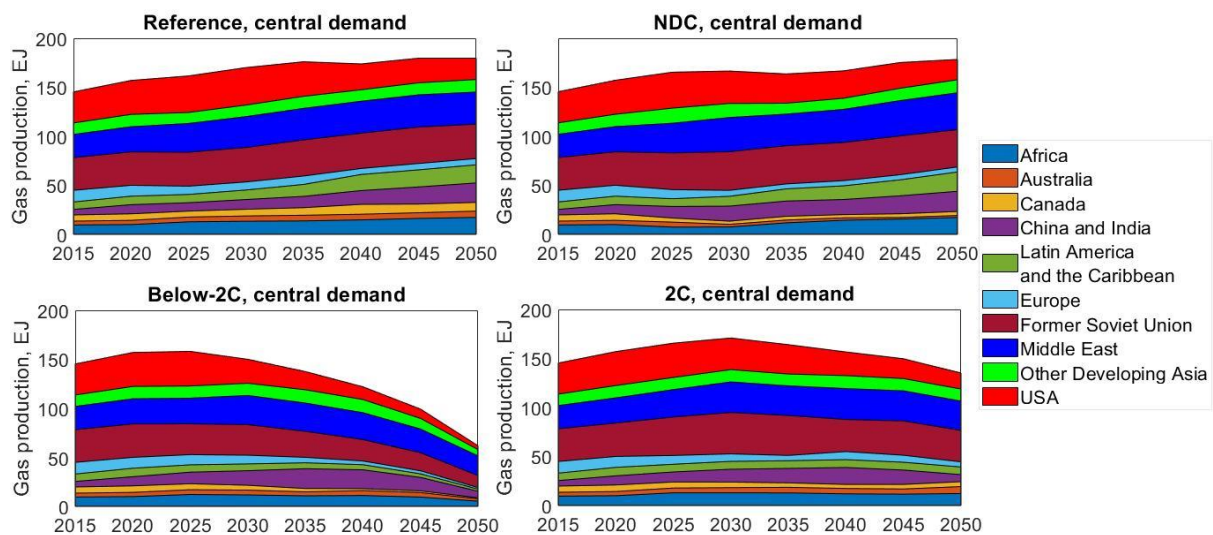


et al., 2018), respectively. For scenarios where carbon budgets are applied, an endogenous carbon price (marginal cost of abating a unit of CO<sub>2</sub>) is generated in TIAM-UCL which therefore adds additional cost onto any consumption of fossil fuels within the model.

For each climate-demand scenario combination, the relevant socioeconomic driver pathways of energy service demands are employed within each scenario. For the low, central, and high demand scenarios, these include GDP and population pathways consistent with SSP1, SSP2 and SSP5, respectively. Within TIAM-UCL, each energy service demand in each region is applied a growth driver, with certain decoupling conditions potentially attached. The functional form of energy service demands and the respective drivers is shown below taken from Pye et al. (2020a):

$$ESD_{r,t} = ESD_{r,t-1} \left( \frac{Driver_t}{Driver_{t-1}} \right)^{\alpha_t}$$

For each service demand, a driver of demand based on different socioeconomic pathways (the SSPs) is applied based on the different shared socioeconomic pathway. These drivers include GDP, GDP per capita, population, the number of households, and the respective share of GDP coming from the services sector. Therefore each SSP pathway will have different trajectories for GDP, population, etc., and therefore different growth drivers for each energy service demand. Additionally, the exponent  $\alpha$  is a decoupling factor which can be used to further adjust the relationship between the demand drivers and demand based on the relevant SSP (Pye et al., 2020a).



**Figure 5. Clockwise from top-left shows global gas production (split by region) for each scenario explored in this work as described in Table 2**

Figure 5 shows the global production outlook from the four “middle-of-the-road” shared socioeconomic pathway 2 demand scenarios we used in this work. It should be noted that the global production pathways are shown out to 2050 from TIAM-UCL in order to provide context to the post-2035 energy system (i.e. beyond the time horizon of GAPTAP). Therefore, whilst we use GAPTAP to provide country-level insights into production and fiscal revenues, we provide some global context across our central demand scenarios from TIAM-UCL out to 2050 given the significant developments in natural gas supply and demand post-2035. Additionally, and as mentioned in the Methods section of this report, TIAM-UCL provides both regional consumption demand inputs and an upper bound constraint for regional production to GAPTAP.

As can be seen from Figure 5, the dominant producers now (Middle East, Former Soviet Union and the United States) continue to account for at least 50% of global production across all scenarios. Production from Latin America and the Caribbean increases in the Reference and NDC scenarios post-2025, driven by increased output from gas associated with oil and the steady ramp-up of unconventional gas production. In contrast, in the 2°C and Below 2°C scenarios Latin American and Caribbean gas production declines out to 2050. This is due to the large-scale exploitation of natural gas in the region being incompatible and cost sub-optimal with the more ambitious global climate policy cases and inconsistent with demand within the region. In our TIAM-UCL results under reference scenarios, gas consumption in Latin America and the Caribbean increases by nearly two-thirds to 2050, driven by demand in the industrial, power and transport sectors. However, in the 2°C scenarios gas consumption drops by a third, with nearly 60% of gas consumption going to the industrial sector in 2050. This is largely due to a decline in gas-based electricity generation and a relatively minor role in road transport. Under below 2°C scenarios there is an even larger reduction, with only a quarter of the base-year gas consumption by 2050. In these scenarios over 50% goes to industrial uses, and a sharper decline is observed in gas-based electricity generation (with some gas remaining largely as back-up capacity). South American gas from unconventional sources struggles to compete on global markets and with declining demand domestically (see Figure 6 (b) and Figure 10), the vast majority of these gas resources are left in the ground. For reference, a detailed analysis of sources (both from a country and geological perspective) of Latin American and Caribbean gas production across the scenarios and sensitivities explored in this work is discussed in Section 3 using the GAPTAP model.

Additionally, Figure 6 shows the supply (a) and demand (b) pathways for natural gas in each of the 9 scenarios explored in TIAM-UCL and listed in Table 2 for Latin America and the Caribbean.<sup>5</sup> As with Figure 5, the results from TIAM-UCL are shown out to 2050 to ensure full transparency of energy system developments post-2035. In the low and central demand scenarios with lower ambition global climate policies (i.e. 'Reference' and 'NDC' scenarios), gas production and consumption both decline slightly before rising again post-2025. This is for several reasons:

1. Due to TIAM-UCL being an optimisation model, the model develops proven gas reserves (including significant volumes of associated gas) first, the majority of which are starting to reach the decline stage by 2020 in Latin America and the Caribbean. Unconventional natural gas production starts to ramp-up in the region (except for Mexico) but cannot do so rapidly enough, therefore there is a slight mismatch between supply and demand;
2. In the 'NDC - central demand' case, 2025 is the first time-period with regional GHG budgets. Latin America and the Caribbean has a high share of its total allotted GHG budget taken up by land-use emissions, and therefore some realignment of the energy system towards low-carbon energy vectors in the region is required in 2025.

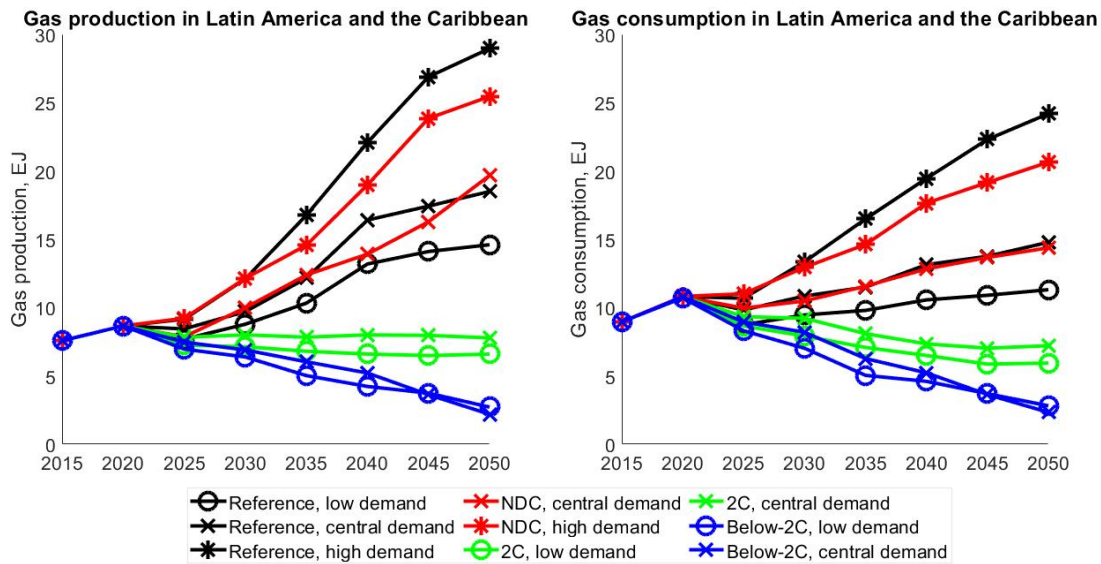
Production and consumption reach their highest values in the SSP5 demand scenarios (Reference and NDC - high demand), whilst in the strong global climate ambition scenarios (2°C and Below 2°C), both production and consumption decline consistently from 2020. The differences between production and consumption are driven by:

- The level of exports from Latin America and the Caribbean in each scenario (i.e. the scale of the region's role in global gas markets), with the scenarios consistent with current NDCs or ignoring climate targets seeing strong exports, whilst in the scenarios resulting in < 2°C natural gas exports from the region decrease considerably;

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<sup>5</sup> Central and South America (CSA) and Mexico are two separate regions in TIAM-UCL but have been aggregated here into a Latin America and the Caribbean region. For information on the countries included in CSA see Pye (2020b).

- Losses of natural gas between the well-head and end-use (both in distribution and end-use processes given efficiencies of technologies are (for the most part) less than 1).



