October 30, 2019

ENGIE ENERGÍA CHILE REPORTED EBITDA OF US$429 MILLION AND NET INCOME OF US$143 MILLION IN THE FIRST NINE MONTHS OF 2019.

EBITDA AMOUNTED TO US$144 MILLION IN THE THIRD QUARTER, A 57% INCREASE COMPARED TO THE THIRD QUARTER OF 2018. THE EBITDA IMPROVEMENT IS LARGELY EXPLAINED BY THE INCREMENTAL VOLUMES CONTRACTED WITH DISTRIBUTION COMPANIES IN THE CENTER-SOUTH SEGMENT OF THE NATIONAL GRID ("SEN").

- **Operating revenues** amounted to US$1,120 million in the first nine months of 2019, an 18% increase compared to the first nine months of 2018, mainly due to the step-up in contracted volumes under the power supply contract with distribution companies in the center-south segment of the SEN. In the second quarter, the company received a compensation for costs attributed to the delay in the IEM project completion.
- **EBITDA** amounted to US$429.2 million in the first nine months of 2019; that is, a 54% increase compared to the same period of 2018, mainly due to the increase in regulated sales to distribution companies and other operating revenue.
- **Net income** amounted to US$143 million in the first nine months of 2019, virtually doubling the net income figure reported in the first nine months of 2018. As a result of the announcements related to the decommissioning of coal-fired plants located in Tocopilla, net income was affected by non-recurring impairments in both periods. Excluding non-recurring effects, net income in the first nine months of 2019 would have reached US$206.8 million, a 66% increase compared to the net recurring income reported in the first nine months of 2018.

Financial Highlights (in US$ millions)

	3Q18	3Q19	Var %	9M18	9M19	Var%
Total operating revenues	**347,3**	**353,2**	***2%***	**950,7**	**1.119,5**	***18%***
Operating income	57,1	103,2	*81%*	177,0	313,6	*77%*
EBITDA	**91,8**	**144,4**	***57%***	**278,5**	**429,2**	***54%***
EBITDA margin	26,4%	40,9%	*13.4 pp*	29,3%	38,3%	*+6.3 pp*
Total non-operating results	(1,6)	(12,0)	*659%*	(71,3)	(109,6)	*54%*
Net income after tax	40,3	68,0	*n.a*	79,1	150,3	*90%*
Net income attributed to controlling shareholders	**37,3**	**62,4**	***n.a***	**72,5**	**143,0**	***97%***
Net income attributed to minority shareholders	3,0	1,2	*-59%*	6,5	7,3	*11%*
Earnings per share (US$/share)	0,035	0,059		0,069	0,136	
Total energy sales (GWh)	2.471	2.873	*16%*	7.308	8.255	*13%*
Total net generation (GWh)	1.345	1.549	*15%*	4.059	3.843	*-5%*
Energy purchases on the spot market (GWh)	917	1.128	*23%*	2.788	4.164	*49%*
Energy purchases - back up (GWh)	208	127	*-39%*	627	373	*-40%*

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, 2019, ECL accounted for 9% of the SEN's installed capacity. ECL primarily supplies electricity to large mining and industrial customers, and it also supplies the entire electricity needs of CGE (ex-EMEL), the sole electricity distribution group in the northern segment of the SEN. On January 1, 2018, ECL began supplying electricity to distribution companies in the center-south segment of the SEN. ECL is currently 52.76% indirectly owned by ENGIE (formerly known as GDF SUEZ). The remaining 47.24% of ECL's shares are publicly traded on the Santiago stock exchange. For more information, please refer to www.engie-energia.cl.

Contents

HIGHLIGHTS:

3Q19

- **Launching of renewables investment program**: On October 11, 2019, ENGIE Energía Chile officially launched its program to invest approximately 1,000 MW in renewable generation projects. The first stage of the program considers three projects to be built in the Antofagasta region: the Calama windfarm and the Capricornio solar PV plant, which are already under construction, and the Tamaya solar PV plant with construction scheduled to begin in the first quarter of 2020. These first three projects will have a total installed capacity of 370 MW and will generate direct employment for up to 1,000 workers during construction.

2Q19

- **Rating confirmation with outlook upgrade**: On June 24, 2019, Fitch Ratings confirmed EECL's BBB issuer default ratings ("IDRs") and revised the outlook to Positive from Stable. At the same time, Fitch confirmed the company's 'AA-(cl)' national-scale rating and changed the outlook to Positive. Fitch ratified EECL's 'First-Class Level 2(cl) local stock rating.

- **Decarbonization announcement**: On June 4, 2019, through a Material Event Notice filed with the Financial Market Commission ("CMF"), ENGIE Energía Chile ("EECL") communicated that it signed an agreement with the Ministry of Energy to decommission coal-fired thermo-electric generation plants (*"Acuerdo de Retiro de Centrales Termoeléctricas a Carbón"*), in the context of (a) the government-sponsored energy matrix decarbonization process and (b) the Company's own energy transition process towards renewable energy generation means. Pursuant to the agreement, EECL confirmed its commitment to the fight against climate change and global warming and declared that it will make its best efforts to diminish the impacts produced by its operation emissions, always considering the security and economic efficiency of the national electricity system, the local economic activity and the eventual social and environmental aspects surrounding the gradual decommissioning of coal-fired plants.

  Pursuant to the agreement, EECL committed to communicate to the National Energy Commission, the disconnection and decommissioning, on January 1, 2022, of the coal-fired units N°14 (136 MW) and N°15 (132 MW) located in the Tocopilla plant. This deadline could be extended to no later than May 31, 2024, in case EECL has not previously completed the development of new renewable generation sources. In accordance to the agreement and subject to their disconnection and decommissioning, such units could pass to a Strategic Reserve Regime ("ERE"), which scope should be defined by January 2021, as informed by the authority.

  On the same date, EECL informed the National Energy Commission of its intention to disconnect and decommission units N°14 and N°15 on the above-mentioned dates, as a result of which the company booked an asset impairment resulting in a US$64 million after-tax loss in its financial statements.

  It should be noted that the decommissioning of units N°14 and N°15 will follow the decommissioning of units N°12 and N°13 of the Tocopilla plant, which actually took place on June 7, 2019, as previously authorized by the National Energy Commission.

- **Provisional dividend**: On May 29, 2019, the Board of Directors approved the distribution of a provisional dividend considering the company's cash generation and the end of a relevant investing period. This US$50 million (US$0.047469416 per share) dividend, on the account of 2019's net income, was paid on June 21, 2019, in pesos at the dollar-equivalent rate published in the Official Gazette on June 19.

- **Interchile's Cardones-Polpaico Transmission Project**: The Interchile transmission project, which reinforces the interconnection of the country's main power grids, began commercial operation on May 30, 2019, contributing to the stabilization and reduction in marginal costs at the different nodes of the National Interconnected System ("SEN").

- **Infraestructura Energética Mejillones Project ("IEM")**: This 375MW coal-fired project began commercial operations on Thursday, May 16, 2019 at 00:41 hours, and has since been generating at base-load as it is one of the most cost-efficient power plants in the system. The main EPC contractor was S.K. Engineering and Construction (Korea) ("SKEC"). Pursuant to the construction contract, the project's handover was subject to the payment of liquidated damages mainly related to the delay in the commercial operation date.

- **Annual Ordinary Shareholders' Meeting**: On April 30, 2019, the Company's shareholders agreed the following:

  a) **Definitive Dividends:** To pay a final dividend of US$22,137,935.42 (or US$0.021017493 per share) on account of 2018's net income, payable on May 24, 2019, to be converted to Chilean pesos at the observed exchange rate published by the Central Bank of Chile on the Shareholders' Meeting date; that is, April 30, 2019.

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

  c) **Local Rating Agencies:** To confirm "Feller Rate Clasificadora de Riesgo" and "Fitch Chile Clasificadora de Riesgo Ltda." as the agencies that will rate the company's shares according to the national rating scale.

1Q2019

- **Acquisitions of the Los Loros and Andacollo solar PV plants**: On March 29, 2019, the company delivered a Material Event notice to the Financial Market Commission ("CMF") communicating the execution of share purchase agreements to acquire the Los Loros solar PV plant with an approximate capacity of 54 MWp for US$34.9 million and the Andacollo solar PV plant with an approximate capacity of 1.3 MWp for 220.6 million Chilean pesos. Both assets were acquired on April 17, 2019.

- **Tamaya-Solar environmental approval**: At the end of March, 2019, the Environmental Assessment Commission of Antofagasta (CEA) unanimously approved the Tamaya Solar project situated in the Tocopilla District in the Antofagasta region. Specifically, the project consists of the construction and operation of a set of photovoltaic panels with nominal capacity of 100 MW and peak capacity of approximately 122.4 MW. The plant will be connected to the grid through the 11 kV bar at EECL's Central Barriles substation, while electricity will be transported to the National Electricity System through the 110 kV Tocopilla transmission line.

- **Local Rating Upgrade**: In January 2019, Feller Rate upgraded EECL's national-scale solvency ratio to 'AA-(cl)' from 'A+(cl)', with stable outlook. The upgrade is explained by the achievement of a more diversified client base, the strong credit quality of counterparties, and a more stable and predictable cash flow generation, which contribute to the improvement of the company's business profile.

- **Decarbonization roundtable:** The Minister of Energy announced the conclusion of the Decarbonization Roundtable, an initiative stemming from a voluntary agreement between the government and the companies belonging to the Chilean Association of Generation Companies. The roundtable sought to discuss the possibilities of closing and reconverting coal-fired generation plants in the future. Upon the conclusion of the roundtable, the authority began a period of bilateral meetings with each generation company.

