February 1, 2023

ENGIE ENERGÍA CHILE REPORTED EBITDA OF US$189 MILLION AND A NET LOSS OF US$389 MILLION IN 2022.

EBITDA REACHED US$71.3 MILLION IN THE FOURTH QUARTER OF 2022 DUE TO IMPROVED HYDROLOGIC CONDITIONS AND AN INCREASE IN ARGENTINE GAS SUPPLY, WHICH CAUSED A REDUCTION IN ENERGY SUPPLY COSTS. GENERATION COSTS REMAINED IMPACTED BY HIGH FUEL PRICES WORLDWIDE.

- **Operating revenues** amounted to US$1,920.3 million in 2022, a 30% increase compared to 2021, mainly due to an increase in physical sales to unregulated clients, the rise in average realized energy prices explained by inflation and fuel-price indices, and revenue resulting from an agreement signed in early February with the company's main LNG supplier.

- **EBITDA** amounted to US$189 million, a 40% decrease compared to 2021. Despite increased revenues, the electricity sales margin dropped due to the increase in generation costs and higher spot prices.

- **Net results** were a US$388.8 million loss, down from the US$47.4 million net profit reported in 2021, partly due to the weaker operating performance explained by record high fuel prices and the resulting high spot prices in the electricity market. However, net results were mainly impacted by significant non-recurring asset impairments explained by the decarbonization process being carried out by the company. Net results were further impacted by the financial cost related to the sale of accounts receivable from distribution companies originated by the application of the price stabilization law. Excluding the non-recurring effect of impairments, 2022 net losses would have been US$64 million.

Financial Highlights (in US$ millions)

	4Q21	4Q22	Var %	12M21	12M22	Var%
Total operating revenues	**392.1**	**521.3**	***33%***	**1,478.6**	**1,920.3**	***30%***
Operating income	19.7	20.3	*3%*	128.7	(0.3)	*-100%*
EBITDA	**71.3**	**71.3**	***0%***	**314.5**	**189.0**	***-40%***
EBITDA margin	18.2%	13.7%	*(14,8pp)*	21.3%	9.8%	*(12,4pp)*
Total non-operating results	(5.8)	(474.7)	*n.a*	(67.9)	(521.1)	*667%*
Net income after tax	8.7	(330.6)	*n.a*	47.4	(388.8)	*n.a*
Net income attributed to controlling shareholders	**8.7**	**(330.6)**	*n.a*	**47.4**	**(388.8)**	*n.a*
Earnings per share (US$/share)	0.008	(0.314)		0.045	(0.369)	
Total energy sales (GWh)	2,923	2,940	*1%*	11,715	12,047	*3%*
Total net generation (GWh)	1,493	1,275	*-15%*	7,746	5,593	*-28%*
Energy purchases on the spot market (GWh)	1,228	1,081	*-12%*	3,311	4,501	*36%*
Energy purchases - back up (GWh)	265	646	*144%*	639	2,134	*234%*

ENGIE ENERGÍA CHILE S.A. ("ECL") is engaged in the generation, transmission and supply of electricity and the transportation of natural gas in Chile. ECL is the fourth largest electricity generation company in Chile and one of the largest electricity generation companies in the northern segment of the SEN national grid (formerly known as SING). As of December 31, 2022, ECL accounted for 7% of the SEN's installed capacity. ECL primarily supplies electricity to large mining and industrial customers, and it also supplies electricity to distribution companies throughout Chile. ECL is currently 59.99% indirectly owned by the French company, ENGIE S.A. The remaining 40.01% of ECL's shares are publicly traded on the Santiago stock exchange. For more information, please refer to www.engie-energia.cl.

Contents

HIGHLIGHTS:

RECENT EVENTS

4Q22

- **88 MW Capricornio solar PV plant starts commercial operation**: The system coordinator officially confirmed the commercial operation of the Capricornio solar PV plant effective on November 21, 2022. The plant is located 35 kilometers away from Antofagasta. It has 87.9 MW of generation capacity from its 249,210 photovoltaic panels capable of supplying renewable energy equivalent to the consumption of 36 thousand homes, implying a reduction of 52,015 tons of CO2. The plant has smart trackers, which allow the solar panels to take advantage of up to 20% more radiation from the sun. These devices can redirect the solar panels so that they remain perpendicular to the sun's rays, following the sun from morning until dark.

- **LNG supply**: By means of an essential fact notice dated December 23, 2022, the Company's Board of Directors, in its extraordinary meeting held on December 22, took notice of the status of the discussions with its liquefied natural gas ("LNG") supplier, Total Energies Gas & Power Limited ("Total"), in the context of the tightness of the international fuel market and its consequential effects for the national electricity system ("SEN"), with a view to ensuring the supply of the 4 LNG cargoes committed for 2023 in the so-called "Contract 1" in force with Total. Despite the conversations carried out and efforts made to this end, the Company has only been able to ensure to date the supply of the 3 LNG cargoes corresponding to the so-called "Contract 2", for the total equivalent of 9.9 TBtu, as communicated both to the National Electric Coordinator and Sociedad GNL Mejillones S.A. for the purpose of coordinating the ship unloading program of the Mejillones terminal. To date, discussions leading to the supply of the Contract 1 LNG cargoes has been unsuccessful. The lower LNG availability in 2023, as compared to previous years, will lead to lower volumes of LNG available for electricity generation in the SEN and, as a result, the Company will have to increase its energy purchases in the spot market to supply its customers. At this date, it is not possible to estimate the impact of this lower LNG availability on the Company's 2023 results. Consequently, the Board of Directors agreed, in the event that the negotiations with Total do not prosper within this month, to exercise in the competent jurisdictions the legal actions leading to enforce the supplier's liability under the existing LNG supply contract.

- **342 MW Lomas de Taltal wind farm and BESS Coya storage projects.** On December 22, through an essential fact, the Company communicated that, in line with its energy transition plan, it signed the following agreements: (a) On December 21, ENGIE signed a contract with companies belonging to the Goldwind group for the supply of the wind turbines necessary for the construction of a wind farm located in the commune of Taltal, Region of Antofagasta ("Lomas de Taltal"). This wind farm will have a total capacity of up to 342 MW and will consist of 57 wind turbines with an individual capacity of 6 MW. Lomas de Taltal will inject renewable energy into the National Electric System ("SEN") through a transmission line, of approximately 20 kilometers, which will be connected at the Parinas substation. The budget of the Lomas de Taltal project considers the supply of main equipment, operation and maintenance of wind turbines, the execution of engineering and civil works, the construction and commissioning of the transmission line, the construction and operation of the camp and work installations, and the electrical connection of the main equipment. In total, this budget amounts to approximately US$ 450 million. The project is expected to begin operations in December 2024. (b) On December 2, 2022, ENGIE signed a contract with Sungrow for the supply and acquisition of a battery energy storage system ("BESS") with capacity of 638MWh, to proceed with the construction of the so-called BESS Coya project. This project will be built at the Coya PV plant, owned by the Company, located in the commune of María Elena, Region of Antofagasta, and currently in operation in the SEN. The BESS Coya project is expected to begin operations in February 2024. Its budget amounts to approximately US$200 million and considers the project's main equipment supply together with the execution of the civil works, and installation, assembly, and electrical connection of its main equipment. In accordance with current regulations, together with the corresponding recognition of sufficiency capacity, BESS Coya will allow EECL to store energy from its own renewable sources for subsequent injection into the SEN during the hours of the day when marginal costs are determined by higher-cost generation technologies, avoiding -incidentally- transmission restrictions.

- **San Pedro wind farms**: In line with its energy transition plan, on December 15 the Company entered into a share purchase agreement (the "SPA") with Trans Antartic Energía S.A., Trans Antartic Energía III S.A., Bosques de Chiloé S.A., Beltaine Renewable Energy S.L. and Inversiones Butalcura S.A. (the "Sellers"), sole and current shareholders of the companies Alba S.A., Alba Andes S.A., Alba Pacífico S.A., Energías de Abtao S.A. and Río Alto S.A., for the acquisition of 100% of the shares of these companies, which owned the following assets: (i) San Pedro I wind farm, which has 18 wind turbines with an installed capacity of 36 MW; (ii) San Pedro II wind farm, which has 13 wind turbines with an installed capacity of 65 MW; and (iii) a wind power generation project currently under development, with potential capacity of up to approximately 151 MW. These assets are located in the commune of Dalcahue, Chiloé, Los Lagos Region in southern Chile. The agreed price was US$ 77 million paid to the Sellers at the time of signing the SPA. On December 1, the local anti-trust commission approved the operation, without conditions and in accordance with the provisions of D.L. 211 of 1973.

- **Impairment**: Every year, management carries out an impairment test according to IAS 36 to ensure that the financial statements reflect a total book value of assets that does not exceed their recoverable value. The recoverable value is calculated as the present value of projected cash flows, discounted at a weighted average cost of capital of 8%. This methodology allows to better estimate the value of the company, since it includes the particularities of its business plan and quantifies specific situations of its contractual position (PPAs) and remaining useful lives of its assets. Cash flow projections are based on certain key assumptions, such as hydrological conditions, fuel prices, marginal system costs, generation assets available in the system, projected demand, contractual terms, etc. The company’s equity value is then calculated by subtracting net debt from discounted future cash flows. Finally, the resulting equity value is compared with the book value of the company's equity. If the book value is greater than the equity value determined with the discounted future cash flow methodology, it gives rise to an impairment. The recoverability analysis must be done per cash-generating unit (“CGU”). EECL is considered a single CGU since it is not possible to associate generation assets with specific contracts, and the dispatch of generation assets is centralized by the National Electric Coordinator. Therefore, the recoverable value was calculated on EECL as a single CGU.

  The test carried out in 2022 resulted in a gross impairment amount of US$436 million. According to accounting rules, impairments affecting a CGU must be first allocated to reduce goodwill, second to capitalized project development costs, and finally to other assets. The minimum carrying amount of an asset may not be less than the higher of its fair value minus disposal costs, its value in use, or zero. When estimating the recoverable amount of each individual asset is not possible, accounting rules require a pro-rata allocation of the impairment among those assets of the CGU that are deemed not to be adding the necessary value to the portfolio. Due to the decarbonization process, the impairment was allocated mainly to thermal assets, followed by gas pipelines and port assets. Renewable assets, which are new, and transmission assets that generate flows in perpetuity, did not suffer any impairment. The impairment has the following effects on EECL’s financial statements:
    i. *Effects on 2022 net results:* The after-tax impact on results -US$ 325 million, bringing the net loss for the year to US$ 388.8 million.
    ii. *Effects on recurring net results in 2022:* Had this non-recurring impairment not been applied, the net result would have been a loss of US$ 63.8 million.
    iii. *Effects on future results:* As a result of lower goodwill and fixed asset values, the cost of depreciation and amortization will decrease in the future, with a positive impact on net results.
    iv. *Effects on cash flow:* The impairment has no effect on 2022 cash flows. In the future, it might cause an increase in net results and in dividend payments.

3Q22

- **Management change**: On October 1, Rosaline Corinthien, former CEO of ENGIE France Renewables, took over the Chief Executive Officer position at ENGIE Energía Chile S.A., in replacement of Mr. Axel

Levêque, who had been the company's CEO since September 2014. For the past three years, Rosaline Corinthien led the development, construction, operation, and maintenance of ENGIE's renewable assets in France. These activities are carried out by 2,500 employees and consider an installed capacity of 3.9 GW of hydroelectricity, 2.7 GW of wind energy and 1.4 of solar energy. This management change was communicated on July 18, by means of a material fact notice.

- **Disconnection of the Unit 15 coal-based plant**: On September 30, 2022, the last coal-fired plant in the Tocopilla site was disconnected, representing a milestone in the country's energy transformation process. The closure of U15 followed the disconnection of U14 on June 30, 2022, and the dismantling of units 12 and 13 disconnected in 2019. The dismantling process was completed in time, within budget, and with no reported accidents.

- **Acquisition of San Pedro wind farms**: On September 30, ENGIE Energía Chile S.A. issued a material fact notice informing of the operation previously communicated to the CMF commission by means of a reserved event dated September 21. On September 29, EECL signed a share purchase promise (the "Contract") with the companies Trans Antartic Energía S.A., Trans Antartic Energía II S.A., Bosques de Chiloé S.A., Beltaine Renewable Energy S.L. and Inversiones Butalcura S.A. (the "Sellers"), current shareholders of the companies Alba S.A., Alba Andes S.A., Alba Pacífico S.A., Energías de Abtao S.A. and Río Alto S.A., for the acquisition of 100% of the shares of these companies, which in turn own (i) the San Pedro I wind farm, currently in operation through 18 wind turbines with an installed capacity of 36 MW; (ii) the San Pedro II wind farm, currently in operation through 13 wind turbines with an installed capacity of 65 MW; and (iii) a wind power generation project currently under development, with potential capacity of approximately 151 MW; all located in the commune of Dalcahue, Chiloé, Los Lagos Region. The Contract is subject to a series of suspensive conditions usual for this type of operations, including the approval of the operation by the local anti-trust commission ("FNE") in accordance with the provisions of D.L. 211 of 1973. The price of the transaction will be US$ 77 million, to be paid at closing once the conditions precedent are fulfilled. This price may be subject to adjustments in accordance with the provisions of the Contract.