**Figure 6: Natural gas production (left) and consumption (right) for Latin America and the Caribbean from the 9 demand-climate policy scenarios explored in TIAM-UCL (as described in Table 2)**

### Combining climate and demand scenarios with gas market-specific sensitivities

To explore the outlook for public revenues from natural gas in Latin America and the Caribbean, we combined the climate policy and socioeconomic demand pathway scenarios we ran in TIAM-UCL with a range of sensitivities in GAPTAP. In short, we take regional consumption of natural gas from each scenario ran in TIAM-UCL and explore gas market uncertainties in GAPTAP by varying tax rates and field development costs. We varied the tax rate for each country and cost input for each field by between 0.5-1.5 of the central input, in increments of 0.25.

### Combining uncertainties and levers

In order to assess the impact of different policy levers (e.g. altering tax rates) combined with exogenous uncertainties (climate policy and energy service demands) have on our key metrics (fiscal revenues and production profiles), we employed a Latin Hypercube exercise to generate our uncertainty combinations. The Latin Hypercube Sample exercise involves taking individual choices from discrete data (e.g. a global climate policy, an energy demand driver, a tax rate, and a field development cost level) into continuous distributions. This was repeated to generate 450 individual sensitivity combinations across the climate policy-demand pathway scenarios from TIAM-UCL.

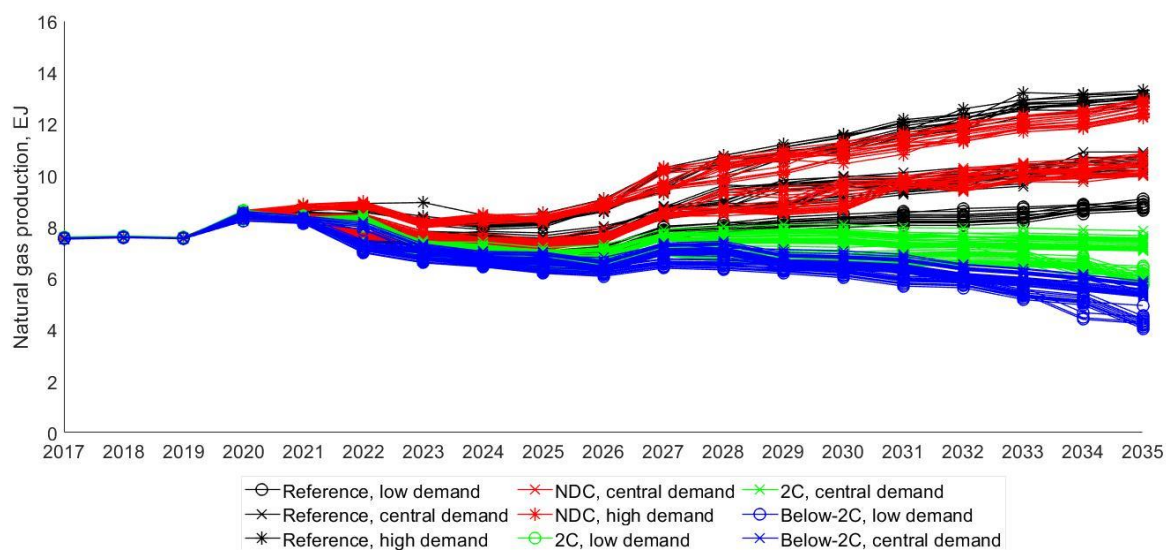
Using a Latin Hypercube Sampling technique allowed a more targeted approach to quantifying the uncertainty across the potential solution space for public revenues from natural gas in Latin America and the Caribbean under different demand and global climate policy pathways. For example, a Monte Carlo simulation would require far more runs and is prone to a more 'random' allocation across the uncertainty space, whereas Latin Hypercube sampling allows a more refined approach to reflect certain outcomes have a higher likelihood than others (e.g. the central demand pathway (SSP2) would be expected to have a higher probability of occurring and therefore sampled more, given it is a "middle of the road" scenario).

### 3. Results

#### Production outlook

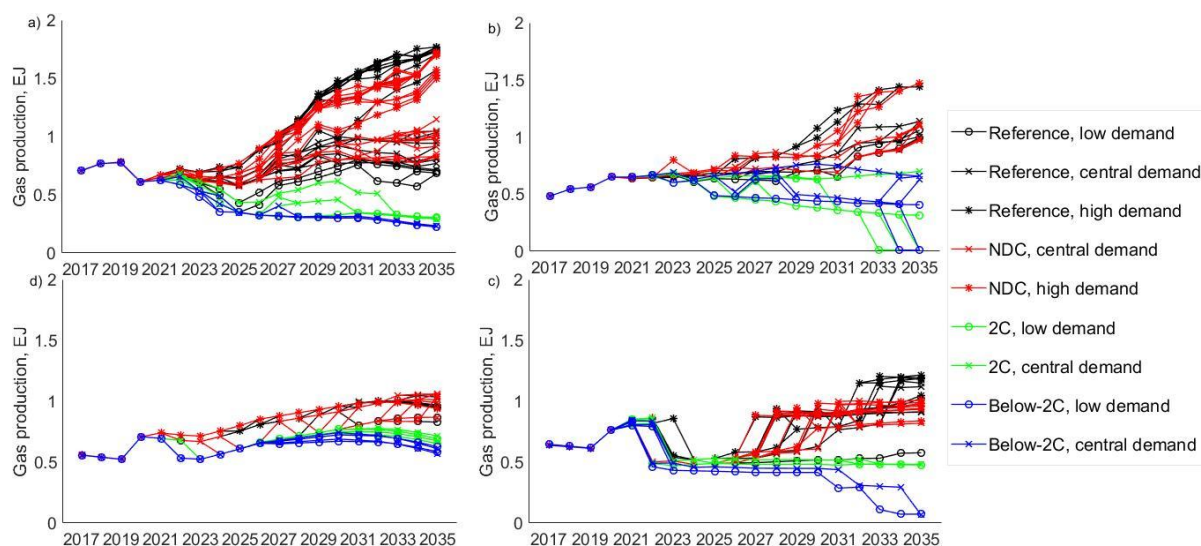
As was shown in Figure 6, regional production peaks in Latin America and the Caribbean in the Reference cases (relative to other pathways), rising to a maximum of nearly ~30 EJ by 2035 in our “Reference- high demand” scenario (i.e., no carbon budgets and SSP5 demand drivers). This is largely driven by higher production from associated natural gas (i.e., gas co-produced with oil) and a ramp-up of unconventional gas, namely shale deposits in Argentina. However, in the scenarios which result in less than 2°C average temperature increase by the end of the century, natural gas production in the region *declines* from 2020, reflecting both a domestic and international shift away from natural gas. Whilst Trinidad and Tobago and Peru continue to export LNG (mainly to Europe and Asia), they do so within the confines of their existing reserve base, with both countries experiencing production decline from some key assets and competition on international markets from lower cost producers.

Figure 7 shows the production pathways for Latin America and the Caribbean for each scenario described in Table 2, and for each combination of tax and cost sensitivities from the sampling distribution. These results are outputs of GAPTAP, with country-level insights discussed subsequently.



**Figure 7: Aggregated production for Latin America and the Caribbean under each of the pathways listed in Table 2**

Figure 8 shows country-level production for key gas producers in Latin America and the Caribbean. We find that varying field costs and tax rates in a range of uncertainty combinations has the largest impact on country-level production and fiscal revenues in the lower ambition climate (Reference and NDC) scenarios (particularly when combined with the higher demand SSP5 pathway). This is due to overall demand for natural gas being higher and therefore more producers are able to compete at the prevailing market price.



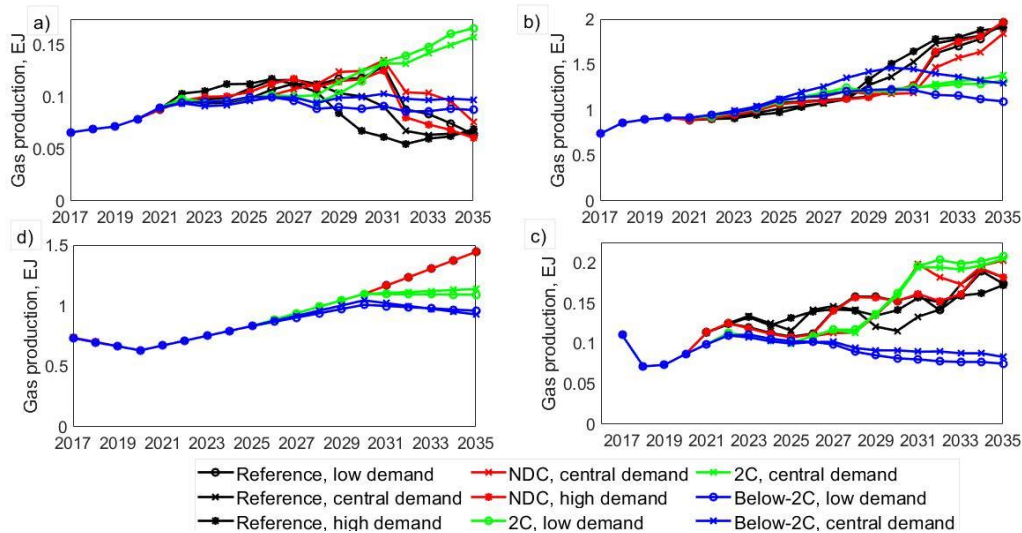
**Figure 8 (a-d): Country-level production across our climate policy and demand scenarios, and tax-cost sensitivities. Clockwise from top-left, (a) Argentina, (b) Brazil, (c) Mexico, (d) Venezuela**

### Gas production by category across the scenarios and sensitivities

As mentioned previously, associated gas continues to play a significant role in Latin America and the Caribbean throughout the time-horizon of GAPTAP. Figure 9 (a-d) shows the maximum<sup>6</sup> country-level production potential of associated natural gas for four countries: Brazil, Colombia, Mexico and Venezuela. For the Central and South America (non-members of the Oil Producing and Exporting Country (OPEC) grouping) region in TIAM-UCL, we use the country-level percentage share of oil production from the BUEGO model (see Figure 3) to split the aggregated associated gas output from TIAM-UCL for each of the 9 core scenarios we ran. These production potentials are then fed into GAPTAP, creating associated gas “fields”. Whilst there has been limited studies into the potential of associated natural gas production across different climate policy scenarios, one indication is the International Energy Agency (IEA) World Energy Outlook (2019) where projections of Brazilian associated gas production from offshore pre-salt oil fields reaches over 2.3 EJ (~ 60 bcm) by 2040 in the IEA’s Stated Policies Scenario. For reference, the NDC scenarios (which most closely align with the IEA’s Stated Policies Scenario) from this work estimate Brazilian associated gas production potential to be 1.8-2 EJ by 2035.

