October 26, 2022

ENGIE ENERGÍA CHILE REPORTED EBITDA OF US$118 MILLION AND A NET LOSS OF US$58 MILLION IN THE FIRST NINE MONTHS OF 2022.

EBITDA REACHED US$57 MILLION IN THE THIRD QUARTER OF 2022. FOLLOWING A WEAK JULY, A TURNAROUND WAS OBSERVED IN AUGUST AND SEPTEMBER DUE TO HIGHER SALES PRICES, IMPROVED HYDROLOGIC CONDITIONS AND AN INCREASE IN ARGENTINE GAS SUPPLY, WHICH CAUSED A REDUCTION IN ENERGY PURCHASE COSTS. GENERATION COSTS REMAINED IMPACTED BY HIGH FUEL PRICES WORLDWIDE.

- **Operating revenues** amounted to US$1,398.9 million in the first nine months of 2022, a 29% increase compared to the first nine months of 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$117.8 million in the first nine months of the year, a 52% decrease compared to the first nine months of 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$58.2 million loss, which negatively compares to the US$38.7 million net profit reported in the first nine months of 2021, mainly due to the weaker operating performance explained by record high fuel prices and the resulting high spot prices in the electricity market. 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 dated November 2019.

Financial Highlights (in US$ millions)

	3Q21	3Q22	Var %	9M21	9M22	Var%
Total operating revenues	**365.8**	**499.7**	*37%*	**1,086.5**	**1,398.9**	*29%*
Operating income	11.0	9.2	*-16%*	109.1	(20.6)	*-119%*
EBITDA	**55.6**	**57.3**	*3%*	**243.3**	**117.8**	*-52%*
EBITDA margin	15.2%	11.5%	*(14,8pp)*	22.4%	8.4%	*(12,4pp)*
Total non-operating results	(0.7)	(18.4)	*n.a*	(62.1)	(46.4)	*-25%*
Net income after tax	8.7	(17.8)	*-105%*	38.7	(58.2)	*-250%*
Net income attributed to controlling shareholders	**8.7**	**(17.8)**	*-105%*	**38.7**	**(58.2)**	*-250%*
Earnings per share (US$/share)	0.008	(0.017)		0.037	(0.055)	
Total energy sales (GWh)	2,986	3,100	*4%*	8,792	9,107	*4%*
Total net generation (GWh)	2,249	1,310	*-42%*	6,254	4,318	*-31%*
Energy purchases on the spot market (GWh)	434	1,308	*201%*	2,083	3,421	*64%*
Energy purchases - back up (GWh)	127	497	*291%*	373	1,488	*299%*

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 September 30, 2022, ECL accounted for 8% 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

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 National Economic Prosecutor's Office ("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 ~USD 34/MWh, above last year's nominal USD 24/MWh. The average reserve price was USD 42/MWh and most of the offers (8.9 TWh) were above that price. The average price offered was ~USD 50/MWh and a large proportion of the offers were in the range of USD 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.

- **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 until the full commissioning of the Interchile project, used to be predominantly in the south-north direction comprising inflows of renewable power generated in the area known as Norte Chico into the SING grid.

Following the commissioning of the last tranche of Interchile's Cardones-Polpaico transmission project on May 30, 2019, marginal costs in the different nodes of the SEN have reported greater stability and lower average levels due to 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					Real (Monthly Average per Node)					
Mes	Crucero 220	Polpaico 220	Charrúa 220	Pto. Montt 220	Temuco 220	Month	Crucero 220	Polpaico 220	Charrúa 220	Pto. Montt 220	Temuco 220
Jan	51	59	57	87	58	Jan	-	-	-	-	-
Feb	76	84	83	151	85	Feb	68	68	69	290	72
Mar	76	84	87	166	90	Mar	95	102	114	210	117
Apr	71	78	83	130	85	Abr	108	118	126	230	127
May	77	82	82	109	84	May	96	102	100	187	101
Jun	67	68	66	63	66	Jun	190	200	196	224	192
Jul	105	122	129	126	129	Jul	116	154	148	241	144
Aug	99	114	128	130	128	Aug	101	112	100	199	90
Sep	47	56	57	68	58	Sep	84	87	82	198	70
Oct	49	50	49	145	50	Oct	-	-	-	-	-
Nov	68	70	70	207	72	Nov	-	-	-	-	-
Dec	85	89	87	212	89	Dec	-	-	-	-	-
YTD	**73**	**80**	**81**	**133**	**83**	**YTD**	**107**	**118**	**117**	**222**	**114**

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.

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$72/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. Argentine gas imports are expected to increase in the fourth quarter due to the start of supply contracts on a firm basis. 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$132/MWh reported in the preceding quarter.

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			83.7			5.51			206.3		
November	77.5			79.8			4.77			159.4		
December	71.4			74.8			3.71			121.1		

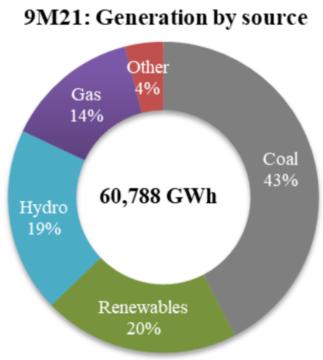
Source: Bloomberg, IEA

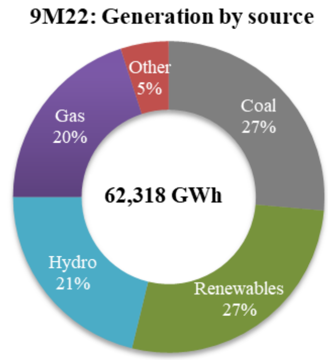
When comparing 2022 with 2021, we can observe higher international fuel prices, with variations of more than 120% on average. Prices began to increase in 2021 due to an important "post-pandemic" reactivation, especially in China. In the last quarter of 2021, the Chinese government took steps to unblock 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 will take effect in mid-August. A few days later, Japan also banned imports of Russian coal.

Generation

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





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In the first nine months of 2022, demand reached a maximum of 11,905.5 MWh/h in February, a 5.3% increase compared to peak demand reported in the first nine months of 2021. Sales reached 57,519.9 GWh in the first nine months, with a 0.7% increase in free customer sales and a 6.2% increase in the regulated client segment.

