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Green hydrogen exports in New Zealand and Chile can improve electricity supply security if configured as local energy insurance

Carlos Alvear [a], Jannik Haas [b,*], Rodrigo Palma-Behnke [a], Rebecca Peer [b], Juan Pablo Medina [c], Jordan D. Kern [d]

[a] *Department of Electrical Engineering, Energy Center, Faculty of Physical and Mathematical Sciences, University of Chile, Santiago, Chile*
[b] *Department of Civil and Natural Resources Engineering, University of Canterbury, Christchurch, New Zealand*
[c] *Business School, Universidad Adolfo Ibáñez, Santiago, Chile*
[d] *Department of Forestry and Environmental Resources, North Carolina State University, Raleigh, NC, United States*

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ABSTRACT

Extreme weather events, for example, prolonged droughts, are increasingly stressing electricity systems and threatening the achievement of energy transition goals. At the same time, countries such as Chile and New Zealand are developing strategies to export renewable energy through green hydrogen. This paper economically evaluates the use of future green hydrogen exports as strategic storage under the logic of energy insurance, based on the assumption that Chile and New Zealand will adopt a hydrogen economy. Our first contribution is to compare the marginal costs of re-electrified green hydrogen, for different scenarios, to the value of lost load in New Zealand and Chile. We then determine the marginal cost of energy produced from green hydrogen based on projected production, transportation, and re-electrification costs for the year 2030. Finally, we estimate the eventual penalties that exporters would incur in the case of breaking their contracts and the overall resulting system costs of using hydrogen for system security. We found that re-electrifying hydrogen can be competitive with conventional technologies at 3 USD/kg. At 1.5 USD/kg, hydrogen is more competitive than fossil fuel-based technologies, for both New Zealand and Chile. Thus, in 2030, it could make economic sense for New Zealand and Chile to use hydrogen as a strategic reserve. The system cost of the proposed insurance scheme in 2030 ranges from 0.53 to 1.76 USD/MWh, which is small compared to total electricity costs. These values can be used for power system expansion and operation planning.

1. Introduction

Countries with great renewable energy potential, such as New Zealand and Chile, are exploring different ways to harness these resources [1,2]. One possible approach is the production of green hydrogen and derived synthetic fuels to replace traditional fuels in sectors that are difficult to electrify [3]. This might create opportunities for the development of a new industry for the production and export of these energy carriers. In fact, both Chile [4] and New Zealand [5] have developed green hydrogen strategies with ambitious production and export targets. This creates a dilemma and potential source of conflicts, as clean energy will be exported to other countries while part of the local energy matrices remains polluting and other goals of the energy transition are still pending [2]. This dilemma is accentuated considering that, due to increasingly frequent extreme weather events, there is a higher risk of major blackouts or unserved energy scenarios [6].

The green hydrogen strategies of the different countries are mainly focused on achieving decarbonization and integration of renewable energies, energy diversification, and economic growth [3]. In this sense, green hydrogen, as an energy vector, could be used in a wide variety of applications, including heating, industries (chemical, metallurgical, refineries, etc.), power, and transportation [3]. However, not all possible applications make economic sense, as Liebreich sorted in the well-known “clean hydrogen ladder” [7]. In particular, integrating green hydrogen into power systems seems promising for seasonal storage and backup services [8]. Once in place, hydrogen can also provide flexibility to power systems [9], as well as other ancillary services [10].

In electric power systems, both expansion planning and operation are often carried out based on mathematical optimization models [11,12]. In most liberalized markets, generators are dispatched in economic

* Corresponding author.
E-mail address: jannik.haas@canterbury.ac.nz (J. Haas).

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merit-order and cleared based on a marginal price [13]. According to theory, marginal pricing can stimulate generation investment to ensure long-term generation capacity adequacy. However, the increasing presence of renewable energy is leading to lower prices in the long term which can also lead to a lack of incentives to invest [14,15]. As a result, and considering the increasing frequency of extreme weather events, it is necessary to incorporate and model such phenomena into the planning process [16].

Traditional approaches incorporate scarcity price signals such as the Value of Lost Load (VoLL) into their market designs [17]. The VoLL represents society's willingness to pay to avoid a power outage and can be presented in dollars per kilowatt-hour, effectively representing the amount an individual would pay to consume a certain amount of electricity during an outage [18,19]. Therefore, any solution that intends to provide energy in stressed power systems must be cheaper than the VoLL to make economic sense [20].

One solution to deal with short-term expected unserved power scenarios is Demand Side Management (DSM). In DSM schemes, consumers modify (reduce or shift) their energy and/or power consumption to increase the flexibility of the power system [21,22]. For instance, in Europe, due to the unavailability of natural gas imports imposed by the Russia-Ukraine conflict, many countries adopted measures to reduce energy consumption, such as modifying thermostat settings or turning off public lighting [23]. Another solution is to increase generation capacity; however, the commissioning of new projects typically takes several years [24]. Expanding transmission capacity to avoid spilling renewable generation or promoting Distributed Generation (DG) can also contribute to the security of supply [25]. However, transmission line construction is capital and time-intensive, and DG growth is usually decentralized using the hosting capacity of the distribution systems.

To deal with events that jeopardize the continuity of supply in electricity systems, some markets have adopted market-wide capacity payments, while others have tried to implement a strategic reserve to complement the spot market. A strategic reserve seeks to secure additional generation capacity in addition to that delivered by the spot market [26,27]. Strategic reserves are only dispatched when market sources are unable to fully supply energy demand and are usually thermal power plants operating under exceptional circumstances [28]. Strategic reserves have been adopted in several countries, such as Germany, Sweden, Finland, and Belgium, to ensure continuity of supply in the face of increasing renewable generation and phasing out of fossil fuel-based generation [27–29]. The National Electricity Market of Australia complements forward contracting obligations with a strategic reserve. The Australian Energy Market Operator has a last-resort role as a reliability and emergency reserve trader [30]. In addition to capacity payments, Chile has defined a strategic reserve mechanism so that coal-fired plants that are no longer part of the normal dispatch due to its decarbonization plan, could still contribute to the security of energy supply [31]. Additionally, several thermal power plants can be converted or reconditioned for the use of hydrogen or derivatives.

Future green hydrogen exports could be another means for strategic energy reserves in a scenario in which an international hydrogen economy and the market have developed for countries like Chile and New Zealand. This potential application is not considered in any of the hydrogen strategies or roadmaps. Chile's national green hydrogen strategy [4] considers targets related to production and export and domestic uses in industries such as mining, transportation, and refineries. The development of hydrogen exports in Chile should prioritize just transitions, ensuring a fair distribution of costs and benefits that protect vulnerable communities, reinforce environmental targets, preserve ecosystems, and consider territorial priorities [1,2]. "A vision for hydrogen in New Zealand" [5] details hydrogen production for electromobility, export, industrial processes, and long-term storage systems, particularly to cope with dry-year electricity scarcity. The current costs of producing, transporting, and using green hydrogen make many of its potential applications unfeasible; however, it is expected that by 2030, cost reductions will allow some hydrogen applications to materialize [32]. In general, as seen in Ref. [3], for most countries, the insertion of green hydrogen into power generation systems is not a priority, neither as a continuous source nor as a backup service. Therefore, using future exports of green hydrogen as a strategic energy reserve is not a purpose addressed in those documents [33,34].

Some publications have studied the use of financial insurance schemes to tackle unserved energy. An insurance risk mechanism is developed in Ref. [26] for the procurement of strategic reserves, based on a specific generator, which adapts to a future with variable generation and flexible demand. In Ref. [33], the utility of an irradiance-based weather derivative, which acts as an index-based insurance for the contract holder in mitigating cloud weather risk, is explored. In Ref. [34], a novel coalitional insurance design for the integrated power and natural gas systems against extreme weather is proposed, where to control the risk of insurer insolvency, the premium of the coalitional insurance is determined based on the resilience assessment-based actuarial framework. In Ref. [35], energy efficiency insurances can diversify property insurance portfolios and reduce regulatory capital for insurers, even potentially superseding financial market instruments such as weather derivatives.