- **Increase in contracted demand under the PPA with distribution companies:** The power supply contract signed with distribution companies back in 2014 became effective on January 1, 2018, with a step-up from an annual maximum of 2,016 GWh in 2018 to an annual maximum of 5,040 GWh starting January 1, 2019, through December 31, 2032. The supply for this contract would come from several sources including existing power plants, additional gas supply arrangements for use in gas-fired plants, the Infraestructura Energética Mejillones ("IEM") project and renewable power plants. Since the interconnection between the SIC and the SING grids did not operate at full capacity until late May 2019 due to delays in the completion of the southernmost segment of the transmission line, EECL has been supplying this contract with energy purchases from the spot market and through bilateral agreements with other generation companies. In November 2018, ENGIE Energía Chile ("EECL") signed a power supply contract with Enel Generación Chile under which EECL will buy energy from Enel for 12 years beginning January 2019, considering annual volumes of 0.5 TWh over the 2019-2021 period, 1 TWh in 2022, and 1.5 TWh over the 2023-2030 period.

- **PPA renegotiations**: In March 2019, the company executed commercial agreements with some of its clients consisting of amendments to power supply agreements, including tariff reductions, a change in price indexation clauses, and the extension of the contracts' life. These clients include Antucoya (~319 GWh), Molycop (~100 GWh), Quiborax (~21 GWh), Mall Plaza (~24 GWh), Puerto Mejillones and Puerto Angamos (~10 GWh). Pursuant to these amendments, supply will be provided by renewable power sources starting in different dates as agreed in each of the contracts. Consequently, energy prices will begin to be readjusted according to the CPI variation rather than to coal price variations. The contracts' life extension and tariff CPI indexation further support the company's plans to invest in renewable capacity to gradually replace its aging coal capacity in accordance with its energy transformation plan.

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, LNG, and diesel and fuel oil, 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. According to data published by the national grid coordinator ("CEN"), one month after Cardones-Polpaico's COD, marginal costs in the center-south segment of the SEN fell by approximately 24.2%, while in the north area, costs decreased by 4.5% as compared to the previous month. The reasons include 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. While 2.3% of total power production was lost in May, in June 100% of the generated power could by transported to consumer centers through transmission lines.

In addition to the interconnection, other factors contributed to the reduction and stabilization of marginal costs, including (i) increased contribution from hydraulic sources; (ii) greater volumes of Argentine gas supply; and (iii) greater LNG availability, which caused some combined-cycle units to operate in an inflexible manner at zero marginal cost.

Marginal Costs

2018	Minimum				Average				Maximum			
Month	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220
Jan	-	-	-	-	50.9	48.9	54.2	49.4	61.0	58.3	236.5	189.2
Feb	4.1	4.0	-	-	54.7	53.2	45.2	48.5	110.6	107.2	268.7	159.2
Mar	36.2	35.5	-	-	75.3	73.5	43.4	59.4	174.6	169.9	168.6	160.2
Apr	46.1	44.4	0.8	-	63.6	61.7	51.4	57.5	162.5	157.9	104.7	147.5
May	30.1	29.5	43.5	-	81.1	78.9	56.7	66.9	156.0	159.9	112.0	136.8
Jun	36.2	34.7	-	-	80.5	77.8	54.1	54.9	187.8	180.9	117.0	114.4
Jul	43.5	39.7	42.1	-	69.1	66.0	56.1	56.5	196.2	188.1	181.9	183.0
Aug	48.7	47.5	39.6	38.0	84.1	81.5	59.8	64.3	199.4	191.7	207.2	198.2
Sep	-	-	-	-	59.7	57.9	54.4	51.7	74.7	71.9	190.2	179.2

2019	Minimum				Average				Maximum			
Month	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220	A. Jahuel 220	Charrúa 220	Crucero 220	P. Azúcar 220
Jan	15.0	14.7	-	-	63.1	61.5	51.5	55.1	166.6	161.3	148.0	161.4
Feb	41.5	40.8	-	-	64.0	62.6	51.2	55.8	162.1	157.2	155.0	155.6
Mar	45.4	44.7	-	-	63.5	62.1	49.2	53.0	152.2	148.9	118.1	123.5
Apr	45.3	44.5	-	-	71.6	70.1	49.3	56.4	178.0	173.3	168.8	172.1
May	40.7	39.6	34.6	-	68.5	66.7	51.9	55.2	198.0	192.2	148.9	145.0
Jun	37.5	36.5	32.5	32.5	53.0	51.3	48.2	50.0	83.3	80.6	78.8	79.9
Jul	36.1	35.4	30.3	6.5	49.6	48.1	46.3	47.7	73.1	69.9	72.1	72.6
Aug	37.5	36.6	29.7	-	52.5	50.3	50.7	50.2	106.1	100.4	106.7	105.5
Sep	28.0	27.3	25.9	26.8	42.9	41.3	40.8	42.0	69.1	65.4	69.9	69.2

Source: Coordinador Eléctrico Nacional

During the first nine months of 2019, marginal costs in the north were relatively lower than those in the south given the dry weather conditions in central-south Chile. At the Crucero node in the ex-SING, the most significant spikes have been related to specific plant trips or transmission issues, and troughs have been explained by the lack of operational flexibility of the CCGTs, which have been prompted to consume their LNG supply, leading to occasional zero marginal-cost episodes at the Crucero node. Furthermore, the growing participation of renewable power, both power generated in the northern region and power imported through the interconnection, has occasionally driven all thermal power plants to operate at their technical minimum levels. Per local regulations, units operating at their technical minimum do not set the marginal cost, thereby contributing to the zero marginal-cost episodes at the Crucero Node.

It should be noted that, given the renewable production intermittence, a larger number of power plants have been required to lower their load. The operating costs reported by plants operating at their technical minimum are remunerated through the over-cost mechanism pursuant to Supreme Decree 130. System over-costs reached US$19.7 million in the first quarter of 2019, down from US$34 million in the first quarter of 2018. In the second quarter of 2019, over-costs reached US$7.7 million, down from 2Q18's US$16.4 million. In the third quarter, over-costs reached US$7 million, down from 3Q18's US$12 million. EECL's pro-rata was US$7.4 million in the first nine months of 2019, approximately 30% of which was passed through to energy prices.

Fuel prices

International Fuel Prices Index

	WTI (US$/Barrel)			Brent (US$/Barrel)			Henry Hub (US$/MMBtu)			European coal (API 2) (US$/Ton)		
	2018	**2019**	**% Variation YoY**	**2018**	**2019**	**% Variation YoY**	**2018**	**2019**	**% Variation YoY**	**2018**	**2019**	**% Variation YoY**
Jan	63.7	52.3	*-18%*	69.1	60.3	*-13%*	3.88	3.15	*-19%*	95.3	81.8	*-14%*
Feb	62.2	55.0	*-12%*	65.3	64.1	*-2%*	2.67	2.72	*2%*	85.8	74.4	*-13%*
March	62.6	58.3	*-7%*	66.0	66.3	*0%*	2.69	2.94	*9%*	79.5	69.6	*-12%*
April	66.6	63.7	*-4%*	71.9	71.3	*-1%*	2.80	2.67	*-5%*	81.8	58.3	*-29%*
May	70.1	60.6	*-14%*	77.1	71.3	*-8%*	2.80	2.63	*-6%*	89.5	56.5	*-37%*
June	67.8	54.7	*-19%*	74.4	64.2	*-14%*	2.97	2.40	*-19%*	96.4	48.9	*-49%*
July	71.0	57.1	*-20%*	74.2	63.8	*-14%*	2.84	2.36	*-17%*	100.8	58.4	*-42%*
August	68.3	54.8	*-20%*	72.7	58.7	*-19%*	2.95	2.22	*-25%*	97.6	54.2	*-44%*
September	70.2	56.3	*-20%*	78.9	62.2	*-21%*	3.00	2.52	*-16%*	100.4	60.4	*-40%*
October	70.2			81.8			3.28			100.3		
November	56.2			90.9			4.18			88.5		
December	49.2			56.9			4.04			87.5		

Source: Bloomberg, IEA

Through most of 2018 international fuel prices increased, particularly oil, with year-on-year increases in the 50% area, followed by coal, which reported year-on-year price increases of up to 20%. However, toward the end of the year, the oil and coal prices upward trends reversed, and we could observe WTI and API2 prices falling to levels in the surroundings of US$49/Barrel and US$87.5/ton, respectively, in December 2018. Henry Hub prices did not follow suit, reporting significant year-on-year increases in the area of 40% in November and December 2018.

In the first nine months of 2019, fuel prices reported year-on-year drops averaging 10% to 15%, with the exception of coal, which reported YoY drops of over 40%, particularly in the second and third quarters, due to high inventory stocks in Europe and Asia, with European stocks reaching their highest levels in the last 5 years. Furthermore, the gas surplus has caused a shift from coal to gas in Asia and Europe, which has dragged coal prices down in both regions.

Generation

The following table provides a breakdown of generation in the northern segment of the SEN (ex – SING) by fuel type:

Total North SEN Generation by Fuel Type (in GWh)

2018

	1Q 2018		2Q 2018		3Q 2018		4Q 2018		12M 2018	
Fuel Type	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*
Coal	3,356	*68%*	3,421	*70%*	3,415	*73%*	2,840	*63%*	13,032	*69%*
LNG	842	*17%*	895	*18%*	616	*13%*	884	*20%*	3,237	*17%*
Diesel / Fuel oil	30	*1%*	16	*0%*	12	*0%*	13	*0%*	71	*0%*
Renewable	682	*14%*	577	*12%*	638	*14%*	783	*17%*	2,680	*14%*
Total gross generation N-SEN	**4,910**	***100%***	**4,909**	*100%*	**4,681**	*100%*	**4,520**	*100%*	**19,020**	*100%*

2019

	1Q 2019		2Q19		3Q19	
Fuel Type	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*
Coal	2,878	*66%*	3,148	*65%*	3,137	*65%*
LNG	810	*19%*	1,072	*22%*	1,272	*26%*
Diesel / Fuel oil	4	*0%*	12	*0%*	0	*0%*
Renewable	670	*15%*	591	*12%*	652	*14%*
Total gross generation N-SEN	**4,362**	*100%*	**4,823**	*100%*	**5,061**	*105%*

Source: Coordinador Eléctrico Nacional

In the third quarter of 2019, gross power generation in the northern segment of the SEN increased 8% compared to the third quarter of 2018. Demand from the Chuquicamata mine recovered after being affected by a 14-day strike in the second quarter and stoppages caused by floods and environmental upgrades at its facilities during the first quarter.

