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Large hydropower, decarbonisation and climate change uncertainty: Modelling power sector pathways for Ecuador

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ABSTRACT

Hydropower plays a critical role in global, South American and Ecuadorian energy policy and for achieving Nationally Determined Contributions (NDCs) aiming to reduce greenhouse gas emissions. However, long-term climatic changes may affect the role of hydropower in meeting energy and climate policy objectives. The effects of climate change on runoff availability for hydropower generation are largely uncertain. This paper uses climate change scenarios derived from a large ensemble of Global Circulation Models as input for an energy system optimisation model (TIMES-EC) to examine least-cost options for the hydropower-dominated Ecuadorian power system in the period to 2050. This is done in the context of three policy cases in order to assess trade-offs between power system configuration, emissions and costs. The results show that in the long-term hydropower will remain as one of the most cost-effective and low emission technologies in the Ecuadorian power sector. However, constraints on deployment and uncertainty around climate change impacts could hinder its ability to contribute to the fulfilment of NDC targets, as well as create uncertainty around long-term power system costs. Strategies to hedge against these risks will likely require that hydropower expansion be complemented by alternative sources, namely incremental shares of thermoelectric generation with natural gas, biomass and geothermal energy.

1. Introduction

Hydropower is the most important source for renewable electricity production in South America, providing 63% of total electricity generation [44]. In the Tropical Andes, a sub-region comprising Colombia, Ecuador, Peru and Bolivia, there are plans to develop at least 151 new hydropower dams greater than 2 MW over the next 20 years [32]. Over the past decade, Ecuador's energy policy has incentivised a doubling of its hydropower capacity, and according to the International Hydropower Association (IHA), the country ranked third after only China and Brazil for countries that added new capacity in 2016 [47]. For countries with significant hydropower potential, hydropower is expected to play a major role in meeting their Nationally Determined Contributions (NDCs) to the Paris Agreement [109] as well as meeting the 7th goal (energy access for all) of the United Nations' (UN) Sustainable Development Goals [111]. The deployment of large hydropower has recently become the cornerstone of Ecuador's NDC, presented at COP21 in Paris [110]. However, research [11,20] shows that future electricity generation from hydropower not only faces uncertainties associated with the current inter-annual variability of runoff patterns but with the impact that climate change would have on the magnitude and sign of change of long-term runoff availability.

Several previous studies have sought to assess the impacts of climate change on hydropower at national [23,34,40,86,89,94,101], regional [11,29,38,104,74,76,98]; and global levels [8,36,49,108,113,119]. To quantify the impacts of climate change on hydropower generation, the most common approach is to run a calibrated baseline hydrological model under changing hydroclimatic conditions (of rainfall, temperature, etc.) to obtain the variation of runoff. This then serves as an input to a power system model (e.g. Ref. [41]) or an integrated energy system

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model (e.g. Ref. [23]). Climate change uncertainty is assessed by deriving a range of scenarios for hydroclimatic variables drawn from the results of one or several Global Circulation Models[1] (GCMs) corresponding to one or several greenhouse gas (GHG) emission or concentration scenarios [13]. For instance, Ref. [23] assessed the vulnerability of hydropower to future climate projections for Brazil with results from one GCM (HadCM3) run under the IPCC's SRES A2 and B2 emission scenarios.[2] Ref. [29] also used the A2 and B2 emission scenarios to assess the impact of climate change throughout the current century on hydropower generation in Latin America and the Caribbean, but only employed the mean value of the GCMs results for each one of the emission scenarios. Ref. [40] used one emission scenario (A1B) but with climate projections from 15 GCMs to assess five hydropower river basins in Cameroon. Ref. [94] employed the more recent IPCC Representative Concentration Pathways (RCPs),[3] RCP4.5 and RCP8.5, for three GCMs (MIROC-ESM, MRI-CGCM3, and MPI-ESM-M) to assess climate change risk for a hydropower project in Nepal. Finally, Ref. [101] assessed climate change impacts on Portugal's hydropower system using the mean results of GCMs for both the SRES A2 and B2 emission scenarios and the RCP4.5 and RCP8.5 concentration scenarios.

The cited studies reveal that hydropower potential can display significant sensitivities to variations in rainfall patterns induced by climate change. Additionally, the studies stress that the main source of uncertainty is associated with projections emerging from different GCMs, demonstrating the importance of using several GCMs to assess uncertainty. Accordingly, there is growing interest in using large ensembles of GCMs to improve the reliability of future projections of hydropower potential [42]. This activity is likely to reveal critical insights about the information made available by climate models when it is applied to strategic energy planning. The paper at hand aims to add a number of additional original contributions to the established literature.

First, this work considers power system impacts arising from a broad range of future hydroclimatic conditions. Previous studies in this area have mainly used only a limited number of projections for future rainfall patterns and aggregated in representative seasons. In contrast, our work instead builds on recently published research by Ref. [14] that assesses a large ensemble of 41 GCMs to characterise the long-term monthly runoff availability for hydropower generation in individual Ecuadorian river basins across a comprehensive range. This allows for a much more granular level of spatial and temporal resolution in the energy model than has been possible in previous studies, and a more rigorous representation of climate change uncertainty.

Second, this paper showcases the first application of the TIMES energy system optimisation model [59], to develop a detailed long-term energy system assessment for the Republic of Ecuador (TIMES-EC). This adds significant value by representing not only the impacts of climate change on hydropower electricity generation, but also the way in which the whole energy system adapts to new conditions. It does this by calculating the least-cost configuration of technologies required to satisfy end-use energy demands. The majority of previous studies in this area have mostly used hydropower electricity simulation models in isolation from the rest of the energy system (e.g. Refs. [35,40,77,94,98]). While TIMES-EC captures a broad energy system perspective, only the changes in the power generation matrix will be assessed in detail for this study due to the particular importance of hydropower in Ecuador's power sector and its relevance for Ecuador's NDC contribution to the Paris Agreement. The TIMES model framework has been previously used to assess energy system impacts due to climate change in Norway [89] and Portugal [101], however our study seeks to explicitely account for the critical differences found in the deployment of hydropower in terms of invesment and operational flexibility. A mixed-integer linear programming (MILP) formulation is employed to capture the typical lumpy investment characteristics of large hydropower projects, while different availability factor definitions are used to represent electricity dispatch for both run-of-river (ROR) and flexible reservoir systems (DAM). Additionally, this work categorises hydropower expansion options in terms of the different project sizes and river basins drawn from detailed up-to-date assessments of Ecuador's hydropower resource potential. This series of innovations goes beyond the approaches found in previous studies that have attempted to represent hydropower in an energy system optimisation model.

Third, the uncertainty of climate change impact on hydropower production are explored in the context of policy case scenarios for an energy system which depends heavily on hydropower. These policy cases wish to contrast a hydro-power energy and climate policy with other long-term options that consider restrictions to hydropower expansion. While a case study specifically for Ecuador is developed, it is believed that the methodoogy and insights from this work are valuable and replicable for strategic energy planning in other hydropower-development states or those planning large-scale hydropower development; which may well in turn have important implications for both their future socio-economic development and their potential decarbonisation efforts [8].

This paper is structured as follows. Section 2 details the study method, including details of the Ecuadorian energy system, the assumptions used in the modelling exercise and the definition of scenarios for climate change and policy cases intended to capture a spectrum of possible future hydropower developments in Ecuador. Section 3 presents and discusses the results, and Section 4 concludes with the implications for policy and recommendations for future research.

2. Method

2.1. TIMES-EC model structure and main assumptions

2.1.1. The Ecuadorian power system

The total installed capacity on the Ecuadorian power system almost doubled between 2007 and 2017. During this period, the country invested close to $US 6 billion in eight flagship projects with a total installed capacity of 2832 MW [102]. Two large-scale projects make up most of this new capacity and both were inaugurated in 2016: Coca Coda Sinclair (1500 MW), a run-of-river (ROR) facility located in the Coca River (Napo basin) and Sopladora (487 MW), an additional phase to the Paute Integral reservoir (DAM) hydropower system in the Paute River (Santiago basin). The remaining six projects are already in advanced construction stages and will be fully operational by 2020. Hydropower installed capacity in Ecuador reached 4412 MW in 2017, which represents 65% of the total installed capacity (6739 MW), with the remaining 32% (2148 MW) being provided by gas and fuel-based thermoelectric plants and 3% (178.5 MW) by other renewables (solar, wind, biomass and biogas) [62]. Hydropower capacity associated with

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[1] General Circulation Models, representing physical processes in the atmosphere are the most advanced tools currently available for simulating the response of the global climate system to increasing greenhouse gas concentrations [51]. Meteorological agencies around the world develop and run GCMs under various GHG emission or concentration scenarios to assess the change in climatic variables.

[2] The Special Report on Emissions Scenarios (SRES) is a report by the Intergovernmental Panel on Climate Change (IPCC) that was published in 2000 and presents six families of scenarios: A1FI, A1B, A1T, A2, B1, and B2 [52]. The A2 storyline describes a fragmented and heterogeneous world, while the B2 storyline and scenarios family describes a world in which the emphasis is on local solutions to economic, social and environmental sustainability.