1.1. Research questions

Green hydrogen (and its derivatives) could temporarily be stored before export to contribute to local energy by re-electrification with fuel cells in case of generation fleet shortages or transmission constraints. In decarbonized systems, these reserves could be key for coping with major extreme weather events. In the early years, it is possible that such reserves could become significant relative to hydrogen export contracts and accessing these reserves might imply a breach in obligations, for which a fair compensation mechanism needs to be in place. The purpose of this work is to provide a reference to define a policy for the emerging export industry of green hydrogen and derived synthetic fuels to contribute to the reliability of the local electricity supply. Concretely, our study contributes to the literature by answering the following research questions.

- Can green hydrogen exports, by acting as a strategic reserve in situations of electricity system stress, cost-effectively help improve the reliability of electricity supply? How do these costs compare with the costs of unserved energy and conventional fossil fuel-based generation? We will provide concrete numbers for Chile and New Zealand, two countries with hydrogen export ambitions.
- How much would it cost to supply such energy from hydrogen reserves in the future for different locations? We will consider the projected costs until 2030, including production, transportation, and re-electrification of green hydrogen for different locations in Chile and New Zealand.
- What should be a fair compensation that exporters of green hydrogen should receive in case the deployment of hydrogen reserves breaches their contracts, and would this scheme still be economically viable?

1.2. Relevance

The results of this study aim to provide evidence on the relevance of coordinating the export of renewable resources while fulfilling national energy transition and decarbonization objectives, taking advantage of the synergies between both objectives and considering that security of supply is often not explicitly considered in countries' green hydrogen strategies with export targets. This would also be a solution to avoid further delaying the phase-out of fossil power plants for energy security reasons. This work is a first step to quantifying a new application or role of hydrogen for meeting security of supply under international energy and insurance market logic.

The rest of this paper is organized as follows. Section 2 details the methodology, proposed insurance scheme, and designed scenarios. Section 3 shows the costs of energy produced from re-electrified hydrogen for different scenarios in New Zealand and Chile, and the cost of implementing an insurance scheme based on green hydrogen exports. Section 4 concludes and proposes future work.

2. Methods

This work aims to demonstrate that the future green hydrogen export industry could act as a backup energy system so as not to compromise the continuity of electric power supply, i.e., avoiding delays in decommissioning polluting power plants for energy security reasons. In such scenarios, the Independent System Operator (ISO) or a private company could act as an insurer that, in exchange for the payment of a premium, prevents unserved energy situations through the acquisition of green hydrogen from exporters, compensating them for any potential losses or penalties.

In normal situations, the system operator manages the wholesale electricity market, where market generators supply consumer demand according to a merit order list. In the future, some of these consumers may be part of the hydrogen supply chain, particularly electrolyzers, which can be represented as consumers that will produce green hydrogen for export. Note that part of the energy needed will also come from dedicated generation units, not necessarily connected to the main electricity system.

In abnormal operating situations, the hydrogen-based strategic reserve may be activated. This would occur when the ISO foresees there could be lost load or unserved energy due to the eventual scarcity of market resources for electricity generation. In these situations, the insurer could purchase the green hydrogen produced by exporters. The hydrogen could be transported to where it is strategically needed and re-electrified using PEM fuel cells or reconditioned thermal units. Additionally, the electricity consumption of electrolyzers can be interrupted to increase the electricity availability for local consumption as a DSM mechanism. Nevertheless, this option highly depends on the existence of local hydrogen storage capabilities to actually allow DSM. Thus, this mechanism is not considered for the base scenario.

It is necessary to calculate a fair hydrogen acquisition price that the insurer would pay to exporters, considering the cost of production and penalties for a possible breach of contract. This cost, in addition to the use of the necessary infrastructure for transportation and re-electrification, must be financed by a premium charged to consumers. Fig. 1 shows an insurance scheme based on the future exports of green hydrogen proposed in this work, where this energy vector acts as a strategic reserve.

Following the general framework proposed in Ref. [26], the methodology described below determines the costs involved with applying the proposed hydrogen insurance scheme. The main objective is to calculate these values to determine if the payment of a premium is more convenient for consumers than the cost of unserved energy or lost load. A methodology is designed and applied to demonstrate that, as described below. This methodology is separated into three stages with initial inputs of hydrogen cost, electricity demand projections, and hydrogen re-electrification technology costs.

Stage 1 compares the costs of re-electrifying green hydrogen, the VoLL, and the costs of fossil fuel-based generation. Stage 2 analyzes the cost components of energy produced from green hydrogen for countries that will become export poles, considering the expected costs of production, transportation, and re-electrification. Subsequently, in Stage 3, a loss analysis is performed, and an insurance scheme is designed. For this, unserved energy scenarios are designed, the losses of exporters are calculated, and finally, the value of the premium is estimated. The result determines if paying a premium is better than having unserved energy or lost load. Fig. 2 shows a flow chart outlining the methodology, which is separated into the input data, the three stages of methodological development, and the main conclusion of this work.

Although, a priori, the proposed scheme based on the future hydrogen exports cannot be considered as insurance per se, the theory of incomplete contracts in economics and law suggests that events that occur ex-post can justify the efficiency of breaching a contract [36]. In effect, the possibility of breaching a contract to some extent is an ex-post insurance scheme against circumstances not anticipated in the contract that make fulfilling its obligations very costly to one party. Thus, the scheme proposed is an insurance and a strategic reserve, as one of the focuses of this work is quantifying the cost for the exporters for insuring the local electricity supply in scarcity periods.

In addition, in the case of international trade, there are clauses (e.g. Force Majeure) for unforeseeable and unavoidable catastrophes that prevent participants from fulfilling obligations [36]. These clauses generally cover natural disasters, such as hurricanes, droughts, earthquakes, and human actions (e.g. armed conflict and man-made diseases). Hence, a special clause can be included in the export contract to take into account these circumstances of electricity deficits, making it more explicit the case analyzed in this work so that the final customer knows the risks related to the supply of green hydrogen energy.

Also, assuming that the capacity of production of green hydrogen is

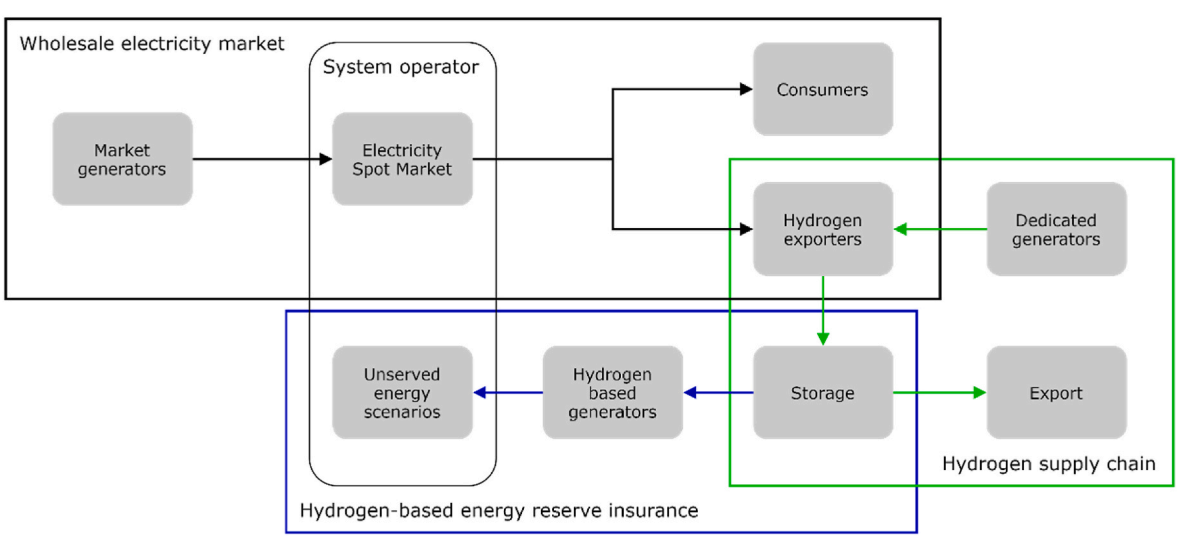

Fig. 1. Green hydrogen-based energy insurance scheme, where the black box represents the wholesale electricity market under normal operating conditions, the green box represents the future hydrogen supply chain, and the blue box represents the strategic reserve proposed in this paper.