The generation mix showed a decrease in coal generation as compared to the third quarter of 2018, and an increase in gas generation, partly due to abundant gas supply and inflexible operation in certain periods, and partly due to LNG's greater suitability to cope with renewable power intermittence. Renewable sources accounted for 14% of total generation in the third quarter, while diesel generation has remained close to zero.

Power demand in the northern segment of the SEN reached a maximum of 3,031 MW in the third quarter of 2019, up from 2,826 MW in the third quarter of 2018.

Electricity production in the northern segment of the SEN (ex-SING), broken down by company, was as follows:

Generation by Company (in GWh)

	2018									
	1Q 2018		**2Q 2018**		**3Q 2018**		**4Q 2018**		**12M2018**	
Company	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*
AES Gener	2,171	*44%*	2,396	*49%*	2,092	*45%*	2,051	*45%*	8,710	*46%*
EECL (with 100% of CTH)	1,538	*31%*	1,411	*29%*	1,465	*31%*	988	*22%*	5,402	*28%*
Enel Generación	34	*1%*	22	*0%*	21	*0%*	63	*1%*	139	*1%*
Other	1,167	*24%*	1,081	*22%*	1,102	*24%*	1,419	*31%*	4,769	*25%*
Total gross generation N-SEN	**4,910**	*100%*	**4,909**	*100%*	**4,681**	*100%*	**4,520**	*100%*	**19,020**	*100%*

	2019					
	1Q 2019		**2Q 2019**		**3Q 2019**	
Company	**GWh**	*% of total*	**GWh**	*% of total*	**GWh**	*% of total*
AES Gener	2,094	*48%*	2,226	*46%*	2,454	*51%*
EECL (with 100% of CTH)	966	*22%*	1,129	*23%*	1,216	*25%*
Enel Generación	249	*6%*	264	*5%*	236	*5%*
Other	1,054	*24%*	1,204	*25%*	1,154	*24%*
Total gross generation N- SEN	**4,362**	*100%*	**4,823**	*100%*	**5,061**	*105%*

Source: Coordinador Eléctrico Nacional

During the third quarter of 2019, EECL reported a 17% decrease in electricity generation, as compared to the third quarter of 2018, and it accounted for 25% of total power production in the north SEN. The recovery in EECL's generation, as compared to its record lows in the 4Q18 and 1Q19, is explained by the commissioning of IEM in May 2019 and an increase in gas generation. AES Gener continued being the leading contributor with 51%, while other non-traditional players, including the Tamakaya (Kelar) CCGT plant and renewable producers, maintained their 24% share of total generation in the area.

Regarding EECL's plant maintenance schedule in the third quarter, CTH was out of service from July 4 to July 23, while CTA underwent major maintenance between June 29 and August 23. IEM was unavailable during part of August and September due to repair works at its pulverizing systems. CTM2 has been out for maintenance since September 29, and it is expected to resume operations by mid-November.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following discussion is based on our unaudited consolidated financial statements for the nine-month periods ended September 30, 2019, and September 30, 2018. 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 2019 compared to 2Q 2019 and 3Q 2018

Operating Revenues

Quarterly Information (In US$ millions)

	3Q 2018		2Q 2019		3Q 2019		% Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Unregulated customers sales…………………..	174.1	*62%*	173.7	*54%*	152.7	*50%*	*-12%*	*-12%*
Regulated customers sales…………………….	100.5	*36%*	146.9	*45%*	146.1	*48%*	*-1%*	*45%*
Spot market sales……………………………..	5.6	*2%*	3.6	*1%*	6.3	*2%*	*73%*	*11%*
Total revenues from energy and capacity sales	**280.3**	*81%*	**324.3**	*77%*	**305.1**	*86%*	***-6%***	***9%***
Gas sales…………………………..	34.8	*10%*	4.2	*1%*	4.4	*1%*	*6%*	*-87%*
Other operating revenue……………………….	32.2	*9%*	94.1	*22%*	43.7	*12%*	*-54%*	*36%*
Total operating revenues………………….	**347.3**	*100%*	**422.5**	*100%*	**353.2**	*100%*	***-16%***	***2%***
Physical Data (in GWh)								
Sales of energy to unregulated customers (1)……	1,584	*64%*	1,550	*57%*	1,610	*56%*	*4%*	*2%*
Sales of energy regulated customers……	876	*35%*	1,183	*43%*	1,232	*43%*	*4%*	*41%*
Sales of energy to the spot market…………….	11	*0%*	-	*0%*	31	*1%*	*n.a*	*194%*
Total energy sales………………………….	**2,471**	*100%*	**2,734**	*100%*	**2,873**	*100%*	***5%***	***16%***
Average monomic price unregulated customers(U.S.$/MWh)(2)	**112.8**		**114.4**		**96.8**		***-15%***	***-14%***
Average monomic price regulated customers (U.S.$/MWh)(3)	**105.2**		**124.2**		**118.6**		***-4%***	***13%***

(1) Includes 100% of CTH sales.

(2) Calculated as the quotient between unregulated and spot revenues from energy and capacity sales and unregulated and spot physical energy sales.

(3) Calculated as the quotient between regulated revenues from energy and capacity sales and regulated physical energy sales.

Energy and capacity sales reached US$305.1 million in the third quarter of 2019, representing a US$25 million or 9% increase compared to the third quarter of 2018, due mainly to higher regulated revenues under the contract with distribution companies in the center-south segment of the SEN, which has a volume step-up beginning 2019.

The increase in physical sales to unregulated clients, as compared to both the third quarter of 2018 and the second quarter of 2019, is primarily explained by the recovery in demand from the Chuquicamata and El Abra mines, while the increase in physical sales to distribution companies, particularly in the year-on-year comparison, is attributed to the increase in contracted volume in our contract with distribution companies in the center-south segment of the SEN. In the third quarter of 2019, physical sales under this contract reached 807 GWh, a 387 GWh increase as compared to the third quarter of 2018.

The 12% decrease in revenues from electricity sales to unregulated clients, as compared to both the third quarter of 2018 and the second quarter of 2019, is due to lower fuel prices, which resulted in lower average realized energy prices, and offset the increase in physical sales.

However, sales to regulated clients increased significantly year-on-year, reaching US$146.1 million in the third quarter of 2019, due to the increase in contracted energy supply with distribution companies in the center-south segment of the SEN, which represented revenues of US$103.1 million during the quarter.

In the third quarter, the company reported US$6.3 million in spot sales revenue, primarily explained by reliquidations related to sufficiency capacity and green taxes as well as by spot energy sales reported by the recently acquired Los Loros solar PV plant.

In the third quarter of 2019, gas sales amounted to US$4.4 million, in line with those reported in the second quarter, but significantly lower than gas sales in the third quarter of 2018, when the company exported gas to Argentina. Normally, 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. However, in the second quarter of 2019, the most relevant item is a US$74.9 million revenue from liquidated damages stipulated in the construction contract with IEM's EPC contractor to compensate EECL for lost capacity revenues and higher costs associated to the delay in project completion.

Operating Costs

Quarterly Information (In US$ millions)

	3Q 2018		2Q 2019		3Q 2019		% Variation	
Operating Costs	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Fuel and lubricants……………………………	(92.0)	38%	(72.8)	27%	(78.4)	31%	8%	-15%
Energy and capacity purchases on the spot market……………………………	(70.3)	29%	(102.8)	37%	(72.1)	29%	-30%	3%
Depreciation and amortization attributable to cost of goods sold……………………………	(32.1)	13%	(38.4)	14%	(40.0)	16%	4%	25%
Other costs of goods sold……………………	(41.2)	17%	(49.2)	18%	(54.8)	22%	11%	33%
Total cost of goods sold………………..	**(235.6)**	97%	**(263.2)**	96%	**(245.3)**	98%	**-7%**	**4%**
Selling, general and administrative expenses…	(8.4)	3%	(8.9)	3%	(8.2)	3%	-8%	-2%
Depreciation and amortization in selling, general and administrative expenses…………	(0.9)	0%	(1.9)	1%	(1.2)	0%	-38%	27%
Other operating revenue/costs………………………	2.6	-1%	(0.2)	0%	4.7	-2%		
Total operating costs….………………	**(242.3)**	100%	**(274.3)**	100%	**(250.0)**	100%	**-9%**	**3%**
Physical Data (in GWh)								
Gross electricity generation								
Coal…………………………………………	1,135	77%	911	60%	867	52%	-5%	-24%
Gas…………………………………………..	313	21%	569	38%	764	45%	34%	144%
Diesel Oil and Fuel Oil……………………	2	0%	1	0%	8	0%	760%	415%
Hydro/Solar………………………………………	15	1%	32	2%	41	2%	29%	169%
Total gross generation…………………	**1,465**	100%	**1,513**	100%	**1,680**	100%	**11%**	**15%**
Minus Own consumption………………..	(110)	-7%	(106)	-7%	(131)	-8%	23%	19%
Total net generation……………………	**1,355**	**54%**	**1,407**	**50%**	**1,549**	**55%**	**10%**	**14%**
Energy purchases on the spot market………..	942	**38%**	1,307	**46%**	1,128	**40%**	-14%	20%
Energy purchases- bridge………..	204	**8%**	124	**4%**	127	**4%**	n.a	n.a
Total energy available for sale before transmission losses………………………	**2,501**	**100%**	**2,838**	**100%**	**2,838**	**100%**	**0%**	**13%**

Gross electricity generation increased by 9% in the third quarter of 2019, as compared to the same quarter the year before, and by 5%, as compared to the second quarter, mainly due to (i) the commissioning of the IEM plant, which began commercial operations on May 16; (ii) the increase in gas generation due to an increase in LNG availability and gas generation's greater flexibility to cope with the intermittence of renewable generation; and (iii) an increase in solar generation following the acquisition of the Los Loros and Andacollo power plants in April.