[3] A Representative Concentration Pathway (RCP) is a greenhouse gas (GHG) concentration (not emission) trajectory adopted by the IPCC that supersede the SRES projections (RCPs: RCP2.6, RCP4.5, RCP6, and RCP8.5). The number refers to the radiative forcing (in W/m2) relative to pre-industrial levels expected by the end of the 21st century [69]. RCP4.5, for example, is a pathway that is consistent with radiative forcing of +4.5 W/m2. Changes in radiative forcing are critical for this project because they imply potential changes in weather patterns.

flexible reservoir DAM systems is 2088 MW while ROR systems comprise 2324 MW. Most of the installed capacity and future potential is located in the Amazon region in the east of the country. There is one power transmission network, the *Sistema Nacional Interconectado* (SNI),[4] which transmits centralised power generation to key consumption centres in the Ecuadorian Highlands and along the Pacific coastline. There are also transmission lines that interconnect the country to Colombia in the North, and Peru in the South. The power sector is vertically integrated and the State owns and operates most of the installed capacity in the country [15]. A summary of the installed power generation capacity in Ecuador is shown in Table 1.

Total electricity consumption reached 22 TWh in 2016; the residential sector was the largest consumer with a share of 32%, followed by the industrial sector at 24%, the commercial sector at 17% and the remaining usage accounted for by others such as public lighting and public services. Total annual electricity demand has grown at an average rate of 5.8% per year over the last decade (2007–2016) [62]. Ecuador's final energy demand (95 million barrel of oil equivalent) is characterised mainly by the consumption of fossil fuels (78%), followed by electricity (15%) and the remainder by other minor sources (such as firewood and biomass) [66]. The transport sector is the largest final energy consumer (46%) (gasoline and diesel), followed by industry (19%) and the residential sector (13%), with the remaining (22%) used by other sectors, such as commerce and agriculture.

2.1.2. Model structure and main assumptions

TIMES (The Integrated MARKAL-EFOM System) is a widely used bottom-up optimisation modelling platform developed as part of the International Energy Agency - Energy Technology Systems Analysis Program (IEA-ETSAP), which provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demands [33,59]. The model minimises the total discounted costs of deploying technologies required to cover energy service demands over a multi-decadal time horizon. It can be used to examine investment decisions and help evaluate how energy and environmental policies impact the energy sector [1,19,24,28,60,82].

TIMES-EC employs 5-year time steps across a 2015–2050 time horizon.[5] Each model period is divided into 36 time-slices, with 12 months in a year, each with a single representative day composed of three periods: morning (8 h), day (12 h) and night (4 h - peak). This time-slice structure is appropriate to study the long-term energy system expansion from an energy balance perspective. Specifically, it was chosen to capture the monthly and diurnal characteristics of hydropower generation and end-use power demand respectively; and is thus aligned well with the data used in this study. Investment decisions are made for each model period and operational decisions are made for each time-slice level, both under perfect foresight over the whole model horizon. Climate change impacts are limited in this analysis to their effect on hydropower supply; possible impacts on other parts of the energy system, such as changes to wind and solar resources, changes to thermal efficiency and the associated de-rating of power plants, and possible changes to energy demand (e.g. heating/cooling), are not accounted for.

An overview of the method used in this study is depicted in Fig. 1 together with the structure of the TIMES-EC energy system model. TIMES-EC has the following inputs: i) End-use energy demands, which are quantified endogenously based on the evolution of exogenously defined socio-economic drivers (i.e. population, households and GDP) and demand elasticities in five end-use sectors; ii) Technological specifications, provided by a comprehensive database of technical and cost data for existing and future energy conversion technologies (efficiency, capacity, availability, lifetime, lead-time, investment costs, and fixed and variable O&M costs); iii) Energy resources, including domestic renewable (solar, wind, biomass, geothermal and runoff) and non-renewable (oil and gas) potential and the prices of imported electricity and fossil fuels; iv) Climate change scenarios which are further specified in Section 2.2 and v) Policy cases, which are further specified in Section 2.3. The key outputs of TIMES-EC include: i) Energy system profile, including installed capacity and energy flows per technology; ii) Total energy (and electricity) system costs, and iii) Energy related GHG emissions.

The future socio-economic evolution of Ecuador and the associated final energy demand projections are the driving forces of the whole energy system modelled in TIMES-EC. Economic evolution follows the Central Bank of Ecuador's projections until 2020 [7], which accounts for the recent economic crisis effects due to low oil prices (2014–2015). After 2020, a single socio-economic scenario is considered, which assumes average growth rates of population and GDP for Ecuador as described by the Shared Socioeconomic Pathways SSP2 narrative developed by the Institute for Applied System Analysis (IIASA). The SSP2 depicts a world in which social, economic, and technological trends do not shift markedly from historical patterns [25,85]. Total average annual growth in GDP during the modelled time horizon is 2.7%, while the population annual average growth rate is 0.67%. The annual discount rate is set to 8%, as used in strategic planning by the Ecuadorian Central Bank [7]. Oil and natural gas prices employed in the model are based on the U.S. Department of Energy – Annual Energy Outlook 2017 [27] reference scenario which considers long-term prices for oil to be 110 US$/barrel by 2050.

Demand technologies have been modelled to represent more than 20 energy service demands (cooking, lighting, water heating, industrial process steam, heavy freight transport, etc.) in different economic sectors (residential, commercial, industry, transport and others, such as agriculture and construction). The electricity demand load profiles of the residential, commercial and industrial sector are derived from hourly-records of power dispatch by the Ecuadorian grid operator [17]. Considering that the transport sector is Ecuador's largest final energy consumer, fuel switching and the introduction of new transportation technologies are modelled, e.g. the introduction of ethanol fuel blends as well as hybrid and electric vehicles [12,45]. Industrial energy demands capture both the growth trend of existing industrial demands and the progressive introduction of a set of energy intensive 'strategic' industries by 2025, which are a key part of Ecuador's current future economic development strategy [62] (see Section 2.3.1). The Supplementary Material includes the full detail of the demand sectors, services, industries and drivers described above.

2.1.3. Electricity supply modelling

Existing installed capacity and capacity that is planned to be online in the near-term (i.e. up to 2025) are both model inputs and have been modelled at the plant level (over 125 plants [62]), whereas the long-term capacity expansion (over 20 new technology options) is a model output. The model has one region representing the SNI transmission network, and six regions to represent different seasonal runoff patterns and hydropower potential in different major river basins (Fig. 2). Transmission lines that interconnect the country with Colombia and Peru are also represented, although current interconnector capacity is limited (650 MW) and the possible future expansion of these links is not considered in this particular analysis. Transmission and distribution

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[4] The oil industry in the eastern part of the country has isolated power generators that are not connected to the SNI. This capacity adds up to 905 MW of crude oil and heavy fuel oil-fired internal combustion engines. This capacity is usually accounted as part of Ecuador's effective capacity, increasing total national capacity to 7606 MW [62].

[5] The total modelling horizon actually spans from 2014 to 2085. The period 2014–2017 serves as a calibration set of years. The model has been expanded up to the year 2085 to capture effects of the long operational life of hydropower (75 year) and also the effects of uncertainty in precipitation towards the end of the century derived from long-term climate data (2100). The long-term horizon taken in the model also ensures that the lock-in effect of capital stock inertia associated to near-term policies is avoided [9,84,114].

Table 1
Ecuadorian power installed capacity in 2007–2017 and potential for electricity generation.

Source	Technology[a]	Installed 2007 MW	Installed 2017 MW	2007–2017 Increase	Potential MW
Hydropower	Run-of-river	430	2324	440%	
	Reservoir	1601	2088	30%	
	Total hydropower	2031	4412	117%	13,002
Other renewables	Wind	–	16.5	–	1600
	Solar PV-US	–	24	–	4.6 kWh/m^2/day
	Biomass	63	136	120%	177 PJ/y
	Land fill gas	–	2	–	n.a.
	Geothermal	–	–	–	900
	Total other renewable	63	178.5	180%	
Fossil fuel (Natural gas and fossil fuels)	OCGT/ST/ICE	1432	2148	50%	n.a.
Total Ecuador (SNI)		3526	6739	91%	

Source [4,21,62–64].

[a] Solar PV-US: Solar photovoltaic utility scale, Wind: on-shore wind, Biomass: bagasse-fired, OCGT: Open cycle gas turbine, ST: Steam turbine, ICE: internal combustion engine, SNI: national interconnected transmission system.