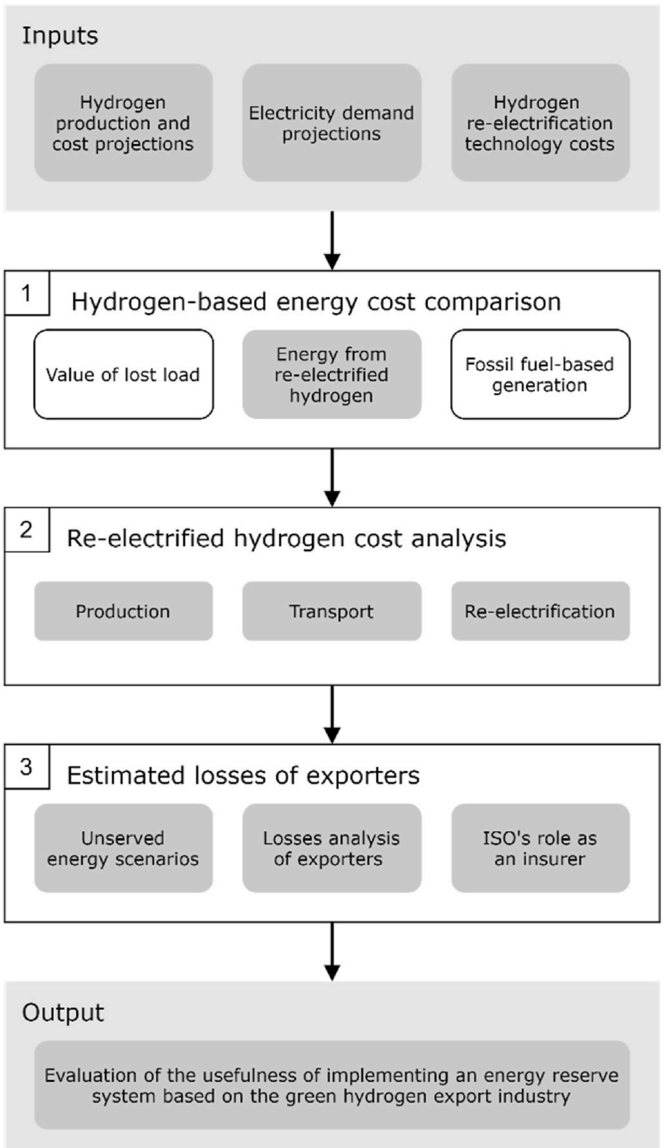

Fig. 2. Flow chart of the methodology developed for this paper. The first box shows the input data, the next 3 boxes show the three stages developed, and the last box shows the main output.

high enough in both countries, this clause could have less penalty because its impact in postponing the export will be only temporary. Moreover, it is assumed that there will be a global market for green hydrogen production by then. Thus, if there is a failure to fulfill the contract, the consumer will be entitled to the penalty payout according to expected contracts which can then be used to get another supplier in the international energy market. Furthermore, in an energy transition scenario, hydrogen, as an energy carrier, will have other viable substitutes, i.e., other fuels like natural gas, ammonia, methanol, or biogas. Therefore, the final consumer could satisfy his energy needs with another supplier of green hydrogen or with a supply of another low-carbon fuel.

This work assumes that the following will take place by 2030:

- Green hydrogen production, transportation, and re-electrification cost reductions will be achieved.
- Green hydrogen strategies in Chile and New Zealand will be successfully implemented.
- A logistics and international market for the sale of green hydrogen and its derived synthetic fuels will exist.
- Infrastructure for the production, transport, and re-electrification of green hydrogen in the producing countries will be available.
- Low-carbon fuels markets will exist and will be viable substitutes for green hydrogen.

2.1. Model input data

The input data are the annual green hydrogen export and cost production projections, the annual electrical energy demand projections, and the hydrogen transport and re-electrification technology costs. As the design of energy insurance is focused on countries that will become poles of production and export of green hydrogen, it is necessary to know the future Levelized Cost of Hydrogen (LCOH) and the expected production and export. It is expected that by 2030 there will be sharp reductions in the LCOH as shown in Ref. [32]. Chile's National Hydrogen Strategy [4] and the vision for hydrogen in New Zealand [5] contain projections of future hydrogen production costs. In addition, projections of energy demand and exports of green hydrogen are part of Chile's long-term energy planning [37]. For New Zealand, energy demand projections are shown in New Zealand's energy outlook [38], while green hydrogen export projections are shown in Ref. [39].

Another important input relates to the expected costs for hydrogen transportation and re-electrification. In terms of transportation, while ship-based logistics are expected to emerge for international trade, it is also expected that pipelines will be retrofitted or built for domestic hydrogen distribution and use [32,40]. In that sense, in case the proposed insurance scheme is activated, a marginal use of the domestic distribution infrastructure is considered. The hydrogen transportation cost (dollars per kilogram per kilometer) for onshore and subsea pipelines are obtained from Ref. [40]. We only considered this variable operating cost and did not account for investment costs (this is assuming that the pipeline exists for other purposes). For re-electrification, it is assumed that power plants based on PEM fuel cells are used marginally, also paying only a variable cost for their use. The information to determine the fuel cell variable cost, in dollars per kilowatt-hour, and fuel cell re-electrification efficiency, in kilowatt-hour per hydrogen kilogram, is obtained from Ref. [41]. All input data used in this work are shown in Table 1.

This paper proposes that the expected future green hydrogen infrastructure can be used marginally to benefit the entire power system. This is not a novel idea since the marginal use of infrastructure for these purposes (such as ancillary services) has already been evaluated and implemented on several occasions. For example, in Ref. [42] PV solar

Table 1
Model input data.

Energy Costs	Chile VoLL	315
(USD/MWh)	New Zealand VoLL	12,500
	Max. spot price Chile 2022	527
	Max. gas EU Dutch TTF 2022	356
	CCGT average cost Europe 2018	113
	Min. gas EU Dutch TTF 2022	73
Green Hydrogen	Chile's production in north region	1.4
Costs (USD/kg)	Chile's production in center region	1.8
	Chile's production in south region	1.3
	Chile's north-central transport	0.2
	Chile's south-central transport	0.9
	New Zealand's production	2.4
	New Zealand's interisland transport	0.2
Annual Energy	Chile 2025	92.8
Demand (TWh)	Chile 2030	103.7
	New Zealand 2030	48.8
Re-electrification	Variable cost (USD/MWh)	10
	Efficiency (kWh/kg)	22

power station, which, in addition to generating power, also contributes to frequency control, is evaluated. Likewise, in Ref. [43], a storage system is evaluated, which, in addition to energy arbitrage, also contributes to power system stability.

2.2. Methodology stages

The designed methodology consists of three steps. In Step 1, the cost of electricity, in dollars per megawatt-hour, produced from re-electrified hydrogen is calculated. For this purpose, different LCOH (considering current and future values) and average re-electrification efficiency are used. These LCOH are taken as the final cost of acquisition by the insurer as they include potential hydrogen transportation, and re-electrification costs, as well as a potential compensation for exporters. Further, the cost of energy, in dollars per kilowatt-hour, produced from re-electrified hydrogen is calculated by dividing the cost of hydrogen by the efficiency of the PEM fuel cell, as shown in equation (1). Then, the cost of energy for the different LCOHs are compared with New Zealand and Chile VoLL (obtained from Refs. [44,45] respectively), with the maximum and minimum price of natural gas in the European market for the year 2020 (obtained from the Natural Gas EU Dutch TTF index [46]), and with the maximum marginal cost of the Chilean spot market for the year 2020, obtained from Ref. [45].

$$C_{H2[USD/kWh]} = \frac{C_{H2[USD/kg]}}{\eta_{RE}} \tag{1}$$

Where:

$C_{H2[USD/kWh]}$ *is the green hydrogen cost in USD/kWh.*

$C_{H2[USD/kg]}$ is the green hydrogen cost in USD/kg.

η_{RE} is the re-electrification efficiency in kWh/kg.

It is important to remark that storage cost is not considered since, if this scheme were to be activated, the hydrogen would go directly from the production stage to the transportation stage and, lastly, to the re-electrification stage. Additionally, only the existing hydrogen storage infrastructure for export is used for the re-electrification stage. It can be easily demonstrated that the development of specific storage infrastructure for the strategic reserve is not efficient from an economical point of view. This point is discussed in section 2.3.