- **True sale of accounts receivable**: On July 14 and 18, respectively, ENGIE Energía Chile S.A. and its subsidiary Eólica Monte Redondo SpA sold to Chile Electricity PEC SpA the fifth group of accounts receivable from distribution companies originated by the implementation of the price stabilization law. The sale, made under the terms and conditions of the agreements signed in 2021 with Goldman Sachs, IDB Invest and Allianz, included accounts receivable for a nominal amount of US$41.3 million. The difference between the nominal amount of accounts sold and the cash price received (US$29.7 million) will be recorded as financial expenses in the third quarter of 2022 (US$11.6 million). Upon the completion of this sale, the total amount of the five groups of accounts receivable sold reached US$222.1 million, leaving a remaining US$42.9 million to be sold under this program. The total financial cost recognized on the sale of the five groups of receivables sold in 2021 and 2022 amounts to US$64.1 million.

- **New price stabilization law #21,472 ("MPC law"):** On July 13, after ratifying the changes made by the Senate, the Chamber of Deputies dispatched to law the "Customer Protection Mechanism" or "MPC" project. This Law seeks to stabilize energy prices for customers of public distribution service concessionaires regulated by the General Law on Electric Services, who are subject to price regulation. The Law also establishes a transitory mechanism with differentiated tariff increases to protect certain regulated clients from increases in their electricity tariff over a period of time. The purpose of the MPC will be to pay the differences originated between (a) the billing of the distribution companies to their final customers for the energy and capacity component and (b) the amount that distribution companies are supposed to pay for the electricity supply to generation companies, in accordance with their respective contractual conditions. The total resources accounted for in the operation of the MPC may not exceed US$1,800 million and their validity will be extended until the balances originated by application of this law are extinguished. Beginning 2023, the National Energy Commission ("CNE") must project semi-annually the total payment of the Remaining Final Balance for a date that may not be later than December 31, 2032. To that end, it will determine the charges that allow the collection of the amounts required for the total restitution of the resources necessary for the correct operation of the MPC. The CNE is currently drafting the exempt resolution setting the guidelines for the implementation of the MPC law.

- **Financing mechanism dealing with the effects of the MPC law:** Pursuant to the "MPC Law", as supplemented by the exempt resolution to be issued by the CNE, under which the tariffs will be stabilized and repaid in the future, generation companies are expected to periodically receive interest bearing securities issued by the Tesorería General de la República of Chile (the "Treasury"), equivalent to the difference between PPA prices and the stabilized prices, for up to an aggregate amount of US$1.8 billion. The Government requested IDB Invest to structure a financial facility and make it available to generation companies at the time the Law enters into force. IDB Invest will purchase the certificates of payment collected from the Treasury by generation companies, and will re-sell them to a special purpose company, which will in turn issue notes under the 144-A/Reg S and 4(a)2 formats. IDB Invest appointed Goldman Sachs to lead the transaction structuring and JP Morgan and Itaú to act as joint book-runners in the issuance of the notes. The certificates of payment will be grossed up for interest expenses and financial costs so that generation companies will receive in full the nominal amount of the bills according to their respective PPA prices. The certificates of payment will be payable by regulated users in full no later than December 31, 2032. The full repayment of the Certificates of Payment benefits from a top-up guarantee by the Government of Chile.

- **Public auction for the supply of regulated customers**: The National Energy Commission (CNE), published the results of the bidding process related to the 2022/01 public auction for the supply of energy to distribution companies. This auction was intended to allocate 15-year PPAs for up to 5.25 TWh per year of demand beginning January 1, 2027. On this occasion, only ~1.2 TWh was preliminarily allocated. The average price of this 1.2 TWh reached ~US$34/MWh, above last year's nominal US$24/MWh. The average reserve price was US$42/MWh and most of the offers (8.9 TWh) were above that price. The average price offered was ~US$50/MWh and a large proportion of the offers were in the range of US$45-50/MWh.

2Q22

- **Explosion at Freeport LNG terminal**: In June 2022, a 3.44 TBtu LNG cargo to be delivered to ENGIE Energía Chile was cancelled by Total Energies Gas & Power Limited ("TOTAL") claiming an assumed force majeure event caused by the prolonged operational outage of the Freeport LNG terminal due to the June 8 explosion at the LNG tank. This force majeure was subsequently reversed by Total, and the process related to this shipment is under review in accordance with the contract.

- **Annual Ordinary Shareholders' Meeting**: On April 26, 2022, the Company's shareholders agreed the following:

  - **Dividend Policy:** No final dividends will be paid on account of 2021's net income,

  - **Auditors:** To appoint EY Servicios Profesionales de Auditoría y Asesorías SpA as the Company's external auditors.

  - **Board Members:** To appoint the following persons as principal and alternate members of the board of directors:

Principal director	Alternate director
Frank Demaille	Aníbal Prieto Larraín
Hendrik De Buyserie	André Cangucu
Pascal Renaud	Guilherme Ferrari
Mireille Van Staeyen	Bernard Esselinckx
Cristián Eyzaguirre Johnston	Ricardo Fischer Abeliuk
Mauro Valdés Raczynski	Enrique Allard Serrano
Claudio Iglesis Guillard	Victoria Vásquez García

1Q22

- **Tamaya solar PV plant**: This 114MWac plant located in the Antofagasta region achieved its commercial operation date on January 14, 2022, as confirmed by the national grid coordinator ("CEN"). This new asset forms part of our ambitious transformation plan, which considers the addition of 2GW of renewable generation and is in line with our zero carbon goals. The Tamaya plant has been injecting power to the system since November 2021. Tamaya is located in Tocopilla and has an installed capacity of 114 MWac, generated with its 298.980 photovoltaic panels.

- **Price stabilization fund**: On March 4, 2022, ENGIE Energía Chile and Eólica Monte Redondo sold to Chile Electricity PEC SpA the fourth group of accounts receivable from distribution companies born from the application of the electricity price stabilization mechanism enacted in November 2019. Chile Electricity PEC raised the financing to buy receivables from four groups of generation companies through a delayed draw private placement with the participation of Allianz, IDB Invest and Goldman Sachs. In the first quarter of 2022, ENGIE and EMR sold accounts receivable with face value of US$13.5 million. They received US$9.6 million in cash proceeds and reported US$3.9 million in financial expenses. The total amount of accounts receivable sold under this program, following the sale of the fourth group, is US$180.8 million, representing approximately 68% of the total amount of accounts receivable to be accrued during the life of the PEC mechanism.

INDUSTRY OVERVIEW

The SING and SIC power grids operated independently until November 24, 2017, when the interconnection of both grids was perfected through EECL's 50%-owned TEN project, giving birth to the SEN (*"Sistema Eléctrico Nacional"*). Currently, the company's generation assets are predominantly located in the northern segment of the SEN, in the area that used to be covered by the so-called SING Grid (*"Sistema Interconectado del Norte Grande"*), which serves a major portion of the country's mining industry. Given local conditions, the northern segment of the SEN is predominantly a thermoelectric system, with generation based on coal and LNG, with growing penetration of renewable sources, including wind, solar, and geothermal. Energy flows through the interconnection are variable, and the commissioning of the Interchile's Cardones-Polpaico transmission project on May 30, 2019, allowed for the coupling of transmission bars at different substations and the injection into the grid of renewable power generation, which was previously being lost due to insufficient transmission capacity.

Marginal costs - SEN

2021			Real		
Mes	**Crucero 220**	**Polpaico 220**	**Charrúa 220**	**Pto. Montt 220**	**Temuco 220**
Ene	51	59	57	87	58
Feb	76	84	83	151	85
Mar	76	84	87	166	90
Abr	71	78	83	130	85
May	77	82	82	109	84
Jun	67	68	66	63	66
Jul	105	122	129	126	129
Ago	99	114	128	130	128
Sep	47	56	57	68	58
Oct	49	50	49	145	50
Nov	68	70	70	207	72
Dic	85	89	87	212	89
YTD	**73**	**80**	**81**	**133**	**83**

2022			Real (Monthly Average per Node)		
Month	**Crucero 220**	**Polpaico 220**	**Charrúa 220**	**Pto. Montt 220**	**Temuco 220**
Ene	69	69	75	213	77
Feb	68	68	69	290	72
Mar	95	102	114	210	117
Abr	108	118	126	230	127
May	96	102	100	187	101
Jun	190	200	196	224	192
Jul	116	154	148	241	144
Ago	101	112	100	199	90
Sep	84	87	82	198	70
Oct	83	69	61	77	54
Nov	112	95	86	100	72
Dec	96	91	89	83	61
YTD	**101**	**105**	**104**	**188**	**98**

Source: Coordinador Eléctrico Nacional.

In the first quarter of 2022, marginal costs increased compared to previous quarters due to several factors: (i) lower reservoir levels which caused a reduction in hydraulic generation; (ii) the increase in international coal and gas prices to unprecedented levels due to the Russia-Ukraine war; (iii) higher transportation costs; and (iv) unavailability of cost-efficient coal plants due to both trips and maintenance outages. This was in part mitigated by the availability of Argentine gas and increased generation from renewables. Therefore, marginal costs at the Crucero node averaged US$72/MWh in the first quarter vs. US$67/MWh in the first quarter of 2021, which was already considered a high average at the time.

In the second quarter of 2022, marginal costs increased compared to previous quarters, not only due to the dry hydrology, which led the authority to order water rationing to build up reservoir levels, but also due to steeper increases in international fuel and transportation prices due to the Russia-Ukraine conflict. In addition, several cost-efficient coal-fired plants in the system reported prolonged planned or forced outages, aggravated by the force-majeure event, which caused an increase in diesel generation in light of the reduction in LNG supply. Marginal costs at the Crucero node averaged US$132/MWh in the second quarter up from US$77/MWh in the second quarter of 2021.

In the third quarter of 2022, marginal costs started to decrease compared to previous quarters, due to improved hydrologic conditions beginning August and availability of Argentine gas in the system, which contributed to a decrease in diesel generation. Argentine gas imports on an uninterruptible basis reached a maximum monthly average of 5 MMm3 and averaged 4.1 MMm3 in the third quarter. Marginal costs at the Crucero node averaged US$100/MWh in the third quarter, up from US$83.9/MWh in the third quarter of 2021, and down from US$131/MWh reported in the preceding quarter.

In the fourth quarter of 2022, despite an increase in Argentine gas imports due to the start of supply contracts on a firm basis, marginal costs remained high mainly due to increases in power demand and in fuel prices as a result of the geopolitical situation. Diesel generation was observed in peak hours given the increased demand and planned and forced outages of thermoelectric power plants.

During 2022, the marginal cost average at the Crucero, Quillota and Charrúa nodes increased by 35% compared to 2021, reaching US$104/MWh. However, the marginal cost averaged US$198/MWh at the Puerto Montt node in the south of Chile given transmission congestions in that area. Thus, high marginal costs were observed together with decoupling and significant day-night variations in the system.

Fuel prices

International Fuel Prices Index

	WTI (US$/Barrel)			Brent (US$/Barrel)			Henry Hub (US$/MMBtu)			European coal (API 2) (US$/Ton)		
	2021	**2022**	**% Variation YoY**	**2021**	**2022**	**% Variation YoY**	**2021**	**2022**	**% Variation YoY**	**2021**	**2022**	**% Variation YoY**
Jan	52.0	84.3	*62%*	54.8	86.2	*57%*	2.71	4.32	*59%*	67.8	167.2	*147%*
Feb	59.0	95.8	*62%*	62.3	96.6	*55%*	5.35	4.75	*-11%*	65.9	194.5	*195%*
March	62.3	107.9	*73%*	65.3	116.2	*78%*	2.61	4.99	*91%*	68.4	325.3	*375%*
April	61.7	101.9	*65%*	64.9	104.5	*61%*	2.67	6.50	*143%*	71.8	319.3	*345%*
May	65.9	111.5	*69%*	68.9	114.3	*66%*	2.93	8.24	*181%*	86.1	328.1	*281%*
June	72.3	114.3	*58%*	74.1	122.4	*65%*	3.35	7.46	*123%*	108.4	352.9	*226%*
July	72.2	101.2	*40%*	75.0	111.6	*49%*	3.85	7.37	*91%*	132.8	389.0	*193%*
August	67.9	93.7	*38%*	71.0	100.7	*42%*	4.05	8.76	*116%*	148.8	364.9	*145%*
September	72.2	85.4	*18%*	75.0	89.5	*19%*	5.27	7.73	*47%*	173.0	328.5	*90%*
October	81.8	87.6	*7%*	83.7	93.3	*11%*	5.51	5.69	*3%*	206.3	267.9	*30%*
November	77.5	82.8	*7%*	79.8	89.9	*13%*	4.77	5.45	*14%*	159.4	213.6	*34%*
December	71.4	76.0	*7%*	74.8	80.3	*7%*	3.71	5.52	*49%*	121.1	227.9	*88%*

Source: Bloomberg, IEA

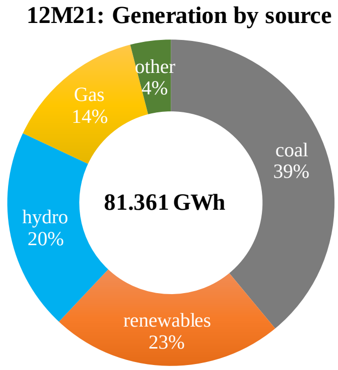
When comparing 2022 with 2021, we can observe higher international fuel prices, with variations of more than 100% on average. Prices began to increase in 2021 due to an important "post-pandemic" reactivation, especially in China. In the last quarter of 2021, the Chinese government took steps to unblock coal supply and stabilize prices, which began to be reflected in a recovery in domestic production and a decline in international prices. However, on January 1, 2022, the Indonesian government banned coal exports, due to problems in domestic supply. This situation continued until January 20, 2022, when the authorities lifted the ban on 139 companies that had met their local supply quotas and were allowed to export immediately. Such a ban led to a significant increase in the main Australian coal price indicator (FOB Newcastle), which reached levels above 200 USD/ton.

