November 2, 2017

ENGIE ENERGÍA CHILE REPORTED EBITDA OF US$200 MILLION AND NET INCOME OF US$69 MILLION IN THE FIRST NINE MONTHS OF 2017.

IN THE THIRD QUARTER OF 2017, EBITDA REACHED US$60.1 MILLION, AFFECTED BY LOWER REVENUES IN THE UNREGULATED SEGMENT AND LOWER SALES TO THE SPOT MARKET. THIRD-QUARTER NET INCOME REACHED US$18.1 MILLION.

- **Operating revenues** amounted to US$782.2 million in the first nine-months of 2017, a 9% increase compared to the same period of 2016, mainly due to higher fuel prices, which resulted in higher average realized monomic prices in the unregulated client segment.
- **EBITDA** amounted to US$200.5 million in the first nine months of the year; that is, an 8%, or US$17.9 million, decrease compared to the first nine months of 2016, mainly due to lower physical sales, new green taxes and higher costs in emission reduction processes, partially offset by cost-saving initiatives.
- **Net income** amounted to US$69.3 million in the first nine months of 2017. The decrease is explained by significant non-recurring income reported in 2016, largely owed to the sale of a 50% interest in the TEN project. Excluding non-recurring effects from asset sales and insurance recoveries, net income amounted to US$60.9 million in the first nine months of 2017, a 3% decrease compared to the same period in 2016.

Financial Highlights (in US$ millions)

US$ millions	**3Q16**	**3Q17**	**Var %**	**9M16**	**9M17**	**Var %**
Total operating revenues	**246.8**	**251.7**	***2%***	**717.9**	**782.2**	***9%***
Operating income	41.6	25.1	*-40%*	114.8	98.1	*-15%*
EBITDA	**76.4**	**60.1**	***-21%***	**218.4**	**200.5**	***-8%***
EBITDA margin	31.0%	23.9%	*-7.1 pp*	30.4%	25.6%	*-4.8 pp*
Total non-operating results	(3.7)	(0.1)		215.9	3.1	
Net income after tax	27.7	18.8	*-32%*	262.4	74.9	*-71%*
Net income attributed to controlling shareholders	**27.0**	**18.1**	***-33%***	**260.6**	**69.3**	***-73%***
Net income attributed to controlling shareholders without non recurring effects	27.0	17.2	*-36%*	62.8	60.9	*-3%*
Net income attributed to minority shareholders	0.7	0.7		1.8	5.6	
Earnings per share (US$/share)	0.026	0.017		0.247	0.066	
Total energy sales (GWh)	2,247	2,148	*-4%*	6,911	6,505	*-6%*
Total net generation (GWh)	1,930	1,421	*-26%*	6,102	4,273	*-30%*
Energy purchases on the spot market (GWh)	414	795	*92%*	1,060	2,458	*132%*
Average marginal cost (US$/MWh)	65.2	48.1	*-26%*	61.5	54.3	*-12%*

ENGIE ENERGÍA CHILE S.A. ("EECL") is engaged in the generation, transmission and supply of electricity and the transportation of natural gas in the north of Chile. EECL is the fourth largest electricity generation company in Chile and one of the largest electricity generation companies in the SING, Chile's second largest power grid. As of September 30, 2017, EECL accounted for 34% of the SING's installed capacity. EECL primarily supplies electricity to large mining and industrial customers, and it also supplies the entire electricity needs of EMEL, the sole electricity distribution group in the SING. EECL is currently 52.76% indirectly owned by ENGIE (formerly known as GDF SUEZ). The remaining 47.24% of EECL's shares are publicly traded on the Santiago stock exchange following Codelco's sale of its 40% shareholding interest on January 28, 2011. For more information, please refer to www.engie-energia.cl

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HIGHLIGHTS:

RECENT EVENTS

- **Public power supply auction:** On October 11, 2017, the National Energy Commission ("CNE") received offers from 24 generation companies to supply electricity to distribution companies for up to 2,200 GWh/y during 20 years beginning January 1, 2024. The bid included hourly supply blocks for up to 1,700 GWh/y, as well as quarterly supply blocks for up to 500 GWh/y.

- **Average node prices supreme decrees:** On October 10, 2017, the Average Node Price decrees corresponding to the tariff setting processes dated January 2017 and July 2017 were published, triggering the application of new tariffs to regulated clients with retroactive effect to January 1 and July 1 of 2017, respectively.