Step 2 determines the expected acquisition cost, disaggregated by the cost of production, transportation, and re-electrification, for six different configurations: four for Chile and two for New Zealand. Table 1 shows the configurations used to determine future hydrogen acquisition costs. The hydrogen production cost is an input, as previously mentioned. The hydrogen transportation costs are calculated by multiplying the transportation cost, as shown in equation (2), in dollars per kilogram per kilometer, indicated in Ref. [40] for the distance shown in Table 2. Thus, the production and transportation costs, in dollars per kilogram of hydrogen, are converted to dollars per megawatt-hour by dividing these costs by the efficiency of the PEM fuel cell. The variable costs of re-electrification using PEM fuel cells, in dollars per megawatt-hour, are calculated by dividing the investment cost, in dollars per megawatt, by the lifetime, in hours, as shown in equation (3). This data is obtained from Ref. [41].

$$C_{H2\ transport} = \frac{C_{ss} \cdot D_{ss} + C_{land} \cdot D_{land}}{\eta_{RE}} \tag{2}$$

Where:

$C_{H2\ transport}$ is the green hydrogen transport cost in USD/kWh.

C_{ss} is the subsea transportation cost in USD/kg/1000 km.

D_{ss} is the subsea distance in km divided by 1000.

C_{land} is the land transportation cost in USD/kg/1000 km.

D_{land} is the land distance in km divided by 1000.

$$C_{H2\ RE} = \frac{CAPEX_{RE}}{T_{RE}} \tag{3}$$

Where:

$C_{H2\ RE}$ is the green hydrogen re-electrification variable cost in USD/kWh.

$CAPEX_{RE}$ is the re-electrification device capex in USD/kW.

T_{RE} is the re-electrification device lifetime.

The objective of Step 3 is to estimate potential financial losses experienced by the exporters in order to determine the fair acquisition price and the premium to be charged to the consumers. To this end, first, unserved energy or lost load scenarios are designed with different energy and months forecasted. The following subsection details the design of these scenarios. For each scenario, the cost of unserved energy is first calculated by multiplying the unserved energy forecast with the respective VoLL as shown in equation (4). The cost of unserved energy is then compared to the cost of implementing the hydrogen-based insurance scheme. To determine the cost of the scheme, liquefied hydrogen carrier ships with a specific capacity as detailed in Ref. [47] are considered, while similar situations in the international natural gas market, such as detailed in Ref. [48], are used to estimate the costs for canceled shipments.

$$C_{forecasted\ UE} = VoLL \cdot E_{forecasted\ UE} \tag{4}$$

Where:

$C_{forecasted\ UE}$ is the total cost of the forecasted unserved energy, in USD.

$VoLL$ is the respective value of lost load, in USD/MWh.

$E_{forecaste\ UE}$ is the forecasted unserved energy, in MWh.

Potential financial losses for hydrogen exporters in the event of delays or defaults in their hydrogen sales contracts due to insurance scheme activation are calculated for each of the designed scenarios. First, the monthly production of green hydrogen for export is determined based on the expected annual production by dividing this amount by 12. This helps calculate how much monthly energy can be generated by hydrogen re-electrification by using PEM fuel cells (we assume this not to be a limiting capacity). Next, using the unserved energy forecast, the hydrogen required to meet that energy demand is calculated. Both calculations are made with equation (5). Using this information, we then calculate how much hydrogen is still available for export (calculated as the difference between total hydrogen production and re-electrified hydrogen), and how many vessels should be canceled (dividing the amount of hydrogen re-electrified by the capacity of the vessels). If the hydrogen provided is not sufficient to meet the entire unserved energy forecast, we then calculate how much energy is left unsupplied (calculated as the difference between the unserved energy forecast and the energy produced from the re-electrified hydrogen).

$$E_{H2} = \eta_{RE} \cdot M_{H2} \tag{5}$$

Where:

E_{H2} is the energy generated from the re-electrification of hydrogen.

M_{H2} is the mass of hydrogen.

The costs of the green hydrogen export-based insurance scheme are calculated as the sum of the hydrogen acquisition cost, the exporters'

Table 2
Configurations used to determine the future hydrogen acquisition cost for Chile and New Zealand. The region of production is detailed, if it is to be transported, and by how much distance.

Country	Production	Transport	Re-electrification
Chile	North	No	In situ
	North	1000 km on shore	Center
	Center	No	In situ
	South	1600 km subsea 500 km onshore	Center
New Zealand	South Island	No	In situ
	South Island	50 km subsea 800 km onshore	North Island

compensation, and the remaining unserved energy in case the available hydrogen is not sufficient. The hydrogen acquisition cost is determined by multiplying the hydrogen re-electrified by the acquisition cost determined in Step 2. Exporters' fair compensation is calculated as the product of the number of canceled shipments times the cost of each canceled shipment (we assumed the penalties to be aligned with observed penalties in the natural gas market). The cost of the remaining unserved energy is calculated by multiplying this amount by the respective VoLL. Finally, the determined cost of this insurance scheme is divided by the expected total annual demand for each scenario. This value, in dollars per megawatt-hour, times the probability of future scarcity scenarios (equivalent frequency) is an estimate of the insurance cost. Equation (6) shows the calculation procedure for the hydrogen-based insurance cost, while equation (7) shows the cost per energy unit.

$$C_{H2\ insurance} = C_{H2\ acquisition} + C_{exporters} + C_{remaining\ UE} \tag{6}$$

Where:

$C_{H2\ insurance}$ is the total cost of hydrogen-based insurance, in USD.

$C_{H2\ acquisition}$ is the cost of hydrogen acquisition, in USD.

$C_{exporters}$ is the compensation cost of exporters, in USD.

$C_{remaining\ UE}$ is the cost of remaining unserved energy after the hydrogen re-electrification, in USD.

$$C_{H2\ insurance\ per\ energy\ demand} = \frac{C_{H2\ insurance}}{E_{demand}} \tag{7}$$

Where:

$C_{H2\ insurance\ per\ energy\ demand}$ is the cost of hydrogen-based insurance per unit of energy demand for a year, in USD/MWh.

E_{demand} is the total energy demand for the respective year, in MWh.

2.3. Design of unserved energy scenarios

To design the scenarios, electricity demand forecasts for the years 2025 and 2030 for Chile [37] and New Zealand [38] are used. For Chile, a demand of 92.8 TWh is forecasted for the year 2025 and 103.7 TWh for the year 2030. The unserved energy scenarios will consider 1 % of the total annual electricity consumption, which corresponds to the worst-case scenario shown in the report “Security of Supply Study, May 2022, Chile” [49]. For New Zealand, a demand of 48.8 TWh is forecasted for the year 2030. The unserved energy scenarios will consider 1 % of total annual energy, which corresponds to a worst-case scenario, as it was for Chile [37,39].

Fig. 3 outlines the scenarios designed for Chile (scenarios 1, 2 and 3) and New Zealand (scenarios 4 and 5).

- Scenario 1, year 2025, 6-month lead time forecasts an unserved energy scenario equal to 928 GWh is forecasted.
- Scenario 2, year 2030, 6-month lead time forecasts an unserved energy scenario equal to 1037 GWh is forecasted.
- Scenario 3, year 2030, 2-month lead time an unserved energy scenario equal to 1037 GWh is forecasted.
- Scenario 4, year 2030, 6-month lead time forecasts an unserved energy scenario equal to 488 GWh is forecasted.
- Scenario 5, year 2030, 2-month lead time, an unserved energy scenario equal to 488 GWh is forecasted.

The amount of green hydrogen exports forecasted for Chile is 32 kton in 2025 and 148 kton in 2030 [37] and 280 kton in 2030 for New Zealand [39]. The frequency of scarcity scenarios is considered for the sensitivity analysis. Each scenario is labeled according to the country where it is based (“CL” for Chile and “NZ” for New Zealand), the year of the projections (”25” for year 2025 and “30” for year 2030) and the months in advance of the forecast (”6 M” for 6 months and “2 M” for 2 months).

The development of specific storage infrastructure as a strategic reserve would involve the investment of 928 GWh storage capacity for Scenario 1. Considering an annualized cost of 10,000 USD/MWh for a storage technology by 2030 [50], the cost of this solution is around 100 USD/MWh (10,000 USD/MWh times 928 GWh divided by 92,8 TWh). As shown in section 3.3, this option is not efficient from an economical point of view.