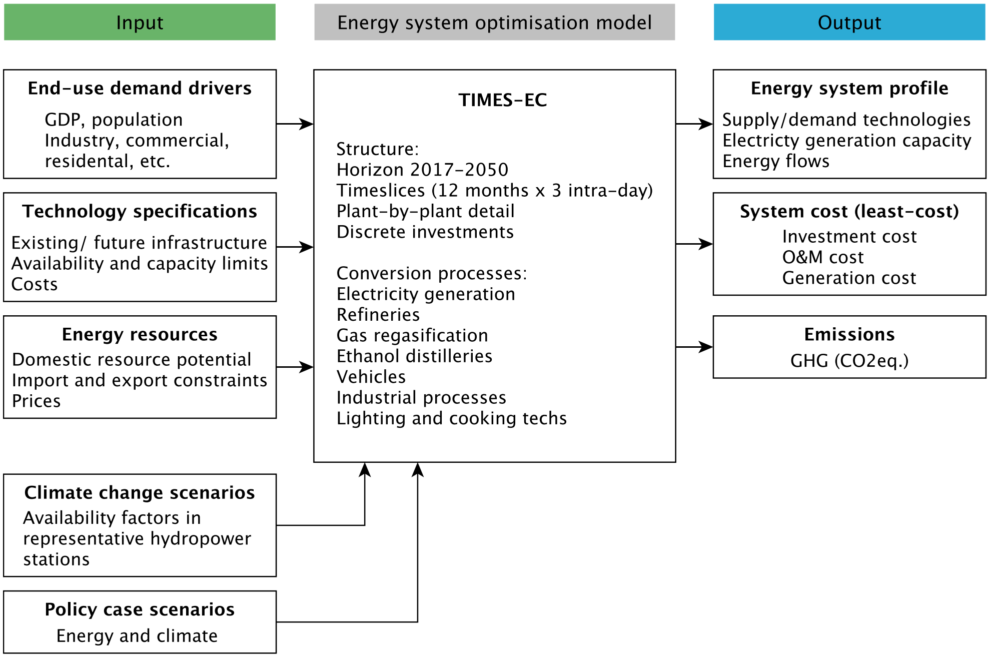

Fig. 1. Methodology overview and TIMES-EC structure.

losses between power plants and final consumers have been aggregated and represent a fraction of electricity generated that decreases from 12% in 2017 to 10% in 2050, in line with Ecuadorian projections for grid improvements [62].

The representation of Ecuadorian renewable energy potentials (hydropower, wind, solar, geothermal and biomass) is based on national studies for current and future technologies (See Table 1). The characterisation of new electricity generation technologies, as cost data and efficiencies, is input to the model based on a range of sources [10,46,53,62,72,99] and the specific observed costs of plants installed in Ecuador during the last decade [62]. In the Supplementary Material, a summary table with the full techno-economic data for all power generation technologies considered in TIMES-EC is presented.

The Ecuadorian national Electrification Master Plan (PME) estimated the total techno-economically feasible hydropower potential[6] to be 22.1 GW [62], which is composed of 4.4 GW that are already installed, 0.7 GW that are under construction, 13 GW that are untapped and are viewed as the technologically feasible and cost effective remaining potential, and an estimated 4 GW that are likely to encounter development restrictions due to environmental conservation concerns, social problems and accessibility issues, all of which lead the Government to conclude that these resources are unlikely be utilized in the future [4]. For our assessment in this paper, we have taken the hydropower project inventory that is presented in the PME (totalling 13 GW) to represent the remaining potential for new hydropower capacity expansion in Ecuador. This has been categorised in our assessment according to the river basin that each potential project is located in and further divided into three capacity sizes: small (1–50 MW), medium (50–450 MW) and large (> 450 MW). In total, 73 projects have been categorised, of which 6 are large (totalling 9756 MW), 18 are medium (totalling 2327 MW) and the remaining 49 are small (totalling 917 MW). In this study, we capture two particular regions: Pacific and Amazon, containing six river basins that are especially relevant for hydropower generation in Ecuador. These can be seen in Fig. 2. The Santiago, Napo and Esmeraldas basins hold the majority of remaining potential in large and medium sized projects, while the Guayas, Jubones and Pastaza basins have only the potential for medium and small sized projects. For the detailed list of hydropower projects included in

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[6] Techno-economically feasible hydropower potential, in the Ecuadorian context, refers to the total capacity of hydropower projects with technologically feasible construction complexity at reasonable or industry-standard investment costs [62].

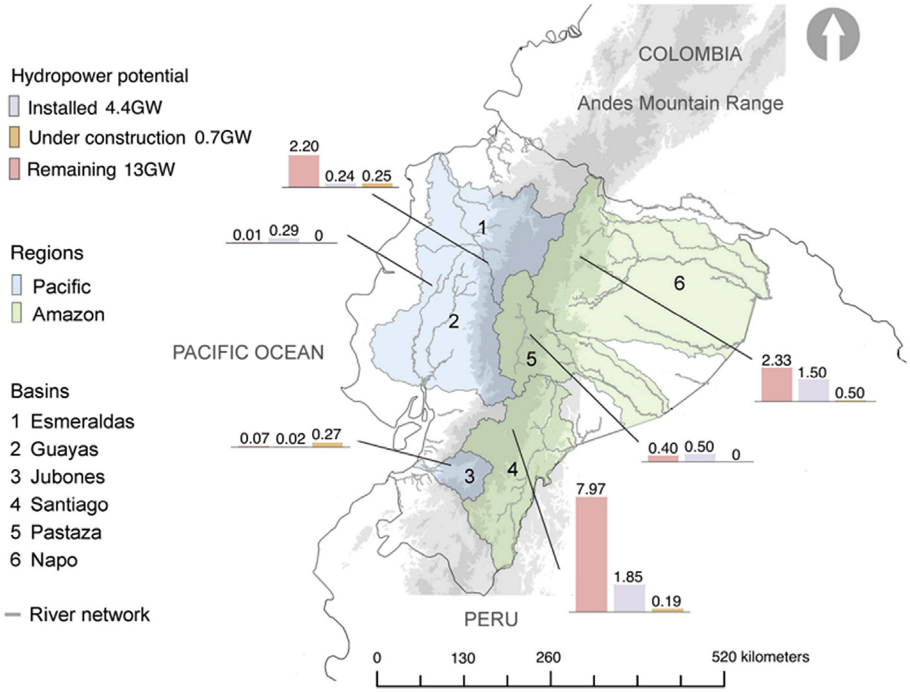

Fig. 2. Ecuador's six major river basins and geographical distribution of the Government's assessment of hydropower potential (GW).
Source: Based on [62].

the model, please see the Supplementary Material.

Hydropower potential has been modelled in TIMES-EC using availability factor attributes to constrain electricity production [57,90,99]. To represent run-of-river (ROR) plants that feature inflexible electricity production, a fixed availability factor according to monthly inflow patterns (termed AF in the model code) has been used in the model and it is assumed that electricity generation from ROR is identical within the daily times-slice periods. In the case of flexible reservoir (DAM) plants, an annual availability factor (AFA in the model code) that constrains the total level of annual electricity generation is used to represent the inter-seasonal storage capacities of each individual DAM hydropower plant. Moreover, a variable seasonal availability factor (AFS_UP and AFS_LO in the model code) with maximum and minimum production levels according to historical data, is used to constrain seasonal electricity generation but allow for operational flexibility within the daily time slice [90].

The TIMES model's discrete investment feature for new capacity additions is used to model the lumpy investment characteristics of medium and large hydropower projects, while investments in small hydropower are treated in a linear fashion. The model can endogenously choose to invest in large and medium hydropower capacity in discrete steps according to the potential and the number of projects in each of the six river basins. For example, the Santiago river basin in the Amazon region shows a significant potential of almost 8 GW (see Fig. 2 above), however most of it is concentrated in two large capacity facilities, namely the Santiago-G8 (3600 MW) and the Zamora (3180 MW) projects [16]. To reflect this, the model is constrained to invest in steps of 1200 MW for large hydropower in this basin, as we assume that these projects would be built in three stages each. This approach reflects the criteria that in a given large river scheme only a corresponding large facility would make technical and economic sense, and the fact that large hydropower projects are almost always built in consecutive stages that accompany demand growth and financing capacity of the operator [73]. The retirement profile of existing hydropower stations has been computed from the annual installed capacity for the period 1970 to 2016 (OLADE 2017) and assuming a hydropower plant lifetime of 75 years [54]. However, given that most of the installed capacity in Ecuador was installed in the mid 1980s, only 50 MW, which was installed before 1975, is anticipated to be retired before 2050.

Solar energy is abundant in Ecuador, with a national average global irradiation of 4.6 kWh/m^2/day [21], while wind energy potential estimates for the long-term are rather limited with 1.6 GW [63], available for a range of winds from 7 m/s to 8.5 m/s at 80 m height. The *Renewables ninja* online tool from Ref. [79] was used to run simulations of the hourly power output for solar photovoltaic power plants and wind farms located in high potential regions. These results were then translated into aggregated availability factors for each of the 36 time slices of TIMES-EC. The variability of solar plants and wind farms was considered through their peak load contribution; assumed to be 0% and 20%, respectively [43,55,68].

Regarding geothermal techno-economic energy potential, the country has identified a handful of prospective projects summing a total of 900 MW across several plants ranging from 26 MW to 330 MW [4]. There is no geothermal capacity currently installed at the time of writing but the first exploration wells were drilled in 2017 [62]. Technical bioenergy potential, which includes agriculture residues, livestock and forestry resources could be equivalent to 177 PJ/y [64]. However, as the distribution chains and technology to use this resource in Ecuador is still incipient, the PME considers that the maximum power generation from biomass could be 12.7 TWh/y by the year 2025 (equivalent to a firm capacity of 500 MW).