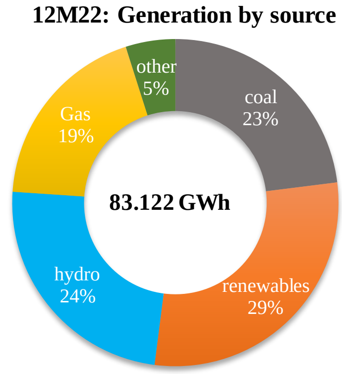
Following the export ban in Indonesia (the world's largest exporter), which affected January prices, Russia's invasion of Ukraine, that began on February 24, aggravated the situation. Russia is the world's third largest coal exporter and the European Union's top supplier. The war caused an increase in the prices of coal, gas, and oil. Russia ceased to be a reliable supplier and countries that commonly used Russian coal began to look for coal in other markets including Indonesia and Australia. Moreover, in early April, the EU agreed to completely ban the import of Russian coal, a move that took effect in mid-August. A few days later, Japan also banned imports of Russian coal.

Towards the end of the year, coal prices fell from the high levels recorded in the second and third quarters of 2022, mainly because Europe built up coal and gas (LNG) stocks in advance of the winter season. However, the beginning of the European winter was quite benign, resulting in lower fuel consumption and high inventory stocks.

Generation

The following chart provides a breakdown of generation in the SEN by fuel type:





Source: Coordinador Eléctrico Nacional.

In 2022, demand reached a maximum of 11,905.5 MWh/h in February, a 5.3% increase compared to peak demand reported in 2021. Sales reached 77,043.7 GWh in 2022, with a 0.8% increase in free customer sales and a 5.4% increase in the regulated client segment.

Regarding renewable energy, solar generation increased by 31.9%, while wind generation rose by 22.5% as compared to 2021. During the first quarter of 2022 new renewable projects with gross capacity of 578.1 MW began operations in the system, while in the second, third and fourth quarters an additional 251.9 MW, 672.5 MW, and 307.6 MW, respectively, became operational.

During the first quarter of 2022, hydroelectric generation dropped by 8%, compared to the same period of 2021 and by 16% when compared to 2020. At the end of the first quarter, the levels at the Laja and Maule reservoirs were in values slightly below those of 2021, not so the case of Chapo, Rapel and Ralco, as the rationing decree allowed for an increase in their levels compared to 2021. The flows from the thaw decreased very early in the first quarter, leading to a decrease in hydroelectric generation. The hydrologic year, spanning from April 2021 through March 2022 was extremely dry with 96.8% exceedance probability, up from 91.7% reported the previous year.

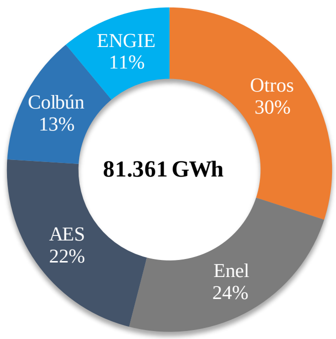
In the second quarter, hydroelectric generation dropped by 3.8% compared to the same quarter of 2021. As of the end of June, most reservoirs reported higher levels that those of the previous two years due to the hydraulic reserve built up thanks to the rationing decree (375 GWh) and the rainfall reported during the start of the rainy season.

In the third quarter, hydraulic generation recovered and increased by 61.2% compared to the third quarter of 2021, due to rainfall and increased water flows in the main river basins. As of the end of the third quarter, most reservoirs reported more accumulated energy reserves than the previous two years. As of September 30, 2022, the hydraulic reserve amounted to 144 GWh.

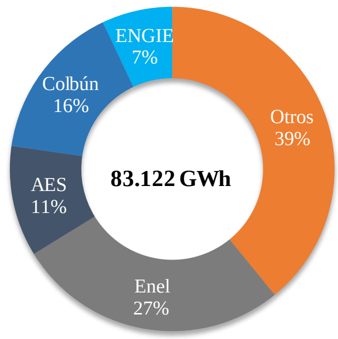
In the fourth quarter, energy in reservoirs was 14% higher than in the same period of 2021, so no hydraulic reserve build-ups will be required for the first half of 2023. A study by the National Coordinator ran nine possible scenarios, and only one of them considers a supply deficit. The supply situation of the SEN system is in better terms according to the supply security study for the November 2022-October 2023 period. In 2022 there was a marked hydrological improvement compared to 2021, which was the second driest year in the hydrological statistics.

Electricity production in the SEN grid, broken down by company, was as follows:

12M21: Generation by company



12M22: Generation by company



Source: Coordinador Eléctrico Nacional

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following discussion is based on our audited consolidated financial statements for fiscal years ended December 31, 2022, and December 31, 2021. These financial statements have been prepared in U.S. dollars in accordance with IFRS and should be read in conjunction with the financial statements and the notes thereto published by the Comisión para el Mercado Financiero (www.cmfchile.cl).

4Q 2022 compared to 4Q 2021 and 3Q 2022

Operating Revenues

Quarterly Information (In US$ millions)

	4Q 2021		3Q 2022		4Q 2022		% Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Unregulated customers sales…………………..	197.2	55%	229.5	50%	239.6	49%	4%	22%
Regulated customers sales…………………….	154.0	43%	205.3	44%	219.3	45%	7%	42%
Spot market sales………………………………..	4.9	1%	26.9	6%	27.0	6%	0%	453%
Total revenues from energy and capacity sales	**356.0**	91%	**461.8**	92%	**485.8**	93%	**5%**	**36%**
Gas sales…………………………..	9.4	2%	11.8	2%	7.6	1%	-36%	-19%
Other operating revenue……………………….	26.7	7%	26.2	5%	27.9	5%	7%	5%
Total operating revenues………………….	**392.1**	100%	**499.7**	100%	**521.3**	100%	**4%**	**33%**
Physical Data (in GWh)								
Sales of energy to unregulated customers (1)……	1,714	59%	1,796	58%	1,773	60%	-1%	3%
Sales of energy regulated customers……	1,184	41%	1,255	41%	1,149	39%	-8%	-3%
Sales of energy to the spot market…………….	25	1%	48	2%	18	1%	-63%	-28%
Total energy sales………………………….	**2,923**	100%	**3,100**	100%	**2,940**	100%	**-5%**	**1%**
Average monomic price unregulated customers(U.S.$/MWh)(2)	**113.4**		**127.8**		**135.1**		**6%**	**19%**
Average monomic price regulated customers (U.S.$/MWh)(3)	**130.0**		**163.6**		**190.8**		**17%**	**47%**

Energy and capacity sales reached US$485.8 million in the fourth quarter of 2022, representing a US$129.8 million, or 36%, increase compared to the fourth quarter of 2021. This was explained by an increase in tariffs due to increases in inflation rates and fuel prices used in contract indexation formulas as well as an increase in volume sales to unregulated clients. The 22% increase in sales to unregulated clients was due to price increases and demand recovery from our main mining customers such as Glencore, Centinela and El Abra. The 42% increase in revenues from sales to regulated customers was due to higher prices, which offset the drop in volume. The latter was explained by the company's lower proportion in the pool of regulated contracts due to the entry of new contracts from other generation companies, and the expiration of one of Eólica Monte Redondo's PPA with CGE (175 GWh) at the end of 2021. Compared to the immediately previous quarter, sales volume to both free and regulated customers reported a slight decrease.

In the fourth quarter of 2022, physical sales to the spot market were 18 GWh, a decrease with respect to the third quarter of 2022 and the fourth quarter of the previous year. Beginning January 1, 2022, EECL took over the supply contract with Minera Centinela from its subsidiary, CTH, and all the power generation of CTH was sold to the spot market during the months of January and February. As of March 1, a contract between CTH and EECL by which all the energy produced by CTH is sold to EECL, began to govern. A similar contract was signed between EECL and Solar Los Loros.

In the fourth quarter gas sales decreased, as compared to both the third quarter of 2022 and the fourth quarter of 2021, given the lower gas supply.

The most relevant items in the 'Other operating revenue' account are sub-transmission tolls and regulatory transmission revenues, which starting 2018 include a single charge called "cargo único", as well as port and maintenance services.

Operating costs

Quarterly Information (In US$ millions)

	4Q21		3Q22		4Q22		% Variation	
Operating Costs	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Fuel and lubricants………………………………	(117.6)	32%	(161.7)	33%	(154.9)	31%	-4%	32%
Energy and capacity purchases on the spot market……………………………	(125.2)	34%	(213.1)	43%	(210.2)	42%	-1%	68%
Depreciation and amortization attributable to cost of goods sold…………………………….	(50.5)	14%	(46.9)	10%	(49.9)	10%	6%	-1%
Other costs of goods sold……………………	(62.9)	17%	(67.6)	14%	(85.1)	17%	26%	35%
Total cost of goods sold………………..	**(356.2)**	96%	**(489.3)**	100%	**(500.2)**	100%	**2%**	**40%**
Selling, general and administrative expenses…	(9.1)	2%	(9.2)	2%	(6.3)	1%	-31%	-31%
Depreciation and amortization in selling, general and administrative expenses…………	(1.0)	0%	(1.1)	0%	(1.1)	0%	-3%	3%
Other operating revenue/costs……………………….	(6.0)	2%	9.2	-2%	6.5	-1%		
Total operating costs….………………	**(372.4)**	100%	**(490.4)**	100%	**(501.1)**	100%	**2%**	**35%**
Physical Data (in GWh)								
Gross electricity generation								
Coal………………………………………….	1,084	67%	775	53%	687	50%	-11%	-37%
Gas…………………………………………..	335	21%	382	26%	289	21%	-25%	-14%
Diesel Oil and Fuel Oil……………………	0	0%	1	0%	1	0%	25%	343%
Hydro/Solar/Wind………………………………	201	12%	303	21%	390	29%	29%	94%
Total gross generation…………………	**1,621**	100%	**1,461**	100%	**1,368**	100%	**-6%**	**-16%**
Minus Own consumption………………..	(128)	-8%	(152)	-10%	(92)	-7%	-39%	-28%
Total net generation……………………	**1,493**	50%	**1,310**	42%	**1,275**	42%	-3%	-15%
Energy purchases on the spot market………..	1,228	41%	1,308	42%	1,081	36%	-17%	-12%
Energy purchases- bridge………..	265	9%	497	16%	646	22%	n.a	n.a
Total energy available for sale before transmission losses………………………	**2,986**	100%	**3,115**	100%	**3,002**	100%	-4%	1%

Gross electricity generation decreased by 16%, compared to the same quarter of 2021, and by 6% compared to the third quarter. The decrease in coal generation was primarily explained by maintenance outages of the IEM and CTM2 plants, lower dispatch priority of other units and the disconnection of the U-15 coal-based unit at the end of September. Gas generation also dropped in the fourth quarter due to maintenance of the U16 combined-cycle unit. Renewable generation increased significantly compared to the fourth quarter of last year as the Calama Wind Farm and the Tamaya photovoltaic park achieved commercial operation in October 2021 and January 2022, respectively, while the Capricornio PV project began its first power injections into the grid in April, the Coya PV project started injecting power to the grid in August, while the San Pedro wind farms were acquired in mid-December.

The fuel cost item showed a decrease compared to the third quarter of 2022 as the company reported lower generation. Despite the 15% drop in gross generation when compared to the fourth quarter of 2021, fuel costs increased by 32% given the sharp increase in fuel prices as a result of the Russia-Ukraine conflict.

The 'Cost of energy and capacity purchases' item increased by US$85 million (68%) compared to the same quarter of 2021. This was mainly due to higher marginal costs or average spot prices, which were partly offset by lower volume of energy purchases in the spot market and purchases of energy under backup contracts with other generators, which more than doubled, reaching 646 GWh in the fourth quarter. As compared to the third quarter, the cost of energy purchases fell 1% due to the lower volume of energy purchased in the spot market accompanied by lower purchase prices. In the fourth quarter of 2022, although there was an increase in hydraulic generation and Argentine gas supply in the system, marginal costs did not fall as much as expected due to failures and maintenance of efficient thermoelectric plants. Therefore, the system had to resort more frequently to diesel generation, especially in November. During the second half of December, the water supply decreased sharply.

In the fourth quarter, depreciation costs in the costs-of-goods-sold item remained at similar levels as those reported in previous quarters.

Other direct operating costs included, among others, operating and maintenance costs, transmission tolls, insurance premiums and cost of fuels sold.

SG&A expenses remained as similar levels as those reported in the third quarter of 2022 and the fourth quarter of 2021.

The Other operating revenue/cost item includes water sales and miscellaneous income as well as recoveries and provisions. EECL's share in TEN's net income, which amounted to US$2.5 million in the fourth quarter, is also included in this item.