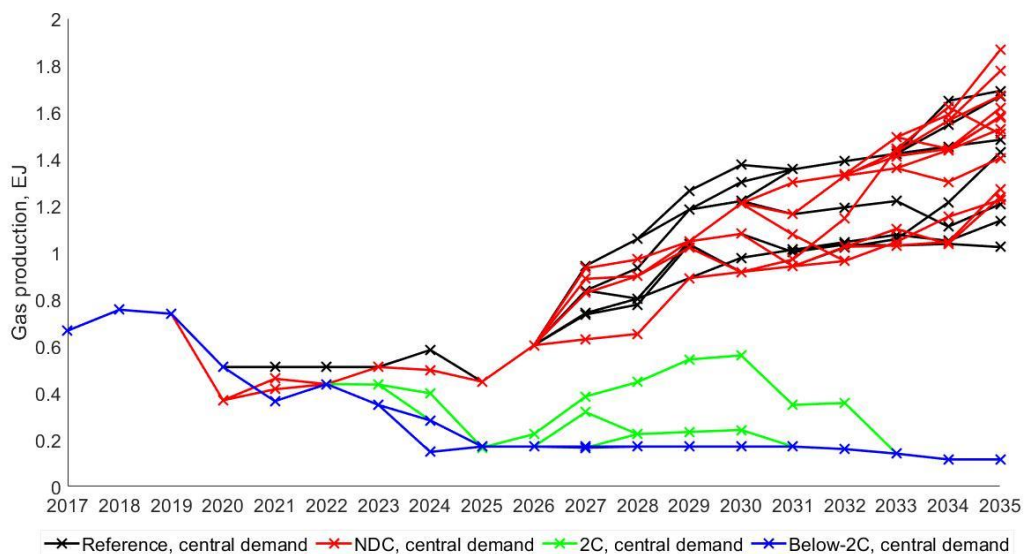
One key finding of this paper is that once global climate policy targets are ramped up in ambition, the room for gas producers in Latin America and the Caribbean to capture market share narrows significantly. In short, when stringent climate policy is enacted, that becomes to dominant driver of natural gas production dynamics between regions, with low cost associated production taking an increasing share of a shrinking market. In the summary section of this report, we gave a range of cumulative production across our scenarios and sensitivities for Argentine shale gas, ranging from 30 EJ in our ‘reference’ (or no climate policy case) to just 4 EJ in the scenarios meeting below-2°C. Figure 10 shows unconventional gas production in Argentina across three of our central demand scenarios.

<sup>6</sup> I.e. maximum associated gas potential available from each TIAM-UCL scenario split between countries based on the shares from BUEGO. GAPTAP does not necessarily use this production potential.



**Figure 9 (a-d): Potential associated gas production by country. Clockwise from top-left, (a) Argentina, (b) Brazil, (c) Colombia, (d) Venezuela**

Figure 8 shows that in the reference scenario shale gas production increases, and there is significant variations in production post-2025 driven by changes in the tax rate and field development cost sensitivity combinations determined by the Latin Hypercube Sample (i.e. increased competition between countries and resource categories to produce). In our central demand reference scenario, shale gas production in Argentina by 2035 is 390-542 percent higher than 2018 levels (reaching around 1.7 EJ/a, or 113% of current Argentina production)<sup>7</sup>. In contrast, when climate policy is enacted to keep global temperatures to below 2°C, Argentine shale production declines to 40% of 2018 production levels by 2035. Unlike the reference scenario, altering tax rates has limited impact once climate policy ambition is ramped up. This is due to a combination of the carbon budget driving decarbonisation and therefore declining gas demand, along with competition from lower cost associated natural gas to supply the remaining gas market.



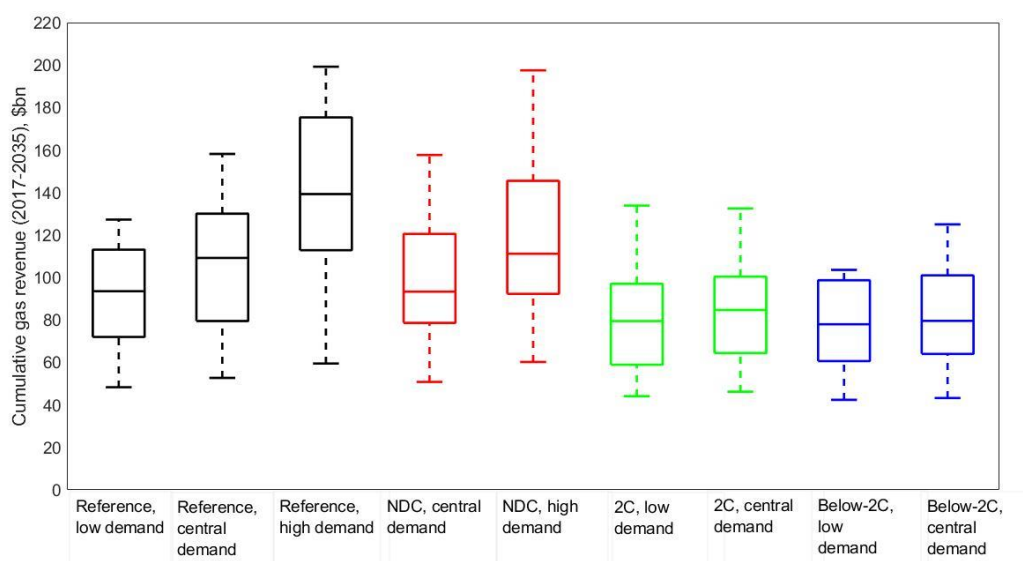
**Figure 10: Unconventional (shale and tight) gas production in Argentina across our central (SSP2) demand scenarios**

<sup>7</sup> For reference, in our high demand reference scenario, shale gas production reaches 3.1 EJ/a by 2035.

## Future government tax take

In this work, public revenues from natural gas are defined as the royalty and taxation payments collected by national governments from upstream natural gas extraction. These are calculated at the field/project level in GAPTAP and discounted to ensure the present value of future tax revenues.

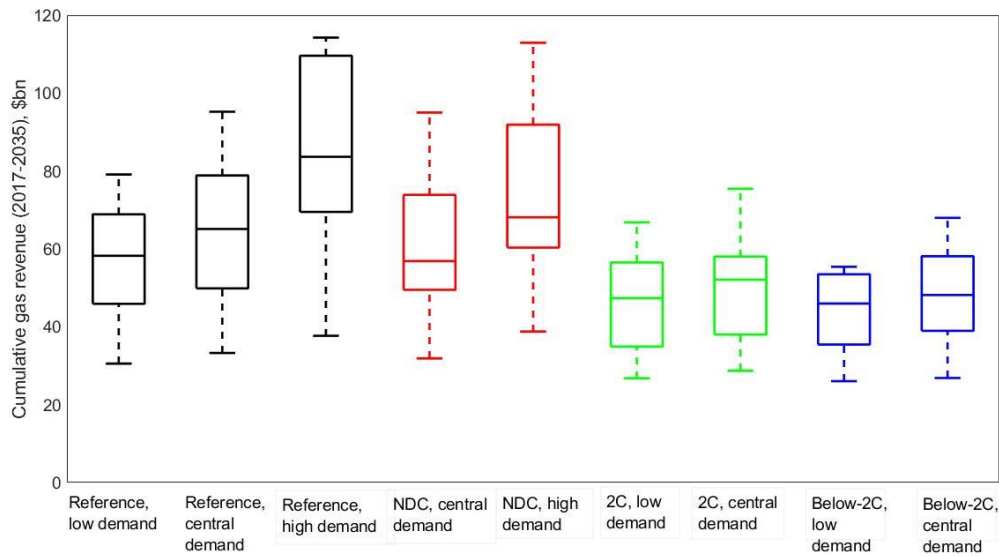
Figure 11 shows a range of cumulative government tax takes across Latin America and the Caribbean for each of the 9 scenarios described in Table 2, using box-and-whisker plots, showing the 25<sup>th</sup>, 50<sup>th</sup> and 75<sup>th</sup> percentile government revenues across the core scenarios with the ranges reflecting the impact of the Latin Hypercube sampling of tax and field cost sensitivities. Each scenario was run independently with a range of sensitivities to take into account uncertainty in future levels of government tax take by altering future taxation rates. These sensitivities inflated or deflated the taxation rates which were gathered from Ernst & Young (2019) and input into GAPTAP as described in Section 2 of this report. By utilising this uncertainty in future taxation rates, the model therefore outputs a total of 450 iterations across the main decarbonisation and demand scenarios described in Table 2. Additionally, Figure 12 shows the same information except for non-OPEC countries in Latin America and the Caribbean.