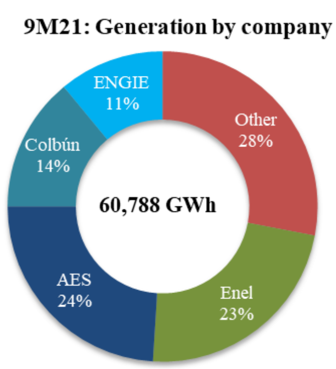
Regarding renewable energy, solar generation increased by 40.8%, while wind generation rose by 35.7% as compared to the first nine months of 2021. During the first quarter of 2022 new renewable projects with gross capacity of 578.1 MW began operations in the system, while in the second and third quarters an additional 251.9 MW and 672.5 MW, respectively, became operational.

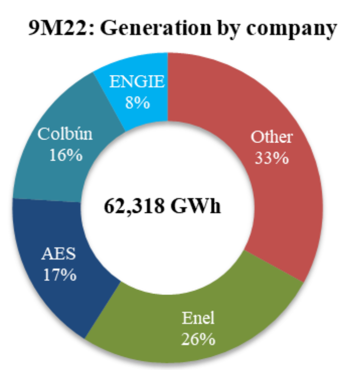
During the first quarter of 2022, hydroelectric generation dropped by 8%, compared to the same period of 2021 and by 16% when compared to 2020. At the end of the first quarter, the levels at the Laja and Maule reservoirs were in values slightly below those of 2021, not so the case of Chapo, Rapel and Ralco, as the rationing decree allowed for an increase in their levels compared to last year. 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 as compared to the previous two years. As of September 30, 2022, the hydraulic reserve amounted to 144 GWh.

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





Source: (

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following discussion is based on our unaudited consolidated financial statements for the 9-month periods ended September 30, 2022, and September 30, 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).

3Q 2022 compared to 3Q 2021 and 2Q 2022

Operating Revenues

Quarterly Information (In US$ millions)

	3Q 2021		2Q 2022		3Q 2022		% Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Unregulated customers sales…………………..	161.3	50%	230.7	52%	229.5	50%	-1%	42%
Regulated customers sales…………………….	160.3	49%	178.5	40%	205.3	44%	15%	28%
Spot market sales………………………………..	3.6	1%	32.0	7%	26.9	6%	-16%	651%
Total revenues from energy and capacity sales	**325.2**	89%	**441.3**	92%	**461.8**	92%	**5%**	**42%**
Gas sales…………………………..	12.1	3%	9.5	2%	11.8	2%	24%	-2%
Other operating revenue……………………….	28.5	8%	30.7	6%	26.2	5%	-15%	-8%
Total operating revenues…………………	**365.8**	100%	**481.4**	100%	**499.7**	100%	**4%**	**37%**
Physical Data (in GWh)								
Sales of energy to unregulated customers (1)……	1,662	56%	1,816	60%	1,796.0	58%	-1%	8%
Sales of energy regulated customers……	1,303	44%	1,204	40%	1,255.5	41%	4%	-4%
Sales of energy to the spot market……………	21	1%	23	1%	48.2	2%	n.a	-
Total energy sales…………………………	**2,986**	100%	**3,043**	100%	**3,100**	100%	**2%**	**4%**
Average monomic price unregulated customers(U.S.$/MWh)(2)	**95.9**		**127.0**		**127.8**		**1%**	**33%**
Average monomic price regulated customers (U.S.$/MWh)(3)	**123.0**		**148.2**		**163.6**		**10%**	**33%**

Energy and capacity sales reached US$461.8 million in the third quarter of 2022, representing a US$136.6 million, or 42%, increase compared to the third 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 42% increase in sales to unregulated clients was due to price increases and demand recovery from our main mining customers such as Codelco, Centinela and El Abra. The 28% 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, there is an increase in sales volume to free customers and a slight decrease to regulated customers.

In the third quarter of 2022, physical sales to the spot market were 48 GWh, an increase with respect to the second quarter of 2022 and the third quarter of the previous year, due to the fact that 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, 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 third quarter gas sales decreased, as compared to the same quarter of last year, while they increased slightly compared to the second 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. During 2021, this item included income recognition corresponding to ENGIE's acquisition of a 40% interest in Inversiones Hornitos SpA through monthly installments according to the terms of the power supply agreement renegotiated with AMSA, which considers a tariff discount.

Operating costs

Quarterly Information (In US$ millions)

	3Q21		2Q22		3Q22		% Variation	
Operating Costs	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Fuel and lubricants………………………………	(160.4)	45%	(203.2)	38%	(161.7)	33%	-20%	1%
Energy and capacity purchases on the spot market……………………………	(85.0)	24%	(212.0)	40%	(213.1)	43%	1%	151%
Depreciation and amortization attributable to cost of goods sold…………………………….	(43.6)	12%	(44.0)	8%	(46.9)	10%	7%	8%
Other costs of goods sold…………………….	(60.1)	17%	(65.9)	12%	(67.6)	14%	3%	13%
Total cost of goods sold……………….	**(349.1)**	98%	**(525.2)**	98%	**(489.3)**	100%	***-7%***	***40%***
Selling, general and administrative expenses…	(6.2)	2%	(9.6)	2%	(9.2)	2%	-4%	48%
Depreciation and amortization in selling, general and administrative expenses…………	(1.0)	0%	(0.9)	0%	(1.1)	0%	17%	16%
Other operating revenue/costs……………………….	1.5	0%	1.3	0%	9.2	-2%		
Total operating costs…………………..	**(354.8)**	100%	**(534.4)**	100%	**(490.4)**	100%	***-8%***	***38%***
Physical Data (in GWh)								
Gross electricity generation								
Coal…………………………………………	1,713	70%	1,085	62%	775	53%	-29%	-55%
Gas…………………………………………..	678	28%	423	24%	382	26%	-10%	-44%
Diesel Oil and Fuel Oil…………………….	2	0%	17	1%	1	0%	-95%	-53%
Hydro/Solar/Wind………………………………	52	2%	226	13%	303	21%	34%	481%
Total gross generation…………………	**2,444**	100%	**1,751**	100%	**1,461**	100%	***-17%***	***-40%***
Minus Own consumption……………..	(195)	-8%	(136)	-8%	(152)	-10%	11%	-22%
Total net generation……………………	**2,249**	***80%***	**1,615**	***51%***	**1,310**	***42%***	***-19%***	***-42%***
Energy purchases on the spot market………..	434	***15%***	1,114	***35%***	1,308	***42%***	17%	201%
Energy purchases- bridge………..	127	***5%***	430	***14%***	497	***16%***	n.a	n.a
Total energy available for sale before transmission losses………………………	**2,810**	***100%***	**3,159**	***100%***	**3,115**	***100%***	***-1%***	***11%***