3. Results and discussion

This section is divided into three parts, aligning with the three stages of the methodology described in the previous section. First, the costs of unserved energy for Chile and New Zealand are compared with the cost of supplying energy using green hydrogen (assuming different values for levelized costs of hydrogen) and fossil fuel-based generation. Second, the cost of providing this energy from hydrogen is calculated for the year 2030 for New Zealand and Chile, including production, transportation, and re-electrification. Third and final, different scenarios of energy scarcity severity and forecast years are evaluated. The possible loss for exporting companies when redirecting green hydrogen exports for re-electrification is estimated.

3.1. Security of hydrogen-based energy supply is cost-competitive under certain circumstances

This subsection compares VoLL with conventional sources and re-electrifying hydrogen and contextualizes the results against spot prices of electricity and gas.

To calculate the average cost of energy generated from re-electrified green hydrogen, hydrogen acquisition costs equal to 1.5, 3, 5, and 7 dollars per kilogram are taken as scenarios (these assumptions will be refined in section 3.2). This range encompasses current ($7 per kilogram) and future ($1.5 per kilogram) LCOH [32]. In addition, an average re-electrification efficiency equal to 22 kWh/kg (56 % relative to the higher heating value of hydrogen) is used, a standard value today for PEM fuel cells [51].

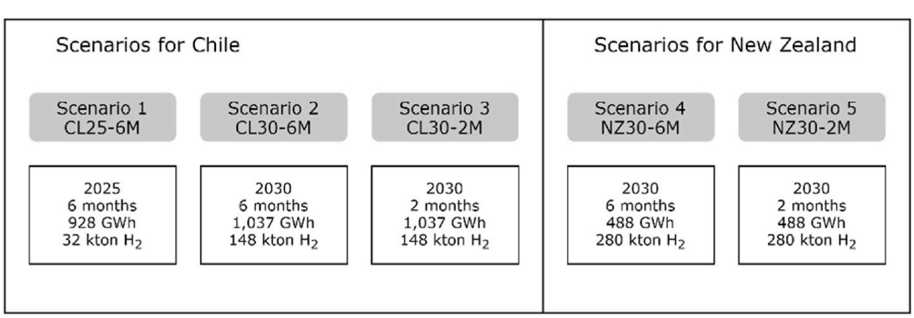

Fig. 3. Scenarios designed to evaluate the hydrogen-based insurance scheme. Each scenario is labeled according to the country where it is based, the year of the projections, and the months in advance.

Fig. 4 shows the above scenarios. The current VoLLs determined by the local regulators for New Zealand and Chile are equal to 314 and 12,500 USD/MWh respectively. The resulting cost of electricity is 318 USD/MWh for 7 USD/kg of hydrogen (hydrogen acquisition cost), 227 USD/MWh for 5 USD/kg of hydrogen, 136 USD/MWh for 3 USD/kg of hydrogen, and 68 USD/MWh for 1.5 USD/kg of hydrogen. For comparison, the maximum Chilean electricity spot market price for the last 12 months was 527 USD/MWh [45], and the average cost of combined cycle gas turbines (CGGT) generation in Europe for 2018, was equal to 113 USD/MWh [50]. For context on the variability of international energy markets, the maximum and minimum prices of the "EU Dutch TTF" (natural gas price index) for the last 12 months are included, equal to 356 and 73 USD/MWh respectively [46].

From Fig. 4 it is clear that, if the hydrogen acquisition cost is 7 USD/kg (similar to current LCOH), the cost of energy produced, 318 USD/MWh, is like Chile's VoLL of 315 USD/MWh and is lower than New Zealand's VoLL of 12,800 USD/MWh. All other cases of lower hydrogen acquisition cost are cheaper than the two VoLLs described above. A remarkable result is that the peak value of the Chilean spot market, which is based on audited variable costs and a centralized dispatch for the last 12 months, is higher than the cost of energy produced from green hydrogen when its acquisition cost is 7 USD/kg. At the same time, the maximum and minimum costs of natural gas in the last 12 months coincide with the costs of energy produced from re-electrified hydrogen, when the acquisition cost of hydrogen is 7 and 1.5 USD/kg respectively. The average CGGT generation cost for 2018 in Europe is similar to the cost of energy produced from re-electrified hydrogen when the hydrogen acquisition cost is 3 USD/kg, a green hydrogen production cost that could be achieved by 2025 [52]. Finally, in scenarios of hydrogen costs of 1.5 USD/kg (that could be achieved by the year 2025 in the case of Chile [4], and by 2030 as world average [52]), hydrogen would be cheaper than all other options to provide security of supply.

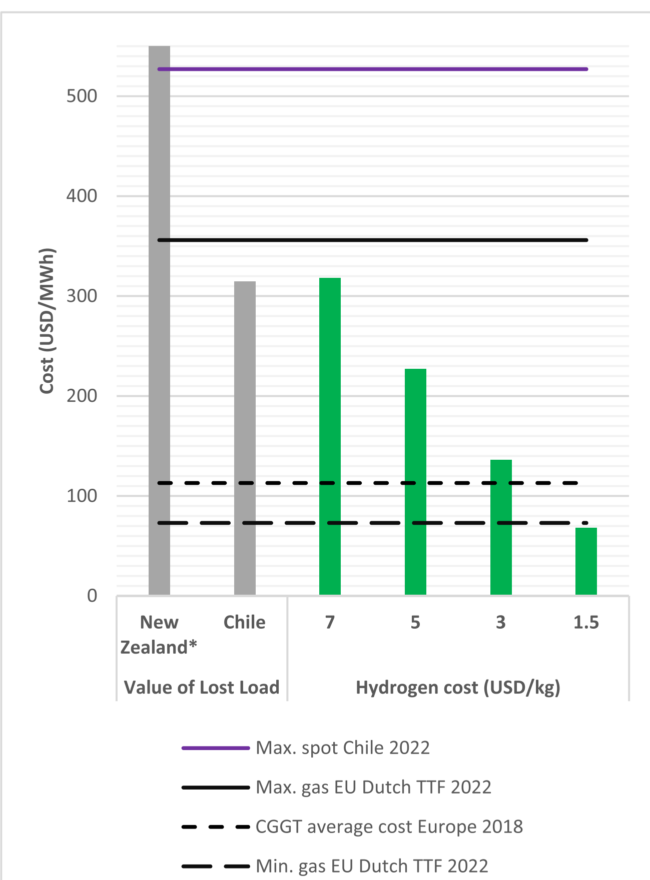

Fig. 4. Energy costs of re-electrified hydrogen compared to different energy costs and VoLL of Chile and New Zealand. *Note that the VoLL of New Zealand is $12,500 USD/MWh, a value not fully plotted due to proportionality.

In summary, re-electrifying hydrogen to improve security of supply can become competitive starting at 3 USD/kg (which is expected to happen in the year 2025). At 1.5 USD/kg, hydrogen could be the most convenient of all options, for both New Zealand and Chile.

3.2. *Cost of hydrogen production is a driver for re-electrification effectiveness*

This subsection further details the cost of energy from re-electrified hydrogen produced in Chile and New Zealand by calculating the transportation and re-electrification costs (as opposed to simply assuming hydrogen acquisition costs as in section 3.1). We use cost projections of green hydrogen technologies for the year 2030.

We made the following assumptions for both Chile and New Zealand. For the year 2030, we assumed that domestic/continental transport of hydrogen will be through onshore or offshore pipelines. For the activation of the proposed insurance scheme, we considered a marginal use of the capacity of these pipelines, with a cost of $0.23 per kilogram and per 1000 km for onshore pipelines, and $0.46 per kilogram and per 1000 km for subsea pipelines [40]. In scenarios, we explore different production and demand locations within each country. Re-electrification cost is calculated based on a PEM fuel cell, with a capital cost equal to 600 USD/kW and 60,000 h of useful life [41]. With these values, an average variable cost equal to 10 USD/MWh for re-electrification is obtained. Assumptions specific to each country are detailed next.

In Chile, it is expected that by 2030 the hydrogen produced will cost 1.4 USD/kg in the northern zone (Atacama/Antofagasta), 1.8 USD/kg in the central zone (Santiago), and 1.3 USD/kg in the southern zone (Magallanes) [4]. Regarding transportation, the following cases are considered: production in the north and in-situ re-electrification, production in the north and transportation over a distance of 1000 km onshore to the main load center in central Chile (the electric transmission system connecting the north and central zone often present congestions, especially in times of energy scarcity), production in the central zone and in-situ re-electrification, and production in the south zone and re-electrification along 1600 km subsea (Magallanes through archipelagos to the mainland) and 500 km onshore to the central zone.