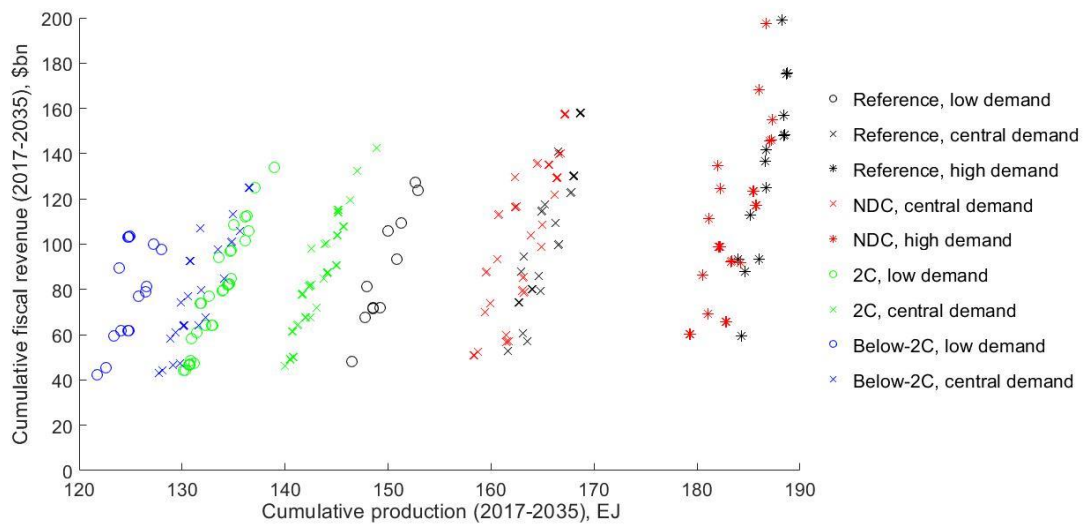
**Figure 11: Range of cumulative tax takes in Latin America and the Caribbean in each individual scenario**

Cumulative revenues in Latin America and the Caribbean are highest in scenarios with high demand (SSP5 pathway) and lower global climate policy ('Reference' and 'NDC' scenarios resulting in temperature increase of 2.8-3.8°C by the end of the century). As described in the previous section, the importance of associated natural gas across all the scenarios can be seen in the difference between Figure 11 (all Latin America and the Caribbean) and Figure 12 (non-OPEC Latin America and the Caribbean, i.e. without Venezuela). Venezuelan associated natural gas is assumed to be on the same extremely high taxation regime as oil (e.g. 50% profit taxation and 33% royalties (Ernst & Young, 2019) but due to its low cost and constraints within the model, Venezuelan associated production maintains a relatively strong presence across all scenarios (see Figure 9).

To show the impact of various tax rate and field cost sensitivities on production and fiscal revenues across the core scenarios, Figure 13 shows cumulative (2017-2035) production plotted against cumulative (2017-2035) tax revenue for the aggregated Latin America and the Caribbean. For each of the 9 climate-demand scenarios, multiple markers reflect variations in cumulative production and/or cumulative revenues due to sensitivities on tax rates and field development costs.

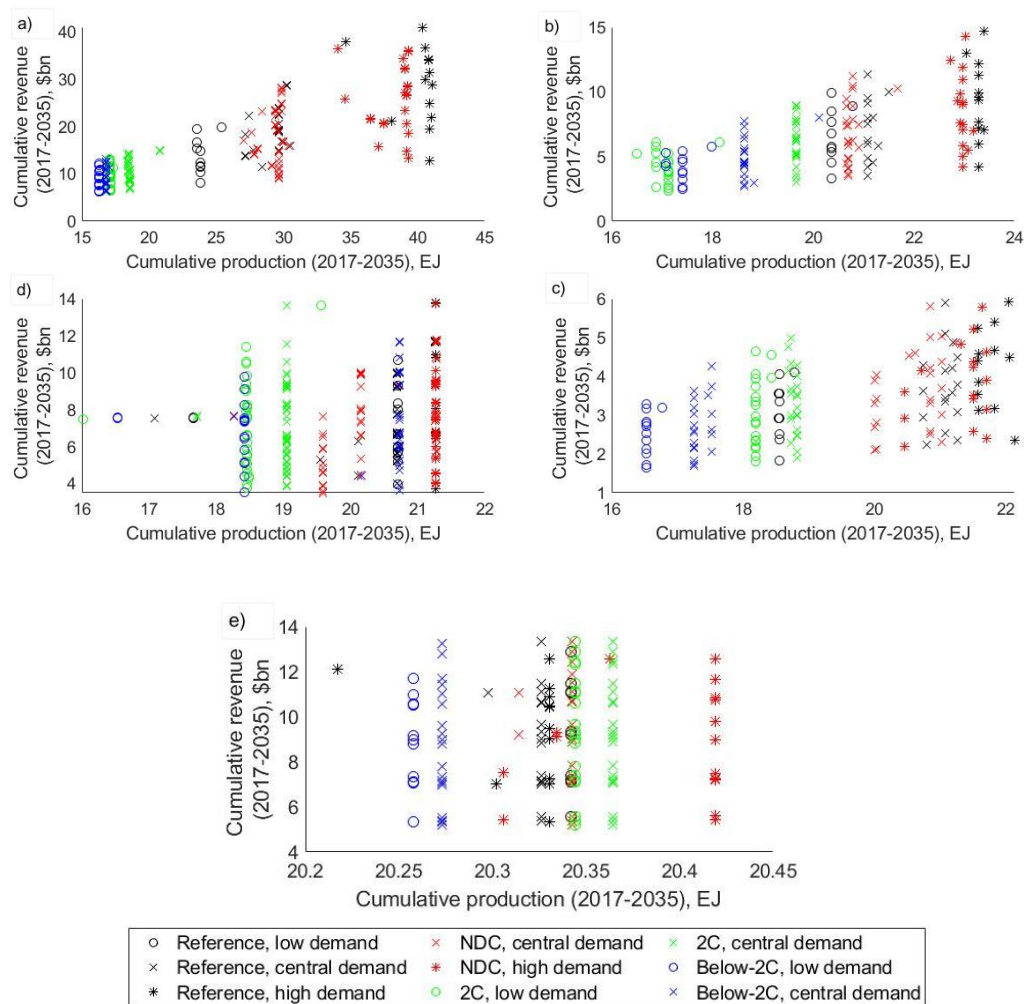


**Figure 12: Range of cumulative tax takes in non-OPEC Latin America and the Caribbean across each individual scenario. The OPEC country not included is Venezuela.**



**Figure 13: Cumulative production (EJ) vs. cumulative fiscal revenue (\$bn) for the Latin America and the Caribbean region, 2017-2035. Each marker colour and shape shows the core scenario whilst any differences within each scenario grouping is due to the tax and cost sensitivity simulation**



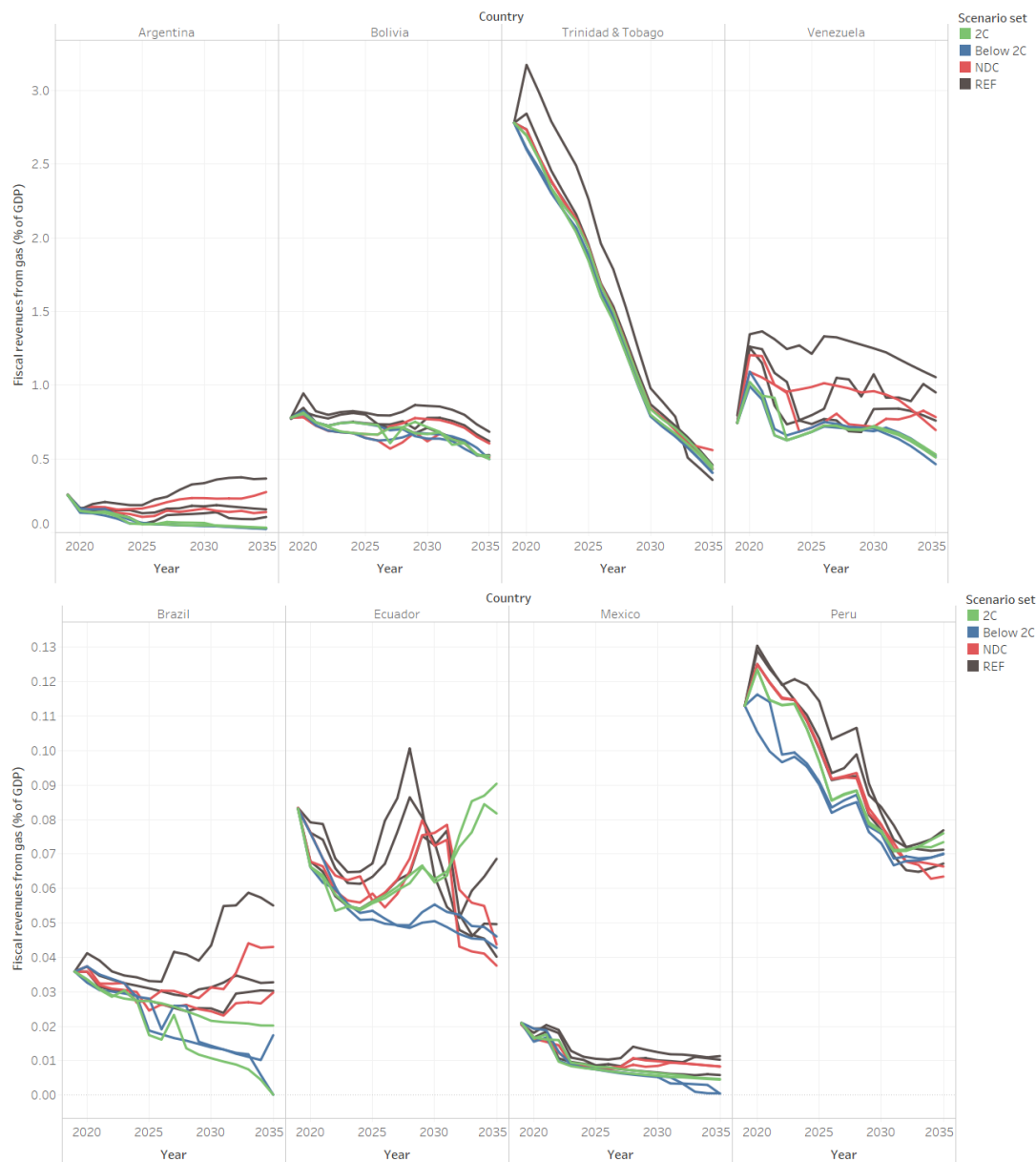


**Figure 14 (a-e): Cumulative production (EJ) vs. cumulative tax take (\$bn) for selection of gas producers in Latin America and the Caribbean. Clockwise from top-left, (a) Argentina, (b) Brazil, (c) Mexico, (d) Bolivia, (e) Trinidad and Tobago**

Panel (a-c) in Figure 14 also confirm that changes to tax rates and field costs have far more of an impact in the lower climate policy scenarios where demand for natural gas is significantly higher and therefore more of the reserve/resource base is able to compete. This was also shown in Figure 8 and 10, where changes in production levels due to tax rate and field cost sensitivities in the lower climate policy scenarios (Reference and NDC) are far greater than in the high climate policy scenarios (2°C and Below 2°C).