Thermal power plants (using natural gas, oil products, biomass, biogas and geothermal energy) for different technology types (steam turbines, combined cycle gas turbines, open cycle gas turbines and internal combustion engines) are modelled by setting identical availability factors for the whole year and allowing them flexibility to cover peak loads since these technologies have low minimum loads and a quick start up time [55,80,115]. The peak reserve margin has been set at a minimum of 20%, following requirements from the Ecuadorian grid operator [17].

2.2. Climate change uncertainty

The Andes mountain range defines the hydrographical system of Ecuador and its river basins (Fig. 2). In this region, GCM experiments run for the Coupled Model Intercomparison Project 5 (CMIP5)[7] present a large range of possible variation for future rainfall changes, which vary not only in magnitude but also allow for both increases and decreases in rainfall [112]. This analysis specifically focuses on the impacts and uncertainties surrounding hydropower resource potential, as these effects are expected to dominate the future Ecuadorian energy system. Future research should also account for other climate change impacts (e.g., on other renewable resource potentials, transmission systems, thermoelectric efficiency, etc.). The stress created by low water resources due to increased competition between other water-dependent economic sectors [22] should also be considered. However, as most of Ecuador's hydropower potential is located in the Amazon region where no more than 4% of the population resides [48], issues of competition for water resources are expected to be low in absolute terms.

This study will focus on the RCP4.5 concentration scenario, which is the scenario most often considered to represent a central estimate of future climate impacts [103] and also most closely aligns with the core objectives of the United Nations 2015 Paris Agreement [109], which include limiting anthropogenic warming to no more than 2 °C above pre-industrial values by 2100 [50]. A previous study by Ref. [14] assessed the monthly precipitation projections from a large ensemble of 41 GCMs driven by RCP2.6, RCP4.5 and RCP8.6 concentration scenarios from the CMIP5 exercise until 2100 [105] for the same six river basins considered in this work. In this exercise it was found that the range of disagreement between individual GCMs (inter-GCM uncertainty) for any RCP scenario is greater than the differences found between the different RCP scenarios (inter-RCP uncertainty). The inter-GCM uncertainty range was also found to have a similar magnitude under all three RCP concentration scenarios. Therefore, this paper will assess the inter-GCM uncertainty for RCP4.5 only, as considering the RCP2.6 and RCP8.6 adds very little value (see the Supplementary Material for a full list of GCMs used by Ref. [14] and their ranges of disagreement).

Table 2 shows the four scenarios that have been defined to represent the diverse range of possible runoff projections for Ecuador. The standard deviation of the CMIP5 emsemble of individual GCMs for the RCP4.5 is used to inform the minimum and maximum uncertainty limits explored in this study, following its widespread application as a common measure of uncertainty in risk analysis approaches and investment portfolio analysis for the power sector [6]. The Wet (+1 standard deviation) and Dry (-1 standard deviation) scenarios imply the strongest impacts of climate change on water resource availability. The Mean scenario uses the mean of the ensemble, which is the value that has been used the most frequently in other climate change impact studies. These scenarios are compared to an additional ‘no climate change’ baseline scenario (NoCC) representing a 30-year average of historic values (1971-2000) in which hydroclimatic variables are assumed to remain unaffected by climate change. Future runoff in this NoCC scenario is therefore assumed to behave exactly according to the past patterns.

Representative hydropower availability factors are projected for each of the six river basins in TIMES-EC for the period until 2050 under each of the above-mentioned climate change scenarios. The availability factor of hydropower is an important TIMES-EC input, as described previously in Section 2.1.3. To obtain the availability factor for each basin, a two-step approach is used:

Step 1: Bias-corrected data of precipitation, potential evapotranspiration and temperature at a $0.5^{\circ} \times 0.5^{\circ}$ resolution, computed by each of the GCMs found in the CMIP5 ensemble for the RCP4.5 scenario, are used to force a statistical hydrological model and compute the changes in average runoff per month.

Step 2: A hydropower electricity model is used to convert runoff into projected availability factors for representative existing hydropower stations in each basin. Both hydrology and hydroelectricity models were validated with historic data and further details can be found in Ref. [14].

Fig. 3 shows the availability factors for the NoCC, Mean, Wet and Dry scenarios for a representative ROR hydropower plant (left panel) and for a DAM hydropower plant in the Esmeraldas basin by 2050. To see the representative availability factors for the rest of the river basins and for further details on the hydrological and hydropower electricity model please refer to the Supplementary Material and Ref. [14].

2.3. Policy cases and scenarios

2.3.1. Energy policy overview - baseline

Ecuador is an upper middle income country [26] with an overall advanced position in terms of energy access, both in relation to end-use energy demand for heat and in terms of electricity service coverage (> 97%) [56,83]. During the last decade, Ecuador's main energy policy has been to attain a power generation matrix with a 90% share of renewable energy by 2017 [62,92]. The policy has been centred around the development of large capacity hydropower infrastructure led by the central government [92,118]. Recent large capacity additions of hydropower (Section 2.1.1) have enabled the share of hydropower electricity generation in the national grid to reach 84% by October 2017, while the share of other renewable energy sources remains low at 2.7% [5]. At present, Ecuador is close to achieving its renewable energy targets for the overall power matrix.

Despite these achievements, the Electricty Master Plan 2016-2025 details plans for an envisioned capacity expansion portfolio that could add a further 2–3.5 GW of hydropower capacity [62]. Regarding long-term energy policy, the National Energy Agenda 2016–2040 sets an explicit policy to continue harnessing hydropower and sustain a predominantly hydro-based power system [67]. Initiatives to deploy other renewable energy projects have historically been weak, as evidenced by the small capacities of PV, wind and biomass in the Ecuadorian grid (see Table 1).

The ‘Transformation of the Productive Matrix’ is a set of national industrial policies which seek to transition Ecuador away from primary resource dependence (namely crude oil exports) towards an industrial and knowledge-based economic model that produces exports with higher added value [81,93]. Within this strategy, one of the main activity areas is the development of strategic energy-intensive industries such as oil refineries, petrochemicals, aluminium, copper and steel industries that are planned to be deployed between 2016 and 2025 [61], and which explicitly rely on the constant deployment of large hydropower infrastructure. Therefore, the reliability and cost of electricity supply is viewed as a critical factor for Ecuadorian economic development. For a detailed list of these strategic industries and more detail of their associated energy demands, please see the Supplementary Material.

Regarding the decarbonisation of electricity demand, the National Plan for Energy Efficiency 2016–2035 (PLANEE) [65] focuses on three main policies, which have been partially implemented: the replacement of inefficient appliances (refrigerators mainly) and switching cooking from subsidised LPG to electricity through induction cook stoves in the residential sector; implementing energy efficiency standards in the industrial sector (ISO 50.001); and switching to efficient public lighting,

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[7] The Coupled Model Intercomparison Project 5 (CMIP5) is a framework for global coupled ocean-atmosphere GCMs. The CMIP5 promotes a standard set of GCM model simulations in order to provide projections of future climate change for the near (2035) and long-term (out to 2100 and beyond) and is the basis for the atmospheric assessments in the latest IPCC's Assessment Report 5 (AR5) [100].

Table 2
Overview of climate change scenarios.

Climate change scenarios	Description
NoCC	30-year average of historic values, representing constant hydroclimatic variables
Mean	mean of the ensemble of individual GCMs for the RCP4.5 CMIP5
Wet	+1 standard deviation of the ensemble of individual GCMs for the RCP4.5 CMIP5
Dry	−1 standard deviation of the ensemble of individual GCMs for the RCP4.5 CMIP5

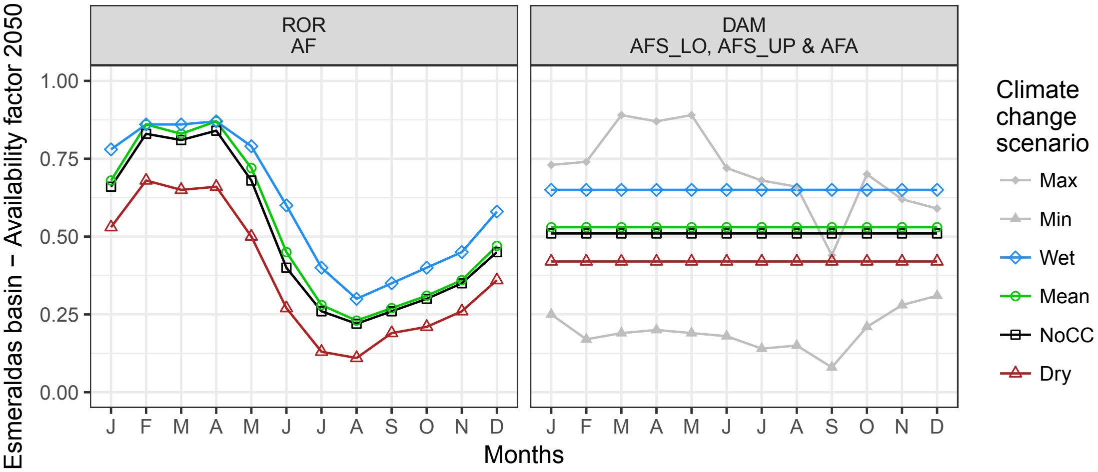

Fig. 3. Hydropower availability factor characteristics for different climate change scenarios in 2050 (NoCC, Mean, Wet and Dry) for an illustrative ROR and DAM hydropower station in the Esmeraldas basin. Notice that as described earlier in Section 2.1.3, ROR (left panel) is characterised only with fixed seasonal availability factors (AF), while DAM is characterised with variable annual availability factors (AFA) in addition to maximum (AFS_UP) and minimum (AFS_LO) seasonal limits.

by using LED technology [18]. The demand scenario in TIMES-EC assumes that all energy efficiency measures stated in the PLANEE will be successfully implemented by 2025.