Electricity margin

Quarterly Information (In US$ millions)

	2021					2022				
	1Q21	2Q21	3Q21	4Q21	2021	1Q22	2Q22	3Q22	4Q22	2022
Electricity Margin										
Total revenues from energy and capacity sales………	**286.8**	**340.5**	**325.2**	**356.0**	**1,308.5**	**365.8**	**441.3**	**461.8**	**485.8**	**1,754.7**
Fuel and lubricants…………………..	(83.6)	(107.6)	(160.4)	(117.6)	(469.2)	(128.4)	(203.2)	(161.7)	(154.9)	(648.2)
Energy and capacity purchases on the spot market……	(104.7)	(90.0)	(85.0)	(125.2)	(404.9)	(163.0)	(212.0)	(213.1)	(210.2)	(798.3)
Gross Electricity Profit	**98.5**	**142.9**	**79.8**	**113.2**	**434.4**	**74.4**	**26.1**	**87.0**	**120.7**	**308.2**
Electricity Margin	*34%*	*42%*	*25%*	*32%*	*33%*	*20%*	*6%*	*19%*	*25%*	*18%*

In the fourth quarter, the electricity margin, or the gross profit from the electricity generation business, increased by US$7.5 million, when compared to the fourth quarter of 2021, although it fell in percentage terms to 25% of energy and capacity revenues because the increase in fuel and energy purchase cost was steeper than the increase in revenues. The US$120 million revenue increase is explained by higher average realized monomic prices due to the increase in the main tariff indexers (CPI, coal and gas prices). Meanwhile, compared to the previous quarter, there was a significant recovery of US$33.7 million in the electricity margin, which rose from 19% to 25% of energy and capacity revenues. On the one hand, energy and capacity revenues increased by US$24 million due to price increases triggered by higher inflation and fuel prices, and on the other, there was a US$6.8 million decrease in fuel costs and a US$2.9 million decrease in energy purchase costs due to lower spot prices. The fuel cost decrease was due to the decrease in generation explained by plant maintenance and lower dispatch priority of more expensive plants. In short, there was a moderate increase in the average supply cost of energy from US$120/MWh in the third quarter of 2022 to US$122/MWh in the fourth quarter, which was offset by the increase in revenues, leading to a recovery in the electricity margin.

Operating results

Quarterly Information (in US$ millions)

EBITDA	**4Q21**		**3Q22**		**4Q22**		**% Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Total operating revenues……………………..	392.1	*100%*	499.7	*100%*	521.3	*100%*	*4%*	*33%*
Total cost of goods sold……………………	(356.2)	*-91%*	(489.3)	*-98%*	(500.2)	*-96%*	*2%*	*40%*
Gross income………………………….	**35.9**	*9%*	**10.4**	*2%*	**21.2**	*4%*	***104%***	***-41%***
Total selling, general and administrative expenses and other operating income/(costs).	(16.2)	*-4%*	(1.2)	*0%*	(0.9)	*0%*	*-23%*	*-94%*
Operating income…..………………..	**19.7**	*5%*	**9.2**	*2%*	**20.3**	*4%*	***120%***	***3%***
Depreciation and amortization……...…………	51.6	*13%*	48.0	*10%*	51.0	*10%*	*6%*	*-1%*
EBITDA…………….….…………….	**71.3**	*18.2%*	**57.3**	*11.5%*	**71.3**	*13.7%*	***24%***	***0%***

EBITDA for the fourth quarter of 2022 reached US$71.3 million, the same level reported in the fourth quarter of 2021, and a turnaround compared to the weaker results reported in the third quarter. This was due to the increase in the electricity margin explained by the increase in operating revenues, which exceeded a moderate increase in average supply costs.

Financial results

Quarterly Information (In US$ millions)

	4Q22		**3Q22**		**4Q22**		**% Variation**	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Financial income………..………………………	0.3	*0%*	13.5	*3%*	1.5	*0%*	*-89%*	*348%*
Financial expense…………….………………	(10.9)	*-3%*	(27.4)	*-7%*	(19.3)	*-5%*	*-30%*	*77%*
Foreign exchange translation, net……………	11.1	*3%*	(3.9)	*-1%*	(9.2)	*-2%*		*-184%*
Other non-operating income/(expense) net…	(6.3)	*-2%*	(0.6)	*0%*	(447.6)	*-107%*		*7012%*
Total non-operating results…………….	**(5.8)**	*-2%*	**(18.4)**	*-4%*	**(474.7)**	*-114%*		
Income before tax……………………. ………	13.9	*4%*	(9.1)	*-2%*	(454.4)	*-109%*	***4875%***	***-3377%***
Income tax………………………………………	(5.2)	*-2%*	(8.6)	*-2%*	123.8	*30%*	*-1536%*	*-2501%*
Net income from continuing operations after taxes …	8.7	*3%*	(17.8)	*-4%*	(330.6)	*-79%*	*1762%*	*-3894%*
Net income to EECL's shareholders	**8.7**	*3%*	**(17.8)**	*-4%*	**(330.6)**	*-79%*	***1762%***	***-3894%***
Earnings per share…………………….	**0.008**		**(0.017)**		**(0.314)**			

Interest expense decreased in the fourth quarter as compared to the third quarter of 2022, when the company recorded US$11.6 million in interest expense on the sale of long-term accounts receivable from distribution companies related to the tariff stabilization law. The difference between the face value of the accounts receivable sold and the cash amount received after applying the financial discount and transaction costs, is being reported as financial expenses. In the fourth quarter of 2021, no sales of PEC receivables were reported. The increase in interest expense as compared to the fourth quarter of 2021 is explained by higher debt levels and the steep increase in market interest rates.

The exchange rate difference reached a US$9.2 million loss in the fourth quarter as a result of greater exchange rate volatility with the Chilean peso tending to appreciate. Fluctuations in exchange rates affect the value of certain assets and liabilities denominated in currencies other than the US dollar, the company's functional currency. These include some accounts receivable and payable, advances to suppliers, value-added tax credit and, more importantly, liabilities for onerous concessions on land and other assets recorded on the balance sheet under the IFRS16 norm.

Net Earnings

In the fourth quarter of 2022, the company reported net losses of US$330.6 million, the worst quarterly result ever.

Quarterly results were affected by non-recurring impacts, due to the recognition of the impairment in the book value of generation assets. Accounting rules (IAS 36) establish that assets must be accounted for in the balance sheet at a value not exceeding their recoverable amount. The latter is the largest of the fair value of the asset minus disposal costs and its value in use. Therefore, when the carrying amount of an asset exceeds its recoverable amount, the asset is impaired and must be depreciated to its recoverable amount. The recoverable value was determined by calculating EECL's equity value (EV) as of June 2022 corresponding to discounted cash flows (hereinafter "DCF") minus net debt. The DCF methodology allows to better estimate the value of EECL, since this method includes the particularities of the business plan and quantifies specific situations, such as the terms and conditions of the PPAs and the remaining useful life of the assets. The recoverability analysis should be done per cash-generating unit ("CGU"). Although the EECL business comprises a single CGU, the assets can be grouped into three different categories depending on their technologies: Thermal generation assets; Renewable energy generation assets, and Power transmission assets. In this case, the amount of the impairment was applied mainly to thermal assets, gas pipelines and port assets, leaving out renewable assets that are new, and transmission assets that generate flows in perpetuity.

The after-tax effect of the impairment on the net result of the fourth quarter was -US$325 million, bringing the net loss for the quarter to US$330.6 million. Had this non-recurring impairment not been applied, the net result for the fourth quarter would have been a loss of US$5.6 million. The impairment of goodwill and fixed assets will result on lower depreciation and amortization costs in the future, with a consequential positive effect on future net results. The impairment had no effect on 2022 cash flows although in the future it might cause an increase in dividend payments.

2022 compared to 2021

Operating Revenues

For the 12-month period ended december 30 (in US$ millions)

	12M21		12M22		Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	%
Unregulated customers sales…………………..	673.6	*51%*	877.7	*50%*	*204.1*	*30%*
Regulated customers sales…………………….	614.3	*47%*	772.8	*44%*	*158.5*	*26%*
Spot market sales……………………………..	20.6	*2%*	104.2	*6%*	*83.6*	*406%*
Total revenues from energy and capacity sales……	**1,308.5**	*88%*	**1,754.7**	*91%*	***446.2***	*34%*
Gas sales…………………………..	37.8	*3%*	48.9	*3%*	*11.1*	*29%*
Other operating revenue……………………….	132.3	*9%*	116.7	*6%*	*-15.6*	*-12%*
Total operating revenues………………….	**1,478.6**	*100%*	**1,920.3**	*100%*	***441.7***	*30%*
Physical Data (in GWh)						
Sales of energy to unregulated customers (1)……	6,675	*57%*	7,074.5	*59%*	*400*	*6%*
Sales of energy regulated customers……	4,946	*42%*	4,734.8	*39%*	*-211*	*-4%*
Sales of energy to the spot market…………….	94	*1%*	238.1	*2%*	*144*	*153%*
Total energy sales………………………….	**11,715**	*100%*	**12,047**	*100%*	***333***	*3%*
Average monomic price unregulated customers(U.S.$/MWh)(2)	**102.6**		**134.3**		***31.7***	*31%*
Average monomic price regulated customers (U.S.$/MWh)(3)	**124.2**		**163.2**		***39.0***	*31%*

Energy and capacity sales reached US$1,754.7 million in 2022, representing a US$446.2 million, or 34%, increase compared to 2021, due to the recovery in the demand from unregulated clients and the higher electricity prices in both the regulated and free client segments. This was explained by increases in inflation rates and fuel prices used in contract indexation formulas (CPI and coal and gas prices).

In terms of physical sales, the unregulated segment showed a recovery in demand due to better indicators related to the evolution of the COVID 19 pandemic. Volume sales to regulated customers decreased slightly due to EECL's lower pro-rata in the pool of regulated contracts given the start of new contracts from other generation companies, and the expiration of one of Eólica Monte Redondo's PPA with CGE (175 GWh) at the end of 2021.

In 2022, physical sales to the spot market increased since, beginning January 1, 2022, EECL assumed the supply contract with Minera Centinela and all the power generation of the subsidiary CTH was sold to the spot market during the months of January and February. As of March 1, EECL signed contracts with CTH and Solar Los Loros under which EECL buys all the energy injected by CTH and Los Loros into the grid. Eólica Monte Redondo reported an increase in sales to the spot market due to the expiration of one of its contracts with distribution companies.

The increase in gas sales in 2022, is explained by an agreement signed in early February with the company's main liquefied natural gas supplier, which allowed the company to optimize annual gas purchase volumes, as well as to resolve a commercial dispute over an LNG cargo that could not be dispatched in the first half of 2021. As a result of this agreement, the company recorded a one-time US$17 million income on its operating results in the first quarter of 2022.

The most relevant items in the 'Other operating revenue' account are sub-transmission tolls and regulatory transmission revenues, which starting 2018 include a single charge called "cargo único", as well as port and maintenance services. In 2021, this item included (i) US$5.3 million in insurance compensations over a past loss reported at the IEM plant and (ii) income recognition of US$12.12 million on ENGIE's acquisition of a 40% interest in Inversiones Hornitos SpA paid in monthly installments according to the terms of the power supply agreement renegotiated with AMSA, which considered a tariff discount. These two factors explain most of the 12% decrease in other operating revenues.

Operating costs

For the 12-month period ended december 30 (in US$ millions)

	12M21		12M22		Variation	
Operating Costs	Amount	% of total	Amount	% of total	Amount	%
Fuel and lubricants………………………………	(469.2)	35%	(648.2)	34%	179.0	38%
Energy and capacity purchases on the spot market…	(404.9)	30%	(798.3)	42%	393.4	97%
Depreciation and amortization attributable to cost of goods sold…	(181.9)	13%	(185.3)	10%	3.4	2%
Other costs of goods sold…………………….	(255.6)	19%	(269.1)	14%	13.6	5%
Total cost of goods sold………………..	**(1,311.6)**	97%	**(1,901.0)**	99%	**589.4**	**45%**
Selling, general and administrative expenses…	(34.1)	3%	(33.8)	2%	-0.3	-1%
Depreciation and amortization in selling, general and administrative expenses…	(3.9)	0%	(4.1)	0%	0.2	5%
Other operating revenue/costs……………………….	(0.4)	0%	18.3	-1%	-18.6	-5185%
Total operating costs…………………..	**(1,349.9)**	100%	**(1,920.6)**	100%	**570.7**	**42%**
Physical Data (in GWh)						
Gross electricity generation						
Coal…………………………………………	5,709	68%	3,503	57%	-2,206	-39%
Gas…………………………………………..	2,274	27%	1,439	24%	-834	-37%
Diesel Oil and Fuel Oil…………………….	23	0%	19	0%	-4	-17%
Hydro/Solar………………………………………	389	5%	1,139	19%	750	193%
Total gross generation…………………..	**8,394**	100%	**6,100**	100%	**-2,294**	**-27%**
Minus Own consumption……………..	(648)	-8%	(507)	-8%	141	-22%
Total net generation…………………….	**7,746**	66%	**5,593**	46%	**-2,153**	**-28%**
Energy purchases on the spot market………..	3,311	28%	4,501	37%	1,190	36%
Energy purchases- bridge………..	639	5%	2,134	17%	1,495	234%
Total energy available for sale before transmission losses………………………	**11,696**	100%	**12,228**	100%	**532**	**5%**

Gross electricity generation decreased 28%, compared to 2021, principally due to decreases in coal-based generation, mainly explained by the IEM overhaul, followed by major maintenance of the CTA, CTH and CTM2 plants. Also, increased hydro and Argentine gas-based generation in the system beginning August, displaced our less efficient coal plants in terms of dispatch priority. Gas generation decreased 37% due to the maintenance of both CCGTs, U16 and CTM3, and the lack of LNG resulting from the cancellation of a shipment as a result of the Freeport incident. This was partially offset by the increase in renewable generation due to the commissioning of the Calama Wind Farm at the end of 2021, the Tamaya PV plant at the beginning of 2022, and the first injections of energy by the Capricornio PV plant in April and the Coya plant in August.