The increase in power generation in the third quarter, as compared to the second quarter, led to increased coal and gas purchase volumes, with a consequential increase in the fuel cost item. However, the fuel cost item decreased by US$13.6 million or 15% when compared to the third quarter of 2018, due to the decrease in fuel prices.

The spot electricity purchase cost item decreased by US$30.7 million (30%) compared to the second quarter due to decreases in both physical energy purchases and spot energy prices. The decrease in energy purchase volumes is explained by increased generation particularly due to IEM's commercial operation since May 16, the acquisition of the Los Loros solar PV plant, an increase in LNG supply, and the completion of the southernmost segment of Interchile's Cardones-Polpaico transmission line on May 31, which permitted an increase in plant dispatch levels and higher energy export volumes from the north SEN to the center-south grid. When compared to the third quarter of 2018, physical energy purchases rose 20% because of our need to meet the increased demand from distribution companies in center-south Chile. In the third quarter, this contract was supplied with energy purchases under contracts with other generation companies (127 GWh in the second quarter) and spot energy purchases (680 GWh). Both types of energy purchases are accounted for under the same item labelled 'Energy and capacity purchases on the spot market'.

Average energy purchase prices have been affected by the full interconnection following the start-up of the last segment of the Interchile transmission project at the end of May 2019. Since then, marginal energy costs have decreased, not only due to the strengthening of the interconnection, but also due to increased Argentine gas imports in the southern region and an increased contribution from hydraulic generation.

In the third quarter, depreciation costs in the costs-of-goods-sold item included IEM's depreciation, but they no longer include the depreciation of units N°12 and N°13, which were disconnected from the grid on June 7.

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

The decrease in SG&A expenses, as compared to the second quarter of 2019 and the third quarter 2018, is mainly due to the effect of the depreciation of the Chilean peso.

The Other operating revenue/cost item includes water sales and miscellaneous income as well as recoveries and provisions. EECL's share in TEN's net income, which amounted to US$2.2 million in the third quarter, is also included in this item.

Electricity Margin

Quarterly Information (In US$ millions)

	2018					2019			
	1Q18	**2Q18**	**3Q18**	**4Q18**	**12M18**	**1Q19**	**2Q19**	**3Q19**	**9M19**
Electricity Margin									
Total revenues from energy and capacity sales………	**278.3**	**284.9**	**280.3**	**278.1**	**1,121.6**	**315.1**	**324.3**	**305.1**	**944.4**
Fuel and lubricants…………………..	(91.9)	(92.0)	(81.3)	(54.8)	(320.0)	(66.5)	(72.8)	(78.4)	(217.8)
Energy and capacity purchases on the spot market……	(57.8)	(70.3)	(78.3)	(95.1)	(301.5)	(122.9)	(102.8)	(72.1)	(297.8)
Gross Electricity Profit	**128.5**	**122.6**	**120.7**	**128.2**	**500.1**	**125.7**	**148.6**	**154.6**	**428.9**
Electricity Margin	*46%*	*43%*	*43%*	*46%*	*45%*	*40%*	*46%*	*51%*	*45%*

In the third quarter, the electricity margin, or the gross profit from the electricity generation business, increased by US$6 million, when compared to the second quarter of 2019, and reached 51% of energy and capacity revenues. On the one hand, we can observe a US$9.2 million revenue decrease, explained by lower sales to unregulated customers and a slight decrease in sales to regulated customers. On the other, despite the US$5.6 million increase in fuel costs explained by the generation recovery, the company reported a US$30.7 million decrease in energy purchase costs owing to lower purchase volumes and prices. The entrance of IEM, which reports one of the lowest variable generation costs among base-load plants in the north system, and lower average energy purchase prices, resulted in lower average energy procurement costs in the third quarter. In sum, despite lower operating revenues, the decrease in average energy supply costs explained the third quarter's electricity margin recovery.

Operating Results

Quarterly Information (in US$ millions)

EBITDA	**3Q 2018**		**2Q 2019**		**3Q 2019**		**% Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Total operating revenues…………………….…	347.3	*100%*	422.5	*100%*	353.2	*100%*	*-16%*	*2%*
Total cost of goods sold……………………	(283.7)	*-82%*	(263.2)	*-62%*	(245.3)	*-69%*	*-7%*	*-14%*
Gross income……………………….	**63.6**	*18%*	**159.3**	*38%*	**107.9**	*31%*	***-32%***	***70%***
Total selling, general and administrative expenses and other operating income/(costs).	(6.5)	*-2%*	(11.1)	*-3%*	(4.7)	*-1%*	*-58%*	*-28%*
Operating income….………………	**57.1**	*16%*	**148.2**	*35%*	**103.2**	*29%*	***-30%***	***81%***
Depreciation and amortization……...…………	34.7	*10%*	40.3	*10%*	41.2	*12%*	*2%*	*19%*
EBITDA……………….….……………….	**91.8**	*26.4%*	**188.5**	*44.6%*	**144.4**	*40.9%*	***-23%***	***57%***

Third-quarter EBITDA reached US$144.8 million, a US$53 million increase compared to the same quarter the year before. This was due to the increase in contracted energy sales with regulated clients in the center-south segment of the SEN and the decrease in average energy procurement costs.

The comparison with the second quarter of 2019 shows a US$43.7 million decrease in EBITDA despite the increase in the electricity margin in the third quarter of 2019. This is explained by the liquidated damages paid by the IEM EPC contractor in the second quarter to compensate for past capacity revenue losses and higher energy supply costs incurred in connection with the delayed start-up of the plant.

Financial Results

Quarterly Information (In US$ millions)

	3Q 2018		**2Q 2019**		**3Q 2019**		**% Variation**	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Financial income……...………………………	1.6	*1%*	1.5	*1%*	0.6	*0%*	*-63%*	*-65%*
Financial expense………….…………………	(4.3)	*-2%*	(8.5)	*-3%*	(13.7)	*-5%*	*61%*	*221%*
Foreign exchange translation, net…………..	1.0	*0%*	(0.1)	*0%*	(3.1)	*-1%*		*-400%*
Other non-operating income/(expense) net…	0.0	*0%*	(90.6)	*-30%*	4.2	*1%*		*13442%*
Total non-operating results……………	**(1.6)**	*-1%*	**(97.7)**	*-32%*	**(12.0)**	*-4%*		
Income before tax…………………… ………	55.5	*20%*	50.5	*17%*	91.1	*30%*	***80%***	***64%***
Income tax……………………………………	(15.3)	*-6%*	(13.9)	*-5%*	(23.1)	*-8%*	*67%*	*52%*
Net income from continuing operations after taxes …	40.3	*15%*	36.7	*12%*	68.0	*22%*	*85%*	*69%*
Net income attributed to controlling shareholders…….	**37.3**	*14%*	**37.7**	*12%*	**62.4**	*21%*	***66%***	***67%***
Net income attributed to minority shareholders……….	3.0	*1%*	3.4	*1%*	1.2	*0%*	*-64%*	*-59%*
Net income to EECL's shareholders	**37.3**	*14%*	**37.7**	*12%*	**62.4**	*21%*	***66%***	***67%***
Earnings per share…………………….	**0.035**		**0.036**		**0.059**			

Interest expense increased as interest ceased to be capitalized upon the completion of the IEM project last May.

Foreign-exchange losses reached US$3.1 million in the third quarter due to greater volatility in foreign exchange rates and the ongoing depreciating trend of the Chilean peso since the beginning of the year. Foreign exchange variations affect the valuation of certain assets and liabilities denominated in currencies other than the US dollar --the company's functional currency--, such as accounts receivable and payable, advances to suppliers, and value-added tax credit.

In the third quarter, the 'Other net non-operating income' account reported a positive result, as opposed to the US$90.6 million loss reported in the second quarter of 2019. The second quarter loss includes the economic impairment associated to the announced closure of the Tocopilla units N°14 and N°15, which amounted to US$87.4 million.

Net Earnings

The applicable income tax rate for both 2018 and 2019 is 27%.

In the third quarter of 2019, after-tax net income reached US$62.4 million, a 66% increase as compared to the second quarter of 2019, which was affected by non-recurring asset impairments. The 67% net income increase as compared to the third quarter of 2018 reflects the increase in contracted volume sales with distribution companies in the center-south segment of the SEN and the decrease in average energy procurement costs.

9M 2019 compared to 9M 2018

Operating Revenues

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

	9M18		9M19		Variation	
Operating Revenues	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Unregulated customers sales…………………..	532.0	*63%*	489.3	*52%*	*-42.7*	*-8%*
Regulated customers sales…………………….	302.4	*36%*	443.6	*47%*	*141.2*	*47%*
Spot market sales……………………………..	9.1	*1%*	11.5	*1%*	*2.4*	*27%*
Total revenues from energy and capacity sales……	**843.4**	*89%*	**944.4**	*84%*	***101.0***	*12%*
Gas sales…………………………..	39.8	*4%*	12.6	*1%*	*-27.2*	*-68%*
Other operating revenue……………………….	67.4	*7%*	162.4	*15%*	*95.0*	*141%*
Total operating revenues………………….	**950.7**	*100%*	**1,119.5**	*100%*	***168.8***	*18%*
Physical Data (in GWh)						
Sales of energy to unregulated customers (1)……	4,621	*63%*	4,584	*56%*	*-37*	*-1%*
Sales of energy regulated customers……	2,662	*36%*	3,635	*44%*	*972*	*37%*
Sales of energy to the spot market……………	25	*0%*	37	*0%*	*12*	*48%*
Total energy sales………………………….	**7,308**	*100%*	**8,255**	*100%*	***947***	*13%*
Average monomic price unregulated customers(U.S.$/MWh)(2)	**116.5**		**108.4**		***-8.1***	*-7%*
Average monomic price regulated customers (U.S.$/MWh)(3)	**113.6**		**122.1**		***8.5***	*7%*

(1) Includes 100% of CTH sales.