Ecuador is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC) and forms part of the Non-Annex I group of countries, and hence has voluntary commitments for GHG mitigation actions. The Ecuadorian government has demonstrated an awareness of the adverse effects of climate change on human and ecological systems [37] and a willingness to strictly adhere to international agreements. Accordingly, Ecuador has formulated a variety of climate mitigation and adaptation policies, including the submission of an intended NDC as part of the COP21 process [110]. At the heart of the Ecuadorian NDC is the inclusion of plans to expand hydroelectric capacity by between 2.8 and 4.3 GW by 2025, which includes the latest capacity additions and more.

Hydropower is therefore currently considered as the main means of attaining energy security in Ecuador, reducing electricity prices, mitigating GHG emissions and forming the backbone for the above-mentioned industrial and economic development strategy. However, as noted in the introduction and in Section 2.2, anthropogenic warming may substantially affect critical hydroclimatic variables that might alter hydropower generation and impact those objectives.

2.3.2. *Policy cases*

A range of policy cases have been developed separately from the future climate change scenarios detailed in Section 2.2. It is emphasized that the policy cases and climate developments are two different types of model input. While the climate assumptions explore the long-term uncertainty of hydropower production under uncertain future hydroclimatic conditions, the policy cases explore different long-term evolutionary pathways for the energy system as the result of various energy and environmental policy decisions.

The first policy case, ‘Boost Hydropower’, represents a continuation of Ecuador's current national hydropower-led energy policy as set out by the PME and in Ecuador's NDC to the Paris Agreement up to the year 2025 [62]. This policy case considers that two new large hydropower projects located in the Santiago basin start operation within the period of analysis: i) Paute-Cardenillo (595.6 MW) by 2023 and ii) Santiago-G8 phases 1–4 (2400 MW) by 2025. At the time of writing, both projects have now completed their final design studies and are considered key to supplying the demand for electricity in future strategic industries. In addition to hydropower, the PME mentions plans for future developments in natural gas (187 MW), geothermal power (150 MW), small hydropower (140 MW) and a batch of wind and small utility scale PV (200 MW). Details for technologies and capacities deployed in this scenario can be found in the Supplementary Material.

The second policy case, ‘Constrain Hydropower’, assumes the cancellation of planned large hydropower projects (> 450 MW). Total future hydropower potential is assumed to be reduced from 13 GW down to 3.2 GW. Current large hydropower plants continue operating, and investments in small and medium sized hydropower projects remain as expansion options. This policy case reflects concerns that large hydroelectric deployment in basins such as the Amazon, the Congo, and the Mekong, have the potential to cause serious environmental and social impacts [31,39,58,88,106,116]. Accordingly, there is the possibility that these projects may experience severe delays, cost overruns and possible reductions of the originally envisaged production capacity [3,96]. The most recent hydropower station in Ecuador, Coca Codo Sinclair (1.5 GW), though currently the largest in terms of its installed capacity, has itself been constructed with only a small storage reservoir due to environmental concerns in a sensitive area for biodiversity in the Amazon [30].

The third policy case, 'Environment Priority', is used to explore how Ecuador might achieve the GHG reduction targets implied by the Ecuadorian NDC but without the use of any additional large hydropower projects. The policy case assumes that the emission levels that are expected to be attained through large hydropower deployment in the Boost Hydropower policy case (which is aligned with Ecuador's NDC) must be achieved, but additionally constrains the deployment of large hydropower infrastructure in a similar fashion to the Constrain

Table 3
Overview of policy cases.

Policy case	Description
Boost Hydropower	Boost the expansion of hydropower according to Government plans up to 2025.
Constrain Hydropower	Constrain the investment in large hydropower, only medium and small hydropower.
Environment Priority	Prioritise emission cap according to the Government NDC and no large hydropower (> 450 MW).

Hydropower policy case. The motivation behind this policy case assumption is to explore the possibility of maintaining low emissions without the environmental and social risks to project delivery associated with large hydropower projects [2]. Table 3 summarises the policy cases that will be addressed in combination with the climate change scenario analysis.

3. Results and discussion

3.1. Installed capacity and electricity generation

In line with the expected socio-economic development for Ecuador in the period 2017 to 2050, TIMES-EC finds that installed electricity generation capacity for all assessed scenarios increases by 15–18 GW by 2050, which amounts to a threefold increase compared to current levels (Fig. 4, top panel). Electricity generation will need to increase by 65–74 TWh/y by 2050, which is up to a threefold increase compared to current levels (Fig. 4, bottom panel). Across the climate change scenarios, the share of total electricity demand which can be supplied by hydropower varies significantly: 29–86% by 2050 (Fig. 5). Whereas the current portfolio is a hydrothermal one dominated by large scale hydropower generation, the model shows that the future could hold a number of different options according to the policy case and climate scenario outcomes that may transpire.

The Boost Hydropower, Constrain Hydropower and Environment Priority policy cases all imply the deployment of large fractions of hydropower in the electricity mix. However, they employ hydropower in different proportions of ROR and DAM type plants, which can be seen in Fig. 4 (where they are light and dark blue, respectively). Under the followed methodology approach and assumptions, the results suggest that in general, under all climate change scenarios, an expansion of hydropower capacity must be complemented by other base load generation capacity. This potentially draws into question whether or not the Ecuadorian Government's focus on achieving a 90% share of hydropower generation by promoting only large hydropower pojects is the best approach from a cost-optimal and technical strategy. Especially considering that natural gas or other renewables such as biomass and geothermal power would be necessary to provide both peak and base load generation in low runoff seasons despite of the large installed hydropower capacity. The model does not deploy more than 11 GW of

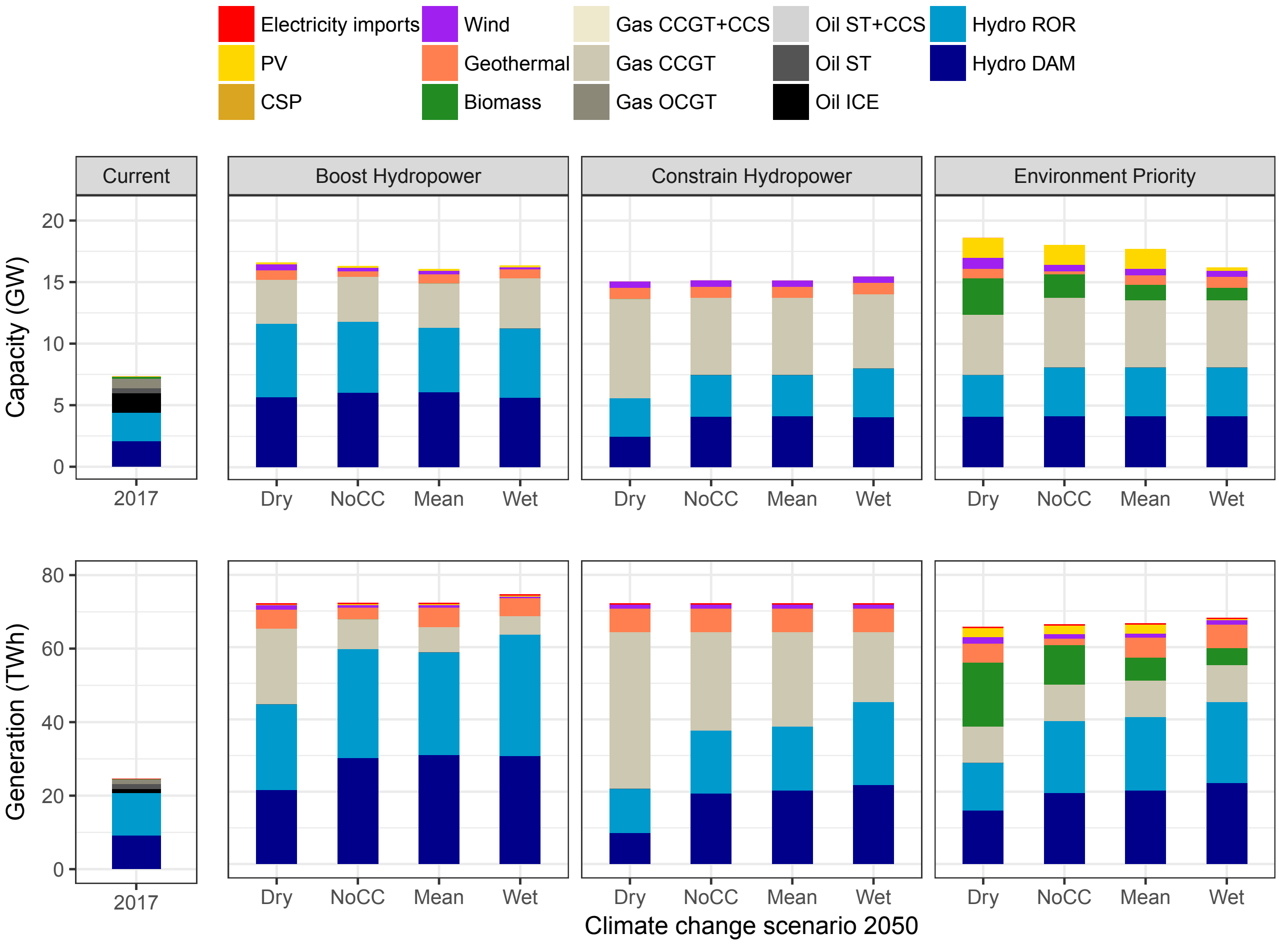

Fig. 4. Installed capacity (top) and electricity generation (bottom) in the power sector by 2017 and 2050 per policy case and climate change scenario.