Despite the decrease in the company's own generation in 2022, the fuel cost item rose by 38% or US$179 million, due to the increase in fuel prices worldwide as a result of the Russia-Ukraine war.

The 'Cost of energy and capacity purchases' item increased by US$393.4 million (97%) compared to 2021. This was mainly due to (i) higher marginal costs, or average spot prices, (ii) a 36% increase in the volumes of energy purchased on the spot market; and (iii) greater purchases of energy under backup contracts with other generators, which more than tripled, reaching 2,134 GWh in 2022. The higher volume of purchases is explained by the lower generation of our efficient units due to maintenance and lower dispatch priority of our less efficient units.

In 2022, depreciation costs in the costs-of-goods-sold item remained at similar levels as those reported in 2021.

Other direct operating costs include, among others, operating and maintenance costs, transmission tolls, insurance premiums and cost of fuels sold. The decrease in this item as compared to 2021 is explained by an US$11.9 million premium for the cancellation of an LNG shipment paid in the first quarter of 2021.

SG&A expenses remained as similar levels as those reported in 2021.

The Other operating revenue/cost item includes water sales and miscellaneous income as well as recoveries and provisions. EECL's share in TEN's net income, which amounted to US$6.7 million in 2022, is also included in this item.

Operating results

For the 12-month period ended december 30 (in US$ millions)

EBITDA	**12M21**		**12M22**		**Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Total operating revenues………………………	1,478.6	*100%*	1,920.3	*100%*	*441.7*	*30%*
Total cost of goods sold……………………	(1,311.6)	*89%*	(1,901.0)	*99%*	*589.4*	*45%*
Gross income………………………….	**167.0**	*11%*	**19.3**	*1%*	***-147.7***	***-88%***
Total selling, general and administrative expenses and other operating income/(costs).	(38.3)	*3%*	(19.7)	*1%*	*-18.7*	*-49%*
Operating income…..……………….	**128.7**	*9%*	**(0.3)**	*0%*	***-129.1***	***-100%***
Depreciation and amortization……...…………	185.8	*13%*	189.4	*10%*	*3.6*	*2%*
EBITDA……………….………………..	**314.5**	*21.3%*	**189.0**	*9.8%*	***-125.5***	***-40%***

2022 EBITDA reached US$189 million, a 40% decrease, or -US$125.5 million, compared to 2021. This was due to the lower margin of the electricity business, in turn explained by the increase in average supply costs due to high fuel prices and the price of energy bought from the spot market. A turnaround in operating results beginning August 2022 is worth noting.

Financial results

For the 12-month period ended december 30 (in US$ millions)

	12M21		**12M22**		**Variation**	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Financial income……….………………………	1.6	*0%*	16.8	*2%*	*15.2*	*944%*
Financial expense…………….…………………	(88.8)	*-8%*	(75.5)	*-8%*	*13.3*	*-15%*
Foreign exchange translation, net……………	22.6	*2%*	(14.7)	*-1%*	*-37.3*	*-165%*
Other non-operating income/(expense) net…	(3.3)	*0%*	(447.7)	*-45%*	*-444.4*	*13368%*
Total non-operating results…………….	**(67.9)**	*-6%*	**(521.1)**	*-52%*		
Income before tax……………………. ………	60.8	*5%*	(521.4)	*-52%*	***-582.2***	***-958%***
Income tax………………………………………	(13.4)	*-1%*	132.7	*13%*	*146.1*	
Net income from continuing operations after taxes	47.4	*4%*	(388.8)	*-39%*	*-436.1*	*-921%*
Net income to EECL's shareholders	**47.4**	*4%*	**(388.8)**	*-39%*	***-436.1***	***-921%***
Earnings per share…………………….	**0.045**		**(0.369)**	*0%*		

Despite the increase in financial debt and market interest rates, interest expense decreased, as compared to 2021, due to the sale of long-term accounts receivable from distribution companies related to the tariff stabilization law. The difference between the face value of the accounts receivable sold and the cash amount received after applying the financial discount and transaction costs, is reported as financial expenses. In 2021, the interest expense account included US$48.7 million from the sale of PEC receivables, while in 2022, this expense reached US$15.6 million.

The exchange rate difference reached a US$14.7 million loss, compared to an US$22.6 million gain in 2021 as a result of greater exchange rate volatility, with the Chilean peso tending to appreciate in the first quarter and to depreciate in the second and third quarters of 2022. Fluctuations in exchange rates affect the value of certain assets and liabilities denominated in currencies other than the US dollar, the company's functional currency. These include some accounts receivable and payable, advances to suppliers, value-added tax credit and, more importantly, liabilities for onerous concessions on land recorded on the balance sheet under the IFRS16 norm.

Net Earnings

In 2022, the company reported a net after-tax loss of US$388.8 million, which negatively compares with a US$47.4 million profit in 2021. As explained earlier, this decrease was in part explained by weaker operating results, although it should be noted that the company returned to positive operating results starting August 2022. However, in the last quarter, the company reported a negative US$325 million after-tax non-recurring impact explained by the impairment carried out on goodwill and fixed assets mainly related to the thermal generation business. Had this impairment not been done, the net result would have been a US$63.8 million loss in 2022.

The impairment of goodwill and fixed assets will result on lower depreciation and amortization costs in the future, with a consequential positive effect on future net results. The impairment had no effect on 2022 cash flows although in the future it might cause an increase in dividend payments.

Liquidity and Capital Resources

As of December 31, 2022, EECL reported consolidated cash balances of US$132.4 million, while its nominal financial debt[1] amounted to US$1,771 million, including US$359.3 million of debt maturing in 2023, with no other major scheduled debt principal payments until January 2025.

For the 12-month period ended december 30 (in US$ millions)

Cash Flow	**2021**	**2022**
Net cash flows provided by operating activities…	132.0	(428.7)
Net cash flows used in investing activities………	(202.7)	(318.1)
Net cash flows provided by financing activities..	52.0	662.8
Change in cash……………….....………….	**(18.8)**	**(84.0)**

Cash Flow from Operating Activities

In 2022, EECL reported net operating cash uses worth US$428.7 million. Cash flows from regular operations represented a net cash outflow of US$358.2 million, due to higher outflows from fuel and electricity purchases explained by extremely high fuel prices observed during the period. Other cash outflows included (i) the reimbursement of a US$30 million payment received by mistake on the last business day of 2021; (ii) interest

(1) Nominal amounts differ from the debt amounts recorded under the IFRS methodology in the Financial Statements, which considers deferred financial expenses and mark-to-market valuations on derivative transactions. The above amount excludes the financial leases related to the long-term tolling agreement with TEN and transactions qualified as financial leases under IFRS 16.

payments for US$48.8 million and (iii) income taxes for US$39.5 million, US$28.1 million of which corresponded to CO2 taxes. These cash outflows were partially offset by US$39.3 million in proceeds from the sale of accounts receivable from distribution companies related to the price stabilization law. In 2021, net operating cash flows amounted to US$132.0 million.

Cash Flow Used in Investing Activities

In 2022, cash flows related to investment activities resulted in a net cash outflow of US$318.1 million, mainly due to capital expenditures and the acquisition of the San Pedro wind farms in Chiloé. This figure is higher than the cash outflows for investment activities reported in 2021, which amounted to US$203 million. Capital expenditures included our investment in the solar PV projects, Tamaya, Capricornio and Coya, the last payments for the Calama wind farm, cash invested in transmission substations, as well as in plant maintenance, as detailed below. Our investment in the San Pedro I and II wind farms, which were acquired through the purchase of the shares of their holding companies, represented a net cash outflow of US$116.3 million.

Capital Expenditures

Our capital expenditures in 2021 and 2022 amounted to US$208.6 million and US$197.4 million, respectively, as shown in the following table. These amounts include VAT payments and capitalized interest. The latter amounted to US$8.4 million in 2022, whereas capitalized interest was US$10.1 million in 2021.

For the 12-month period december 30 (in US$ millions)

CAPEX	**2021**	**2022**
Substation…………………	8.3	20.7
Overhaul power plants & equipment maintenance and refurbishing…………………	13.1	22.1
Overhaul equipment & transmission lines	6.6	4.0
PV Power Plant……………	105.4	109.5
Wind farm……………..	65.2	19.5
Others……………………………………………	10.0	21.6
Total capital expenditures……………………….	**208.6**	**197.4**

Cash Flow from Financing Activities

In 2022, the main flows related to financing activities were (i) short-term loans, which increased by US$305 million, (ii) a US$35 million 18-month loan with BCI, (iii) a new US$250 million 5-year loan with Scotiabank, and (iv) a US$77 million 5-year loan with Santander for the purchase of the shares of the holding companies, owners of the San Pedro wind farms in Chiloé.

Short-term loans taken in 2022 include Banco de Crédito del Perú (US$70 million), Banco Santander (US$55 million), Scotiabank (US$50 million plus the renewal of a US$50 million loan due in April), BCI (US$50 million), Itaú (US$30 million), and Banco de Chile (US$50 million). In such way, short-term bank debt reached a balance of US$355 million at year-end 2022. The US$4.3 million current portion of the long-term debt of Energías de Abtao (owner of the San Pedro II wind farm) must be added to short-term debt obligations. The long-term portion of this debt amounted to US$75.1 million at YE 2022, which the company agreed to prepay before October 15 2024. The taking over of this debt did not represent cash flows during the period.

Other less relevant cash flows included the payment of installments under financial lease contracts. Interest paid on 144-A bonds, the IDB financing and short-term loans were recorded in the Cash from operations section. Likewise, the funds received from the sale of accounts receivable from distributors, for a total of US$39.3 million, were reflected in the Cash from operations section.

Contractual Obligations

The following table sets forth the maturity profile of our debt obligations as of December 31, 2022.

Notes:

(1) The tolling contract signed with TEN for the use of dedicated transmission assets is considered a financial leasing operation and is accounted for under accounts payable to related companies.

(2) According to the IFRS16 Leasing rules, leasing obligations for land and vehicle rentals were accounted for as financial debt.

Contractual Obligations as of 12/31/22

Payments Due by Period (in US$ millions)

	Total	**< 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Bank debt………………………………………………	**921.4**	359.3	112.8	340.8	108.5
Bonds (144 A/Reg S Notes)……………………..	**850.0**	-	350.0	-	500.0
Financial lease - Tolling Agreement TEN………	**53.4**	1.7	3.9	4.7	43.2
Financial lease - IFRS 16…………………………	**141.6**	6.4	12.4	8.5	114.3
Deferred financing cost…………………………..	**(17.4)**	-	(6.6)	(6.3)	(4.6)
Accrued interest…………………………………..	**24.0**	24.0	-	-	-
Mark-to-market swaps……………………………	**-**	-	-	-	-
Total	**1,973.0**	**391.4**	**472.5**	**347.6**	**761.4**

As of December 31, 2022, the company's consolidated debt totaled US$1,778.6 million (US$1,973.6 including IFRS 16 financial leases).

Short-term debt maturities amounted to US$391.5 million, including a US$50 million loan with Banco de Crédito del Perú, due February 2, 2023, two loans totaling US$30 million with Banco Santander, due February 6, 2023, a US$50 million loan with Scotiabank due April 31, 2023, a US$20 million loan with Banco de Crédito del Perú due April 21, 2023, a US$30 million loan with Itaú maturing on April 28, 2023, a US$50 million loan with BCI due on May 21, 2023, a US$50 million loan with Scotiabank maturing on May 19, 2023, a US$25 million loan with Santander maturing May 20, 2023, and a US$50 million loan with Banco de Chile maturing November 15, 2023. These loans are denominated in US dollars, they accrue a fixed interest rate and are documented by a simple promissory note reflecting the repayment obligation on the agreed date, with no other operating or financial covenants, and a prepayment option at no cost for the company. In addition, short-term debt maturities included the US$4.3 million current portion of the San Pedro II project financing.

Medium and long-term bank debt reached US$453.6 million as of December 31, 2022 (US$125 million with BID Invest, US$250 million with Scotiabank, US$35 million with BCI, US$77 million with Santander and US$75,1 million with Itaú, Banco Consorcio and Consorcio Seguros de Vida related to the taking over of the project financing of the San Pedro II wind farm. These loans are described in the following paragraphs.

On December 23, 2020, the Company and IDB Invest signed a financing agreement under which IDB Invest committed to extend a US$125 million loan to ENGIE Energía Chile within an initiative seeking to accelerate the decarbonization of the energy matrix in Chile. The financing includes a US$74 million senior loan from IDB

Invest, a US$15 million mixed financing provided by the Clean Technology Fund (CTF), and a US$36 million loan from the China Fund for Co-financing in Latin America and the Caribbean (China Fund). The transaction, with a tenor of up to 12 years, was used to finance the construction, operation, and maintenance of the Calama wind farm. This innovative financing solution is designed to promote the acceleration of decarbonization activities by monetizing the actual displacement of CO2 emissions achieved through the anticipated decommissioning of coal-based plants whose generation will be replaced with the renewable power output of the Calama wind farm. In the absence of a carbon market, the financial structure provides for a minimum price for the avoided emissions to be paid through the reduction in the financial cost of the CTF loan. In case a carbon market is developed during the life of the loan, CTF and Engie will share any positive difference between the market price and the minimum price set at the beginning of the financing. On August 27, 2021, the company drew the full amount available under these facilities. As of December 31, 2022, the loan reported a remaining average life of 7 years.