3Q2017

- **Regulations:** The CNE has invited different players and stakeholders of the electricity sector to discuss the drafts and implementation of the regulations associated to the new Transmission Law. Draft regulations on the following topics have already been issued for discussion: a) Auxiliary services, b) Coordination, and c) Power capacity sufficiency level (formerly known as firm capacity).

- **CNE resolutions:** The CNE issued *"Resolución Exenta #512"* confirming, among other matters, that the installations of the TEN project form part of the interconnection between the SING and SIC power grids. It also issued *"Resolución Exenta #544"* determining the 2018 applicable transmission charges or tariffs for the National and Zonal transmission systems.

- **Credit ratings:** In July 2017, Fitch Ratings affirmed EECL's BBB long-term international credit rating and A+(cl) local credit rating, both with stable outlook. Standard and Poor's also affirmed EECL's BBB rating with stable outlook based on EECL's EBITDA generation expectations and long-term power supply agreements.

2Q2017

- **Distribution law:** In April 2017, the National Energy Commission ("CNE") sponsored working sessions to discuss proposed amendments to the Distribution Law. The authority expects to send a draft bill to Congress by the end of 2017.

- **Energy sector plan:** The Ministry of Energy presented a preliminary version of Energy Sector Plan, which provides the government's view on the development of the country's energy sector over the following 30 years.

- **Regulations related to the Transmission Law:** During the second quarter, the CNE and the Ministry of Energy have continued the discussions surrounding the specific regulations for the implementation of the recently enacted Transmission Law. The authority expects to publish these regulations by the end of 2017.

- **Final report for distribution companies' supply auction:** In May, the CNE approved the final report related to distribution company auctions referred to in article 131 of the Electric Services General Law. Based on the study's results, the CNE considered launching a bidding process during 2017 for supply beginning in 2024.

1Q 2017

- **New power grid coordinator**: On January 1, 2017, a new coordination body, the "CEN" or "*Coordinador Eléctrico Nacional*" took office to manage the "SEN" or "*Sistema Eléctrico Nacional*", a single power grid that will result from the interconnection of the SIC and the SING grids beginning 2018. The CEN will replace the CDEC-SIC and CDEC-SING coordination and dispatch centers, which had been functioning since the nineties following the enacting of the Electricity Law.

- **Low power demand in the SING:** During the first quarter, electricity generation in the SING decreased by 12.6% compared to the first quarter of 2016, largely due to the 43-day strike at the Escondida mine.

- **Annual Ordinary Shareholders' Meeting**: On April 25, 2017, the Company's shareholders agreed the following:

  a) **Definitive Dividends:** To pay a final dividend of US$12,849,087.20 (or US$0.012198773 per share) on account of 2016's net income, payable on May 18, 2017, to be converted to Chilean pesos at the observed exchange rate published by the Central Bank of Chile on May 15.

  b) **Auditors:** To confirm Deloitte Auditores Consultores Limitada 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.

PROJECT STATUS AS OF SEPTEMBER 30, 2017:

i. **Infraestructura Energética Mejillones Project ("IEM"):** This 375MW coal-fired project is progressing within schedule and budget. The EPC contractor is S.K. Engineering and Construction (Korea) ("SKEC"). The main SKEC subcontractors are Salfa for civil works and Belfi for marine works. The project's overall progress rate was approximately 89% as of the end of September. Boiler hydrostatic tests and first energization of the transformer were carried out. The project team is currently working towards the first fire, scheduled for the end of the year. The IEM project, excluding the new port, will cost approximately US$896 million, of which US$611 million had already been paid as of September 30, 2017, excluding capitalized interest. IEM is scheduled to begin operations in the third quarter of 2018.

ii. **New Port in Mejillones ("Puerto Andino"):** This new port is being built by the EPC contractor, Belfi, and is scheduled to be handed over to start the load tests in the fourth quarter of 2017. The port will cost approximately US$122 million, US$95 million of which had been paid as of September 2017. As of that date, the project presented an 88% overall progress rate.

iii. **The TEN project:** This transmission project ceased to be consolidated in EECL's books due to the sale of a 50% ownership stake, and it is now jointly controlled with Red Eléctrica Chile, an indirect subsidiary of Red Eléctrica Corporación (Spain). As of September 30, the project presented a 99% overall progress rate, and its connection and energization is scheduled for the month of November.

   The TEN project considers capital expenditures of approximately US$770 million. On December 6, 2016, TEN successfully closed a long-term project financing with ten national and international financial institutions.