(2) Calculated as the quotient between unregulated and spot revenues from energy and capacity sales and unregulated and spot physical energy sales.

(3) Calculated as the quotient between regulated revenues from energy and capacity sales and regulated physical energy sales.

Energy and capacity sales reached US$944.4 million in the first nine months of 2019, representing a 12% or US$101 million increase compared to the first nine months of 2018, mainly due to increased sales to regulated clients resulting from the contracted energy step-up with distribution companies in the center-south segment of the SEN grid. This contract contributed revenues of US$308.5 million in the first nine months of 2019.

Physical energy sales to unregulated clients decreased particularly during the first quarter due to temporary stoppages at mining operations caused by the Altiplanic Winter and environmental improvement works to comply with new gas emission regulatory requirements. Through the second quarter, demand from Chuquicamata and El Abra recovered, although towards the end of the quarter Chuquicamata's demand slowed down due to the 14-day strike in June. In the third quarter, the demand recovery from Chuquicamata was partially offset by lower demand from Centinela and El Tesoro due to works at their mining operations. Physical sales to regulated clients increased due to the contracted demand step-up effective since the beginning of 2019. Demand under the regulated contract with distribution companies in the center-south segment of the SEN reached 2,387 GWh in the first nine months of 2019, an 88% increase from the 1,266 GWh reported in the first nine months of 2018.

Physical sales to the spot market decreased 48%. The spot market sales and purchase items also include the retroactive annual firm capacity price and monthly energy adjustment payments per the re-liquidations made by the grid coordinator.

The 68% decrease in gas sales is explained by gas exports to Argentina, which were reported in 2018. The Other operating revenue account is composed of transmission tolls and regulatory transmission revenues, among others. In the first nine months of 2019, this item included US$74.9 million in liquidated damages paid by the IEM EPC contractor to compensate for past capacity revenue losses and higher energy supply costs attributed to the delayed start-up of the project.

Operating Costs

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

	9M 2018		9M 2019		Variation	
Operating Costs	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Fuel and lubricants………………………………	(265.2)	34%	(217.8)	27%	-47.4	-18%
Energy and capacity purchases on the spot market…	(206.4)	27%	(297.8)	37%	91.4	44%
Depreciation and amortization attributable to cost of goods sold…	(98.6)	13%	(111.6)	14%	13.0	13%
Other costs of goods sold…………………….	(182.7)	24%	(156.9)	19%	-25.8	-14%
Total cost of goods sold……………….	**(752.9)**	97%	**(784.1)**	97%	**31.2**	**4%**
Selling, general and administrative expenses…	(27.1)	4%	(26.2)	3%	-0.9	-3%
Depreciation and amortization in selling, general and administrative expenses…	(2.9)	0%	(4.0)	0%	1.1	38%
Other operating revenue/costs……………………….	9.2	-1%	8.4	-1%	0.8	-8%
Total operating costs…..………………	**(773.7)**	100%	**(805.8)**	100%	**32.2**	**4%**
Physical Data (in GWh)						
Gross electricity generation						
Coal………………………………………….	3,304	75%	2,372	57%	-932	-28%
Gas…………………………………………..	1,051	24%	1,689	41%	638	61%
Diesel Oil and Fuel Oil…………………….	7	0%	10	0%	4	54%
Hydro/Solar……………………………………….	50	1%	87	2%	38	75%
Total gross generation…………………	**4,411**	100%	**4,158**	100%	**-253**	**-6%**
Minus Own consumption……………..	(352)	-8%	(315)	-8%	37	-11%
Total net generation……………………	**4,059**	**54%**	**3,843**	**46%**	**-216**	**-5%**
Energy purchases on the spot market……….	2,788	**37%**	4,164	**50%**	1,376	49%
Energy purchases- bridge……….	627	**8%**	373	**4%**	-254	-
Total energy available for sale before transmission losses………………………	**7,474**	**100%**	**8,380**	**100%**	**907**	**12%**

The 8% decrease in gross electricity generation in the first nine months of 2019, as compared to the first nine months of 2018, is mainly attributed to a 28% decrease in coal generation. The generation mix revealed a higher contribution of gas generation given its greater flexibility to cope with the intermittency of renewable output and higher contribution of solar generation due to the acquisition of the Los Loros and Andacollo PV plants in April. The increased penetration of renewable sources in the system, the frequent dispatch of coal plants at lower load factors, and higher priced coal inventories explained the decrease in coal generation in 2019 despite the commissioning of IEM in May.

The decrease in international coal prices, coupled with the decrease in generation, resulted in an 18% decrease (US$47.4 million) in the fuel cost item in the first nine months of 2019.

The electricity purchase costs item increased by US$91.4 million (44%) since physical purchases rose by 33% to supply the increase in distribution companies' contracted volumes and to compensate for the lower generation levels. This was partly offset by lower average spot prices, particularly in the second and third quarters of 2019, as a result of the full interconnection of the grids on May 31 and the operation of gas plants in inflexible mode. The contract with distribution companies in the center-south SEN was supplied with contracts with other generation companies (373 GWh) and energy purchased from the spot market (2,014 GWh). Both types of purchases are included in the same accounting item.

The increase in depreciation costs is explained by the net effect of the incorporation of IEM and the decommissioning of units N°12 and N°13 on June 7, 2019.

Other direct operating costs included, among others, transmission tolls, operating and maintenance costs, cost of fuel sold, and insurance premiums. This item, as a whole, increased due to higher maintenance costs.

SG&A expenses remained stable despite the foreign-exchange fluctuations during both periods.

The 'Other operating revenue/cost' item includes water sales, services and office rentals as well as the proportional result in TEN, which amounted to US$5.6 million in the first nine months of 2019.

Operating Results

For the 6-month period ended september 30 (in US$ millions)

EBITDA	**9M 2018**		**9M 2019**		**Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Total operating revenues………………………	950.7	*100%*	1,119.5	*100%*	*168.8*	*18%*
Total cost of goods sold……………………	(752.9)	*79%*	(784.1)	*70%*	*31.2*	*4%*
Gross income…………………………	**197.8**	*21%*	**335.4**	*30%*	***137.6***	***70%***
Total selling, general and administrative expenses and other operating income/(costs).	(20.8)	*2%*	(21.8)	*2%*	*1.0*	*5%*
Operating income…..………………	**177.0**	*19%*	**313.6**	*28%*	***136.6***	***77%***
Depreciation and amortization……...…………	101.5	*11%*	115.6	*10%*	*14.1*	*14%*
EBITDA………………….……………….	**278.5**	*29.3%*	**429.2**	*38.3%*	***150.8***	***54%***

In the first nine months of 2019, EBITDA reached US$429.2 million, a 54% increase compared to the first nine months of 2018 due to (i) the US$57 million electricity margin increase, mainly explained by increased volume sales to distribution companies and lower average energy supply costs, and (ii) the effect of the liquidated damages paid by the IEM EPC contractor to compensate for past capacity revenue losses and higher energy supply costs attributed to the delayed start-up of the project.

Financial Results

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

	9M 2018		9M 2019		Variation	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Financial income………..………………………	4.7	*1%*	3.3	*1%*	*-1.3*	*-28%*
Financial expense…………….…………………	(9.4)	*-2%*	(25.4)	*-4%*	*-16.0*	*170%*
Foreign exchange translation, net……………	(0.6)	*0%*	(2.0)	*0%*	*-1.5*	*269%*
Share of profit (loss) of associates accounted for using the equity method	-	*0%*	-	*0%*	*0.0*	
Other non-operating income/(expense) net…	(66.0)	*-12%*	(85.5)	*-14%*	*-19.4*	
Total non-operating results…………….	**(71.3)**	*-13%*	**(109.6)**	*-18%*		
Income before tax……………………. ………	105.6	*20%*	204.1	*34%*	***98.4***	***93%***
Income tax………………………………………	(26.6)	*-5%*	(53.8)	*-9%*	*-27.2*	
Net income from continuing operations after taxes …	79.1	*15%*	150.3	*25%*	*71.2*	*90%*
Net income attributed to controlling shareholders…….	**72.5**	*14%*	**143.0**	*24%*	***70.5***	***97%***
Net income attributed to minority shareholders……….	6.5	*1%*	7.3	*1%*	*0.7*	*11%*
Net income to EECL's shareholders	**72.5**	*14%*	**143.0**	*24%*	***70.5***	***97%***
Earnings per share……………………..	**0.069**		**0.136**			

Financial income decreased slightly due to lower average cash balances.

Interest expense increased as interest ceased to be capitalized in IEM upon the project completion last May.

Foreign-exchange differences resulted in a US$2 million loss in the first nine months of 2019, which negatively compares to the US$1.6 million loss reported in the first nine months of 2018, due to greater volatility in exchange rates, with a depreciating trend of the Chilean peso.