Bolivia would appear to be inelastic to changes in the tax rate from Figure 14 (d) in that production does not shift when the tax rate increases/decreases. Whilst this is contrary to the general pattern in other countries where higher tax rates (and therefore higher public revenues) increase the price required to bring a gas field online and, in some cases, disincentivizes field development, Bolivia has two key characteristics which differ to some other gas producers in the region. Firstly, Bolivian production is heavily concentrated in a few giants, but mature, fields (Margarita, Sabalo, Itau) and production from these continues relatively independent of any changes to Bolivian tax rates, albeit with decline rates setting in. Secondly, Bolivia acts as a ‘swing supplier’ once gas contracts with Brazil and Argentina run out in 2020. In short, any additional supply needed to meet demand is taken from both international spot markets and from Bolivian exports gas through the existing pipelines to Argentina and Brazil given there is residual production capacity in Bolivia once these contracts end.

The relative importance of gas revenues to governments in the region is illustrated in Figure 15. The graphs show variation in the contribution of fiscal revenues from gas to producers in the region, with different trajectories but a similar pattern overall - where deep decarbonisation scenarios for a given country contribute less to budgets than their NDC and reference scenarios, largely due to declining production. For instance, the contribution of fiscal revenues from gas for Brazil can range from nearly 0.06% of GDP in 2035 for high demand reference scenarios to less than 0.01% in below 2°C scenarios. Although in monetary terms this is a considerable amount in fiscal revenues, its contribution to the budget is relatively minor given the size of the Brazilian economy. On the other hand, other countries see a relatively small potential loss of fiscal revenues in absolute terms, but experience a more significant gap to their budget. Trinidad & Tobago seems to be less sensitive to global climate policies, since their fiscal revenues decline in all scenarios; but it's the most impacted in the region, from nearly 3% in 2020 to about 0.5% of GDP in 2035.



**Figure 15. Contribution of fiscal revenues from gas (% of GDP) by climate scenario.** Each line represents one of the scenarios in Table 2. The colour of the lines refer to the global demand scenario under different temperature targets. The upper panel shows the countries with larger contributions to GDP (Argentina, Bolivia, Trinidad and Tobago and Venezuela), while the lower panel shows a selection of countries with small contributions to GDP (Brazil, Ecuador, Mexico and Peru).

Whilst Figure 15 shows falling fiscal contributions, these will be partially offset by reducing expenditure on supply-side subsidies in Latin American and Caribbean countries, where tax exemptions/relief, direct per unit production subsidies, or including a price floor for producers to ensure a certain price is paid (e.g. with unconventional gas producers in Argentina) are all currently in place in different countries. Increasing attention in the transition away from fossil fuel dependency is now being directed at supply side interventions, including the removal of supply side financial incentives and production moratoriums on new developments (Erickson et al., 2018). These supply side interventions should complement demand side measures including prices on carbon (which is endogenously generated in the more stringent climate policy scenarios we explore using TIAM-UCL) and phasing-out sales of carbon intensive products. Additionally, many countries in the region subsidise different end-use consumers to varying degrees. As discussed previously, whilst a detailed exploration of these is outside the scope of this work, it would nevertheless make for interesting future exploration, both in terms of demand response to rising sectoral prices and the concurrent elasticity of supply.

### Unburnable reserves

Given that consumption of natural gas in 2035 is lower than our base year of 2017-18 in our high climate policy scenarios (keeping global mean temperatures below 2°C), we now explore the proportion of 3P natural gas reserves which remain undeveloped.

Table 3 below shows the range of cumulative production across our high global climate ambition scenarios (carbon budgets and climate parameters consistent with keeping global warming below 2°C) for a selection of countries in Latin America and the Caribbean. We also provide unburnable numbers for the whole region (including other producers such as Colombia and Peru), and the region without Venezuela which (as Table 3 shows) covers just over half of the total regional reserves. We used 3P (i.e., proved, probable and possible) reserves from a range of sources because it provides flexibility for movements of natural gas volumes into a different classification. When considering reserves over a period of time, it is highly likely volumetric estimates will change due to revisions (in either direction), extended recovery, and new discoveries. Therefore, 1P reserves were deemed too restrictive for this purpose.

**Table 3: Unburnable natural gas reserve ranges across the higher climate ambition scenarios (i.e., 2°C - low and central demand; and below 2°C -low demand central demand) for a selection of key gas producers**

Country	Natural gas reserves 2017, 3P (EJ)	Cumulative production, 2017-2035	Unburnable reserves, %
Argentina	26 (SEC, 2019)	16.3-20.8	19-37
Bolivia	20 (Peña Balderrama et al., 2018)	16-20	2-20
Brazil	25.5 (FIRJAN, 2018; Chavez-Rodriguez, 2016)	16.2-24.1	5-36
Mexico	58 (PEMEX, 2015)	16.3-22	62-72
Trinidad and Tobago	22 (Energy Chamber of Trinidad and Tobago, 2016)	20.3-20.5	7-8
Venezuela	222 (OECD et al., 2020; IEA, 2019)	23.5-25.5	89
Latin America and the Caribbean aggregated	425.2	121.8-148.9	65-71
Latin America and the Caribbean non-OPEC (no Venezuela)	203.3	98.3-123.3	39-50

## 4. Conclusions

Gas producers face headwinds over the coming decades, as multiple factors reduce the role of gas in Latin America, the Caribbean and the rest of the world. A significant share of reserves may not be exploited as a consequence of reduced gas demand due to greenhouse gas emission targets or competitiveness effects. We find that across the region, 39-50% of reserves (or 65-71% including Venezuela) remain in the ground under scenarios consistent with the achievement of the Paris Agreement temperature targets (that is a warming of 2°C or below).

From the analysis conducted, public revenues from natural gas operations are far more sensitive to overall demand changes and the stringency of future decarbonization than any government effort to maximize revenue through tax rate changes. Given the level of decarbonization required to meet below-2°C targets, consumption in Latin America and the Caribbean needs to fall 32-45% below 2018 levels. In such a scenario we estimate that median revenues are \$80 billion, compared with a median \$111 billion across scenarios that ignore all climate target.

As decarbonization commitments are ramped up, their impact on demand is much more significant than other changes associated with tax levels or specific field level costs. In other words, it is demand destruction which appears to be the greatest driver of production and revenue reductions. Countries with large resources (Argentina, Brazil and Mexico) see the largest range of uncertainty in terms of cumulative tax take out to 2035 across the scenarios and tax rate-field cost combinations we conducted in this work. However, although Trinidad & Tobago sees less uncertainty and potential monetary losses, their public finances are the most affected in relative terms (revenues are stagnant while GDP grows).

We also find that as oil production in Latin America and the Caribbean decreases, production of associated gas declines. Therefore, reductions in oil production go hand in hand with gas production declines. We find that this remaining associated gas production and utilization covers an increasing share of production in the region in the high climate policy scenarios. This is due to gas demand reducing in the 'Below 2°C' scenarios more rapidly than oil production: gas demand falls 35-47% between 2020 and 2035, whereas oil production declines 13-15%.

Given that scenarios consistent with the Paris Agreement sees global gas consumption and production decline, governments in Latin America and the Caribbean should focus revenue generation efforts in other sectors. However, we also see that current exporters (including Bolivia and Trinidad & Tobago) continue to export, albeit at declining volumes, both to markets in the region (Bolivia) and global LNG markets (Trinidad & Tobago) across all scenarios we explored in this work. We therefore suggest a managed decline of these assets including aligning remaining revenues from exports into the longer-term shift to a decarbonised energy system.

We also find that natural gas is phased-out of the power generation and residential sectors in Latin America and the Caribbean, meaning widespread investment in smaller scale natural gas distribution networks would be stranded under our scenarios consistent with 2°C and below 2°C warming. Whilst these insights focus on Latin America and the Caribbean, they may be of interest to other gas producers across the world.

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## Appendices

### Appendix 1. Modelling mechanisms in GAPTAP

This section discusses the modelling mechanisms in GAPTAP. GAPTAP is formed of three main modules: a long-term contract module, a domestic production module (which satisfies a section of regional consumption which is assumed to have to come from that regions' indigenous fields), and a trade competition module, where spot supply competes against other exporters on a spot market, as well as any residual contracted quantities. The equations laid out below form the mathematical foundations of GAPTAP, and are taken from the forthcoming thesis by Welsby.