Gross electricity generation decreased by 40%, compared to the same quarter of 2021, and by 17% compared to the second quarter. Renewable generation increased significantly compared to the third 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, and the Coya PV project in August.

The year 2022 started with lower hydraulic reserves in the system. Lower generation, both hydraulic and thermal, was offset by higher generation of renewable assets. Despite this, marginal costs have increased as a result of the rise in fuel prices, explained by the current geopolitical situation, and the increase in demand. In the months of April, May and June, increased diesel-based dispatch was observed at peak times due to increases in demand, unit failures and lower LNG availability for EECL (Freeport event). Hydraulic generation remained low through mid-May when rainfall began in the center-south region. It is worth mentioning that on June 30, Unit 14 was disconnected from the system. However, in August and September, there was an increase in water and Argentine gas supply, decreasing diesel-based generation, as well as generation from coal units with lower dispatch priority, such as U15, CTM1 and CTM2, while the CTA and CTH coal units were under maintenance. Lastly, on September 30, Unit 15, the last coal-fired plant in Tocopilla, was disconnected from the grid.

The fuel cost item showed a decrease compared to the second quarter of 2022 as the company reported lower generation. Despite the 40% drop in gross generation when compared to the third quarter of 2021, fuel costs remained flat 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$128 million (150%) compared to the same quarter of 2021. This was mainly due to higher marginal costs or average spot prices, as well as to a 200% increase in the volume of energy purchases in the spot market and purchases of energy under backup contracts with other generators, which quadrupled, reaching 497 GWh in the third quarter. The higher energy purchase volumes is explained by the lower generation of our efficient units due to maintenance and by the increased water and Argentine gas availability, which displaced some of our coal-fired units in terms of dispatch priority. As compared to the second quarter of 2022, the cost of purchasing energy and capacity increased by just 1% because the increase in purchase volumes was offset by lower spot energy prices in the third quarter.

In the third 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 second quarter of 2022 and the third 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$0.86 million in the third quarter, is also included in this item.

Electricity margin

Quarterly Information (In US$ millions)

	2021					2022		
	1Q21	**2Q21**	**3Q21**	**4Q21**	**2021**	**1Q22**	**2Q22**	**3Q22**
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**
Fuel and lubricants…………………..	(83.6)	(107.6)	(160.4)	(117.6)	(469.2)	(128.4)	(203.2)	(161.7)
Energy and capacity purchases on the spot market……	(104.7)	(90.0)	(85.0)	(125.2)	(404.9)	(163.0)	(212.0)	(213.1)
Gross Electricity Profit	**98.5**	**142.9**	**79.8**	**113.2**	**434.4**	**74.4**	**26.1**	**87.0**
Electricity Margin	*34%*	*42%*	*25%*	*32%*	*33%*	*20%*	*6%*	*19%*

In the third quarter, the electricity margin, or the gross profit from the electricity generation business, increased by US$7.2 million, when compared to the third quarter of 2021, although it represented only 19% of energy and capacity revenues because of the revenue increase. The US$136.6 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$60.9 million in the electricity margin, which rose from of 6% to 19% of energy and capacity revenues. On the one hand, energy and capacity revenues increased by US$20.5 million due to price increases triggered by higher inflation and fuel prices, and on the other, there was a US$41.5 million decrease in fuel costs due to the decrease in generation explained by plant maintenance and lower dispatch priority of more expensive plants combined with flat energy purchase costs due to the decline in spot energy prices. In short, there was a decrease in the average supply cost of energy from US$131/MWh in the second quarter of 2022 to US$120/MWh in the third quarter, which added to the increase in revenues, led to the electricity margin recovery.

Resultado operacional

Quarterly Information (in US$ millions)

EBITDA	**3Q21**		**2Q22**		**3Q22**		**% Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Total operating revenues………………………	365.8	*100%*	481.4	*100%*	499.7	*100%*	*4%*	*37%*
Total cost of goods sold……………………	(349.1)	*-95%*	(525.2)	*-109%*	(489.3)	*-98%*	*-7%*	*40%*
Gross income…………………………	**16.7**	*5%*	**(43.8)**	*-9%*	**10.4**	*2%*	***-124%***	***-38%***
Total selling, general and administrative expenses and other operating income/(costs).	(5.7)	*-2%*	(9.2)	*-2%*	(1.2)	*0%*	*-87%*	*-80%*
Operating income…………………..	**11.0**	*3%*	**(53.0)**	*-11%*	**9.2**	*2%*	***-117%***	***-16%***
Depreciation and amortization……..…………	44.6	*12%*	45.0	*9%*	48.0	*10%*	*7%*	*8%*
EBITDA………………..………………..	**55.6**	*15.2%*	**(8.0)**	*-1.7%*	**57.3**	*11.5%*	***-814%***	***3%***

EBITDA for the third quarter of 2022 reached US$57.3 million, a turnaround compared to the weaker results reported in previous quarters. This was due to the increase in the electricity margin, particularly in August and September, explained by the increase in operating revenues and the decrease in average supply costs.