Other net non-operating income recorded an US$85.5 million loss due to the asset impairment related to the future closure of the coal-fired units N°14 and N°15 in Tocopilla, which represented and after-tax loss of US$63.8 million (US$87.4 million before-tax loss). In the first nine months of 2018, this item also included an asset impairment related to the decommissioning of the coal-fired units N°12 and N°13 in Tocopilla, which represented and after-tax loss of US$51.8 million (US$71 million before-tax loss). This item also included insurance recoveries on property damages at the CTM3 and U16 CCGTs. Insurance recoveries amounted to US$2.1 million in the first nine months of 2019, down from US$4.9 million in the first nine months of 2018.

Net Earnings

The applicable income tax rate for both periods is 27%.

In the first nine months of 2019, net income after taxes reached US$143 million, a 97% increase compared to the first nine months of 2018. When isolating the non-recurring effects related to the asset impairments, net recurring income would have been US$206.4 million, a 66% increase compared to the US$124.4 million net recurring income reported in the first nine months of 2018. As explained earlier, the impairment of units N°14 and N°15 negatively impacted net results in the first nine months of 2019, but they were offset by the liquidated damages paid by IEM’s EPC contractor, which had US$54.7 million positive after-tax impact on operating results in the first nine months of 2019.

Liquidity and Capital Resources

As of September 30, 2019, EECL reported consolidated cash balances of US$166.1 million. This position compares with a total nominal financial debt[1] of US$830 million, with US$80 million maturing within one year.

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

Cash Flow	**2018**	**2019**
Net cash flows provided by operating activities…	250.9	333.9
Net cash flows used in investing activities………	(200.0)	(140.1)
Net cash flows provided by financing activities..	(21.2)	(91.2)
Change in cash……………...…………	**29.7**	**102.6**

Cash Flow from Operating Activities

In the first nine months of 2019, cash flow generated from operating activities reached approximately US$424.1 million including US$80 million in liquidated damages paid by the IEM EPC contractor mainly to compensate for the margin losses attributed to the delay in the project completion. However, the cash flow statement shows US$333.9 million in cash flow from operating activities since this figure is presented after income taxes (US$44.3 million), green taxes (US$24.9 million) and interest payments (US$21 million). This represented a significant increase compared to US$250.5 million of operating cash flow reported in the first nine months of 2018, mainly due to the increase in volume sales to distribution companies and the above-mentioned compensatory payments, which offset the increase in interest expense and income taxes. It should be noted that cash interest payments actually amounted to US$39.7 million, US$19.2 million of which were capitalized and accounted for as investments in fixed assets. In the first nine months of 2018, cash interest payments amounted to US$41.3 million, US$39.3 million of which were capitalized and accounted for as investments in fixed assets.

Cash Flow Used in Investing Activities

In the first nine months of 2019, cash flows from investing activities resulted in a net cash expenditure of US$140.2 million, mainly due to (i) cash investments in the IEM project (US$75.8 million including capitalized interest), (ii) expenditures in plant maintenance and transmission assets (US$16.7 million), (iii) the investment in the Calama wind farm and solar PV plants (US$24.6 million) and (iv) the acquisition of the solar PV plants, Los Loros and Andacollo (US$35.3 million). This item also shows a US$21.6 million cash inflow corresponding to debt repayments from the related company, TEN, in January 2019. This payment was in great part possible because ENGIE Energía Chile issued a corporate guarantee in favor of TEN's project-finance lenders, which allowed TEN to release cash deposited in the debt service reserve account required by the project-finance terms. The net cash used in investing activities decreased as compared to the US$199.6 million reported in the first nine months of 2018 mainly due to the completion of the IEM project in May 2019.

Capital Expenditures

Our capital expenditures in the first nine months of 2018 and the first nine months of 2019 amounted to US$197.7 million and US$126.1 million, respectively, as shown in the following table. These amounts include VAT payments and capitalized interest.

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

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

CAPEX	**2018**	**2019**
CTA ………………………………………………….	0.2	0.0
CTA (New Port) ……………………………………..	32.2	1.0
CTH …………………………………………………	1.2	0.0
IEM ……………………………………………………	141.7	75.8
Overhaul power plants & equipment maintenance and refurbishing…………………	5.7	6.7
Environmental improvement works………………	0.1	0.3
2.5	9.1	10.0
	0.1	2.5
	-	22.1
Others……………………………………………	7.4	7.7
Total capital expenditures……………………….	**197.7**	**126.1**

Cash Flow from Financing Activities

Among the main financing cash flows in the first nine months of 2019 we can mention dividends, which reached US$79.3 million and included the following payments: (i) final and additional dividends in an amount of US$22 million paid last May to EECL's shareholders; (ii) the first provisional dividend on account of 2019 earnings in the amount of US$50 million paid last June; (iii) a US$4 million dividend paid in March to the minority shareholder in Inversiones Hornitos (CTH), and (iv) another US$4 million dividend paid to the minority shareholder in Inversiones Hornitos in July.

The company also reported activity related to its short-term bank debt, which resulted in a US$10 million net debt reduction. At the end of March, the company renewed a US$40 million short-term loan with Scotiabank, extending its maturity through June 26, 2019, and subsequently to June 19, 2020. Likewise, the company renewed a US$40 million loan with Banco Estado, extending its maturity date to June 25, 2020 and repaid a US$10 million loan with Banco Estado that matured in April. To partially finance the acquisition of the solar PV plants, the company borrowed US$15 million for 30 days with Banco Estado and repaid this loan at maturity on May 3.

In sum, in the first nine months of 2019 cash from financing activities resulted in a net cash outflow of US$91.2 million, an increase compared to the US$21.2 million net cash outflow reported in the first nine months of 2018, mainly due to greater dividend payments and the decrease in short-term debt.

Contractual Obligations

The following table sets forth the maturity profile of our debt obligations as of September 30, 2019.

Contractual Obligations as of 9/30/19
Payments Due by Period (in US$ millions)

	Total	**< 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Bank debt……………………………………..……	80.0	80.0	-	-	-
Bonds (144 A/Reg S Notes)……………………..	750.0	-	400.0	-	350.0
Financial lease - Tolling Agreement TEN………	58.2	1.2	2.8	3.4	50.8
Leasing NIIF 16………………	16.7		5.6	5.6	5.6
Deferred financing cost…………………………..	(13.8)	-	(7.2)	(3.3)	(3.3)
Accrued interest…………………………………..	16.9	16.9	-	-	-
Mark-to-market swaps……………………………	0.1	0.1	-	-	
Total	**908.1**	**98.2**	**401.1**	**5.6**	**403.1**

Notes:

a. 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.

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

During 2017 and 2018, EECL took one-year debt to finance the remainder of its 2015-2018 investment plan. Short-term debt reached its maximum level at US$150 million in April 2018 and has since fallen to US$80 million as of September 30, 2019. These loans are in US dollars and accrue interest at a fixed rate. They are documented by simple promissory notes (*"pagarés"*) reflecting the payment obligation on the due date, with no operational or financial restrictions and permitted prepayment at any time with no penalties for the company. As of June 30, 2019, the company had two outstanding short-term obligations: a US$40 million loan with Scotiabank and a US$40 million loan with Banco Estado both maturing in June 2020.

The bonds include our US$400 million, 10-year, 5.625% 144-A/Reg.S notes maturing January 15, 2021 and our 144 A/Reg S issue for a total amount of US$350 million with a single principal payment in January 2025 and a 4.5% p.a. coupon rate.

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 approximately US$58 million and is payable in monthly instalments totaling approximately US$7 million per year.

As of September 30, 2019, the company reported leasing obligations in respect to vehicles and other assets for a total of US$16.7 million, which qualify as financial debt under IAS 16 accounting norm.

In the first quarter of 2019, due to the completion of its 2015-2018 investment plan, good liquidity and open access to financial markets, EECL requested the cancellation of its US$100 million committed revolving credit facility with a group of five international banks.

Dividend Policy

Our dividend policy 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 two 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 April 30, 2019, at the Annual Ordinary Shareholders Meeting, our shareholders approved the Board's proposal to pay a final dividend of US$22,137,925.42 (US$0.021017493 per share) payable on May 24, 2019, in Chilean pesos using the peso-dollar observed rate published by the Official Gazette on April 30, the date of the Shareholders' Meeting.

On May 28, 2019, the company's Board of Directors approved the distribution of a provisional dividend on account of 2019's net earnings, in an amount of US$50,000,000 or US$0.047469416 per share. The dividend was paid on June 21, 2019, in Chilean pesos using the peso-dollar observed rate published by the Official Gazette on June 19, 2019, to those shareholders listed in the company's shareholders' registry at midnight of the fifth business day prior to the distribution date. Such dividend was approved in consideration to the company's cash generation and the fulfillment of an intensive investment period.

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

Risk management policy

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

EECL has established risk management procedures, which include a description of the risk assessment methodology and a risk matrix. Additionally, the company established a Risk and Insurance Committee, responsible for the risk matrix review, analysis and approval as well as the proposal of risk mitigation measures. The risk matrix is updated and reviewed semiannually, while action plans are monitored on a permanent basis. Management presents the company's risk management performance to the board on an annual basis.

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

Hedging Policy

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

Business Risk and Commodity Hedging

Our business is subject to the risk of variations in the availability of fuels and their prices. 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 recent trend to dissociate PPA price indexation from fossil fuel price fluctuations, we maintain residual exposure to certain international commodity prices. For example, the tariff of the EMEL contract, which became effective at the beginning of 2012, is readjusted semiannually according to the Henry Hub and the U.S. CPI indices. However, there is a mismatch between the Henry Hub index used to define the EMEL tariff (4-month average prior to the tariff fixing, which takes place every six months) and the Henry Hub index prevailing at the time each LNG shipment is made. In the specific case of this contract, this risk is somewhat naturally hedged by a contractual indexation triggered any time the price formula reports a fluctuation of 10% or more. We periodically define and execute financial hedging strategies to cover our residual exposure to international commodity price risks. Therefore, we have occasionally taken financial swap contracts to reduce our residual exposure to Brent and Henry Hub.