#### Long term contracts

Equation 1 shows the formula used to generate cash flows for each contract. This provides a matrix of cash flows for each time (i.e. annual) and price iteration, for each contract.

$$CF(LTC_r)_{t,P(Contract)_i,a} = \frac{((FP_{a,t} * P(Contract)_i * (1 - TaxIncome_{c,t})) - (FP_{a,t} * FieldCost_{a,t} * Index_{c,t}) - (FP_{a,t} * VAROM_{c \rightarrow importer}) - (\frac{INVCost_{a,t+t+1+1}}{5})) * (1 - TaxProfit_{c,t})}{(1 + \delta_a)^t}$$

(Equation 1)

where,

$r$  = region

$t$  = time-period  $t$  running from 2015 to 2035 in annual time-slices (i.e.  $t=1:1:21 =$

2015:1:2035)

$a$  = contract  $a$

$FP_{a,t}$  = field/contract volume in time  $t$ , for  $FP_{a,t} = MaxLTC_a * MinACQ_a * BinaryLTC_{a,t}$

where,

$MaxLTC_a$  = maximum contracted quantity for contract  $a$

$MinACQ_a$  = minimum annual contracted quantity for contract  $a$ ,  $0 < MinACQ_a \leq 1$

$BinaryLTC_{a,t}$  = exogenous binary matrix with long-term contract duration (i.e. this tells the model when contracts start and end)

$P(Contract)_i$  = contract price input/iteration  $i$ , where  $i=1:1:21$

$TaxIncome_{c,t}$  = tax-take on production income/revenue (e.g. royalties) from fiscal regime of country  $c$  in time  $t$

$FieldCost_a$  = field cost for field  $a$

$Index_{c,t}$  = additional indexation mark-up on contract price, e.g. from oil indexation.

$VAROM_{c \rightarrow importer}$  = cost of trade (transportation cost for pipeline, unit investment cost plus shipping for LNG)

$INVCost_{a,t}$  = investment cost for pipeline (altered with a cost of capital assumption), with a five-year time-lag (i.e. assume the pipeline is paid off over five years and investment costs start five years before gas flow begins)

$TaxProfit_{c,t}$  = tax-take on profit stream from fiscal regime of country  $c$  in time  $t$

$\delta_a$  = discount rate for specific field/contract/project  $a$

$CF(LTC_r)_{t,P(Contract)_i,a}$  = output cash flow matrix ( $t \times P(Contract)_i$ ) for each contract  $a$  in region  $r$



The net present value vector for each contract is calculated by summing cash flows across the contract lifetime, for each price iteration  $P(Contract)_i$ , as shown in Equation 2.

$$NPV(LTC)_a = \sum_{t=start(a_i)}^{end(a_i)} CF(LTC_r)_{t,P(Contract)_i,a}$$

(Equation 2)

where,

$t$  = time-period

$end(a_i)$  = end period of contract

$start(a_i)$  = start period of contract (or start of CAPEX for pipeline infrastructure)

$CF(LTC_r)_{t,P(Contract)_i,a}$  = cash flow in time  $t$ , price iteration  $P(Contract)_i$ , for contract  $a$  in region  $r$  (output matrix from Equation 1)

$NPV(LTC)_a$  = net present value for each contract  $a$  summed through the whole contract lifetime. Therefore,  $NPV(LTC)_a$  is a  $1 \times P(Contract)_i$  vector

For each contract, the sum of each contracts cash flow matrix which generates positive net present value across its lifetime yields the output price for that contract. For example, if  $NPV(LTC)_a$  is a vector of summed cash flow matrices through a project lifetime and each column represents the price iteration  $P(Contract)_i$ , then the column where  $NPV(LTC)_a > 0$  yields the output price (a scalar) for each contract. Equation 3 shows the calculation of each contract marginal output price.

$$P(Contract)_a = length(NPV(LTC)_a < 0) + 1$$

(Equation 3)

where,

$NPV(LTC)_a$  = net present value of summed cash flows from Equation 2

$length(NPV(LTC)_a < 0)$  = length of the vector  $NPV(LTC)_a$  for which the NPV is negative, i.e. to the margin of turning positive. Therefore adding 1 to this vector length identifies the price at which  $NPV(LTC)_a$  turns positive through its lifetime.

$P(Contract)_a$  = scalar long-term contract price output for field/contract  $a$ , equal to the marginal price which brings the field online (i.e. generates a positive NPV when summed across the contract life-time)

Whilst the assumption of a singular contract price output is a simplification, it reflects the fact that contracts are often signed with an assumed break-even price across the contract duration. For example, a long-term contract project involving a pipeline may well yield negative cash flows in the first years when the capital expenditure is being amortised, however across the lifetime of the project, the output contract price yields a positive NPV. Additionally, because the initial run of the long-term contract module is 'fixed', in the sense that there is an exogenous assumption of both the duration of contracts and that an importing country must take at least the minimum quantity in each year of the contract, allowing the entire module to run through the modelling period to output the marginal contract price first can be justified.

The scalar price output ( $P(Contract)_a$ ) is then multiplied by a binary matrix depending on whether the contract is in place in each year. These marginal prices (i.e. the price at which NPV becomes positive) are then used to generate a regional price output. Additionally,  $P(Contract)_a$  is used to estimate government revenue from each contract.

$$WP_{a,t} = \frac{FP_{a,t}}{\sum_{a=1}^n FP_{a,t}}$$

(Equation 4)

where,

$FP_{a,t}$  = contract  $a$  volume in time period  $t$

$n$  = total number of contracts in each region

$WP_{a,t}$  = weighted share of contract  $a$  in time period  $t$ , where  $WP_{a,t} < 1$ , ( $a \times t$  matrix)

Equation 5 then shows how an aggregated regional long-term contract price is derived, by summing the marginal price of each contract ( $P(Contract)_a$ ) multiplied by its share of total contracts into each region, in each year.

$$Price(LTC_r)_t = \sum_{a=1}^n P(Contract)_a * WP_{a,t}$$

(Equation 5)

where,

$P(Contract)_a$  = scalar long-term marginal contract price output for field/contract  $a$  from Equation 3

$n$  = total number of contracts  $a$  in each region  $r$

$WP_{a,t}$  = weighted production share of regional total of contract  $a$  in time period  $t$ , where  $WP_{a,t} < 1$ , ( $a \times t$  matrix)

$Price(LTC_r)_t$  = weighted contracted price output in time-period  $t$  for region  $r$ , ( $1 \times t$  vector)

### **Domestic production**

The cash flow equation assigned to each domestic gas field is shown in Equation 6, incorporating several parameters. This generates a matrix of cash flows in each year and for each price iteration, for individual gas fields.

$$CF(Domestic_r)_{t,P(Domestic)_i,a} = \frac{((FP_{a,t} * P(Domestic)_i * (1 - TaxIncome_{c,t})) - (FP_{a,t} * (FieldCost_{a,t} - Subsidy_{c,t}))) * (1 - TaxProfit_{c,t})}{(1 + \delta_a)^t}$$

(Equation 6) where,

$r$  = region

$t$  = time  $t$

$P(Domestic)_i$  = input price iteration

$a$  = field/project  $a$

$FP_{a,t}$  = production from field  $a$  in time  $t$ , for  $FP_{a,t} = FP_{a,t} * BinaryDomestic_{a,t}$

where,

$FP_{a,t}$  = production from field  $a$  in time  $t$

$BinaryDomestic_{a,t}$  = endogenously generated binary matrix which determines whether the field is producing (1) or not producing (0)

Therefore, taking the full  $a \times t$  matrix of  $FP_{a,t}$  and  $BinaryDomestic_{a,t}$ , the Hadamard Product (element-wise) can be used for the two matrices of the same size, where the product of each element yields:

$$[FP \cdot BinaryDomestic]_{i,j} = FP_{i,j} \cdot BinaryDomestic_{i,j}$$

for,  $1 \leq i \leq a$ ,  $1 \leq j \leq t$

$TaxIncome_{c,t}$  = tax-take on production revenue (e.g. royalties) for country  $c$  in time  $t$

$FieldCost_{a,t}$  = field cost for field  $a$  in time  $t$

$Subsidy_{c,t}$  = subsidy for country  $c$  in time  $t$

$TaxProfit_{c,t}$  = tax-take on profit stream from fiscal regime of country  $c$  in time  $t$

$\delta_a$  = discount rate for specific field/contract/project  $a$

$CF(Domestic_r)_{t,P(Domestic)_i,a}$  = output cash flow matrix ( $t \times P(Domestic)_i$ ) for each field/project  $a$  in region  $r$

The net present value vector of each domestic field is calculated by summing cash flows from the year the field is bought online up to the iteration of  $t$ , for each price iteration  $P(Domestic)_i$ , as shown in Equation 7.

$$NPV(Domestic)_a = \sum_{t=start(a_t)}^t CF(Domestic_r)_{t,P(Domestic)_i,a}$$

(Equation 7)

where,

$t$  = time-period

$start(a_t)$  = initial production start year

$CF(Domestic_r)_{t,P(Domestic)_i,a}$  = cash flow in time  $t$ , price iteration  $P(Domestic)_i$ , for field  $a$  in region  $r$  (output matrix from Equation 6)

$NPV(Domestic)_a$  = net present value for each field  $a$  summed through the producing lifetime up to  $t=t$ . Therefore,  $NPV(Domestic)_a$  is a  $1 \times P(Domestic)_i$  vector

Unlike the LTC module where the NPV for each contract is assessed by iterating through all years, in the domestic module the iteration through time is only up to year  $t$ . For each field, the sum of cash flows which generates positive net present value from the initial production year up to the iteration of year  $t$  yields the marginal output price for that field in that year. For example, if  $t=6$  (i.e. 2020),  $NPV(Domestic)_a$  is a vector of summed cash flows from the year production started through to year  $t=6$  (i.e. 2020). Therefore, the column of the vector  $NPV(Domestic)_a$  where  $NPV(Domestic)_a > 0$  yields the output price (a scalar) for the field in 2020, considering cash flows 2015 to 2020. This means that unlike the long-term contract calculation of prices, some degree of asymmetric information is assumed in the domestic module. This is particularly important for scenarios where subsidies are removed from the cash flow equation, or tax/cost sensitivities are conducted to quantify uncertainties in demand responses and overall price level changes. The marginal output price for each field, in each year, is shown in Equation 8 (a) and (b)

$$P(Domestic)_a = length(NPV(Domestic)_a < 0) + 1$$

(Equation 8 (a))

$$P(Domestic)_{a,t} = P(Domestic)_a \cdot BinaryDomestic_{a,t}$$

(Equation 8 (b))

where,

$NPV(Domestic)_a$  = net present value of summed cash flows from Equation 6

$length(NPV(Domestic)_a < 0)$  = length of the vector  $NPV(Domestic)_a$  for which the NPV is negative, i.e. to the margin of turning positive. Therefore adding 1 to this vector length identifies the price at which  $NPV(Domestic)_a$  turns positive up to year  $t$ . Because each time-period  $t$  is assessed in turn (rather than looping through the model horizon as with the 'fixed' LTC module), the scalar parameter  $length(NPV(Domestic)_a)$  can change between years.  $P(Domestic)_a$  = scalar price output for field  $a$ , equal to the marginal price which brings the field online (i.e. generates a positive NPV when summing cash flows up to year  $t$ )

$BinaryDomestic_{a,t}$  = endogenously generated binary matrix which determines whether the field is producing (1) or not producing (0).