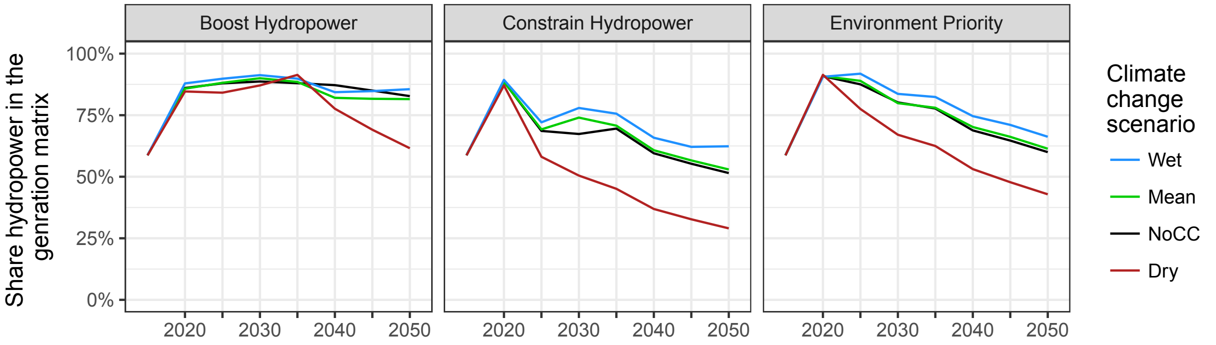

Fig. 5. Share of total electricity demand supplied by hydropower generation for the 2015–2050 period per policy case and climate change scenario.

new hydropower capacity in any of the assessed policy and climate change scenarios by 2050, which is below the threshold of the remaining assessed potential (detailed in Section 2.1.2). However, we note that a limitation of our study is that the time scale resolution of TIMES-EC does not allow the full value of DAM hydropower flexibility to be captured. Although a combination of different availability factors has been used to characterise the value of inter-seasonal storage capacity of DAM hydropower (AFS and AFA; see Section 2.1.3), the representation at the intra-day time scale level is limited (morning, day and peak; see Section 2.12). A finer time scale resolution at the hourly level might show an increasing amount of DAM hydropower deployment necessary to cover instantaneous peak demand and to provide the required flexibility to compensate for the intermittency of variable renewable energy generation. This could be better assessed in the future by soft-linking TIMES-EC to a power dispatch model detailed time and spatial resolution (e.g. Refs. [24,95]). In Fig. 4 only a snaphot of the power mix in 2050 is shown. Please refere to the Supplementary Material for the evolution of the power mix from 2015 to 2050.

3.1.1. Boost Hydropower policy case

Generally, it can be observed in Fig. 4 that the Boost Hydropower case results, which are intended to represent the Ecuadorian Government's intended policy trajectory in favour of hydropower, have the highest proportion of hydropower capacity (> 10 GW). However, once the fixed DAM capacity is installed until 2025 in line with the current policies stated in the PME, TIMES-EC then installs only ROR hydropower for the remainder of the time horizon. The Mean and Wet scenarios have similar capacity portfolios dominated by hydropower, some natural gas and only a few renewables (PV, wind and geothermal). Interestingly, in the Dry scenario (where there is a significant drop in rainfall) the model still considers ROR hydropower to be a least-cost option to supply electricity; although reduced ROR generation is supplemented with a large uptake of generation with natural gas. The model does not deploy further generation capacity with oil products, suggesting a change on how themal plants are currently operated in the country (mostly internal combustion engines fired with heavy and residual fuel oil).

Electricity generation (Fig. 4 bottom) in the Boost Hydropower policy case is slightly higher than in the Constrain Hydropower and Environment Priority cases across all climate scenarios. This is particularly visible in the Boost Hydropower Wet scenario, where the abundance of hydropower resource allows the system to switch from fossil fuels to electricity (see Supplementary Material for the electricity demand by sector for all scenarios). Hydropower production ranges from a possible +7% increase for the Wet scenario (63 TWh/y) to a −25% reduction for the Dry scenario (44 TWh/y) when compared to the NoCC scenario as a baseline (59 TWh/y). Combined cycle gas turbines are the technologies buffering hydropower variability. The share of electricity generated from natural gas remains low for the NoCC and Wet climate scenarios but increases in the Dry scenario to compensate for lower hydropower generation. In the Boost Hydropower scenario, the share of electricity demand that can be supplied by hydropower ranges from 62% up to 86% in 2050 (Fig. 5), which shows that hydropower can remain a major generation source even in the occurrence of a dry climate scenario.

3.1.2. Constrain Hydropower policy case

The scenarios using the Constrain Hydropower policy case assumptions prohibit the investment in additional large hydropower projects, representing a future where environmental and social concerns limit their construction. However, despite these restrictions on large hydropower capacity, the model results show that a significant fraction of small and medium sized hydropower may still be cost-optimal to deploy in the model (Fig. 4, top), even taking into account their limited operational flexibility. Although in all scenarios under the Constrain Hydropower policy hydropower is around 50% of total installed capacity (Fig. 4, top), it is shown increased levels of investment in flexible thermal plants fuelled by natural gas (6–8 GW). This is a dispatchable electricity generation technology that is less sensitive to climatic variations, and one that appears to effectively fill in the gap created by the lack of large hydropower capacity in this scenario. Capacity investments for geothermal (0.9 GW) are similar, but wind (0.5 GW) is larger in the Constrain Hydropower policy case compared to the Boost Hydropower policy case. No solar capacity is selected in this policy case.

Regarding electricity generation (Fig. 4, bottom), the Constrain Hydropower scenarios show an increased variability of hydropower output compared to the Boost Hydropower cases. These range from a possible +21% increase in the Wet scenario (45 TWh/y) to a −44% reduction for the Dry scenario (21 TWh/y) when compared against the NoCC scenario as a baseline (37 TWh/y). This wider range of hydropower output appears to occur largely as the results of the reduced reliance on DAM capacity with inter-seasonal storage and the dominant presence of ready-dispatchable gas-fired thermal generation. The Constrain Hydropower case shows the potential for the leading role that natural gas generation might come to play in Ecuador in the event that large hydropower development is not possible and a dry climate scenario comes to pass. Ecuador has a relatively small level of proven domestic natural gas reserves (10.9 billion m^3) [75], and therefore the Constrain Hydropower scenario considers that by 2050 Ecuador would likely need to import all of its natural gas. This has implications for Ecuadorian energy security. For example, energy security could be negatively impacted in the event that natural gas import contracts cannot be secured in a timely fashion or in the event that sufficient onshore or even floating storage regasification units are not built in due time. While not explicitly modelled in our analysis it is also worth highlighting that higher annual temperatures driven by climate change could well have effects on plant cooling systems required for thermal electricity generation [87]. In the Constrain Hydropower scenario the share of electricity demand that can be supplied by hydropower ranges from 29% up to 62% in 2050 (Fig. 5), which represents a negative offset of around −30% compared to the estimated range for the Boost

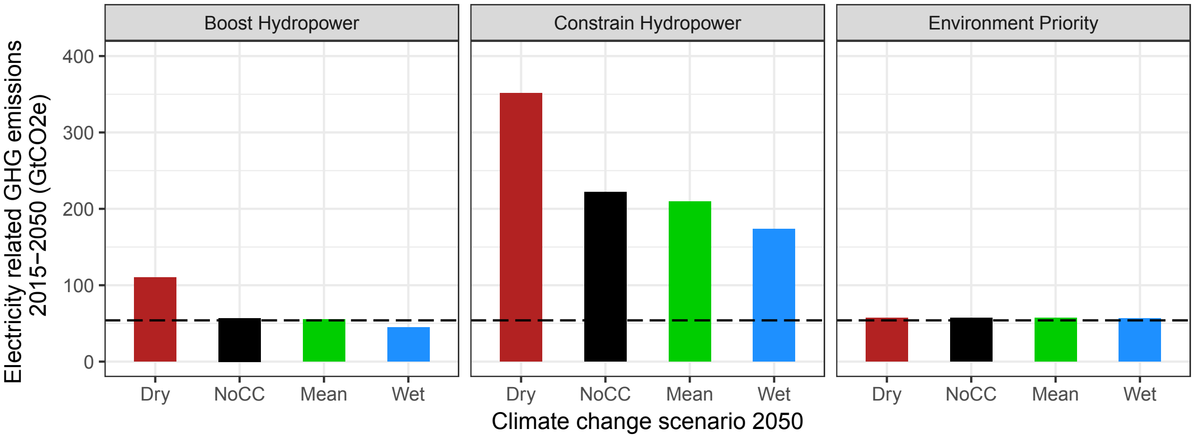

Fig. 6. Electricity related GHG emissions for the period 2015–2050 per policy case and climate change scenario. The dashed line represents Ecuador's NDC emission level (53 $GtCO_2e$).