Financial results

Quarterly Information (In US$ millions)

	3Q22		**2Q22**		**3Q22**		**% Variation**	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Financial income………..………………………	0.4	*0%*	0.7	*0%*	13.5	*3%*	*1932%*	*2984%*
Financial expense…………….…………………	(8.9)	*-3%*	(13.0)	*-3%*	(27.4)	*-7%*	*110%*	*207%*
Foreign exchange translation, net…………..	8.0	*2%*	4.0	*1%*	(3.9)	*-1%*		*-148%*
Other non-operating income/(expense) net…	(0.2)	*0%*	0.1	*0%*	(0.6)	*0%*		*168%*
Total non-operating results…………….	**(0.7)**	*0%*	**(8.3)**	*-2%*	**(18.4)**	*-4%*		
Income before tax……………………. ………	10.3	*3%*	(61.3)	*-15%*	(9.1)	*-2%*	***-85%***	***-189%***
Income tax……………………………………	(1.6)	*0%*	17.1	*4%*	(8.6)	*-2%*	*-150%*	*436%*
Net income from continuing operations after taxes …	8.7	*3%*	(44.2)	*-11%*	(17.8)	*-4%*	*-60%*	*-305%*
Net income to EECL's shareholders	**8.7**	*3%*	**(44.2)**	*-11%*	**(17.8)**	*-4%*	***-60%***	***-305%***
Earnings per share……………………..	**0.008**		**(0.042)**		**(0.017)**			

The increase in interest expense, as compared to the second quarter and the third quarter of 2021, is explained by the effects of 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 third quarter of 2022, the interest expense account included an US$11.6 million expense from the sale of PEC receivables, while in the third quarter of 2021, only US$0.5 million was recorded and no such expenses were reported in the second quarter of 2022.

The exchange rate difference reached a US$3.9 million loss in the third quarter as a result of greater exchange rate volatility with the Chilean peso tending to depreciate. 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 third quarter of 2022, the company reported net losses of US$17.8 million, a decline compared to the same quarter in 2021, but a recovery compared to the second quarter of 2022, reflecting a turnaround in operating results since August 2022.

9M 2022 compared to 9M 2021

Operating Revenues

For the 9-month period ended september 30(in US$ millions)

	9M21		9M22		Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	%
Unregulated customers sales…………………..	476.4	*50%*	638.1	*50%*	*161.6*	*34%*
Regulated customers sales…………………….	460.4	*48%*	553.5	*44%*	*93.1*	*20%*
Spot market sales……………………………..	15.7	*2%*	77.2	*6%*	*61.5*	*391%*
Total revenues from energy and capacity sales……	**952.5**	*88%*	**1,268.8**	*91%*	***316.3***	*33%*
Gas sales…………………………..	28.4	*3%*	41.3	*3%*	*12.9*	*45%*
Other operating revenue……………………….	105.6	*10%*	88.8	*6%*	*-16.8*	*-16%*
Total operating revenues………………….	**1,086.5**	*100%*	**1,398.9**	*100%*	***312.4***	*29%*
Physical Data (in GWh)						
Sales of energy to unregulated customers (1)……	4,961	*56%*	5,301.4	*58%*	*341*	*7%*
Sales of energy regulated customers……	3,762	*43%*	3,585.6	*39%*	*-176*	*-5%*
Sales of energy to the spot market…………….	69	*1%*	220.0	*2%*	*151*	*217%*
Total energy sales………………………….	**8,792**	*100%*	**9,107**	*100%*	***315***	*4%*
Average monomic price unregulated customers(U.S.$/MWh)(2)	**97.8**		**129.6**		***31.7***	*32%*
Average monomic price regulated customers (U.S.$/MWh)(3)	**122.4**		**154.4**		***32.0***	*26%*

Energy and capacity sales reached US$1,398.9 million in the first nine months of 2022, representing a US$312.4 million, or 29%, increase compared to the first nine months of 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 the first nine months of 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 the first nine months of 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 16% decrease in other operating revenues.

Operating costs

For the 9-month period ended september 30 (in US$ millions)

	9M21		9M22		Variation	
Operating Costs	Amount	% of total	Amount	% of total	Amount	%
Fuel and lubricants………………………………	(351.6)	*36%*	(493.2)	*35%*	*141.7*	*40%*
Energy and capacity purchases on the spot market…	(279.7)	*29%*	(588.1)	*41%*	*308.4*	*110%*
Depreciation and amortization attributable to cost of goods sold…	(131.4)	*13%*	(135.4)	*10%*	*4.0*	*3%*
Other costs of goods sold……………………	(192.7)	*20%*	(184.1)	*13%*	*-8.6*	*-4%*
Total cost of goods sold………………..	**(955.4)**	*98%*	**(1,400.8)**	*99%*	***445.4***	***47%***
Selling, general and administrative expenses…	(25.0)	*3%*	(27.5)	*2%*	*2.5*	*10%*
Depreciation and amortization in selling, general and administrative expenses…	(2.8)	*0%*	(3.0)	*0%*	*0.2*	*6%*
Other operating revenue/costs………………………	5.7	*-1%*	11.7	*-1%*	*-6.1*	*108%*
Total operating costs…..………………	**(977.5)**	*100%*	**(1,419.6)**	*100%*	***442.1***	***45%***
Physical Data (in GWh)						
Gross electricity generation						
Coal…………………………………………	4,625	*68%*	2,815	*59%*	*-1,810*	*-39%*
Gas…………………………………………..	1,938	*29%*	1,151	*24%*	*-788*	*-41%*
Diesel Oil and Fuel Oil…………………….	23	*0%*	18	*0%*	*-5*	*-21%*
Hydro/Solar………………………………………	187	*3%*	749	*16%*	*561*	*299%*
Total gross generation…………………	**6,774**	*100%*	**4,733**	*100%*	***-2,041***	***-30%***
Minus Own consumption………………..	(520)	*-8%*	(415)	*-9%*	*106*	*-20%*
Total net generation……………………	**6,254**	*72%*	**4,318**	*47%*	***-1,936***	***-31%***
Energy purchases on the spot market………..	2,083	***24%***	3,421	***37%***	*1,338*	*64%*
Energy purchases- bridge………..	373	***4%***	1,488	***16%***	*1,114*	*299%*
Total energy available for sale before transmission losses………………………	**8,710**	***100%***	**9,226**	***100%***	***516***	***6%***

Gross electricity generation decreased 30%, compared to the first nine months of 2021, principally due to decreases in coal-based generation, mainly explained by the IEM overhaul, followed by major maintenance of the CTA and CTH 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 41% 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 the first nine months of 2022, the fuel cost item rose by 40% or US$141.7 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$308.4 million (110%) compared to the first nine months of 2021. This was mainly due to (i) higher marginal costs, or average spot prices, (ii) a 64% increase in the volumes of energy purchased in the spot market; and (iii) greater purchases of energy under backup contracts with other generators, which increased by four times, reaching 1,488 GWh in the first nine months of 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 the first nine months of 2022, depreciation costs in the costs-of-goods-sold item remained at similar levels as those reported in the same period of 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 the first nine months of 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 the first half 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$4.2 million in the first nine months of the year, is also included in this item.