   In its south end, the TEN project must connect to the national power grid at the Nueva Cardones substation belonging to the Nueva Cardones-Polpaico 500kV transmission project sponsored by Interchile, an affiliate of the Colombian group ISA. Interchile has communicated delays in the construction of the southernmost segment of its project, but this should not affect the interconnection of the SING and SIC power grids. To complete the interconnection and begin receiving regulated revenues, TEN requires to be connected in its north end to the SING grid through the new 3-kilometer transmission line connecting the Los Changos substation (TEN) to the Kapatur (MEL/Saesa) substation. The construction of the Changos-Kapatur and 140-km. Changos-Kimal connections, were awarded to Transelec by the Chilean authorities. Transelec signed an EPC contract with EECL for the construction of the 3-kilometer long Changos-Kapatur transmission system. TEN will also be connected through dedicated systems to EECL's IEM and CTM power plants in Mejillones.

INDUSTRY OVERVIEW

The company operates in the SING Grid (Sistema Interconectado del Norte Grande or '*Northern Grid*'), Chile's second largest power grid, which serves the country's north and a major portion of its mining industry. Given local conditions, it is predominantly a thermoelectric system, with generation based on coal, natural gas, LNG, and diesel and fuel oil. The system has been reporting growing penetration of renewable sources, mainly wind and solar.

Marginal Costs

Marginal Costs Crucero 220 kV

(In US$ per MWh)

Period	2016	2017	% Variation YoY
Q1	48.8	59.5	*22%*
Q2	70.3	55.5	*-21%*
Q3	**65.2**	**48.1**	***-26%***
July	82.1	48.5	*-41%*
August	49.6	47.3	*-5%*
September	64.0	48.6	*-24%*
Q4	62.8		
Year	**61.8**	**54.3**	***-12%***

Average Operating Cost (SING)

(In US$ per MWh)

Period	2016	2017	% Variation YoY
Q1	34.3	42.3	*23%*
Q2	37.0	41.1	*11%*
Q3	**35.9**	**39.0**	***9%***
July	39.8	39.4	*-1%*
August	33.8	38.0	*12%*
September	34.1	39.7	*17%*
Q4	37.8		
Year	**36.3**	**40.8**	***13%***

Source: Coordinador Eléctrico Nacional

In the first quarter of 2017, marginal costs, or spot energy prices, averaged US$59.5/MWh, a 22% increase compared to the first quarter of 2016. Similarly, the average system cost, which represents the power plants' weighted average variable cost per MWh, increased by 23% as a result of higher international fuel prices.

In the second quarter, marginal energy costs decreased as compared to the first quarter, although the reduction compared to last year was more evident due to the commissioning of new base-load power plants in the SING in 2016 (first Cochrane unit in July 2016 and second unit in October 2016).

In the third quarter, marginal costs remained quite stable, with monthly averages below US$50/MWh, supported by a wider spinning reserve and a new LNG technical norm defined by the Coordinator. The system's average operating cost remained below US$40/MWh, as most of the power was generated by cost-efficient sources (coal, gas and renewables).

The marginal cost volatility observed in the first quarter due to the intermittence of renewable power sources, changes in demand and sudden base-load plant outages, could be subsequently reduced thanks to measures adopted by the system coordinator beginning April 2017. The coordinator increased the spinning reserve, which led to a more stable dispatch of coal-fired plants (more units at lower load dispatched at any time). Moreover, the new Technical Norm changed the maximum capacity dispatch levels of combined-cycle gas turbines (CCGTs), which resulted in higher dispatch priority to CCGTs. It also extended the planning horizon for natural gas availability from one day to one week. All this has allowed the coordinator to better regulate the dispatch of coal plants and CCGTs, avoiding the dispatch of higher-cost diesel engines during hours lacking sun and wind generation or in case of base-load plant failures.

Overcosts

Overcosts

(In US$ millions)

Period	2016 Total	2016 EECL Prorata	2017 Total	2017 EECL Prorrata	% Variation (YoY) Total	% Variation (YoY) EECL Prorata
Q1	9.4	4.8	6.7	3.7	*-29%*	*-23%*
Q2	13.6	4.5	11.6	5.9	*-15%*	*31%*
Q3	**8.9**	**3.9**	**10.5**	**4.9**	***17%***	***25%***
July	3.6	1.6	4.7	2.3	*28%*	*40%*
August	1.8	0.9	3.3	1.6	*82%*	*73%*
September	3.5	1.4	2.5	1.1	*-29%*	*-23%*
Q4	10.1	4.9				
Year	**42.1**	**18.2**	**28.7**	**14.6**	***-32%***	***-20%***

Source: Coordinador Eléctrico Nacional

In the first quarter, the system's global over-costs decreased to US$6.7 million, a 29% year-on-year decrease, whereas in the second and third quarters, over-costs rose to the US$10 million per-quarter level. Although over-costs have been showing a more erratic behaviour, their relevance has substantially decreased. Cumulative over-costs during the first nine months of 2017 amounted to US$28.7 million versus US$32 million in the first nine months of 2016.