In the case of New Zealand, a production cost of 2.4 USD/kg is expected for the year 2030 [32]. This document does not specify the region in which these costs are achieved, but we assumed the southern end of the South Island, trying to capture its wind and hydro potential, as well as current developments [5]. Regarding transportation, two cases will be assumed: one where in-situ re-electrification is used, and another where a hydrogen pipeline is used, going from the southern tip of the South Island to the southern tip of North Island (location with a robust electricity system), with 800 km onshore and 50 km subsea.

Fig. 5 shows the cost components of re-electrified hydrogen, in dollars per megawatt-hour, for each of the above cases. The horizontal lines show the cost of energy when the hydrogen has an acquisition value equal to 1.5 and 3 USD/kg, to compare it to the previous subsection. For the Chilean cases, the costs of energy from re-electrified hydrogen per megawatt-hour are $74 for northern production and in-situ re-electrification, $84 for northern production and transport to the center, $92 for central production and in-situ re-electrification, and $108 for southern production and transport to the center. In the New Zealand cases, the costs per megawatt-hour are $119 for South Island production and re-electrification and $92 for South Island production and transport to North Island. Table 3 shows a breakdown of the above values by production cost, transportation cost, and re-electrification cost. The attached database specifies how each of the above costs is calculated.

All cases in this plot show the cost of hydrogen production as the most important component, accounting for between 55 % and 92 % of

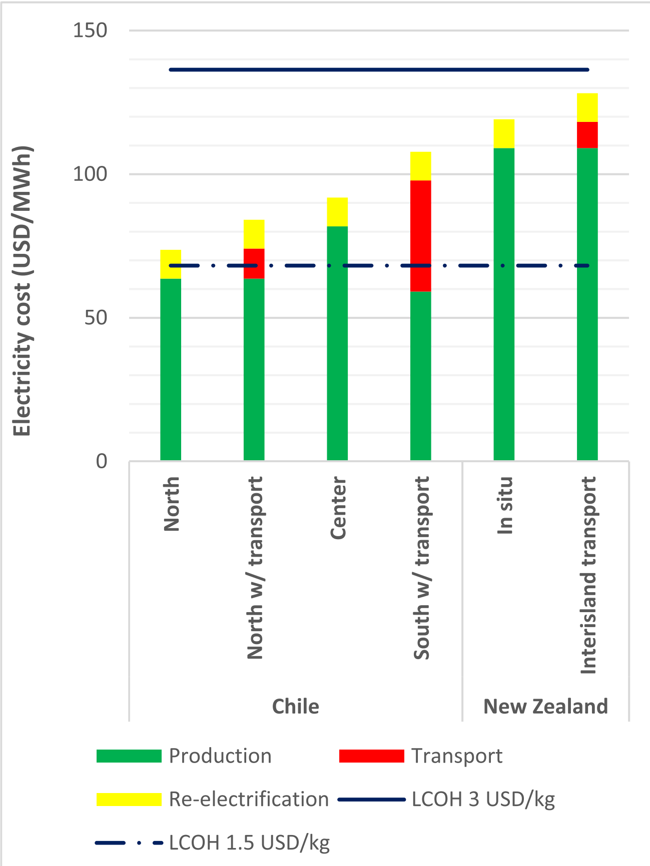

Fig. 5. Expected electricity costs for 2030 from re-electrified hydrogen.

the final cost of energy. Transportation is a minor component since its contribution only stands out when there is a long distance between the production point and the re-electrification point and there is subsea transportation, as in the case of hydrogen produced in the southern zone of Chile, where it represents 36 % of the final energy cost. The strongest assumption is that these pipelines will already exist to meet local demand, allowing hydrogen transportation in scarcity events at marginal costs.

In the case of Chile, all hydrogen production costs are below 100 USD/MWh. While Magallanes has the cheapest hydrogen production sites, after considering transportation, it shows the highest total cost. Note that producing hydrogen in the north and transporting it to the center is less expensive than producing it in the center itself: the difference in production costs offsets the additional transportation cost. The resulting electricity costs from hydrogen are between 74 and 108 USD/MWh.

For New Zealand, the hydrogen production cost is about 110 USD/MWh. The cost of inter-island transportation, equal to 10 USD/MWh, is not significant, due to the short distance between the two islands. The cost of electricity produced from green hydrogen does not exceed 130 USD/MWh. The cost of hydrogen production is the most important component. The transportation cost represents only 7 % of the final cost (which translates into 9 USD/MWh).

There is an important difference between the Chilean and New Zealand cases, which lies in the final electricity costs. In all cases, Chile obtains lower final costs than New Zealand, since, even when hydrogen must be transported over a long distance (for example, Magallanes – Santiago case), given the lower production cost in Chile. Still, in both countries hydrogen for security of supply seems competitive against conventional options. There are significant challenges in reducing the cost of hydrogen technologies before they can compete with conventional and renewable generation technologies. However, the forecasted costs for 2030 make it possible to think of green hydrogen as a technology that can serve as strategic energy storage amid the massive insertion of non-conventional renewable generation. However, as can be seen in the countries' green hydrogen strategies, the use of green hydrogen in power systems has not been sufficiently discussed, as its use in that industry is not foreseen.

It is interesting to compare the future production and transportation costs used in this work with those reported by various sources for different locations and modes of transportation. For instance, Ref. [53] estimates a minimum cost of 1.5 USD/kg and a global average of 2 USD/kg by 2030. However, there are countries such as Japan where the cost of production is expected to be, at best, 4 USD/kg [54]. This last value, as reviewed, makes it unfeasible for hydrogen technologies to compete with conventional technologies, so cost and production sites are key. Regarding transportation, this work considered a marginal use of pipelines, with a cost of 0.2 USD/kg. This value is lower than those seen in other sources and is mainly explained by the fact that this work considers domestic transport [40]. shows a transportation cost of between 0.1 and 1 USD/kg for pipelines, and between 1 and 2 USD/kg for ship transport, either as liquefied hydrogen (LH2), ammonia (NH3), or liquid organic carrier (LOHC). In Ref. [32], a cost of between 2 and 3 USD/kg is indicated for ship transportation of these same carriers. Thus, the final acquisition cost of hydrogen will strongly depend on its production and transportation costs, therefore, the results of this work are not directly applicable to any region or any transportation route.

In summary, the future (2030) green hydrogen costs of New Zealand and Chile make economic sense for an export-based energy reserve system to enable the decarbonization of their respective power systems.

3.3. The hydrogen-based insurance cost calculation

This subsection details possible scenarios of unserved energy scenarios for Chile and New Zealand. In each scenario of unserved energy forecasting, the economic damage to the system is defined based on the respective VoLL. Then, for each scenario, the amount of hydrogen needed to cover the unserved energy is estimated and compared to what is expected to be stored and available for export. Subsequently, the penalties that exporters of green hydrogen may face because of delays or non-fulfillment of their sales contracts due to the repurposing of hydrogen for re-electrification are estimated.

The frequency and capacity of hydrogen shipments are estimated based on the expected capacity of hydrogen transport available in the

Table 3
Cost of production, transportation and re-electrification of the energy produced from green hydrogen.

Country	Case	Costs (USD/MWh)			
		Production	Transportation	Re-electrification	**Total**
Chile	North	64	0	10	74
	North w/transport	64	10	10	84
	Center	82	0	10	92
	South w/transport	59	39	10	108
New Zealand	In situ	109	0	10	119
	Interisland transport	109	9	10	128

literature. A ship with a capacity of 11.3 kton of liquid hydrogen is shown in Ref. [47]. This information is used to estimate the frequency and number of ships that may be canceled in each scenario. A penalty equal to $12 million is considered, aligned to values from the natural gas market [48]. Finally, the costs that the insurer would have to incur to acquire the hydrogen needed to meet the unserved energy forecast are estimated. This is done by adding the costs determined in the previous subsection and the payment to compensate for the penalties, as estimated in this subsection.

Nevertheless, it is important to mention that the proposed insurance scheme must be part of the supply contracts for export to inform the final customer of the risks related to the supply of this energy. Moreover, it is assumed that by then there will be a global market for green hydrogen production. Thus, if there is a failure to fulfill the contract, the consumer will be entitled to the penalty payout according to expected contracts, which can then be used to get another supplier. Furthermore, in an energy transition scenario, hydrogen, as an energy carrier, will have other acceptable substitutes (other fuels).