On July 26, 2022, the company signed a US$250 million, 5-year bullet green financing facility with Scotiabank. The first loan under this facility, for an amount of US$150 million, was booked on July 28, and the remaining US$100 million was disbursed on September 7. The loan accrues variable interest, using the SOFR benchmark rate. To hedge against interest-rate risk, the company took interest-rate swaps with Banco de Chile for a notional amount equivalent to 70% of the facility, fixing the SOFR rate at 2.872% p.a.

On December 16, 2022, the company took a US$35 million green loan with BCI, maturing on May 22, 2024, which has the same contractual terms as the rest of the company's short-term debt.

On December 15, 2022, the company signed a 5-year credit agreement for a total committed amount of US$170 million with Banco Santander. On that date, the first US$77 million of this financing was disbursed to pay for the purchase of shares of the San Pedro wind farms in Chiloé. The remaining US$93 million will remain available for disbursement until February 15, 2023. The loan accrues interest at a variable rate based on SOFR plus a margin. To hedge interest rate risk, the company took interest rate swap derivatives with Banco Santander for a notional amount equivalent to 70% of the loan principal. Through this swap, the SOFR rate was fixed at an average rate of 3.418% p.a. for that portion of the loan.

On December 15, 2022, the company took over the project financing held by Energías de Abtao S.A. (owner of the San Pedro II Wind Farm) with Itaú, Consorcio Seguros de Vida and Banco Consorcio for a total of US$79.4 million, of which US$4.3 million was due in 2023. By taking over this debt, EECL agreed to prepay the entire principal amount owed by October 15, 2024. On December 27, 2022, the company paid the accrued interest as of that date (US$1.3 million) and received a US$2.4 million cash compensation for unwind of the interest-rate swap held with Itaú. The loan accrues an interest rate equivalent to 6 months LIBOR plus 4% and has the usual project financing restrictions in addition to EECL's guarantee covering debt service. The company expects to prepay this financing with the resources from the second disbursement of the loan with Banco Santander described in the previous paragraph.

EECL holds two bonds under the 144A/RegS format. The first one is a US$350 million issue with a single principal payment in January 2025 and a 4.5% p.a. coupon rate. On January 28, 2020, the company closed a new 144A/RegS issue to fully refinance the US$400 million notes originally due in January 2021. The new issue amounts to US$500 million, has a 3.4% coupon rate and is due on January 28, 2030.

Leasing obligations refer to a long-term tolling agreement signed with TEN for the use of dedicated transmission assets connecting EECL's plants in Mejillones with the national grid at the Los Changos substation. The tolling agreement is out to 20 years at which time EECL will take ownership of the asset. The agreement has a present value of US$53.4 million and is payable in monthly instalments totaling approximately US$7 million per year until 2037.

As of December 31, 2022, the company reported leasing obligations related to land use concessions, vehicles, and other assets for a total amount of US$141.6 million, which qualified as financial debt under the IFRS 16 accounting norm.

Finally, on the last business day of 2021, the company received a US$30 million duplicated payment from a customer. The amount had to be accounted for as financial debt and funds were returned at the beginning of 2022.

Dividend Policy

Our dividend policy, last approved at the Annual Ordinary Shareholders' Meeting dated April 26, 2022, consists of paying the minimum legal required amounts (30% of net income), although higher amounts may be approved if the company's conditions so allow. Our dividend payment for each year is proposed by our Board of Directors based on the year's financial performance, our available cash balance and anticipated financing requirements for capital expenditures and investments. As possible, and subject to Board approval, the company will pay provisional dividends based on the net results of the first three quarters plus the definitive dividend to be paid in May of each year.

The dividend policy proposed by our Board is subsequently approved at a Shareholders' Meeting as established by law.

On July 27, 2021, the company's Board approved the payment of a US$41.5 million (US$0.0393996153 per share) provisional dividend on account of 2021's net earnings. This dividend was paid on August 26, 2021. This dividend represented a distribution equivalent to 87.6% of the net income of the year 2021, so the board chose to propose to the Shareholders' Meeting that a definitive dividend not be distributed against the 2021 net profit in May 2022.

The record of dividends paid since 2010 is shown in the following table:

Cash Dividends paid by Engie Energía Chile S.A.

Payment Date	Dividend Type	Amount (in US$ millions)	US$ per share
May 4, 2010	Final (on account of 2009 net income)	77,7	0,07370
May 4, 2010	Additional (on account of 2009 net income)	1,9	0,00180
May 5, 2011	Final (on account of 2010 net income)	100,1	0,09505
Aug 25 2011	Provisional (on account of 2011 net income)	25,0	0,02373
May 16 2012	Final (on account of 2011 net income)	64,3	0,06104
May 16 2013	Final (on account of 2013 net income)	56,2	0,05333
May 23 2014	Final (on account of 2013 net income)	39,6	0,03758
Sept 30,2014	Provisional (on account of 2014 net income)	7,0	0,00665
May 27 ,2015	Final (on account of 2014 net income)	19,7	0,01869
Oct 23 ,2015	Provisional (on account of 2015 net income)	13,5	0,01280
Jan 22, 2016	Provisional (on account of 2015 net income)	8,0	0,00760
May 26, 2016	Final (on account of 2015 net income)	6,8	0,00641
May 26, 2016	Provisional (on account of 2016 net income)	63,6	0,06038
May 18, 2017	Final (on account of 2016 net income)	12,8	0,01220
May 22,2018	Final (on account of 2017 net income)	30,4	0,02888
Oct 25 ,2018	Provisional (on account of 2018 net income)	26,0	0,02468
May 24 ,2019	Final (on account of 2018 net income)	22,1	0,02102
June 21 ,2019	Provisional (on account of 2019 net income)	50,0	0,04747
Dec 13 ,2019	Provisional (on account of 2019 net income)	40,0	0,03798
Nov 30 ,2020	Provisional (on account of 2020 net income)	66,6	0,06323
May 20 ,2021	Final (on account of 2020 net income)	51,1	0,04847
Aug 26 ,2021	Provisional (on account of 2021 net income)	41,5	0,03940

Risk management policy

In the normal course of business, EECL is exposed to several risk factors that may impact its operating and financial performance.

The company's financial risk management strategy seeks to safeguard EECL's operating stability and sustainability in a context of risk and uncertainty.

EECL has established risk management procedures, which include a description of the risk assessment methodology and the construction of a risk matrix called Enterprise Risk Management, which is approved annually and is reviewed quarterly in each of the company's functional committees where risk mitigation action plans are defined and monitored. Management presents the company's risk management performance to the board on a quarterly basis.

Hedging Policy

Our hedging policy intends to protect the company against our exposure to certain risks, as follows:

Business Risk and Commodity Hedging

We are exposed to commodity price volatility since electricity generation activities require continued supply of fossil fuels, mainly coal, gas and diesel oil, with international prices that fluctuate according to market and political variables beyond the company's control. Coal purchases are mostly made through annual contracts, the prices of which are linked to traditional indices such as API 2, API 10 or Newcastle. Purchases of diesel oil and certain purchases of liquefied natural gas are made at prices based on international oil values (WTI or Brent). The company has long-term liquefied natural gas purchase contracts with prices tied to Henry Hub.

Fuel prices are a key factor for the dispatch of thermoelectric generation plants, the company's average generation cost and the marginal costs of the electricity system in which it operates. Therefore, our business is subject to the risk of variations in the availability of fuels and their prices. Historically, our policy has been to hedge as much as possible against these risks through the indexation of the energy tariffs incorporated in our PPAs, and the fuel mix taken into consideration in the tariffs. However, given (i) the volume fluctuations that our PPAs may have; (ii) the variability that our plant dispatch profile may experience; (iii) our inability to perfectly match at all times our fuel cost mix with the tariff indexation in our PPAs; and (iv) the growing trend to dissociate PPA price indexation from fossil fuel price fluctuations, we maintain residual exposure to certain international commodity prices. For example, as a result of our decarbonization strategy, the tariff indexation of several of our PPAs has been switched from coal prices to US CPI beginning 2021 or 2022, as the case may be. This assumes power supply based on renewable sources or energy purchases at prices linked to inflation rather than fuel prices. As long as we have a mismatch in the indexation of our power sources and our PPA tariffs, we will have exposure to commodity price fluctuations. In the past, the company has periodically defined and executed financial hedging strategies to cover its residual exposure to international commodity price risks and is in the process of defining a hedging strategy for 2022-23. During 2021, and with greater intensity in the course of 2022, this risk has materialized. In our country, the hydrological year has been extremely dry, with the consequent decrease in hydraulic generation. This has coincided with difficulties in the supply of coal and natural gas due to the rise in demand together with restrictions on the world production of these fuels, as well as difficulties in freight, which resulted in price increases to very high levels even before the start of the war between Russia and Ukraine that raised prices to levels never seen before. Consequently, the average costs of own generation and the marginal costs of the system have reached levels much higher than those of previous years, which have been reflected in the reduction of the operating margins of the electricity business. The Company partially mitigates its exposure to the risk of fluctuations in fuel prices through (i) the signing of supply contracts with other generators in the system that have allowed it to reduce its energy purchases from the spot market (3.2 TWh contracted for 2023, versus 2.1 TWh for 2022 and 0.7 TWh in 2021) and its exposure to marginal cost; (ii) its long-term LNG supply contracts; (iii) the entry into operations of new renewable energy generation projects that reduce dependence on fossil fuels, (iv) the acquisition of uncontracted renewable generation assets, and (v) the transfer of higher costs to final tariffs. Possible breaches of contractual terms by our suppliers in the supply of liquefied natural gas or coal also exposes the Company to replace its power generation with alternative fuels or greater purchases of energy in the spot market, increasing its exposure to the variables that determine the marginal costs of the system.

Currency Hedging

Given that most of our revenues and costs are denominated in US dollars and that we seek to incur debt in US dollars, we face limited exposure to foreign exchange risk. In the specific case of regulated contracts, the price is calculated in US dollars and is then converted to Chilean pesos at the average monthly exchange rate observed in the invoiced month. In terms of the impact on the company's income statement, these contracts' exposure to foreign currency risk is limited as revenues are recognized at contract prices. However, delays in the publication of the Average Node Price decrees may impact the company's cash flow as monthly invoices are translated to Chilean pesos at exchange rates that remain fixed over the life of the tariff decree and differ from the monthly exchange rates considered in the contracts. Although these differences are adjusted after the Average Node Price decrees are published, the uncertainty as to the timing and amount of these adjustments does not allow for an effective hedge through derivative instruments. The delay in the collection of foreign-exchange adjustments has significantly increased after the approval of the Price Stabilization law in November 2019 and the MPC law published in August 2022. Per the Price Stabilization law and resolution #72, by which the National Energy Commission set the terms of its implementation, accounts receivable from distribution companies have accumulated at a rate that is highly sensitive, among other variables, to the CLP/USD exchange rate. To face this risk and mitigate its effect on the company's cash flow and liquidity, the company, and its subsidiary EMR, signed agreements with Goldman Sachs and IDB Invest to sell, without recourse, these accounts receivable from distribution companies to a special purpose company called Chile Electricity PEC SpA. On January 29, 2021, Chile Electricity PEC issued 144 A/Reg S bonds for US$489 million to buy the first two groups of accounts receivable from the four main generation groups in Chile, including ENGIE. On June 30, 2021, Chile Electricity PEC purchased the third group of accounts receivable from generation companies with funds provided by US$419 million 4a2 delayed draw notes with the participation of Allianz, IDB Invest and Goldman Sachs. Upon the publication of the respective node price decrees, similar transactions were perfected on March 4, 2022, for the fourth group of accounts receivable and July 14, 2022, for the fifth group. Since the sale of receivables is made in US dollars, without recourse to the generation companies, EECL and EMR have been able to reduce the foreign-exchange and credit exposure associated to these long-term accounts receivable and have improved their liquidity in exchange for a discount, which has impacted the income statement in 2021 and 2022. In 2021, the related financial expense reached US$49.6 million, while in 2022, it amounted to US$15.6 million.

Our main cost in Chilean pesos is personnel and certain operating and administrative costs, which account for approximately 10% of our operating costs. Given that most of our revenues are either in US dollars or in Chilean pesos adjusted for the exchange rate, our costs in Chilean pesos represent our main exposure to foreign-currency risks. Therefore, we have hedged a portion of our recurrent costs in Chilean pesos through forward contracts. As of December 31, 2022, the Company reported forward FX contracts for a total nominal amount of US$108 million, with monthly maturities of US$9 million between January and December 2023.

In the past we have signed foreign-currency derivative contracts to hedge the UF and EUR cash flows stemming from EPC contracts, to avoid cash flow or investment value variations resulting from foreign currency fluctuations that are beyond management's control. As of December 31, 2022, there were no outstanding derivative contracts associated with such EPC contract cash flows.