$P(Domestic)_{a,t}$  = matrix of marginal output prices for field  $a$  in time period  $t$ , with  $P(Domestic)_a$  the sum of cash flow up time period  $t$

Therefore  $P(Domestic)_{a,t}$  is the matrix of marginal prices for each gas field  $a$  in time period  $t$ , with  $P(Domestic)_{a,t}$  calculated from summed cash flows up to time  $t$ , rather than the whole project lifetime as with the LTC module. GAPTAP therefore incorporates imperfect information into the price clearing algorithm in the domestic module.

Unlike the LTC module, where the importing country is assumed to be a price-taker and therefore each field runs through the pricing iteration loop independent of any demand response, in the domestic module, demand responds as the price iterates upwards, as shown in Equation 9.

$$ConsumptionElastic_{r,t} = ConsumptionDomestic_{r,t} * (Elasticity_r)^{P(Domestic)_{a,t}}$$

(Equation 9)

where,

$ConsumptionDomestic_{r,t}$  = initial consumption demand to be met by indigenous production in region  $r$  and time period  $t$

$Elasticity_r$  = short-term elasticity, expressed as a percentage,  $1+PED$  (i.e. assuming  $PED$  is negative)

$P(Domestic)_{a,t}$  = marginal price which brings field  $a$  online from Equation 8. Therefore, the **maximum elastic response** to demand will be the marginal price which brings all required fields online.

$ConsumptionElastic_{r,t}$  = domestic consumption once elastic response has been calculated in each year as price iterates upwards to bring sufficient supply online, in region  $r$  and time period  $t$

Field level production in time  $t$  is therefore summed, with additional supply bought online if necessary, until the condition in Equation 10 is met; that is the price iteration runs through the fields for each time  $t$  until:

$$ConsumptionElastic_{r,t} \leq \sum_{a=1}^n FP_{a,t}$$

(Equation 10) where,

$ConsumptionElastic_{r,t}$  = altered domestic consumption taking into account demand response to price changes (output of Equation 9)

$FP_{a,t}$  = production from gas field  $a$  in time  $t$

$n$  = number of fields required to satisfy the inequality (i.e. until supply is greater than or equal to  $ConsumptionElastic_{r,t}$ )

Therefore, the  $n^{th}$  field is that which, when summed with the outputs of fields  $1:1:n-1$ , brings supply into equilibrium with  $ConsumptionElastic_{r,t}$  (i.e. the adjusted domestic consumption figure generated in Equation 9). The following numerical example is intended to provide a simplistic indication of the above formula:

$ConsumptionDomestic_{r,t} = 1000$  units

$Max(P(Domestic)_{a,t}) = \text{maximum domestic field marginal price output for fields } 1:1:n = 10$

$Short-run PED = -0.0017$  (DECC, 2016)

$Elasticity_{r,t} = (1 + (-0.0017))$

$ConsumptionElastic_{r,t} = 1000 * (1 - 0.0017)^{10} = 983.13$  units

Whilst GAPTAP sequentially brings gas fields online in the domestic module until the inequality in Equation 10 is satisfied, some key additional constraints/features are included:

1. As GAPTAP iterates through the price required to bring fields online, an additional condition in the algorithm allows the model to 'skip' through the production matrix in each year and bring lower cost fields online, under the following conditions:
  - Production in time  $t-1$  was zero. In short this is to stop GAPTAP 'dropping' field production as the price clearing algorithm iterates to bring supply and demand into equilibrium
  - If the marginal price to develop field  $a$  is greater than the prevailing regional marginal price in the previous time-period
  - There is sufficient supply from lower cost fields to meet  $ConsumptionElastic_{r,t}$  (i.e. meet the condition in Equation 10)
2. GAPTAP determines which fields are available for domestic markets and which are potentially isolated. Each gas field in the domestic production matrix is assigned a value (0, 1, 2):
  - If field  $a = 0$ , then that field can only contribute to domestic (indigenous) consumption.
  - If field  $a = 1$ , then the model decides whether the field supplies the domestic market (if there is still residual demand), or if the field can be used for export volumes.
  - If field  $a = 2$ , then the field can only supply export quantities and cannot be used for the domestic market. A key example is the residual production capacity from the Yamal LNG fields (i.e. after long-term contracts have been satisfied), which are not connected to Russian domestic gas networks and therefore any remaining volumes are assumed to be available for exports on spot markets.

Related to the points above and as mentioned previously, GAPTAP generates an endogenous binary matrix for each region indicating whether a field is supplying to the domestic market or not (parameter  $BinaryDomestic_{a,t}$  from Equation 6 and 8). An additional binary matrix is created to 'shadow'  $BinaryDomestic_{a,t}$  indicating which fields are available to supply the trade module, i.e. identify residual field supply. This parameter, which will be referred to as  $BinaryDomesticResidualSpot_{a,t}$ , in combination with  $BinaryDomestic_{a,t}$ , allows GAPTAP to track field production profiles, particularly if fields are switching between supplying the domestic market and spot supply in the trade module. Therefore, fields assigned  $a = 2$  (in point 2 above), automatically have production volumes available in the trade module, whilst fields assigned  $a = 1$  can supply the trade module assuming  $BinaryDomestic_{a,t} = 0$ .

Combining Equation 8-10, Equation 11 (a) and (b) shows the construction of a weighted marginal price for the domestic module of each region in GAPTAP. As with the construction of a weighted price in the long-term contract module, the contribution of individual fields to total regional supply is first weighted.

$$WP_{a,t} = \frac{FP_{a,t}}{\sum_{a=1}^n FP_{a,t}}$$

(Equation 11 (a)) where,

$FP_{a,t}$  = production from gas field  $a$  in time  $t$

$n$  = number of fields required to satisfy the inequality in Equation 10

$WP_{a,t}$  = weighted contribution of each field to summed field-level production which brings supply into equilibrium with  $ConsumptionElastic_{r,t}$

The weighted contribution from each field to total domestic supply is then multiplied by the marginal output price derived in Equation 8 for each field  $a$  and time-period  $t$ . These are then summed to generate a weighted marginal output price for the domestic supply module for each region.

$$Price(Domestic_r)_t = \sum_{a=1}^n P(Domestic)_{a,t} \cdot WP_{a,t}$$

(Equation 11 (b))

where,

$n$  = number of fields required to satisfy Equation 10, i.e. summed field- supply  $\geq ConsumptionElastic_{r,t}$

$WP_{a,t}$  = weighted contribution of each field to summed field-level production which brings supply into equilibrium with  $ConsumptionElastic_{r,t}$

$P(Domestic)_{a,t}$  = matrix of marginal output prices for field  $a$  in time period  $t$  from Equation 8.

$P(Domestic)_{a,t} \cdot WP_{a,t}$  = element-wise multiplication of matrices using Hadamard product

$Price(Domestic_r)_t$  = summed weighted marginal price across all fields contributing to the domestic supply module, for region  $r$  in time  $t$  (i.e. generating a 1 x21 vector)

### Trade competition (spot) module

Equations 12 shows the calculation of cash flows for each year and price iteration for fields providing feedstock gas into the spot supply module for each region.

$$CF(Spot_r)_{t,P(Spot)_i,a} = \frac{((FP_{a,t} * P(Spot)_i * (1 - TaxIncome_{c,t})) - (FP_{a,t} * FieldCost_{a,t})) * (1 - TaxProfit_{c,t})}{(1 + \delta_a)^t}$$

(Equation 12)

where,

$r$  = region

$t$  = time  $t$

$P(Spot)_i$  = input price iteration

$a$  = field/project  $a$

$FP_{a,t}$  = production from field  $a$  in time  $t$ , for  $FP_{a,t} = FP_{a,t} \cdot BinarySpot_{a,t}$

where,

$FP_{a,t}$  = production from field  $a$  in time  $t$ , with fields available determined by the shadow binary matrix  $BinaryDomesticResidualSpot_{a,t}$  mentioned in the previous section indicating where residual supply was available after fields have produced to satisfy domestic production requirements

$BinarySpot_{a,t}$  = endogenously generated binary matrix which determines whether the field is producing (1) or not producing (0).