Hydropower scenario.

3.1.3. Environment Priority policy case

This scenario restricts the future deployment of large hydropower projects at the same time as constraining cumulative emissions for the 2017–2050 period at the level of those expected for the Boost Hydropower and NoCC scenario (53 $GtCO_2e$), which reflects Ecuador's current position on energy system decarbonisation. This policy scenario generally shows the highest total cumulative installed capacity (up to 18 GW by 2050) out of all of the scenarios (Fig. 4, top). Compared to the Boost Hydropower case, the TIMES-EC model compensates for the shortfall in electricity from large hydropower in the Environment Priority case by deploying larger a significant capacities of solar PV (0.5–2 GW), biomass electricity (1–3 GW) and wind power (around 1 GW). Given the larger shares of intermittent generation capacity from weather-dependant renewables, the model also installs natural gas generation capacity in a proportional fashion in order to provide backup to the system. Levels of natural gas generation capacity in the Environment Priority scenarios (5–6 GW) reaches levels lower than the Constrain Hydropower policy case but higher than of the Boost Hydropower scenario. No carbon capture and storage (CCS) technologies are detected in the results, despite being available for the model to choose. Taking a closer look at the solar technologies, it is verified that PV technology, both at the utility scale and at the level of distributed generation is the preferred choice in the model. Concentrating Solar Power (CSP) type plants with several hours of thermal energy storage systems are available in the model but are still not found to be economical to deploy even in the most critical Dry scenario. Wind power resources above 7.5 m/s at 80 m are deployed while geothermal potential is also installed at levels similar to those found in the Constrain Hydropower scenario (0.7 GW). The model still considers small and medium ROR hydropower plant deployment as the least-cost source of electricity for mitigating emissions with levels similar to the Constrain Hydropower scenarios, and a slight increase in DAM hydropower is registered, even including the Dry case.

In terms of electricity generation (Fig. 4, bottom), the Environment Priority set of scenarios shows a variability of hydropower output ranging from a possible +14% increase in the Wet scenario (45 TWh/y) to a −30% reduction in the Dry scenario (28 TWh/y), when compared against the NoCC scenario as a baseline (39 TWh/y). Even though PV has a considerable level of installed capacity in these scenarios, it only reaches a maximum share of 7% of electricity generated in 2050 in the Dry scenario (5 TWh/y out of 65 TWh/y). Generation from biomass (mainly through direct biomass combustion plants) is the source of electricity generation that the model appears to rely the most to buffer the possible variations in future hydropower output. This can be seen very clearly in the Environment Priority Dry scenario where electricity generated from direct biomass combustion plant almost equates to the output of hydropower (~28 TWh/y). This scenario unveils the potential importance of biomass generation for future deep decarbonisation policy in Ecuador. Given that wind and geothermal potential are almost completely tapped, that solar PV may also reach its technical potential due to intermittency issues, and that concentrating solar power and natural gas with CCS appear to both be prohibitively expensive to deploy, the main alternative left in the model for a low-carbon scenario that has constraints on large hydropower plants appears to be biomass generation. Biomass power could also have its own issues that merit further investigation. We should highlight that the biomass resource itself could be exposed to climate vulnerabilities due to the effects of higher temperatures and extreme hydrological conditions, such as both floods and droughts. The use of biomass for energy generation also brings with it a broader set of social and environmental concerns, that should be investigated in future research efforts. In the Environment Priority case, the share of electricity demand that could be supplied by hydropower in 2050 is between 43% and 66%, roughly in the middle of the Boost Hydropower and the Constrain Hydropower cases (Fig. 5).

3.2. Emissions and costs

Fig. 6 shows cumulative electricity-related GHG emissions for the period 2015–2050 for all modelled scenarios. The emission level of the Boost Hydropower policy case and NoCC climate scenario is considered in this analysis as the expected value associated with the Ecuadorian NDC (53 $GtCO_2e$). It can be seen that under the Boost Hydropower policy case set, the impact of climate variation on emissions is small, although there is doubling in emissions under Dry conditions (110 $GtCO_2e$) and a slight fall under Wet conditions (48 $GtCO_2e$). All four policy cases for the Constrain Hydropower scenario, where large hydropower is prohibited, imply a large increase in emissions as compared to the Boost Hydropower case. Even when future climate variations result in an increase in rainfall, emissions are almost three times larger than the equivalent Boost Hydropower case (compare the Wet Boost Hydropower and Wet Constrain Hydropower scenarios in Fig. 6). In the event of a dry scenario where future climate change decreases rainfall in Ecuador, and where the government does not wish to (or is unable to) pursue large hydropower projects, there is a very large increase in emission levels. Under the Constrain Hydropower policy case and the Dry climate scenario, energy related GHG emissions reach 350 $GtCO_2e$, representing almost a seven-fold increase compared to the level implied in the current Ecuadorian NDC. Overall, the model results indicate that

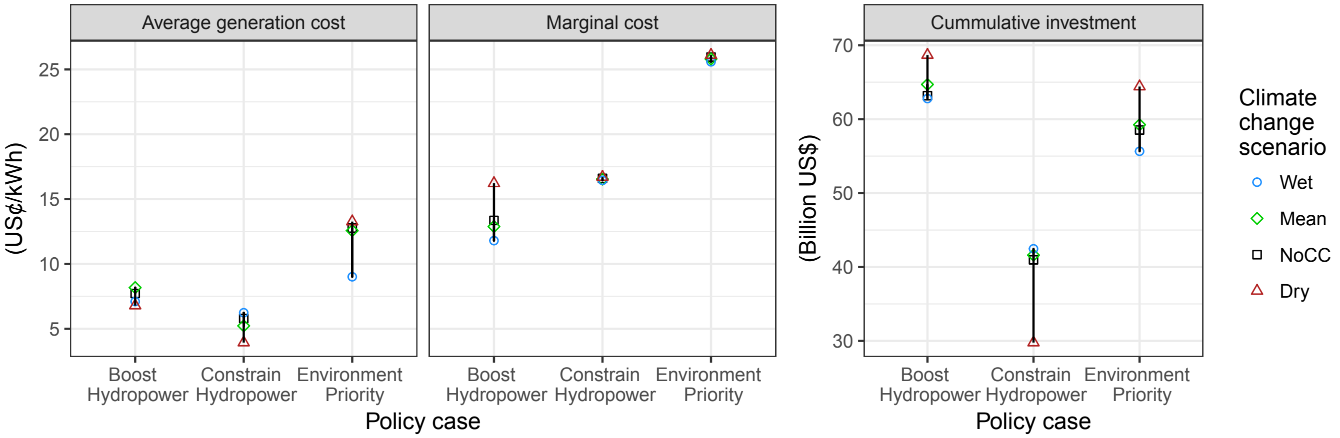

Fig. 7. Average long-term electricity generation cost (left), average marginal cost (middle) and cumulative investment (right) for different policy cases and climate change scenarios, for the period 2015–2050. Figures are in $\$US_{2015}$.

it may become difficult to prevent emissions from energy production increasing over time on a cost-optimal pathway without large-scale hydropower. This poses a trade-off between the social and environmental issues found at the local level, and the efforts to mitigate GHG emissions at the regional and global levels. As described earlier in Section 2.3.2, an alternative set of pathways for maintaining emissions at the implied NDC level without large-scale hydropower is explored –namely, the Environment Priority policy case. However, this approach comes at a cost, as discussed below.

The analysis using TIMES-EC finds that future policy decisions and variations in hydropower production associated with climate change have an uncertain impact on future electricity system costs, namely average generation costs, marginal generation costs and cumulative investment costs (Fig. 7). In general, the choice of policy case appears to have a greater impact on prices than future variations in climate. Irrespective of the policy case, climate change uncertainty causes an uncertainty in the average generation cost of around 3 US¢/kWh (Fig. 7, left). Across the policy cases, the range of average generation costs is much broader (10 US¢/kWh). The Constrain Hydropower policy case is the cheapest option, although as discussed earlier, the Constrain Hydropower case may bring with it significant implications for future GHG emissions. The most expensive option from an average generation cost perspective is the Environment Priority case, with a range that almost doubles the one of the Constrain Hydropower case. The Boost Hydropower case has a middle-of-the-road average generation cost compared to the other policy cases (6–8 US¢/kWh).