Operating results

For the 9-month period ended september 30 (in US$ millions)

EBITDA	**9M21**		**9M22**		**Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Total operating revenues………………………	1,086.5	*100%*	1,398.9	*100%*	*312.4*	*29%*
Total cost of goods sold……………………	(955.4)	*88%*	(1,400.8)	*100%*	*445.4*	*47%*
Gross income…………………………	**131.2**	*12%*	**(1.9)**	*0%*	***-133.1***	***-101%***
Total selling, general and administrative expenses and other operating income/(costs).	(22.1)	*2%*	(18.8)	*1%*	*-3.4*	*-15%*
Operating income…………………	**109.1**	*10%*	**(20.6)**	*-1%*	***-129.7***	***-119%***
Depreciation and amortization……...…………	134.2	*12%*	138.4	*10%*	*4.2*	*3%*
EBITDA…………………………………	**243.3**	*22.4%*	**117.8**	*8.4%*	***-125.5***	***-52%***

EBITDA for the first nine months of 2022 reached US$117.8 million, a 52% decrease, or -US$125.5 million, compared to the first nine months of 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 6-month period ended june 30(in US$ millions)

	9M21		9M22		Variation	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Financial income……….………………………	1.3	*0%*	15.2	*2%*	*14.0*	*1107%*
Financial expense……………..…………………	(77.9)	*-7%*	(56.2)	*-6%*	*21.7*	*-28%*
Foreign exchange translation, net…………..	11.5	*1%*	(5.5)	*-1%*	*-17.0*	*-147%*
Other non-operating income/(expense) net…	3.0	*0%*	(0.0)	*0%*	*-3.0*	*-101%*
Total non-operating results…………….	**(62.1)**	*-6%*	**(46.4)**	*-5%*		
Income before tax……………………. ………	46.9	*4%*	(67.0)	*-7%*	***-114.0***	***-243%***
Income tax………………………………………	(8.3)	*-1%*	8.9	*1%*	*17.1*	
Net income from continuing operations after taxes	38.7	*3%*	(58.2)	*-6%*	*-96.8*	*-250%*
Net income to EECL's shareholders	**38.7**	*3%*	**(58.2)**	*-6%*	***-96.8***	***-250%***
Earnings per share…………………….	**0.037**		**(0.055)**	*0%*		

Despite the increase in financial debt, interest expense decreased, as compared to the first nine months of 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 being reported as financial expenses. In the first nine months of 2021, the interest expense account included US$49.6 million from the sale of PEC receivables, while in the first nine months of 2022, this expense reached US$15.6 million.

The exchange rate difference reached a US$5.5 million loss, compared to an US$11.5 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 the first nine months of 2022, the company reported a net after-tax loss of US$58.2 million, which negatively compares with a US$38.7 million profit in the first nine months of 2021. As explained earlier, this decrease was primarily explained by a weaker operating result, although it should be noted that the company returned to positive operating and net results starting August 2022.

Liquidity and Capital Resources

As of September 30, 2022, EECL reported consolidated cash balances of US$69.0 million, while its nominal financial debt[1] amounted to US$1,505 million, including US$280 million of short-term debt maturing in 2023, with no other scheduled debt principal payments until January 2025.

(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.

For the 9-month period ended septeber 30 (in US$ millions)

Cash Flow	**2021**	**2022**
Net cash flows provided by operating activities…	(8.4)	(470.5)
Net cash flows used in investing activities………	(138.0)	(151.9)
Net cash flows provided by financing activities..	28.1	476.8
Change in cash………………...…………	**(118.4)**	**(145.6)**

Cash Flow from Operating Activities

In the first nine months of 2022, EECL reported net operating cash uses worth US$470.5 million. Cash flows from regular operations represented a net cash outflow of US$405.3 million, due to higher outflows from fuel and electricity purchases explained by extremely high fuel prices observed during the period. In addition, 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 payments for US$43.4 million and (iii) income taxes for US$37.2 million, US$27.6 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 the first nine months of 2021, net cash outflows from operations reached US$8.4 million.

Cash Flow Used in Investing Activities

In the first nine months of 2022, cash flows related to investment activities resulted in a net cash outflow of US$151.9 million, mainly due to capital expenditures. This figure is higher than the cash outflows for investment activities reported in 2021, which amounted to US$138 million. Capital expenditures included our investment in the solar PV projects, Tamaya, Capricornio and Coya, and in transmission substations, as well as in plant maintenance.

Capital Expenditures

Our capital expenditures in the first nine months of 2021 and 2022 amounted to US$145.7 million and US$148.6 million, respectively, as shown in the following table. These amounts include VAT payments and capitalized interest. The latter amounted to US$6.0 million in the first nine months of 2022, whereas capitalized interest in the first nine months of 2021 was US$7.7 million.

For the 9-month period september 30 (in US$ millions)

CAPEX	**2021**	**2022**
Substation…………………	7.2	11.7
Overhaul power plants & equipment maintenance and refurbishing…………………	10.2	6.6
Overhaul equipment & transmission lines	3.9	3.1
PV Power Plant……………	57.8	93.0
Wind farm……………..	59.8	17.7
Others……………………………………………	6.9	16.5
Total capital expenditures……………………….	**145.7**	**148.6**

Cash Flow from Financing Activities

In the first nine months of 2022, the main flows related to financing activities were the new US$250 million 5-year loan with Scotiabank and short-term loans, which increased by US$230 million. These were taken with Banco de Crédito del Perú (US$70 million), Banco Santander (US$30 million), Scotiabank (US$50 million plus the renewal of a US$50 million loan due in April), BCI (US$50 million), and Itaú (US$30 million). 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 September 30, 2022.