Therefore, taking the full  $a \times t$  matrix of  $FP_{a,t}$  and  $BinarySpot_{a,t}$ , the Hadamard Product (element-wise) can be used for the two matrices of the same size, where the product of each element yields:

$$[FP \cdot BinarySpot]_{i,j} = FP_{i,j} \cdot BinarySpot_{i,j}$$

for,  $1 \leq i \leq a$ ,  $1 \leq j \leq t$

$TaxIncome_{c,t}$  = tax-take on production revenue (e.g. royalties) for country  $c$  in time  $t$

$FieldCost_{a,t}$  = field cost for field  $a$  in time  $t$

$TaxProfit_{c,t}$  = tax-take on profit stream from fiscal regime of country  $c$  in time  $t$

$\delta_a$  = discount rate for specific field/contract/project  $a$

$CF(Spot)_{t,P(Spot)_i,a}$  = output cash flow matrix ( $t \times P(Spot)_i$ ) for each field/project  $a$  in region  $r$

As with the domestic module, the net present value of each field with production capacity to supply to spot markets is calculated by summing cash flows from the year the field is bought online up to the iteration of  $t$ , for each price iteration  $P(Spot)_i$ , as shown in Equation 13.

$$NPV(Spot)_a = \sum_{t=start(a_i)}^t CF(Spot_r)_{t,P(Spot)_i,a}$$

(Equation 13) where,

$t$  = time-period

$start(a_i)$  = initial production start year

$CF(Spot_r)_{t,P(Spot)_i,a}$  = cash flow in time  $t$ , price iteration  $P(Spot)_i$ , for field  $a$  in region  $r$  (output matrix from Equation 12)

$NPV(Spot)_a$  = net present value for each field  $a$  summed through the producing lifetime up to  $t=t$ . Therefore,  $NPV(Spot)_a$  is a  $1 \times P(Spot)_i$  vector

The same process used in the domestic production module for generating marginal prices for each field, in each year, is used in the spot module, as shown in Equation 14 (a) and (b).

$$P(Spot)_a = length(NPV(Spot)_a < 0) + 1$$

(Equation 14 (a))

$$P(Spot)_{a,t} = P(Spot)_a \cdot BinarySpot_{a,t}$$

(Equation 14 (b))

where,

$NPV(Spot)_a$  = net present value of summed cash flows from Equation 13

$length(NPV(Spot)_a < 0)$  = length of the vector  $NPV(Spot)_a$  for which the NPV is negative, i.e. to the margin of turning positive. Therefore adding 1 to this vector length identifies the price at which  $NPV(Spot)_a$  turns positive up to year  $t$ .

$P(Spot)_a$  = scalar price output for field  $a$ , equal to the marginal price which brings the field online (i.e. generates a positive NPV when summing cash flows up to year  $t$ )

$BinarySpot_{a,t}$  = endogenously generated binary matrix which determines whether the field is producing (1) or not producing (0). Introduced above in the derivation of Equation 12.

$P(Spot)_{a,t}$  = matrix of marginal output prices for field  $a$  in time period  $t$ , with  $P(Spot)_a$  the sum of cash flow up time period  $t$

Unlike the domestic production module where gas fields come online to meet the condition in Equation 10 (i.e. summed field production is at least equal to the elasticity altered demand from domestic fields), in the first iteration of the spot module where price indications are generated, Equation 15 constrains the volumes which each region can (initially) supply into the spot supply and trade competition module.

$$\sum_{a=1}^n FP_{a,t} \leq Capacity(Export)_{r,t}$$

(Equation 15)

where,

$CapacityExport_{r,t}$  = remaining export capacity in region  $r$  and time  $t$ , net export volumes from the long-term contract module

$FP_{a,t}$  = production from field  $a$  in time  $t$

$n = n^{th}$  field for which Equation 15 holds. If there is more surplus production capacity for the spot module than export infrastructure,  $n$  will be the last field for which Equation 15 holds.

The next step of the process is to generate a regional feedstock gas price for spot supply from each exporting region with residual production capacity left over after domestic supply requirements have been met. The same process used in the domestic module of weighting the marginal output price of each field based on its contribution to the total modular supply is used in the spot module. Therefore, Equation 16 (a) and (b) shows the derivation of a regional price for feedstock gas into the spot supply and trade competition module.

$$WP_{a,t} = \frac{FP_{a,t}}{\sum_{a=1}^n FP_{a,t}}$$

(Equation 16 (a))where,

$FP_{a,t}$  = production from gas field  $a$  in time  $t$

$n$  = number of fields available to supply gas for export on a spot basis, ensuring the inequality in Equation 15 is maintained

$WP_{a,t}$  = weighted contribution of each field to the potential regional supply of gas into spot markets, ensuring the inequality in Equation 15 is maintained

$$Price(Spot_r)_t = \sum_{a=1}^n P(Spot)_{a,t} * WP_{a,t}$$

(Equation 16 (b))

The weighted output spot price in Equation 16 (b),  $Price(Spot_r)_t$ , can be interpreted as the feedstock price for any natural gas sold on a spot market from exporting region  $r$ . For the United States in particular, feedstock gas for LNG exports are taken directly from natural gas hubs and therefore the price of spot LNG exports from the US is strongly related to the prevailing domestic price. However, in other regions, only certain fields can supply the spot module, reflecting a) residual production capacity at export projects predominantly satisfying long-term contracts and b) a lack of infrastructure to get gas from transmission systems to isolated export projects.

## Appendix 2. Fiscal regime set-up in GAPTAP

The fiscal regime of each country in GAPTAP is represented in a simplified way based largely on Ernst&Young (2017, 2019). Additionally, subsidy information is taken from the IEA's subsidy database for consumption and applied to individual fields in each country in order to artificially deflate the price required to bring the field online. The regime for each country in Latin America and the Caribbean in the model is shown in Table A1 and Table A2. A distinction is made between taxation on production streams and overall profit taxes. Additionally, production subsidies in the form of tax breaks for certain categories of projects (e.g. lower tax rates for deep-water projects in Trinidad and Tobago (see Table 2)) are also taken into account.

**Table A1. Assumptions for Latin America and the Caribbean country fiscal regimes: Fiscal regime formation**

Producer	Fiscal regime
<b>Argentina</b>	Concession and PSC
<b>Bolivia</b>	PSC
<b>Brazil</b>	Concession and PSC
<b>Colombia</b>	Concession
<b>Mexico</b>	Concession, PSC, Service Contracts
<b>Peru</b>	Concession and Service Contracts
<b>Trinidad and Tobago</b>	Concession and PSC
<b>Venezuela</b>	Concession

**Table A2. Assumptions for Latin America and the Caribbean country fiscal regimes: Taxes and subsidies**

Producer	Field	Revenue tax share (royalty per unit production)	Profit tax share
<b>Argentina</b>	Carina	0.12	0.30
<b>Argentina</b>	Loma de la Lata	0.12	0.30
<b>Argentina</b>	Ara-Canadon Alfa	0.12	0.30
<b>Argentina</b>	Ramos	0.12	0.30
<b>Argentina</b>	San Pedrito	0.12	0.30
<b>Argentina</b>	Neuquen_1-17	0.12	0.30
<b>Bolivia</b>	Margarita	0.12	
<b>Bolivia</b>	Sabalo	0.12	
<b>Bolivia</b>	Incahuasi x-1 ST	0.12	
<b>Bolivia</b>	Itau	0.12	
<b>Brazil</b>	Mexilhao	0.05-0.15	0.34
<b>Brazil</b>	Fazenda Cedro	0.05-0.15	0.34
<b>Brazil</b>	Guaricema	0.05-0.15	0.34
<b>Brazil</b>	Riachuelo	0.05-0.15	0.34
<b>Brazil</b>	1-RJS-587 (Urugua) <sup>8</sup>	0.05-0.15	0.34
<b>Colombia</b>	Chuchupa	0.048-0.25 <sup>9</sup>	
<b>Mexico</b>	Associated	Breakeven Price/102.85	
<b>Mexico</b>	Reynosa	0.2-0.3 <sup>10</sup>	
<b>Mexico</b>	Jose Colomo	0.2-0.3	
<b>Mexico</b>	Burgos_1-21	0.2-0.3	

<sup>8</sup> PSC's on 15% royalty levels, whereas concession royalties between 5-10%

<sup>9</sup> Based on production levels

<sup>10</sup> First four years of production at 30% and then lowered to 20%



Peru	Cashiriari	0.05-0.2 <sup>11</sup>	0.315
Peru	Pagoreni 1X	0.05-0.2	0.15
Peru	San Martin	0.05-0.2	0.30
Trinidad and Tobago	KK 4-2	0.13	0.35-0.5 <sup>12</sup>
Trinidad and Tobago	Red Mango	0.13	0.35-0.5
Trinidad and Tobago	Serrette	0.13	0.35-0.5
Venezuela	Santa Barbara	0.33	0.5
Venezuela	Perla	0.33	0.5
Venezuela	Yucal-Placer	0.33	0.5
Venezuela	Quiriquire	0.33	0.5
Venezuela	Patao	0.33	0.5
Venezuela	Mejillones	0.33	0.5

Additionally, Equation 17 provides an example of how tax revenues are calculated in GAPTAP, using the outputs from Appendix 1 including marginal prices and production volumes.

Equation 17 (a) and (b) therefore show total government tax revenue for each gas field in the domestic module, across the producing lifetime of each field in the domestic module. As with government revenue in the long-term contract module, a distinction is made between revenues on income and profit streams.

$$Tax(DomesticIncome_c)_a = \sum_{t=start(a_t)}^{end(a_t)} \frac{(P(Domestic)_{a,t} * FP_{a,t} * TaxIncome_{c,t})}{(1 + \delta_a)^t} \quad (\text{Equation 17 (a)})$$

$$Tax(DomesticProfit_c)_a = \sum_{t=(start(a_t))}^{end(a_t)} \frac{((FP_{a,t} * P(Domestic)_{a,t} * (1 - TaxIncome_{c,t})) - (FP_{a,t} * FieldCost_{a,t}) - (FP_{a,t} * Subsidy_{c,t})) * (TaxProfit_{c,t})}{(1 + \delta_a)^t} \quad (\text{Equation 17 (b)})$$

where,

$P(Domestic)_{a,t}$  = marginal price output for field  $a$  in time  $t$ , taken from Equation 8 (b)

$Tax(DomesticIncome_c)_a$  = total government tax revenue for country  $c$  from income stream of field  $a$ , forming an  $a \times 1$  vector

$Tax(DomesticProfit_c)_a$  = total government tax revenue for country  $c$  from total profit stream of field  $a$ , forming an  $a \times 1$  vector

Note: the notations for Equation 17 (a) and (b) are the same as Equation 6 in Appendix 1.

The arithmetic sum (i.e. addition of two vectors the same size) of Equation 17 (a) and (b) provides country-level revenue for each gas field supplying the domestic module.

<sup>11</sup> Based on production levels

<sup>12</sup> Profit tax levels for deep-water projects are lower end at 35% with the remaining projects on 50% profit tax rate