While the average generation cost is important for investors, the marginal cost is the metric that will likely affect government policies the most (such as subsidies for clean energy), as consumers are charged based on marginal costs (Fig. 7, middle). It is observed that climate change has a higher impact on the marginal cost range in the Boost Hydropower case (12–16 US¢/kWh), in which part of the peak demand could be covered with cheap hydropower, particularly in the occurrence of a Wet or NoCC scenario. The marginal cost achieved under the Constrain Hydropower scenario set, although more expensive than the Boost Hydropower scenarios, stands out for its narrow range of variation under different climate conditions (all instances around 16 US ¢/kWh) and accordingly appears to have a low level of climate vulnerability. In this gas-dominated power matrix, flexible gas-fired generation will be the technology of preference to cover peak demands. The marginal costs found under the Environment Priority case have also a narrow uncertainty band (Fig. 7, middle), but is very high reflecting the fact that expensive biomass generation is used to cover peak demands. Environment Priority therefore stands out as a policy case that could achieve low emissions, hedge against both climate change uncertainty and possible risks to delivery associated with large hydropower projects but with larger average and marginal generation costs.

Fig. 7 (right) also presents the cumulative investment costs for the 2015–2050 period. The Boost Hydropower policy case is found to generally be the most capital-intensive option (around US$ 65 billion), the Constrain Hydropower case is generally the cheapest option (around US$ 35 billion), and the Environment Priority case appears to represent an intermediate point between the two (around US$ 60 billion). The Boost Hydropower policy case is found to be the most capital-intensive pathway of all because it would account not only for building new large hydropower plants but also require to install further capacity to supply electricity as a result of the risk of generation shortfalls due to dry conditions. The Constrain Hydropower policy case presents the least capital-intensive option, as it is dominated by natural gas technologies with lower investment costs compared to hydropower and other renewables. However, it should be noted that this scenario does little to keep Ecuador on a path towards a low carbon future and has high emissions, as well as having implications for energy security due to the requirement for future natural gas imports, as discussed earlier. The Environment Priority policy case is the middle case – less capital intensive than the Boost Hydropower approach while also offering a generation matrix that is capable of maintaining low emissions consistent with Ecuador's current NDC.

3.3. Summary of trade-offs among scenarios

The balancing of economic development against responsible environmental stewardship under uncertain future resource costs and climatic conditions is a complex challenge to contend with. This creates a series of trade-offs. In a global move towards developing deep decarbonisation pathways and net zero emissions balances, NDC policies may need to reflect on these trade-offs and challenges [119]. Table 4 shows a summary of the trade-offs found amongst the policy cases explored in this research, namely regarding their risk exposure to climate change, their costs and their GHG emission levels, as well as the key issues for security of supply in each scenario. While the hydropower-led policy pathway demonstrates promising results in terms of lowering emissions, it is significantly exposed to climate risks, and the social and environmental concerns surrounding large hydropower development could also ultimately make it less viable than the other options. If Ecuador were to abandon the current drive towards large-scale hydropower, this could result in a policy pathway that favours natural gas-fuelled generation, which of course is cheaper but would cause the power system to significantly increase its GHG emissions. In turn, this could cause the Ecuadorian Government to miss its own emission targets as stated in its NDC. More critically, this approach could also

Table 4
Trade-offs between risks, costs and emissions for policy case scenarios for the Ecuadorian power sector in 2050.

	Policy case		
	Boost Hydropower	Constrain Hydropower	Environment Priority
Risks due to:			
Clim. change	High	Low	Low
Soc. & env. issues	High	Intermediate	Low
Costs, emissions and technology:			
Gen. cost	Intermediate	Low	High
Investment	High	Low	Intermediate
Emissions	Low	High	Low
Technologies	Hydropower + gas	Gas + hydropower (small and medium)	Hydropower (small and medium) + biomass + gas
Security of supply	Good only if precipitation behaves as the past or increases.	Good only if gas imports are secured.	Good only if biomass resource can be tapped and its vulnerability to climate change is low.

expose the country to the risks of depending on foreign natural gas imports, given Ecuador's limited domestic reserves. Therefore, a policy choice that considers the greater deployment of other renewable energy systems could be an important alternative to either of these two options. This third pathway could hedge against uncertainty by increasing Ecuador's resilience to future variation in climate conditions, involve lower up-front investment costs overall, and limit the risks that the existing hydropower-led policy has regarding environmental concerns and social resistance. However, as presented in this study, this alternative would entail an increase in generation costs. While increasing the cost burden on consumers to simultaneously achieve greater stability and protect the environment may be a challenge for the Ecuadorian government to implement in practice, it would seem to be a reasonable long-term compromise worth considering.

4. Conclusions and insights for policy

Hydropower plays a critical role within global, South American and Ecuadorian energy policies for a future low-carbon economy. Nonetheless, hydropower itself is vulnerable to climate change as it is dependent on water resources. Even though climate change impacts on hydropower are widely recognized and flagged in the literature, their quantification in terms of uncertainty and their knock-on effects on energy policy decisions have been very limited to date. Few studies have focused on the impacts of climate change on energy supply and even fewer on the uncertainty drawn by a large set of GCM projections. This paper contributes to filling these gaps by simultaneously quantifying not only the uncertainty of hydropower generation due to climate change models, but also exploring the overall impacts on long-term costs and GHG emissions for the power sector in the context of different future policy choices.

The Ecuadorian Government's current approach towards future energy policy development is overwhelmingly dominated by an enthusiasm for new hydropower projects. Ecuador's future hopes for energy security, maintaining stable electricity prices, mitigating GHG emissions and providing a springboard for industrial and economic development all hinge on this strategy. However, the government's current policy is predicated on the assumption that there will be only small changes in future hydrological conditions and the levels of runoff available to drive hydropower projects. This analysis shows that according to GCM projections this is only one of the possible outcomes under a changing climate, and that there is the potential for both increased rainfall and decreased rainfall in the future. Long-term policy decisions determine the level of impact that climate change could have on the least-cost power expansion pathway. For the policy scenarios assessed in this paper, our model-based analysis found that changes in water availability could induce a variation of electrical hydropower generation for supplying total electricity demand of between 29% and 86%. Our work demonstrates that hydropower vulnerability to climate change in Ecuador is a reality that the country must plan for. When climate modelling uncertainty is considered, both high or (more critically) low water resource scenarios are very real possibilities that should be captured in future strategic analysis for the Ecuadorian government.

Beyond Ecuador, countries that are planning large hydropower deployment as a central pillar of their long-term energy policy should take into consideration a broader perspective of future climate conditions in conjunction with the scientific community that researches the impacts of climate change scenarios (such as those implied by the RCPs); energy policy analysts should explore large ensembles of results from GCMs to capture future uncertainties in hydropower output in their strategic planning. Additionally, we highlight that long-term energy system optimisation models which capture the impacts of climate change can be useful to complement short-term power system dispatch models which usually work with time horizons too short to capture long-term climate variations. Energy policy and the investment decision-making process can also be better assisted by quantifying the existing and potential trade-offs amongst emissions, investment costs and climate resilience. This paper serves as one such example of how this can be achieved.

Finally, we would like to highlight a number of areas that could provide a focus for future research. First, consumer behaviour and their interactions of multiple agents is only captured in an abstract fashion through sensitivities in TIMES-EC. GDP growth for an emerging economy such as Ecuador is highly uncertain and the income per capita or per household should be a stronger incentive for change in demand and the uptake of newer and more efficient (and often more expensive) technologies. Further efforts should include calibration of consumer energy demand behaviour to reflect that of a developing country as well as the exploration of other GDP evolution scenarios (perhaps under another of the IPCC Shared Socioeconomic Pathways) that could consider higher end-use demands and further electrification of the energy system, particularly in the transport sector [70,78]. Second, hydropower reservoirs are not explicitly modelled in TIMES-EC and therefore reservoir size cannot be optimised endogenously in the model. The sizing of a hydropower reservoir is an extremely site specific exercise that depends on topographic characteristics, while the operation of such a system depends not only on the conditions found in the wider electricity system but also on downstream constraints for water release in addition to environmental flows [119]. This challenges the expected flexibility that a reservoir hydropower plant could actually have and points towards further research linking integrated energy system optimisation models with reservoir design and management optimising modelling tools [22,29,35,107]. The scenario assessment does not capture short-term recurring uncertainties such as historical or climate change induced seasonal water resource variability. Climate change effects could comprise cyclical *mixed* wet and dry scenarios in which the uncertainty of the future hydrological conditions are never resolved, such as the ones caused by the El Niño Southern Oscillation [117]. Uncertainties around large hydropower investment costs have also been found to be highly uncertain and recurring [96,97]. Approaches that integrate these types of uncertainties into energy system optimisation models should be explored in the future, such as probabilistic approaches [71] and stochastic programming [91], which have recently been integrated into TIMES.

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Appendix A. Supplementary data

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