Contractual Obligations as of 09/30/22

Payments Due by Period (in US$ millions)

	Total	< 1 year	1 - 3 years	3 - 5 years	More than 5 years
Bank debt……………………………………….……	**655.0**	280.0	1.1	259.9	114.0
Bonds (144 A/Reg S Notes)……………………..	**850.0**	-	350.0	-	500.0
Financial lease - Tolling Agreement TEN………	**53.8**	1.6	3.8	4.6	43.8
Financial lease - IFRS 16………………………….	**126.1**	5.0	11.3	7.6	102.3
Deferred financing cost…………………………..	**(17.4)**	-	(6.6)	(3.3)	(7.6)
Accrued interest…………………………………..	**11.1**	11.1	-	-	-
Mark-to-market swaps……………………………	**3.2**	3.2	-	-	-
Total	**1,681.7**	**300.9**	**359.6**	**268.8**	**752.5**

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.

As of September 30, 2022, the company's short-term debt amounted to US$280 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, and a US$50 million loan with Scotiabank maturing on May 19, 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.

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.

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.

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.

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$53.8 million and is payable in monthly instalments totaling approximately US$7 million per year until 2037.

As of September 30, 2022, the company reported leasing obligations related to land use concessions, vehicles and other assets for a total amount of US$126.1 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 (2.1 TWh contracted for 2022 versus 0.7 TWh in 2021) and, therefore, 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.

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 the first nine months of 2022. In 2021, the related financial expense reached US$49.6 million, while in the first nine months of 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 September 30, 2022, the Company reported forward FX contracts for a total nominal amount of US$88.5 million, with monthly maturities between October 2022 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 September 30, 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 September 30, 2022, 55% 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 September 30, 2022, lease liabilities denominated in currencies other than the dollar amounted to US$126.1 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 September 30, 2022, 87.7% of our financial debt was at fixed rates, while 12.3% (US$110 million under the IDB Invest financing and US$75 million under the Scotiabank 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 September 30, 2022

Contractual maturity date (in US$ millions)

	Average interest rate	2022	2023	2024	2025	Thereafter	Grand Total
Variable Rate							
(US$)	4.5101% p.a.	-	-	-	2.8	107.3	110.0
(US$)	3.7571% p.a.	-	-	-	-	75.0	75.0
Total Variable Rate		**-**	**-**	**-**	**2.8**	**182.3**	**185.0**
Fixed Rate							
(US$)	2.5189% p.a.	-	280.0	-	-	-	280.0
(US$)	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		**-**	**280.0**	**-**	**350.0**	**690.0**	**1,320.0**
TOTAL		**-**	**280.0**	**-**	**352.8**	**872.3**	**1,505.0**

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 clients 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.

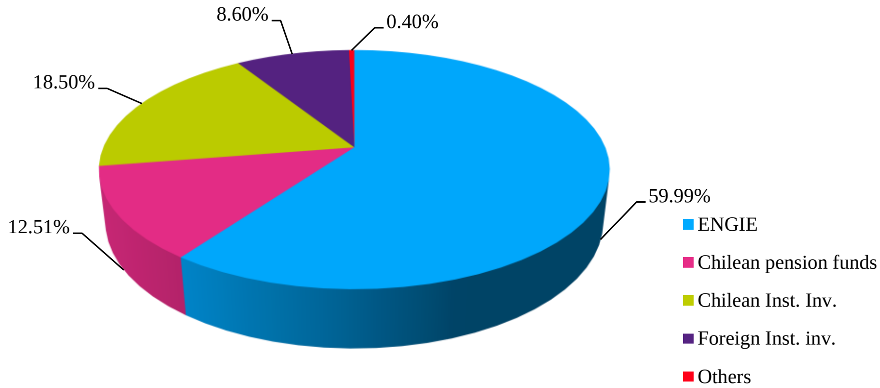
Over the last years, the electricity generation business and its customer base have evolved. Particularly, consumers with demand between 500 kW and 5 MW are allowed to contract their power supply directly with generation companies rather than through distribution companies. This disintermediation trend 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 September 30, 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.

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 consequent 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 SEPTEMBER 30, 2022

Number of shareholders: 1,780



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**	**9M21**	**12M21**	**1Q22**	**2Q22**	**3Q22**	**9M22**
Physical Sales									
Sales of energy to unregulated customers.	1,628	1,671	1,662	4,961	6,675	1,689	1,816	1,796	5,301
Sales of energy to regulated customers	1,197	1,262	1,303	3,762	4,946	1,126	1,204	1,255	3,586
Sales of energy to the spot market………	24	24	21	69	94	149	23	48	220
Total energy sales…………………………	**2,849**	**2,956**	**2,986**	**8,792**	**11,715**	**2,964**	**3,043**	**3,100**	**9,107**
Gross electricity generation									
Coal………………………………………….	1,280	1,633	1,713	4,625	5,709	955	1,085	775	2,815
Gas…………………………………………..	622	639	678	1,938	2,274	345	423	382	1,151
Diesel Oil and Fuel Oil…………………….	13	8	2	23	23	1	17	1	18
Renewable……………………………………….	62	74	52	187	389	220	226	303	749
Total gross generation…………………	**1,977**	**2,353**	**2,444.3**	**6,774**	**8,394**	**1,520**	**1,751**	**1,461**	**4,733**
Minus Own consumption……………….	(146)	(179)	(195)	(520)	(648)	(128)	(136)	(152)	(415)
Total net generation……………………	**1,831**	**2,174**	**2,249**	**6,254**	**7,746**	**1,393**	**1,615**	**1,310**	**4,318**
Energy purchases on the spot market……….	932	717	434	2,083	3,311	999	1,114	1,308	3,421
Energy purchases- bridge	122	124	127	373	639	561	430	497	1,488
Total energy available for sale before transmission losses………………………	**2,885**	**3,015**	**2,810**	**8,710**	**11,696**	**2,952**	**3,159**	**1,805**	**7,916**