Currency Hedging

Given that most of our revenues and costs are denominated in U.S. dollars and that we seek to incur debt in U.S. dollars, we face limited exposure to foreign exchange risk. Our main costs denominated in Chilean pesos are personnel and administrative expenses, which account for approximately 10% of our total operating costs. In the specific case of regulated contracts, their price is calculated in dollars and is converted to pesos at the average monthly exchange rate; therefore, the foreign currency exposure related to these contracts has been substantially reduced. Given the dollarized nature of most of our revenues, the portion of operating and administrative costs in pesos represents our main exposure to foreign-currency risks. Therefore, we have hedged a portion of our recurrent costs in pesos through forward contracts and zero-cost collars.

The company and its CTA subsidiary signed foreign-currency derivative contracts to hedge the UF and EUR cash flows stemming from the EPC contracts with S.K. Engineering and Construction and Belfi, respectively, to avoid variations in cash flows and the final value of the investment resulting from foreign currency fluctuations out of management's control. As of June 30, 2019, there were no outstanding derivative contracts associated to EPC contract cash flows.

Interest Rate Hedging

We seek to maintain a significant portion of our long-term debt at fixed rates in order to minimize interest-rate exposure. As of September 30, 2019, 100% of our financial debt, for a principal amount of US$830 million, was at fixed rates, including US$80 million in short-term loans with interest rates fixed for one year at the time of disbursement.

As of Septemeber 30, 2019
Contractual maturity date (in US$ millions)

	Average interest rate	2019	2020	2021	2022	Thereafter	Grand Total
Fixed Rate							
(US$)	5.625% p.a.	-	-	400.0	-	-	400.0
(US$)	4.500% p.a.	-	-	-	-	350.0	350.0
(US$)	2.333% p.a.		80.0	-	-	-	80.0
Total		**-**	**80.0**	**400.0**	**-**	**350.0**	**830.0**

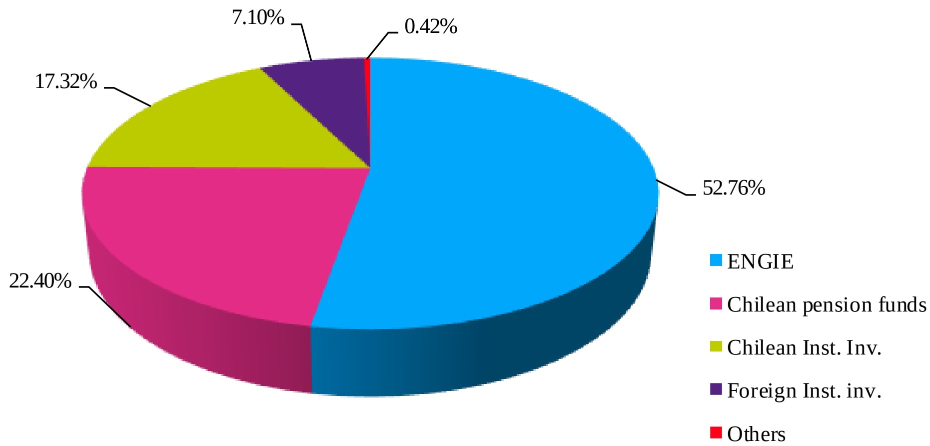
Credit Risk

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 level of credit risk. However, these companies are exposed to variations in commodity prices, particularly copper. Although our clients have demonstrated significant resilience to down-cycles, our company closely follows up this exposure through its 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. Over the last years, the electricity generation business has evolved towards a more atomized customer base as 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 has led the company to sign contracts with smaller commercial and industrial clients with a potentially higher credit risk. To mitigate this risk, the company has implemented a commercial counterparty risk policy, which among other considerations, requires the review of the credit risk before engaging in a power supply agreement. As of September 30, 2019, the contracts signed with smaller commercial and industrial clients represented a low percentage of our overall client portfolio.

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.

OWNERSHIP STRUCTURE AS OF SEPTEMBER 30, 2019

Number of shareholders: 1,797



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

APPENDIX 1

PHYSICAL DATA AND SUMMARIZED QUARTERLY FINANCIAL STATEMENTS

Physical Sales

Physical Sales (in GWh)

	2018				2019			
	1Q18	2Q18	3Q18	9M18	1Q19	2Q19	3Q19	9M19
Physical Sales								
Sales of energy to unregulated customers.	1,485	1,552	1,584	4,621	1,423	1,550	1,610	4,584
Sales of energy to regulated customers	915	871	876	2,662	1,220	1,183	1,232	3,635
Sales of energy to the spot market………	8	7	11	25	6	-	31	37
Total energy sales………………………….	**2,408**	**2,430**	**2,471**	**7,308**	**2,649**	**2,734**	**2,873**	**8,255**
Gross electricity generation								
Coal………………………………………….	1,167	1,001	1,135	3,304	594	911	867	2,372
Gas…………………………………………..	347	391	313	1,051	356	569	764	1,689
Diesel Oil and Fuel Oil…………………….	2	3	2	7	2	1	8	10
Renewable……………………………………….	20	14	15	50	14	32	41	87
Total gross generation………………….	**1,536**	**1,410**	**1,465**	**4,411**	**965**	**1,513**	**1,680**	**4,158**
Minus Own consumption……………..	(123)	(110)	(120)	(352)	(78)	(106)	(131)	(315)
Total net generation…………………….	**1,414**	**1,301**	**1,345**	**4,059**	**888**	**1,407**	**1,549**	**3,843**
Energy purchases on the spot market………..	929	942	917	2,788	1,729	1,307	1,128	4,164
Energy purchases- bridge	215	204	208	627	122	124	127	373
Total energy available for sale before transmission losses………………………	**2,558**	**2,447**	**2,469**	**7,474**	**2,739**	**2,838**	**2,804**	**8,380**

Quarterly Income Statement

IFRS								
Operating Revenues	1Q18	2Q18	3Q18	9M18	1Q19	2Q19	3Q19	9M19
Regulated customers sales………………………	102.5	99.3	100.5	302.4	150.6	146.9	146.1	443.6
Unregulated customers sales…………………..	173.6	184.3	174.1	532.0	163.0	173.7	152.7	489.3
Spot market sales……………………………..	2.1	1.3	5.6	9.1	1.6	3.6	6.3	11.5
Total revenues from energy and capacity sales……………………………	**278.3**	**284.9**	**280.3**	**843.4**	**315.1**	**324.3**	**305.1**	**944.4**
Gas sales…………………………..	3.4	1.6	34.8	39.8	4.1	4.2	4.4	12.6
Other operating revenue……………………….	17.5	17.8	32.2	67.4	24.6	94.1	43.7	162.4
Total operating revenues…………………	**299.1**	**304.3**	**347.3**	**950.7**	**343.8**	**422.5**	**353.2**	**1,119.5**
Operating Costs							-	-
Fuel and lubricants………………………………	(91.9)	(92.0)	(81.3)	(265.2)	(66.5)	(72.8)	(78.4)	(217.8)
Energy and capacity purchases on the spot	(57.8)	(70.3)	(78.3)	(206.4)	(122.9)	(102.8)	(72.1)	(297.8)
Depreciation and amortization attributable to cost of goods sold..	(32.8)	(32.1)	(33.7)	(98.6)	(33.2)	(38.4)	(40.0)	(111.6)
Other costs of goods sold…………………….	(51.1)	(41.2)	(90.4)	(182.7)	(52.9)	(49.2)	(54.8)	(156.9)
Total cost of goods sold……………….	**(233.6)**	**(235.6)**	**(283.7)**	**(752.9)**	**(275.5)**	**(263.2)**	**(245.3)**	**(784.1)**
Selling, general and administrative expenses…	(9.2)	(8.4)	(9.4)	(27.1)	(9.0)	(8.9)	(8.2)	(26.2)
Depreciation and amortization in selling, general and administrative expenses…	(1.0)	(0.9)	(1.0)	(2.9)	(0.9)	(1.9)	(1.2)	(4.0)
Other revenues………..……………………….	2.6	2.6	3.9	9.2	3.9	(0.2)	4.7	8.4
Total operating costs….……………….	**(241.2)**	**(242.3)**	**(290.2)**	**(773.7)**	**(281.5)**	**(274.3)**	**(250.0)**	**(805.8)**
							0	0
Operating income….……………….	**57.9**	**62.0**	**57.1**	**177.0**	**62.2**	**148.2**	**103.2**	**313.6**
							0	0
EBITDA……………….….……………….	**91.7**	**95.0**	**91.8**	**278.5**	**96.3**	**188.5**	**144.4**	**429.2**
Financial income………..………………………	1.2	1.8	1.6	4.7	1.2	1.5	0.6	3.3
Financial expense…………….…………………	(2.8)	(2.3)	(4.3)	(9.4)	(3.2)	(8.5)	(13.7)	(25.4)
Foreign exchange translation, net…………..	(0.1)	(1.5)	1.0	(0.6)	1.1	(0.1)	(3.1)	(2.0)
Share of profit (loss) of associates accounted for using the equity method	-	-	-	-	-	-	-	-
Other non-operating income/(expense) net………………………	0.1	(66.2)	0.0	(66.0)	0.9	(90.6)	4.2	(85.5)
Total non-operating results……………	**(1.6)**	**(68.2)**	**(1.6)**	**(71.3)**	**0.1**	**(97.7)**	**(12.0)**	**(109.6)**
Income before tax…………………..………	56.4	(6.2)	55.5	105.6	62.4	50.5	91.1	204.1
Income tax………………………………………	(14.7)	3.4	(15.3)	(26.6)	(16.8)	(13.9)	(23.1)	(53.8)
Net income from continuing operations after taxes …….	41.7	(2.9)	40.3	79.1	45.6	36.7	68.0	150.3
Net income attributed to controlling shareholders……………….	**39.2**	**(4.0)**	**37.3**	**72.5**	**42.9**	**37.7**	**62.4**	**143.0**
Net income attributed to minority shareholders……………….	2.4	1.1	3.0	6.5	2.7	3.4	1.2	7.3
Net income to EECL's shareholders…….	**39.2**	**(4.0)**	**37.3**	**72.5**	**42.9**	**37.7**	**62.4**	**143.0**
Earnings per share…………………….. (US$/share)	**0.037**	**(0.004)**	**0.035**	**0.069**	**0.041**	**0.036**	**0.059**	**0.136**