Fuel prices

International Fuel Prices Index

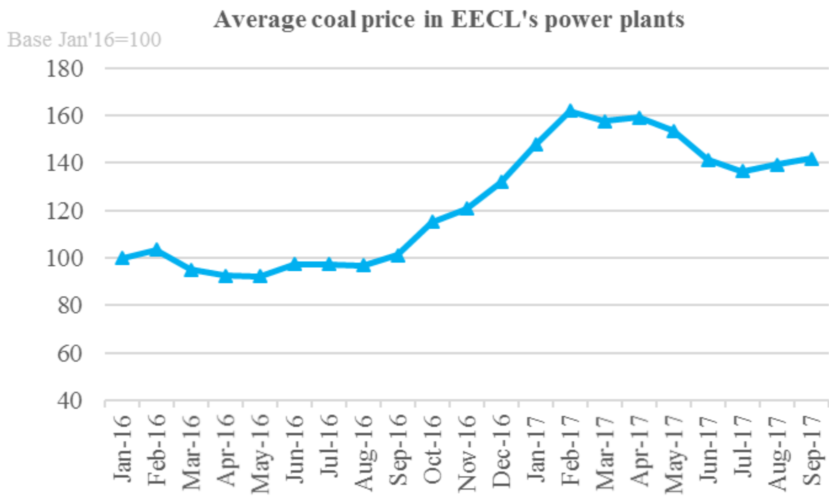
	WTI (US$/Barrel) 2016	WTI 2017	WTI % Variation YoY	Brent (US$/Barrel) 2016	Brent 2017	Brent % Variation YoY	Henry Hub (US$/MMBtu) 2016	Henry Hub 2017	Henry Hub % Variation YoY	European coal (API 2) (US$/Ton) 2016	European coal 2017	European coal % Variation YoY
Q1	33.4	51.7	*55%*	34.5	54.0	*57%*	1.99	3.02	*51%*	39.3	66.0	*68%*
Q2	45.5	48.1	*6%*	46.0	50.1	*9%*	2.15	3.08	*43%*	48.3	66.9	*38%*
Q3	44.9	48.2	*7%*	45.8	51.7	*13%*	2.88	2.95	*2%*	58.8	77.6	*32%*
Q4	49.2			50.1			3.04			67.9		
Year	**43.3**	**49.3**	***14%***	**44.1**	**52.0**	***18%***	**2.52**	**3.01**	***20%***	**53.6**	**69.1**	***29%***

Source: Bloomberg, IEA

Following the trend already observed in the last months of 2016, international fuel prices increased by about 60% in the first quarter of 2017 when compared to the first quarter of 2016, with coal showing the steepest increase. However, when compared to the last quarter of 2016, fuel prices increased by only 1 digit, with an increase in oil prices and a slight decrease in coal and gas prices.

During the second quarter, international fuel prices remained at similar levels as those reported in the first quarter. When compared to the second quarter of 2016, oil prices reported a one-digit increase, while gas and coal prices reported two-digit increases.

In the third quarter, fuel prices reported an uneven performance. While oil and natural gas experienced minimal variations from the second quarter, international coal prices increased significantly by 16%.



Source: Coordinador Eléctrico Nacional

The average coal prices in PPA tariffs increased by approximately 53% compared to the first nine months of 2016, in line with the international coal-price trend. The chart above shows the price trend of the coal mix used in our power plants.

Generation

The following table provides a breakdown of generation in the SING by fuel type:

Total SING Generation by Fuel Type (in GWh)

	2016							
	1Q 2016		2Q 2016		3Q 2016		9M 2016	
Fuel Type	GWh	% of total	GWh	% of total	GWh	% of total	GWh	% of total
Coal	3,802	78%	3,737	76%	3,807	78%	11,345	77%
LNG	502	10%	402	8%	524	11%	1,427	10%
Diesel / Fuel oil	305	6%	468	10%	197	4%	970	7%
Renewable	278	6%	281	6%	337	7%	896	6%
Total gross generation SING	**4,887**	100%	**4,888**	100%	**4,864**	100%	**14,639**	100%