Table 4 shows the inputs and results for each scenario. The first part shows the data for the normal operation of the power system, including the future annual and monthly exports of green hydrogen and the frequency of shipments per year. The second part shows the requirements of the contingency, including the forecast of unserved energy and the hydrogen required to satisfy it completely. The third part shows the balance of hydrogen that can be effectively re-electrified, considering the monthly and annual hydrogen re-electrified, and the remaining annual hydrogen to serve exports. With this information, in part four, an energy balance is made for the contingency designed from the re-electrified hydrogen and displayed in the final set of rows. The energy generated from the hydrogen is calculated, and, in case the availability of hydrogen is insufficient, the remaining unserved energy is also calculated. Note that in the long-term, the proposed strategic hydrogen reserve might be kept in storage tanks, but in the early years of the transition, the hydrogen production is quite low compared to the contingency. This might result in canceling export vessels to repurpose the hydrogen for electrification. We calculated the costs of this extreme scenario.

In scenario 1 (CL25-6 M), 42 kton of hydrogen are needed to fully satisfy the unserved energy forecast, equal to 928 GWh. Considering the expected monthly production, only 16 kton could be re-electrified, resulting in 352 GWh, with 576 GWh being the remaining unserved energy. In this scenario, one shipment is canceled. In scenarios 2 and 3, 47 kton of hydrogen are needed to fully satisfy the unserved energy forecast, equal to 1037 GWh. By expected monthly production, 47 kton could be re-electrified in scenario 2 and only 25 kton in scenario 3. This implies that in scenario 2, 1037 GWh are supplied, with no final unserved energy and 4 shipments canceled. In scenario 3, 543 GWh are re-electrified, with 494 GWh being the final unserved energy and 2 canceled shipments. In scenarios 4 and 5, 22 kton of hydrogen are needed to fully satisfy the unserved energy forecast, equal to 488 GWh. By expected monthly production, 22 kton could be re-electrified in both scenarios. This implies that both scenarios supply 488 GWh, with no final unserved energy and 2 shipments.

Table 4
Energy, hydrogen, and cost balance for the designed evaluation scenarios.

	Scenario				
	CL25-6 M	CL30-6 M	CL30-2 M	NZ30-6 M	NZ30-2 M
I. Normal operation					
Annual exports (kton)	32	148	148	280	280
Monthly export production (kton)	2.7	12.3	12.3	23.3	23.3
Shipments per year	3	13	13	25	25
II. Energy and months of contingency					
Unserved energy (GWh)	928	1037	1037	488	488
Months in advance	6	6	2	6	2
Hydrogen required (kton)	42.2	47.1	47.1	22.2	22.2
III. Hydrogen balance in contingency					
Monthly hydrogen re-electrified (kton)	2.7	7.9	12.3	3.7	11.1
Annual re-electrified hydrogen (kton)	16.0	47.1	24.7	22.2	22.2
Remaining annual export (kton)	16.0	100.9	123.3	257.8	257.8
IV. Final energy balance					
Re-electrified hydrogen energy (GWh)	352	1037	543	488	488
Remaining unserved energy (GWh)	576	0	494	0	0
Shipments cancelled	1	4	2	2	2

Fig. 6 shows the resulting costs of the 5 scenarios. In each of these scenarios, the cost of unserved energy is compared to the total cost of implementing the hydrogen-based design, which includes the hydrogen acquisition cost, the penalty for canceled shipments, and the final unserved energy due to insufficient hydrogen.

The costs of unserved energy, assuming VoLL, are $292 million for scenario “CL25-6 M″, $326 million for scenarios “CL30-6 M″ and “CL30-2 M″, and $6100 million for scenarios “NZ30-6 M″ and “NZ30-2 M”. The costs of the hydrogen export-based insurance scheme are detailed below. For scenario 1 the costs are $32 million for the hydrogen acquisition, $36 million for the penalty to exporters, and $181 million for the final unserved energy. Scenario 2 costs are $95 million for hydrogen acquisition and $50 million for the penalty to exporters. Scenario 3 costs are $50 million for the hydrogen acquisition, $26 million for the penalty to exporters, and $156 million for the final unserved energy. Scenario 4 and 5 costs $62 million for the hydrogen acquisition and $24 million for the penalty to exporters. The total costs of the hydrogen-based insurance scheme (without counting the remaining unserved energy) are $49 million for Scenario 1, $145 million for Scenario 2, $76 million for Scenario 3, and $86 million for Scenario 4 and 5.

To estimate the premium that all consumers must pay in the case of frequency of one scarcity scenario per year, the annual energy demand is divided by the total cost of energy obtained from re-electrified hydrogen (considering acquisition cost and penalty compensation) for each scenario. Thus, for the costs of the proposed scheme to be financed in each scenario, each consumer would have to pay 0.532 USD/MWh in scenario 1, 1.403 USD/MWh in scenario 2, 0.734 USD/MWh in scenario 3, and 1.763 USD/MWh in scenarios 4 and 5 if this scheme were to work every year. However, it is unlikely to have such a scenario every year. Nevertheless, if this were the case, the situation would be addressed in the normal power system planning and operation processes. Therefore, a sensitivity analysis is performed considering different frequencies of energy scarcity, which is shown in Table 5.

Table 5 shows that, as energy scarcity scenarios occur less frequently, the cost to finance the hydrogen-based energy insurance scheme decreases. For example, in the case that the frequency of one scarcity scenario takes place every five years, the average unit cost that each consumer would have to pay is 0.106 USD/MWh in Scenario 1, 0.281 USD/MWh in Scenario 2, 0.147 USD/MWh in Scenario 3, and 0.353 USD/MWh in Scenarios 4 and 5.

For all five scenarios, implementing an insurance scheme based on green hydrogen exports results in lower costs than having unserved energy situations, even when the available hydrogen is insufficient to fully supply the forecast. In scenario “CL25-6 M″ only 38 % of the unserved energy forecast can be supplied, which implies a 19 % cost reduction with respect to the unserved energy scenario. In scenario “CL30-6 M″, 100 % of the unserved energy forecast is supplied, which implies a cost reduction of 51 % with respect to the unserved energy scenario. In scenario “CL30-2 M″, only 52 % of the unserved energy forecast can be supplied, which implies a 27 % cost reduction with respect to the unserved energy scenario. From these three scenarios, the

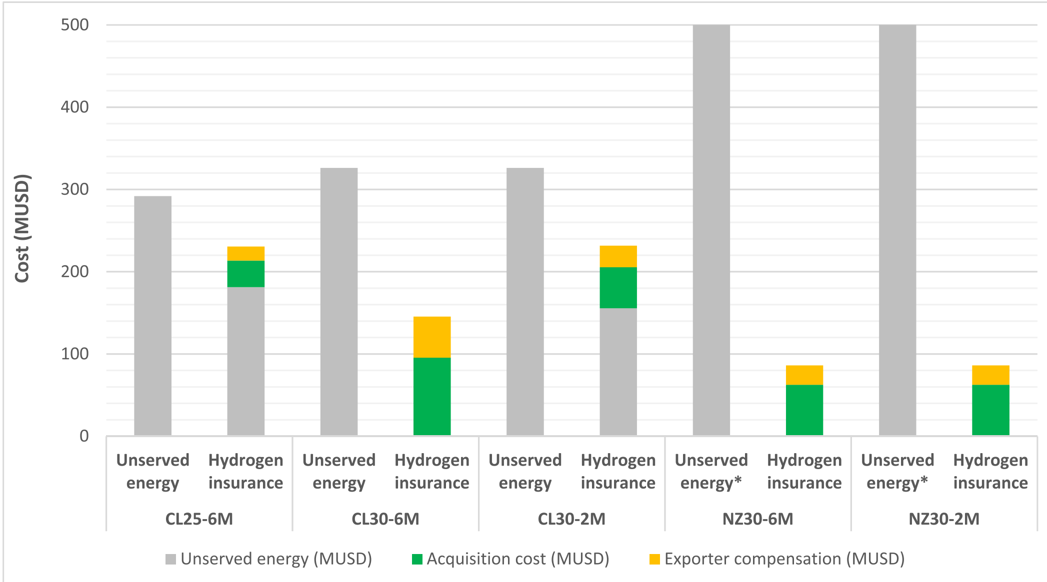

Fig. 6. Cost comparison for each scenario between unserved energy and hydrogen-based insurance scheme. *Note that unserved energy cost of New Zealand is $6100 MUSD, beyond the range of the figure.