Quarterly Income Statement

Quarterly Income Statement (in US$ millions)

IFRS

Operating Revenues	**1Q21**	**2Q21**	**3Q21**	**9M21**	**1Q22**	**2Q22**	**3Q22**	**9M22**
Regulated customers sales………………………	123.1	177.0	160.3	460.4	169.7	178.5	205.3	553.5
Unregulated customers sales…………………..	158.4	156.7	161.3	476.4	177.8	230.7	229.5	638.1
Spot market sales………………………………..	5.3	6.9	3.6	15.7	18.3	32.0	26.9	77.2
Total revenues from energy and capacity sales…………………	**286.8**	**340.5**	**325.2**	**952.5**	**365.8**	**441.3**	**461.8**	**1,268.8**
Gas sales…………………………..	7.7	8.7	12.1	28.4	20.1	9.5	11.8	41.3
Other operating revenue……………………….	37.8	39.3	28.5	105.6	32.0	30.7	26.2	88.8
Total operating revenues………………….	**332.3**	**388.5**	**365.8**	**1,086.5**	**417.9**	**481.4**	**499.7**	**1,398.9**
Operating Costs								
Fuel and lubricants………………………………	(83.6)	(107.6)	(160.4)	(351.6)	(128.4)	(203.2)	(161.7)	(493.2)
Energy and capacity purchases on the spot	(104.7)	(90.0)	(85.0)	(279.7)	(163.0)	(212.0)	(213.1)	(588.1)
Depreciation and amortization attributable to cost of goods sold..	(44.4)	(43.4)	(43.6)	(131.4)	(44.4)	(44.0)	(46.9)	(135.4)
Other costs of goods sold…………………….	(71.4)	(61.2)	(60.1)	(192.7)	(50.5)	(65.9)	(67.6)	(184.1)
Total cost of goods sold……………….	**(304.1)**	**(302.1)**	**(349.1)**	**(955.4)**	**(386.4)**	**(525.2)**	**(489.3)**	**(1,400.8)**
Selling, general and administrative expenses…	(9.1)	(9.6)	(6.2)	(25.0)	(8.7)	(9.6)	(9.2)	(27.5)
Depreciation and amortization in selling, general and administrative expenses…	(0.8)	(1.0)	(1.0)	(2.8)	(0.9)	(0.9)	(1.1)	(3.0)
Other revenues………...……………………….	2.6	1.6	1.5	5.7	1.3	1.3	9.2	11.7
Total operating costs…………………..	**(311.5)**	**(311.2)**	**(354.8)**	**(977.5)**	**(394.7)**	**(534.4)**	**(490.4)**	**(1,419.6)**
						0		
Operating income…………………..	**20.7**	**77.3**	**11.0**	**109.1**	**23.1**	**(53.0)**	**9.2**	**(20.6)**
EBITDA……………….………………..	**65.9**	**121.7**	**55.6**	**243.3**	**68.5**	**(8.0)**	**57.3**	**117.8**
Financial income………..………………………	0.6	0.3	0.4	1.3	1.1	0.7	13.5	15.2
Financial expense…………..…………………	(52.2)	(16.8)	(8.9)	(77.9)	(15.7)	(13.0)	(27.4)	(56.2)
Foreign exchange translation, net……………	1.7	1.9	8.0	11.5	(5.6)	4.0	(3.9)	(5.5)
method	-	-	-	-	-	-	-	-
Other non-operating income/(expense) net………………………	3.6	(0.5)	(0.2)	3.0	0.5	0.1	(0.6)	(0.0)
Total non-operating results……………	**(46.3)**	**(15.1)**	**(0.7)**	**(62.1)**	**(19.7)**	**(8.3)**	**(18.4)**	**(46.4)**
Income before tax…………………..………	(25.5)	62.2	10.3	46.9	3.4	(61.3)	(9.1)	(67.0)
Income tax………………………………………	8.0	(14.6)	(1.6)	(8.3)	0.4	17.1	(8.6)	8.9
Net income from continuing operations after taxes …….	(17.6)	47.6	8.7	38.7	3.8	(44.2)	(17.8)	(58.2)
Net income attributed to controlling shareholders………………	**(17.6)**	**47.6**	**8.7**	**38.7**	**3.8**	**(44.2)**	**(17.8)**	**(58.2)**
Net income attributed to minority shareholders………………	-	-	-	-	-	-	-	-
Net income to EECL's shareholders…….	**(17.6)**	**47.6**	**8.7**	**38.7**	**3.8**	**(44.2)**	**(17.8)**	**(58.2)**
Earnings per share…………………….. (US$/share)	**(0.017)**	**0.045**	**0.008**	**0.037**	**0.004**	**(0.042)**	**(0.017)**	**(0.055)**

Balance Sheet

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

	2021 December	2022 September
Current Assets		
Cash and cash equivalents	215.7	71.1
Accounts receivable	171.4	215.0
Recoverable taxes	23.9	35.7
Current inventories	158.3	310.8
Other non financial assets	46.9	129.5
Total current assets	**616.2**	**762.1**
Non-Current Assets		
Property, plant and equipment, net	2,746.1	2,739.9
Other non-current assets	636.5	793.4
TOTAL ASSETS	**3,998.9**	**4,295.4**
Current Liabilities		
Financial debt	106.2	299.6
Other current liabilities	291.3	222.6
Total current liabilities	**397.5**	**522.2**
Long-Term Liabilities		
Financial debt	1,152.4	1,380.4
Other long-term liabilities	277.0	253.2
Total long-term liabilities	**1,429.4**	**1,633.7**
Shareholders' equity	2,172.0	2,139.5
Equity	**2,172.0**	**2,139.5**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,998.9**	**4,295.4**

Main Balance Sheet Variations

The main balance-sheet variations between December 31, 2021, and September 30, 2022, are the following:

Cash and cash equivalent: The company's cash balances decreased by US$147 million to US$69 million as of September 30, mainly because of (i) net operating cash outflows (US$405 million), (ii) interest payments (US$43 million), (iii) income tax payments (US$37.2 million, including CO2 taxes), and (iv) capital expenditures (US$143 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 of 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$230 million) and the Scotiabank loan (US$250 million).