Quarterly Balance Sheet

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

	2018	2019
	December	September
Current Assets		
Cash and cash equivalents (1)	61.5	166.1
Accounts receivable	187.9	172.5
Recoverable taxes	10.2	12.1
Current inventories	158.9	140.3
Other non financial assets	9.1	11.5
Total current assets	**427.6**	**502.4**
Non-Current Assets		
Property, plant and equipment, net	2,635.7	2,620.1
Other non-current assets	399.4	387.8
TOTAL ASSETS	**3,462.7**	**3,510.4**
Current Liabilities		
Financial debt	111.0	91.2
Other current liabilities	194.7	209.4
Total current liabilities	**305.8**	**300.6**
Long-Term Liabilities		
Financial debt	792.2	750.0
Other long-term liabilities	226.7	267.8
Total long-term liabilities	**1,018.9**	**1,017.8**
Shareholders' equity	2,069.8	2,127.0
Minority' equity	68.2	65.0
Equity	**2,128.0**	**2,192.0**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,462.7**	**3,510.4**

(1) Includes short-term investments classified as available for sale.

Main Balance Sheet Variations

The main balance-sheet variations between December 31, 2018, and September 30, 2019, are the following:

Cash and cash equivalents: The company's cash balances increased by US$104.6 million mainly because of (i) strong operating cash flow generation, (ii) the US$21.6 million debt repayment from TEN, and (iii) the US$80 million payment of liquidated damages by the IEM EPC contractor, all of which allowed the company to finance the following main expenditures: (i) insurance premiums (US$9.4 million); (ii) income taxes and green taxes (US$56.3 million); (iii) debt principal and interest (US$49.7 million); (iv) dividends (US$79.3 million); (v) capital expenditures (US$106.9 million excluding capitalized interest); and (vi) the acquisition of solar PV assets (US$32.3

million net of the cash balances at the time of the purchase). Cash balances were invested in time deposits with strongly rated banks.

Accounts receivable: The US$15.4 million decrease comprises changes in two different accounts: On the one hand, accounts receivable from third parties reported a US$0.4 million increase. On the other hand, intercompany receivables decreased by US$15.8 million mainly due to the US$21.6 million debt payment by TEN last January.

Current inventories: An US$18.6 million inventory decrease can be observed due to a decrease in fuel inventories (coal US$8.6 million and hydrated lime US$1.1 million) as well as in spare-part inventories (US$8.5 million) related to the units N°14 and N°15, which will be decommissioned.

Other non-financial assets – current: The US$2.4 million increase in this item is explained by a US$6.8 million advanced payment of insurance premiums that was partially offset by lower advanced payments to other suppliers (US$0.9 million), lower VAT fiscal credit balances (US$1.4 million) and amortization of other deferred charges (US$2.1 million).

Property, plant and equipment, net: Two factors in opposite directions explain the US$16.3 million decrease in this account: One the one hand, the following factors caused an increase in this item: (i) the recognition of assets with rights of use associated to the implementation of IFRS16 (US$18.4 million) (ii) the incorporation of Solar Los Loros SPA and SD Andacollo (US$14.0 million); and (iii) the capital expenditures in the construction of the IEM project and other investments in fixed assets (US$129.8 million). On the other hand, the following factors caused a decrease in the net PP&E account: (i) the period's depreciation (US$99.7 million), and (ii) the impairment of units N°14 and N°15 (US$78.9 million). The investment in the IEM project includes capitalized interest as well as net revenues and costs reported while the plant was operating in test mode. Among others, US$5.1 million of the liquidated damages paid by the IEM EPC contractor were deducted from the PP&E account.

Other non-current assets: The decrease in this item is explained by the amortization of intangible assets (US$12.9 million), a US$6.1 million net decrease in other non-financial, non-current assets, and the lower value in the investment in TEN. The latter is explained by the impact of the mark-to-market variations of hedging instruments on TEN's net worth (US$17.7 million), which was netted against the period's net income (US$6.5 million). The decrease in these items was slightly offset by a US$0.8 million increase in accounts receivable from related parties.

Financial debt – current: This item reported an US$18.7 million net decrease mainly explained by US$38.3 million in interest payments on the 144-A bonds and the US$11.5 million short-term debt reduction including principal and interest payments. These amounts were partially offset by US$30.6 million in interest expense accrued during the first nine months of the year.

Other current liabilities: The increase in this item is explained by (i) a US$31.2 million increase in the income tax provision; and (iii) a US$4.2 million increase in the VAT fiscal debit account. These increases were offset by a US$3.7 million decrease in obligations with the company's personnel and a US$17.3 million decrease in other commercial accounts payable, including the payment of amounts owed to the IEM project EPC contractor.

Long-term financial debt: The US$18.4 million increase in this account is explained by the recognition of leasing liabilities associated to the implementation of IAS 16.

Other long-term liabilities: The changes in this ítem are mainly explained by net deferred taxes; in particular, the deferred taxes related to the asset impairments and the incorporation of Solar Los Loros SpA.

Shareholders' equity: The US$57.2 million increase in shareholders' equity is made up of (i) the first nine months's net income (US$143 million), minus (ii) an US$18.4 million decrease in the mark-to-market of hedging instruments, minus (iii) US$67.4 million corresponding to dividend payments. This last amount was deducted from equity and paid to our shareholders in the first nine months of 2019.

Minority interest: The US$3.3 million decrease in minority interest is explained by US$8.7 million in dividends paid to the minority shareholder in Inversiones Hornitos, which was partially offset by the US$7.3 million proportional net income reported in the first nine months of 2019.

APPENDIX 2

Financial information

	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19
EBITDA*	91.7	95.0	91.8	97.3	96.3	188.5	144.4
Net income attributed to the controller	39.2	(4.0)	37.3	30.1	42.9	37.7	62.4
Interest expense	2.8	2.3	4.3	3.4	3.2	8.5	13.7

* Operating income + Depreciation and Amortization for the period

	Sep/18	Sep/19
LTM EBITDA	354.1	526.5
LTM Net income attributed to the controller	179.1	173.1
LTM Interest expense	18.9	28.7
Financial debt	918.5	899.4
Current	126.8	92.4
Long-Term	791.7	807.0
Cash and cash equivalents	107.6	166.1
Net financial debt	810.9	733.3

Financial Ratios

FINANCIAL RATIOS					
			Dec/18	Sep/19	Var.
LIQUIDITY	Current ratio (current assets / current liabilities)	(times)	1.40	1.67	***19%***
	Quick ratio ((current assets - inventory) / current liabilities)	(times)	0.88	1.20	***37%***
	Working capital (current assets – current liabilities)	MMUS$	121.8	201.8	***66%***
LEVERAGE	Leverage ((current liabilities + long-term liabilities) / networth)	(times)	0.62	0.60	***-3%***
	Interest coverage * ((EBITDA / interest expense))	(times)	29.42	18.31	***-38%***
	Financial debt –to- LTM EBITDA*	(times)	2.40	1.71	***-29%***
	Net financial debt – to - LTM EBITDA*	(times)	2.38	1.39	***-41%***
PROFITABILITY	Return on equity* (LTM net income attributed to the controller / net worth attributed to the controller)	%	5.0%	8.1%	***63%***
	Return on assets* (LTM net income attributed to the controller / total assets)	%	3.0%	4.9%	***64%***

*LTM = Last twelve months

As of September 30, 2019, the current ratio and the quick ratio were 1.67x and 1.20x, respectively. Current assets increased, particularly cash balances, while current liabilities decreased slightly due to reductions in debt balances, provisions and accounts payable, which were partially offset by an increase in taxes payable. As a result, working capital, as measured by total current assets minus total current liabilities, increased. Liquidity remained strong due to the company's cash balances and strong cash generation ability.

The leverage ratio, as measured by total liabilities-to-equity, reached 0.60x as of September 30, 2019, a slight decrease compared to December 2018's 0.62x due to the US$10 million net repayment of short-term debt.

As of September 30, 2019, interest coverage was 18.31x, below December 2018's 29.42x, despite the EBITDA increase. This is explained by the increase in interest expense since interest ceased to be capitalized in the IEM project following its completion in May 2019.

The leverage ratio, as measured by Gross financial debt-to-EBITDA, decreased to 1.71 times, as a result of the EBITDA increase and the debt reduction. Net financial debt-to-EBITDA decreased further to 1.39 times due to the larger EBITDA and higher cash balances at the end of September 2019.

Return on equity and return on assets reached 8.1% and 4.9%, respectively, an increase compared to year-end 2018's ratios, due to the earnings increase explained in this report.

CONFERENCE CALL 3Q2019

ENGIE Energía Chile is pleased to inform you that it will conduct a conference call to review its results for the period ended September 30, 2019, on Wednesday, November 6, 2019
at 10:00 a.m. (USA-NY) – 12:00 p.m. (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
+1(844) 686-3841 (toll free US).

To join the conference, please state the name of the conference (**ENGIE Energía** ; no other Conference ID will be requested. Please connect approximately 10 minutes prior to the scheduled starting time.

To access the phone replay, please dial +**1 (877) 344-7529 /** +**1 (412) 317-0088**
Passcode I.D.: 10135922. A conference call replay will be available until November 13th, 2019.