Table 5
Sensitivity analysis for different power scarcity frequencies.

Scarcity frequency	CL25-6 M (USD/MWh)	CL30-6 M (USD/MWh)	CL30-2 M (USD/MWh)	NZ30-6 M (USD/MWh)	NZ30-2 M (USD/MWh)
1 year	0.532	1.403	0.734	1.763	1.763
2 years	0.266	0.701	0.367	0.881	0.881
3 years	0.177	0.468	0.245	0.588	0.588
4 years	0.133	0.351	0.184	0.441	0.441
5 years	0.106	0.281	0.147	0.353	0.353
6 years	0.089	0.234	0.122	0.294	0.294
7 years	0.076	0.200	0.105	0.252	0.252
8 years	0.067	0.175	0.092	0.220	0.220
9 years	0.059	0.156	0.082	0.196	0.196
10 years	0.053	0.140	0.073	0.176	0.176

more hydrogen that can be re-electrified, the greater the proportional reduction in the cost of the hydrogen-based insurance scheme with respect to the forecasted cost of unserved energy. Due to the difference between Chile's Value of Lost Load, equal to 315 USD/MWh, and the final hydrogen acquisition cost, equal to 154 USD/MWh, the cost can be reduced by half when there is enough hydrogen to supply all the forecast unserved energy.

In scenarios "NZ30-6 M″ and "NZ30-2 M″ the results are similar since New Zealand's green hydrogen export forecast is proportionally higher than Chile's with respect to the energy demand forecast for the year 2030. Thus, the more hydrogen that is re-electrified and the less unserved energy there is, the lower the cost to the system. When hydrogen can fully supply the unserved energy forecast, the cost reduction is more than 50 %. Also, the proposed green hydrogen export-based insurance scheme achieves higher cost reductions for unserved energy in New Zealand, which is explained by higher VoLL, higher hydrogen production forecast, and lower annual electricity demand. Only in one case for Chile is it possible not to have unserved energy scenarios. This can be overcome by considering the investment of additional hydrogen storage capacity for the base case. Nevertheless, these additional strategies are out of the scope of this analysis. In New Zealand in all scenarios, it is possible to meet the forecast of unserved energy. In this sense, if hydrogen is not sufficient to supply the unserved energy, it will not be able to contribute to the decarbonization of the electricity system, since it will have to resort to fossil fuels.

This insurance mechanism, unlike financial ones, allows improvements in electricity supply. This represents an advantage since traditional insurance must compensate for economic losses, according to VoLL. In contrast, in the proposed scheme the insurer must compensate the penalties that exporters may incur, a cost considerably lower than that of the lost load. In that sense, this insurance is more convenient both from an individual and systemic point of view since the power supply is not affected. Globally, there are two mechanisms to deal with unserved energy scenarios: capacity markets and strategic reserves. In Europe, these mechanisms usually cost between 110 and 1700 USD/MWh [28]. The high price variability is because these mechanisms are typically based on fossil fuels, and their prices tend to increase during the same situations that lead to the forecast of unserved energy.

The premise of this work is to use future green hydrogen production for export as a strategic reserve against forecasted unserved energy scenarios. However, in such scenarios, a simpler option could be to not produce hydrogen, i.e., to reduce energy demand by not operating the electrolyzers. This solution faces limitations since the electricity production based on variable renewable energies is not able to cope with the electricity load profile (i.e., electricity consumption during the night in the case of solar energy). Thus, the hydrogen conversion is needed as local storage. Additionally, this solution may not apply in all cases, since the electrolyzers could have dedicated generation systems, representing a net zero demand, or these electrolyzers could be isolated from the main power system, as in the case of Magallanes, in southern Chile.

In summary, the total cost of this scheme to the consumers can range from 49 to 145 million dollars. This translates to a unitary cost that ranges from 0.532 to 1.763 USD/MWh if the frequency of scarcity scenarios is once a year. These costs are small compared to the energy costs in electricity markets (in Chile, around 110 USD/MWh and in New Zealand, around 90 USD/MWh for industry [55]) and allow the insurance mechanism to be fully funded. If the frequency of scarcity scenarios is once every five years, the unit average costs range from 0.106 to 0.353 USD/MWh. If the frequency of scarcity scenarios is once every ten years, the unit average costs range from 0.053 to 0.176 USD/MWh.

3.4. Limitations and outlook

This paper evaluates how expected future hydrogen production infrastructure in hydrogen-exporting countries is equivalent to having insurance for extreme situations of electricity scarcity, as a way of an additional degree of flexibility to the system. Some limitations and observations of the work developed are.

- The proposed system, meant for rare and extreme situations, isn't economically viable to have its own infrastructure. Instead, it suggests utilizing an expected future infrastructure for green hydrogen production, transportation, and re-electrification.
- In our analysis, we redefined domestic hydrogen transportation costs by modeling them as the incremental utilization of a pipeline network assumed to be constructed for domestic distribution and consumption. However, it is worth noting that there are currently no concrete plans for the construction of such a network in either Chile or New Zealand.
- In this work, hydrogen transportation is assumed to take place via pipelines. Nevertheless, as this is a marginal cost, the cost of any transportation mode can be used.
- In this work, hydrogen re-electrification using PEM fuel cells is used. Nevertheless, as this is a marginal cost, the cost of any re-electrification mode, such as combustion in reconditioned thermal power plants, can be used.

4. Conclusions and future work

This work assesses the viability of hydrogen exports to act as a strategic energy storage for improving energy security. For this purpose, we performed a system analysis based on the following stages: i) compare the costs of re-electrified green hydrogen, for different scenarios, to the value of lost load and peaker plants of New Zealand and Chile; ii) quantify the hydrogen costs including production, transportation and re-electrification for the year 2030 in both countries; and iii) estimate the penalties that exporters would incur in case of breaking their contracts and the overall resulting system costs of using hydrogen for system security.

The costs of re-electrified hydrogen are clearly lower than the penalty for lost load, but the current costs are significantly higher than fossil fuel technologies (often used to provide system backup). Hydrogen costs of 3 USD/kg start to become competitive for this application. At costs of around 1.5 USD/kg of hydrogen, likely to happen around the year 2030 for some places in the world, using hydrogen for supply security is more convenient than fossil fuels.

Taking a closer look at Chile and New Zealand, when examining the cost components of hydrogen for this application, the main cost relates to production. Transportation costs can be high when production and re-electrification sites are distant from each other. By 2030, the total cost of hydrogen is expected to be less than 3 USD/kg in Chile and New Zealand (some sites are closer to 1.5 USD/kg), even in those cases where hydrogen must be transported.

Finally, we calculated the total cost of hydrogen acting as insurance. The average total cost of the scheme proposed in this paper ranges from 0.53 to 1.76 USD/MWh if the frequency of scarcity scenarios is once every five years. Those are small compared to system electricity costs. Based on this, using hydrogen as an energy insurance scheme when a green hydrogen export industry is already in place might make economic sense. Especially when hydrogen re-electrification can fully supply the forecasted unserved energy, the scheme costs can be significantly reduced.

Future research based on this paper will be focused on the following topics:

- The optimal allocation of re-electrification capacity to minimize the unserved energy scenarios;
- Exploring improved methods for estimating penalties associated with canceled hydrogen shipments for final customers;
- Expanding the analysis for the utilization of locally produced synthetic fuels in existing power plants.

We expect these findings to be helpful for policymakers to better define the role of future hydrogen exports as enablers of the energy transition targets at the local level. Thus, contributing to security of supply with new options of energy storage.

CRediT authorship contribution statement

Carlos Alvear: Writing – review & editing, Writing – original draft, Visualization, Methodology, Investigation, Formal analysis. **Jannik Haas:** Writing – review & editing, Writing – original draft, Visualization, Methodology, Funding acquisition, Formal analysis. **Rodrigo Palma-Behnke:** Writing – review & editing, Writing – original draft, Visualization, Funding acquisition, Formal analysis, Conceptualization. **Rebecca Peer:** Writing – review & editing, Methodology, Funding acquisition, Formal analysis. **Juan Pablo Medina:** Writing – review & editing, Formal analysis. **Jordan D. Kern:** Writing – review & editing, Formal analysis.

Declaration of competing interest

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Data availability

Data is on zenodo: https://zenodo.org/records/8433459

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