Our cash investment policy states that at least 80% of cash balances must be invested in US dollars unless a different percentage is required to maintain a natural currency hedge between assets and liabilities. This policy allows for the necessary flexibility to achieve a natural hedge for obligations in currencies other than the company's functional currency, the US dollar. As of December 31, 2022, 92.7% of our available cash and short-term investments were denominated in US dollars.

The Company presents an exposure to foreign exchange risk of a purely accounting nature related to contracts for onerous concessions or other types of contracts such as real estate or vehicle fleet leases that are considered as financial leases under the IFRS16 standard. These contracts comprise assets for rights of use that correspond to non-monetary assets, recorded at their initial cost, in dollars, the company's functional currency. Their counterparts correspond to monetary liabilities reflecting the present value of the installments to be paid under the financial contracts. Most of these liabilities are denominated in Chilean currency, adjusted for inflation (Unidades de Fomento (UF) or Unidades Tributarias (UTM)). As these are monetary liabilities, they are periodically readjusted and converted into dollars at the exchange rate observed at the end of each accounting period. In short, the liability denominated in CLP, UF or UTM is subject to periodic readjustments, being exposed to fluctuations in exchange rates, while the asset remains fixed in dollars. This mismatch may give rise to accounting profits or losses in our income statements. However, financially, the value of the asset for rights of use is closely related to the value of the liability since both should reflect the present value of the installments payable under the financial contracts. As of December 31, 2022, lease liabilities denominated in currencies other than the dollar amounted to US$141.6 million.

Interest Rate Hedging

The stability and predictability of our cash flows is also exposed to interest rate risk, principally with respect to the portion of our indebtedness that bears interest at floating rates. We seek to maintain a significant portion of our long-term debt at fixed rates to minimize interest-rate exposure. As of December 31, 2022, 83.8% of our financial debt was at fixed rates, while 16.2% (US$110 million under the IDB Invest financing, US$75 million under the Scotiabank loan, and US$23.1 million under the Santander loan) was at floating rates. We have excluded the IFRS 16 financial leases from this calculation. These obligations are mortgage-style liabilities payable in fixed equal installments.

As of December 31, 2022

Contractual maturity date (in US$ millions)

	Average interest rate	2023	2024	2025	2026	Thereafter	Grand Total
Variable Rate							
(US$)	7.2057% p.a.	-	-	2.8	5.0	102.3	110.0
(US$)	4.6389% p.a.	-	-	-	-	75.0	75.0
(US$)	7.3138% p.a.	-	-	-	-	23.1	23.1
(US$)	8.726% p.a.	4.3	75.1	-	-	-	79.4
Total Variable Rate		**4.3**	**75.1**	**2.8**	**5.0**	**200.4**	**287.5**
Fixed Rate							
(US$)	3.3882% p.a.	355.0	-	-	-	-	355.0
(US$)	7.3000% p.a.	-	35.0	-	-	-	35.0
(US$)	5.9680% p.a.	-	-	-	-	53.9	53.9
(US$)	1.0000% p.a.	-	-	-	-	15.0	15.0
(US$)	4.0910% p.a.	-	-	-	-	175.0	175.0
(US$)	3.4000% p.a.	-	-	-	-	500.0	500.0
(US$)	4.5000% p.a.	-	-	-	350.0	-	350.0
Total Fixed Rate		**355.0**	**35.0**	**-**	**350.0**	**743.9**	**1,483.9**
TOTAL		**359.3**	**110.1**	**2.8**	**355.0**	**944.3**	**1,771.4**

Credit Risk

In the normal course of business, and when investing our cash, we are exposed to credit risk. In our regular electricity generation business, we deal mostly with financially strong mining companies, which report low levels of credit risk. These companies are exposed to variations in commodity prices, particularly copper. Although our clients have demonstrated significant resilience to down-cycles, we closely monitor their exposure through our commercial counterparty risk policy.

We also sell electricity to regulated clients, which provide electricity supply to residential and commercial consumers and report low levels of credit risk. Lower growth in energy demand from end consumers could adversely affect our financial condition, operating results and cash flows. While the Electricity Price Stabilization Law enacted in November 2019 is not expected to significantly affect our revenues as recognized in the income statement, it has been affecting our cash flow with higher working capital requirements and higher financial costs. To address this risk and mitigate the effects on its cash flow, in early 2021, the company signed agreements with Goldman Sachs and IDB Invest to sell, without recourse to the company, these receivables to a special purpose company called Chile Electricity PEC SpA. On February 8, March 31 and June 30, 2021, the Company sold the accounts receivable corresponding to the Average Note Price decrees of January 2020, July 2020, and January 2021, respectively, for a total nominal value of US$167.3 million, receiving liquid resources of US$118.6 million and reporting a financial cost of US$49.6 million. On March 4 and July 14, 2022, the Company sold the accounts receivable corresponding to the Average Node Price decree of July 2021 and January 2022, respectively, for a total nominal value of US$54.8 million, receiving a US$39.3 million cash payment and reporting a US$15.5 million financial cost. There is remainder to be sold corresponding to the balances stipulated in the Average Node Price decree of July 2022, which is for review at the Comptroller's Office. Once published, the company is expected to be able to sell balances of approximately US$48 million. With the enactment of the MPC Law, and until the publication of the Average Node Price decree of July 2022 and the Exempt Resolution that will lay the foundations for the effective application of the Law, accounts receivable have continued to be generated for the differential between the stabilized price (PEC) and the contractual rates. Once the decree and the exempt resolution are published, the Treasury will issue Certificates of Payment that the Company will be able to sell under a mechanism similar to the one implemented for the PEC1 law, but this time without assuming costs for financial discounts. The deferral in collection resulting from the delay in the publication of decrees has significantly affected the liquidity and indebtedness of the company.

Over the last years, the electricity generation business and its customer base have evolved. Particularly, consumers with demand between 500 kW and 5 MW are allowed to contract their power supply directly with generation companies rather than through distribution companies. This disintermediation trend led us to sign contracts with smaller commercial and industrial clients with potentially higher credit risk. To mitigate this risk, we implemented a commercial counterparty risk policy, which among other considerations, requires the review of the credit risk of the client before entering into a power supply agreement. As of December 31, 2022, the contracts signed with smaller commercial and industrial clients represented a low percentage of our overall client portfolio, and the company has stopped marketing actively this segment.

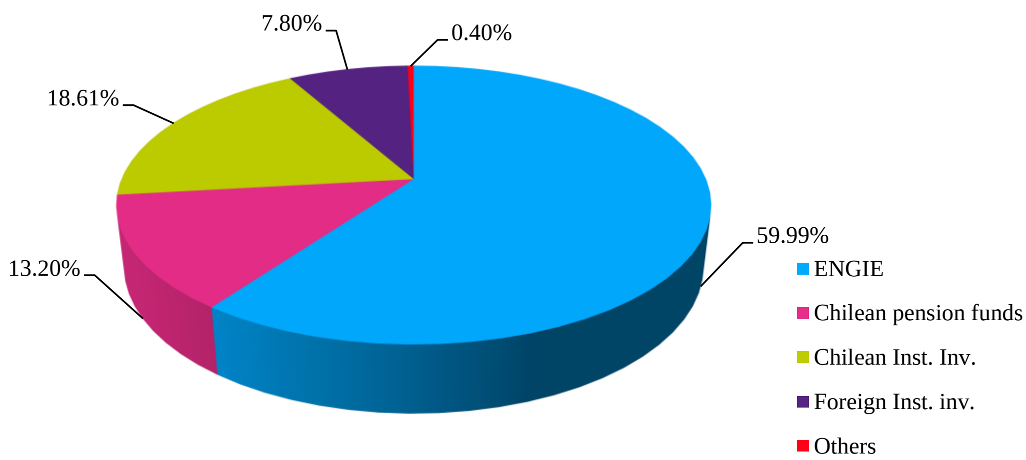
Due to its contractual position, the Company is normally one of the main net payers within the payment chain of the Chilean electricity sector. Although it is exposed to delinquency or non-payment defaults by operators in the electricity sector, these amounts represent a relatively lower percentage of monthly collection. Breaches by other electricity system operators could expose the Company to increasing sales volumes to regulated customers at the rates of the company's current contracts.

The outbreak of the COVID-19 pandemic has led to economic downturns, economic stimulus packages and inflation, with the consequential uncertainty about the behavior of power demand and the financial capacity of consumers of essential services to afford the timely payment of their bills. Although the demand for electricity by regulated customers has recovered, the extension of the basic services law has resulted in a slower collection of certain smaller regulated customers, with the consequential increase in the company's working capital financing needs. To face this situation the company has instructed its commercial areas to maintain close, direct contact with our customers to monitor the situation and take timely measures as necessary to both support our customers and mitigate the impact on the company's performance.

Our cash management policy is to invest in investment-grade institutions only, and only within the short term. We also measure our counterparty risk when dealing with derivatives and guarantees, and we have individual counterparty limits to manage our exposure and ensure proper diversification of our credit risk.

OWNERSHIP STRUCTURE AS OF DECEMBER 31, 2022

Number of shareholders: 1,769



TOTAL NUMBER OF SHARES: 1,053,309,776

APPENDIX 1

PHYSICAL DATA AND SUMMARIZED QUARTERLY FINANCIAL STATEMENTS

Physical Sales

Physical Sales (in GWh)

	2021					2022				
	1Q21	2Q21	3Q21	4Q21	12M21	1Q22	2Q22	3Q22	4Q22	12M22
Physical Sales										
Sales of energy to unregulated customers.	1,628	1,671	1,662	1,714	6,675	1,689	1,816	1,796	1,773	7,074
Sales of energy to regulated customers	1,197	1,262	1,303	1,184	4,946	1,126	1,204	1,255	1,149	4,735
Sales of energy to the spot market………	24	24	21	25	94	149	23	48	18	238
Total energy sales………………………….	**2,849**	**2,956**	**2,986**	**2,923**	**11,715**	**2,964**	**3,043**	**3,100**	**2,940**	**12,047**
Gross electricity generation										
Coal…………………………………………..	1,280	1,633	1,713	1,084	5,709	955	1,085	775	687	3,503
Gas…………………………………………..	622	639	678	335	2,274	345	423	382	289	1,439
Diesel Oil and Fuel Oil…………………….	13	8	2	0	23	1	17	1	1	19
Renewable………………………………………	62	74	52	201	389	220	226	303	390	1,139
Total gross generation………………….	**1,977**	**2,353**	**2,444.3**	**1,621**	**8,394**	**1,520**	**1,751**	**1,461**	**1,368**	**6,100**
Minus Own consumption………………..	(146)	(179)	(195)	(128)	(648)	(128)	(136)	(152)	(92)	(507)
Total net generation…………………….	**1,831**	**2,174**	**2,249**	**1,493**	**7,746**	**1,393**	**1,615**	**1,310**	**1,275**	**5,593**
Energy purchases on the spot market………..	932	717	434	1,228	3,311	999	1,114	1,308	1,081	4,501
Energy purchases- bridge	122	124	127	265	639	561	430	497	646	2,134
Total energy available for sale before transmission losses………………………	**2,885**	**3,015**	**2,810**	**2,986**	**11,696**	**2,952**	**3,159**	**3,115**	**3,002**	**12,228**

Quarterly Income Statement

Quarterly Income Statement (in US$ millions)