Accounts receivable: The US$43.5 million increase comprises changes in two different accounts: On the one hand, accounts receivable from third parties reported a US$44.5 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$1.0 million.

Current inventories: The US$152.5 million increase in this item is mainly explained by a US$115.5 million increase in coal inventory and a US$33.5 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.

Recoverable taxes: This item reported an US$11.8 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 non-financial assets – current: The US$82.6 million increase in this item is explained by a US$64.9 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$7.3 million increase in advances to suppliers, and a US$10.5 million increase in prepaid insurance payments.

Property, plant and equipment, net: The US$6.2 million decrease in PP&E is explained by capital expenditures related to investments in renewable energy and transmission projects (US$117.8 million), which were offset by depreciation of US$124 million.

Other non-current assets: The net US$156.9 million increase in this item resulted primarily from an US$134.8 million increase in long-term accounts receivable associated to the enactment of the price stabilization law, a US$12 million increase in capitalized development costs in projects with reasonable execution viability, and a US$23.2 million increase in the equity value of TEN explained by the net profit of the period and the variation in the reserve of coverage derivatives. Conversely, the recognition of assets by right of use, mainly onerous concessions on land for renewable projects (IFRS16), exhibited a US$5.0 million decrease.

Financial debt – current: This item reported a US$193.4 million increase. Short-term bank debt increased by US$230 million due to new loans from Banco de Crédito del Perú, Banco Santander, Scotiabank, Itaú and BCI. 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 by an US$8.2 million decrease in accrued interest on the 144-A bonds given the interest payment schedule in January and July of each year relative to the cut-off date of the financial statements being compared in this analysis.

Other current liabilities: The US$68.7 million net decrease in this item is explained by a US$67.5 million decrease in accounts payable to suppliers, a decrease in provisions related to employee benefits following the payment of annual performance bonuses (-US$2.9 million) and a decrease in VAT fiscal debit (-US$3.5 million). The income tax provision reported a US$3.6 million increase.

Long-term financial debt: The US$228 million increase in long-term financial debt is primarily explained by the new US$250 million 5-year green bullet loan with Scotiabank, partially offset by a US$20 million decrease in financial lease liabilities mainly due to 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$253.2 million, reported a US$23.8 million decrease due to a US$20 million decrease in deferred tax liabilities and a US$3.8 million reduction in the plant dismantling provision attributed to the dismantling works carried out at the coal-based units 12 and 13 in Tocopilla, which were decommissioned in 2019.

Shareholders' equity: The US$32.5 million decrease in shareholders' equity is mainly explained by the period's net loss (US$58.2 million), which was partially offset by the net increase in the mark-to-market valuation of financial derivatives (US$25.6 million net of taxes).

APPENDIX 2

Financial information

	1Q20	2Q20	3Q20	4Q20	1Q21	2Q21	3Q21	4Q21	1Q22	2Q22	3Q22
EBITDA*	99.1	103.0	135.8	117.5	65.9	121.7	55.6	71.3	68.5	-8.0	57.3
Net income attributed to the controller	25.6	40.6	57.0	40.3	-17.6	47.6	8.7	8.7	3.8	-44.2	-17.8
Interest expense	28.5	10.6	10.5	9.9	52.2	16.8	8.9	10.9	15.7	13.0	27.4

* Operating income + Depreciation and Amortization for the period

	Dec/20	Dec/21	Sep/22
LTM EBITDA	455.3	314.5	189.0
LTM Net income attributed to the controller	163.5	47.4	(49.5)
LTM Interest expense	59.5	88.8	67.1
Financial debt	1,032.9	1,258.6	1,680.1
Current	68.6	106.2	299.6
Long-Term	964.3	1,152.4	1,380.4
Cash and cash equivalents	235.3	215.7	71.1
Net financial debt	797.6	1,042.9	1,609.0

Financial Ratios

	FINANCIAL RATIOS				
			Dec/21	**Sep/22**	**Var.**
LIQUIDITY	Current ratio (current assets / current liabilities)	(times)	1.55	1.46	***-6%***
	Quick ratio ((current assets - inventory) / current liabilities)	(times)	1.15	0.86	***-25%***
	Working capital (current assets – current liabilities)	MMUS$	218.7	239.9	***10%***
LEVERAGE	Leverage ((current liabilities + long-term liabilities) / networth)	(times)	0.84	1.01	***20%***
	Interest coverage * ((EBITDA / interest expense))	(times)	3.54	2.82	***-20%***
	Financial debt –to- LTM EBITDA*	(times)	4.00	8.89	***122%***
	Net financial debt – to - LTM EBITDA*	(times)	3.32	8.51	***156%***
PROFITABILITY	Return on equity* (LTM net income attributed to the controller / net worth attributed to the controller)	%	2.2%	-2.3%	***-205%***
	Return on assets* (LTM net income attributed to the controller / total assets)	%	1.2%	-1.2%	***-196%***

*LTM = Last twelve months

As of September 30, 2022, the current ratio and the quick ratio were 1.46x and 0.86x, 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 1.01 times, above the level reported at year-end 2021, as the company incurred debt to finance operations and capital expenditures during the first nine months of the year.

The interest coverage ratio for the 12 months ended on September 30, 2022, was 2.8x, 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 from regulated customers related to the price stabilization law, which had its heaviest impact in the first nine months of last year.

The leverage ratio, as measured by Gross financial debt-to-EBITDA, increased to 8.89 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 8.51x as a result of the decrease in cash balances, the debt increase and the EBITDA reduction.

Return on equity and return on assets reached -2.3% and -1.2%, respectively, a deterioration compared to the ratios reported at year-end 2021 due to the period's net loss.

CONFERENCE CALL 9M22

ENGIE Energía Chile is pleased to inform you that it will conduct a conference call to review its results as of and for the nine-month period ended September 30, 2022, on Thursday November 3, 2022 at 11:00 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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To join the conference, please state the name of the conference (**ENGIE ENERGIA**; no other Conference ID will be requested.
Please connect approximately 10 minutes prior to the scheduled starting time.

To access the phone replay, which will be available until November 10, 2022, please dial
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