IFRS										
Operating Revenues	**1Q21**	**2Q21**	**3Q21**	**4Q21**	**12M21**	**1Q22**	**2Q22**	**3Q22**	**4Q22**	**12M22**
Regulated customers sales………………………	123.1	177.0	160.3	154.0	614.3	169.7	178.5	205.3	219.3	772.8
Unregulated customers sales…………………..	158.4	156.7	161.3	197.2	673.6	177.8	230.7	229.5	239.6	877.7
Spot market sales………………………………..	5.3	6.9	3.6	4.9	20.6	18.3	32.0	26.9	27.0	104.2
Total revenues from energy and capacity sales…………………	**286.8**	**340.5**	**325.2**	**356.0**	**1,308.5**	**365.8**	**441.3**	**461.8**	**485.8**	**1,754.7**
Gas sales…………………………..	7.7	8.7	12.1	9.4	37.8	20.1	9.5	11.8	7.6	48.9
Other operating revenue……………………….	37.8	39.3	28.5	26.7	132.3	32.0	30.7	26.2	27.9	116.7
Total operating revenues………………….	**332.3**	**388.5**	**365.8**	**392.1**	**1,478.6**	**417.9**	**481.4**	**499.7**	**521.3**	**1,920.3**
Operating Costs										
Fuel and lubricants………………………………	(83.6)	(107.6)	(160.4)	(117.6)	(469.2)	(128.4)	(203.2)	(161.7)	(154.9)	(648.2)
Energy and capacity purchases on the spot	(104.7)	(90.0)	(85.0)	(125.2)	(404.9)	(163.0)	(212.0)	(213.1)	(210.2)	(798.3)
Depreciation and amortization attributable to cost of goods sold..	(44.4)	(43.4)	(43.6)	(50.5)	(181.9)	(44.4)	(44.0)	(46.9)	(49.9)	(185.3)
Other costs of goods sold…………………….	(71.4)	(61.2)	(60.1)	(62.9)	(255.6)	(50.5)	(65.9)	(67.6)	(85.1)	(269.1)
Total cost of goods sold………………..	**(304.1)**	**(302.1)**	**(349.1)**	**(356.2)**	**(1,311.6)**	**(386.4)**	**(525.2)**	**(489.3)**	**(500.2)**	**(1,901.0)**
Selling, general and administrative expenses…	(9.1)	(9.6)	(6.2)	(9.1)	(34.1)	(8.7)	(9.6)	(9.2)	(6.3)	(33.8)
Depreciation and amortization in selling, general and administrative expenses…	(0.8)	(1.0)	(1.0)	(1.0)	(3.9)	(0.9)	(0.9)	(1.1)	(1.1)	(4.1)
Other revenues………...……………………….	2.6	1.6	1.5	(6.0)	(0.4)	1.3	1.3	9.2	6.5	18.3
Total operating costs…..………………..	**(311.5)**	**(311.2)**	**(354.8)**	**(372.4)**	**(1,349.9)**	**(394.7)**	**(534.4)**	**(490.4)**	**(501.1)**	**(1,920.6)**
							0		0.0	0.0
Operating income…..………………..	**20.7**	**77.3**	**11.0**	**19.7**	**128.7**	**23.1**	**(53.0)**	**9.2**	**20.3**	**(0.3)**
EBITDA……………….….……………….	**65.9**	**121.7**	**55.6**	**71.3**	**314.5**	**68.5**	**(8.0)**	**57.3**	**71.3**	**189.0**
Financial income………..………………………	0.6	0.3	0.4	0.3	1.6	1.1	0.7	13.5	1.5	16.8
Financial expense……………..…………………	(52.2)	(16.8)	(8.9)	(10.9)	(88.8)	(15.7)	(13.0)	(27.4)	(19.3)	(75.5)
Foreign exchange translation, net……………	1.7	1.9	8.0	11.1	22.6	(5.6)	4.0	(3.9)	(9.2)	(14.7)
method	-	-	-	-	-	-	-	-	-	-
Other non-operating income/(expense) net………………………	3.6	(0.5)	(0.2)	(6.3)	(3.3)	0.5	0.1	(0.6)	(447.6)	(447.7)
Total non-operating results……………	**(46.3)**	**(15.1)**	**(0.7)**	**(5.8)**	**(67.9)**	**(19.7)**	**(8.3)**	**(18.4)**	**(474.7)**	**(521.1)**
Income before tax…………………...………	(25.5)	62.2	10.3	13.9	60.8	3.4	(61.3)	(9.1)	(454.4)	(521.4)
Income tax………………………………………	8.0	(14.6)	(1.6)	(5.2)	(13.4)	0.4	17.1	(8.6)	123.8	132.7
Net income from continuing operations after taxes …….	(17.6)	47.6	8.7	8.7	47.4	3.8	(44.2)	(17.8)	(330.6)	(388.8)
Net income attributed to controlling shareholders……………….	**(17.6)**	**47.6**	**8.7**	**8.7**	**47.4**	**3.8**	**(44.2)**	**(17.8)**	**(330.6)**	**(388.8)**
Net income to EECL's shareholders…….	**(17.6)**	**47.6**	**8.7**	**8.7**	**47.4**	**3.8**	**(44.2)**	**(17.8)**	**(330.6)**	**(388.8)**
Earnings per share…………………….. (US$/share)	**(0.017)**	**0.045**	**0.008**	**0.008**	**0.045**	**0.004**	**(0.042)**	**(0.017)**	**(0.314)**	**(0.369)**

Balance Sheet

Quarterly Balance Sheet (in U.S.$ millions)

	2021 December	2022 December
Current Assets		
Cash and cash equivalents	215.7	132.4
Accounts receivable	171.4	226.1
Recoverable taxes	23.9	35.2
Current inventories	158.3	264.1
Other non financial assets	46.9	178.1
Total current assets	**616.2**	**835.8**
Non-Current Assets		
Property, plant and equipment, net	2,746.1	2,576.6
Other non-current assets	636.5	915.8
TOTAL ASSETS	**3,998.9**	**4,328.3**
Current Liabilities		
Financial debt	106.2	389.5
Other current liabilities	291.3	270.7
Total current liabilities	**397.5**	**660.2**
Long-Term Liabilities		
Financial debt	1,152.4	1,579.5
Other long-term liabilities	277.0	274.6
Total long-term liabilities	**1,429.4**	**1,854.1**
Shareholders' equity	2,172.0	1,813.9
Equity	**2,172.0**	**1,813.9**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,998.9**	**4,328.3**

Main Balance Sheet Variations

The main balance-sheet variations between December 31, 2021, and December 31, 2022, are the following:

Cash and cash equivalent: The company's cash balances decreased by US$83.3 million to US$132.4 million as of December 31, mainly because of (i) net operating cash outflows (US$358 million), (ii) interest payments (US$49 million), (iii) income tax payments (US$39 million, including CO_2 taxes), and (iv) capital expenditures and acquisitions (US$309 million). In addition, the company reimbursed a US$30 million duplicated payment received from a client on the last business day of 2021. These expenditures were partly offset by the proceeds from the sale of accounts receivable from distribution companies related to the price stabilization mechanism (US$39.3 million) and proceeds of new short-term bank loans (US$340 million), the Scotiabank loan (US$250 million) and the Santander 5-year loan (US$77 million) to finance the acquisition of the wind farms in Chiloé.

Accounts receivable: The US$54.7 million increase comprises changes in two different accounts: On the one hand, accounts receivable from third parties reported a US$57.6 million increase mainly due to higher tariffs and because certain relevant invoices were collected ahead of their maturity in December 2021. On the other hand, intercompany receivables, mainly from Engie Gas, decreased by US$0.9 million and personnel accounts fell by US$2 million.

Current inventories: The US$105.8 million increase in this item is mainly explained by a US$91.7 million increase in coal inventory, including a shipment in transit, and an US$11.2 million increase in LNG inventory. The increase in the coal inventory stock is due to both price increases and the decision to keep a higher reserve inventory given the current market situation. The increase in LNG inventory is also explained by higher prices and because of the timing of shipments relative to the cut-off dates of the financial statements used in the comparison. Limestone and diesel oil inventory also increased by US$3.4 million and US$2.3 million, respectively, while spare parts inventory decreased by US$4.6 million.

Recoverable taxes: This item reported an US$11.3 million increase due to a US$29 million increase in recoverable taxes from previous periods, offset by lower monthly provisional tax payments (-US$17.5 million). Both effects are explained by the drop in taxable income and the use of instant depreciation in recent projects.

Other current assets: The US$131.2 million increase in this item is explained by an US$85.3 million increase in the VAT fiscal credit balance due to the increase in fuel purchases and capital expenditures in new projects, as well as by a US$21.9 million increase in advances to suppliers, and the positive mark-to-market of financial derivatives which resulted in current financial assets of US$17.9 million at year-end 2022.

Property, plant and equipment, net: The US$169.5 million decrease in PP&E is explained by capital expenditures related to investments in renewable energy and transmission projects and the acquisition of wind farms, which were offset by US$381 million of asset impairments and depreciation of US$187.4 million.

Other non-current assets: The net US$279.3 million increase in this item resulted primarily from an US$239.1 million increase in long-term accounts receivable associated to the enactment of the price stabilization law. Other items that reported an increase included (i) deferred taxes (US$74.8 million), (ii) the equity value in TEN due to net income and mark-to-market on derivatives (US$15.4 million), and (iii) financial asset valuations (US$5.1 million). These were partially offset by the decrease in capitalized project development costs (US$8.7 million), amortization of intangibles (US$16.3 million), and a goodwill impairment (US$25.1 million). The recognition of assets by right of use, mainly onerous concessions on land for renewable projects (IFRS16), exhibited a US$6.7 million decrease.

Financial debt – current: This item reported a US$283.3 million increase. Short-term bank debt increased by US$305 million due to new loans from Banco de Crédito del Perú, Banco Santander, Scotiabank, Itaú, BCI and Banco de Chile. In addition, short-term debt includes US$4.3 million corresponding to current maturities of the project financing of the San Pedro 2 wind farm. The debt increase was partially offset by the reimbursement of the duplicated payment of a US$29.8 million invoice on the last business day of last year, which had to be reported as financial debt at year-end 2021, and a decrease of US$5.5 million in the mark-to-market of derivatives.

Other current liabilities: The US$20.6 million net decrease in this item is explained by a US$36.2 million decrease in accounts payable to suppliers, which was partially offset by an increase in provisions related to employee benefits (US$3.4 million) and current taxes (US$8.9 million).

Long-term financial debt: The US$427.1 million increase in long-term financial debt is primarily explained by a US$250 million 5-year green bullet loan with Scotiabank; a new 5-year loan from Banco Santander, of which US$77 million had been disbursed as of December 31, 2022; a US$35 million from BCI maturing in May 2024; and the taking over of the San Pedro II project financing with US$75.1 million maturing in 2024. Financial lease liabilities, however, fell due to payment of installments and foreign-exchange adjustments. These leases are primarily related to onerous concessions on land for the development of renewable energy generation projects.

Other long-term liabilities: Other long-term liabilities, which amounted to US$274.6 million, reported a US$2.4 million decrease due to a US$91.3 million increase in the plant dismantling provision, which was offset by a US$93.8 million decrease in deferred tax liabilities.

Shareholders' equity: The US$358.1 million decrease in shareholders' equity is mainly explained by the period's net loss (US$388.8 million), which was partially offset by a US$30.7 million increase in reserves owing to the merger of companies. The period's net loss was mainly explained by lower operating results and the asset impairment related to the company's decarbonization plan, which considers the gradual decommissioning and transformation of coal-based assets. This impairment and the write-off of intangible assets had a net after tax effect of -US$325 million over EECL's 2022 net results.

APPENDIX 2

Financial information

	4Q20	1Q21	2Q21	3Q21	4Q21	1Q22	2Q22	3Q22	4Q22
EBITDA*	117.5	65.9	121.7	55.6	71.3	68.5	-8.0	57.3	71.3
Net income attributed to the controller	40.3	-17.6	47.6	8.7	8.7	3.8	-44.2	-17.8	-330.6
Interest expense	9.9	52.2	16.8	8.9	10.9	15.7	13.0	27.4	19.3

* Operating income + Depreciation and Amortization for the period

	Dec/20	Dec/21	Dec/22
LTM EBITDA	455.3	314.5	189.0
LTM Net income attributed to the controller	163.5	47.4	(388.8)
LTM Interest expense	59.5	88.8	75.5
Financial debt	1,032.9	1,258.6	1,969.0
Current	68.6	106.2	389.5
Long-Term	964.3	1,152.4	1,579.5
Cash and cash equivalents	235.3	215.7	132.4
Net financial debt	797.6	1,042.9	1,836.6

Financial Ratios

	FINANCIAL RATIOS		Dec/21	Dec/22	Var.
LIQUIDITY	Current ratio (current assets / current liabilities)	(times)	1.55	1.27	***-18%***
	Quick ratio ((current assets - inventory) / current liabilities)	(times)	1.15	0.87	***-25%***
	Working capital (current assets – current liabilities)	MMUS$	218.7	175.6	***-20%***
LEVERAGE	Leverage ((current liabilities + long-term liabilities) / networth)	(times)	0.84	1.39	***65%***
	Interest coverage * ((EBITDA / interest expense))	(times)	3.54	2.50	***-29%***
	Financial debt –to- LTM EBITDA*	(times)	4.00	10.42	***160%***
	Net financial debt – to - LTM EBITDA*	(times)	3.32	9.72	***193%***
PROFITABILITY	Return on equity* (LTM net income attributed to the controller / net worth attributed to the controller)	%	2.2%	-21.4%	***-1074%***
	Return on assets* (LTM net income attributed to the controller / total assets)	%	1.2%	-9.0%	***-849%***

*LTM = Last twelve months

As of December 31, 2022, the current ratio and the quick ratio were 1.27x and 0.87x, respectively, reflecting the decrease in current assets and the increase in current liabilities; specifically, the decrease in cash balances and the increase in financial debt as well as in trade payables. As a result, working capital, as measured by total current assets minus total current liabilities, decreased.

The leverage ratio, as measured by total liabilities-to-equity, reached 1.39 times, above the level reported at year-end 2021, as the company incurred debt to finance operations and capital expenditures during 2022.

The interest coverage ratio in 2022 was 2.5x, which represents a decrease compared to 3.54x reported at year-end 2021, mainly due to the combination of a reduction in EBITDA and a decrease in interest expense related to the discount applied to the sale of long-term accounts receivable originated by the price stabilization law, which had its heaviest impact in 2021.

The leverage ratio, as measured by Gross financial debt-to-EBITDA, increased to 10.42 times due to the increase in debt combined with the drop in EBITDA explained earlier in this report. Net financial debt-to-EBITDA increased to 9.72x as a result of the decrease in cash balances, the debt increase, and the EBITDA reduction.

Return on equity and return on assets reached -21.4% and -9.0%, respectively, a deterioration compared to the ratios reported at year-end 2021 due to the period's net losses, which were largely explained by non-cash asset impairments.

CONFERENCE CALL 2022

ENGIE Energía Chile is pleased to inform you that it will conduct a conference call to review its results as of and for the year-ending December 31, 2022, on Wednesday March 8, 2023
at 10:00 a.m. (EST) – 12:00 (Chile)

hosted by:
Eduardo Milligan, CFO ENGIE Energía Chile S.A.

To participate, please dial:
+1(412) 317-6378, international or
+**56 44 208 1274** Chile or
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