	2017							
	1Q 2017		2Q 2017		3Q 2017		9M 2017	
Fuel Type	GWh	% of total	GWh	% of total	GWh	% of total	GWh	% of total
Coal	3,344	78%	3,776	80%	3,826	77%	10,946	78%
LNG	413	10%	476	10%	524	10%	1,413	10%
Diesel / Fuel oil	35	1%	28	1%	32	1%	94	1%
Renewable	477	11%	466	10%	617	12%	1,561	11%
Total gross generation SING	**4,269**	100%	**4,747**	100%	**4,999**	100%	**14,014**	100%

Source: Coordinador Eléctrico Nacional

During the first quarter of 2017, gross power generation dropped 12.6% compared to the first quarter of 2016, largely as a result of the 43-day strike at the Escondida mine. The maximum system demand reached 2,429 MW in the first quarter, 5% below the peak demand observed in 1Q16. The coal/gas generation mix remained relatively stable, while the contribution from renewable power reported an increase, displacing diesel generation to just 1%.

In the second quarter, gross power generation decreased 2.9% year-on-year, with an increase in energy generated by renewable sources and a moderate increase in gas and coal, all of which displaced diesel generation.

In the third quarter, gross power generation advanced 2.8% year-on-year, with a relevant increase from renewable sources (+151 GWh as compared to 2Q17 and +280 GWh as compared to 3Q16), leading to a slight decrease in the share of coal in the generation mix.

The SING's electricity production broken down by company was as follows:

Generation by Company (in GWh)

2016

	1Q 2016		2Q 2016		3Q 2016		9M 2016	
	GWh	*% of total*	GWh	*% of total*	GWh	*% of total*	GWh	*% of total*
Company								
AES Gener	1,661	*34%*	1,968	*40%*	2,158	*44%*	5,787	*40%*
EECL (with 100% of CTH)	2,411	*49%*	2,114	*43%*	2,082	*43%*	6,606	*45%*
Enel Generación	550	*11%*	490	*10%*	161	*3%*	1,201	*8%*
Other	265	*5%*	316	*6%*	464	*10%*	1,044	*7%*
Total gross generation SING	**4,887**	***100%***	**4,888**	***100%***	**4,864**	***100%***	**14,639**	***100%***

2017

	1Q 2017		2Q 2017		3Q 2017		9M2017	
	GWh	*% of total*	GWh	*% of total*	GWh	*% of total*	GWh	*% of total*
Company								
AES Gener	1,990	*47%*	2,362	*50%*	2,364	*47%*	6,716	*48%*
EECL (with 100% of CTH)	1,550	*36%*	1,553	*33%*	1,542	*31%*	4,644	*33%*
Enel Generación	128	*3%*	145	*3%*	210	*4%*	483	*3%*
Other	601	*14%*	687	*14%*	883	*18%*	2,172	*15%*
Total gross generation SING	**4,269**	*100%*	**4,747**	*100%*	**4,999**	*100%*	**14,014**	*100%*

Source: Coordinador Eléctrico Nacional

During the first quarter of 2017, EECL reported a 35.7% year-on-year decrease in electricity generation, accounting for 36% of the system's power production. EECL's gas generation decreased 45%, and coal generation at the Tocopilla complex fell 41%, mainly due to economic dispatch decisions by the coordinator. Regarding EECL's plant maintenance schedule in the first quarter, the CTA 177MW coal-fired plant was out of service for 27 days beginning March 10, 2017.

During the second quarter, EECL's generation levels remained at levels similar to those reported in the first quarter. During the 2Q17, the following plants underwent planned maintenance: U13 (86 MW-coal) during 33 days, CTA (177 MW-coal) for 4 days, U12 (87 MW-coal) for 27 days and CTM1 (160 MW-coal) for 10 days.

In the third quarter, EECL's generation remained at similar levels in the range of 1,540 GWh. Major maintenance works during the quarter included U14 (136MW-coal) for 13 days, U15 (130MW-coal) for 14 days, and CTM3 (226MW-natural gas) for 33 days.

EECL's lower participation in the SING's generation was largely owed to the commissioning of new cost-efficient power plants in the system throughout 2016. EECL's lower gas generation was also explained by the company's greater gas availability during the first quarter of last year, when AES Gener's Cochrane and Tamakaya Energía's Kelar plants had not yet begun commercial operation.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following discussion is based on our consolidated financial statements for the nine-month periods ended September 30, 2017 and 2016. 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 Superintendencia de Valores y Seguros (www.svs.cl).

3Q 2017 compared to 2Q 2017 and 3Q 2016

Operating Revenues

Quarterly Information (In US$ millions)

	3Q 2016		2Q 2017		3Q 2017		% Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	% of total	QoQ	YoY
Unregulated customers sales………………….	162.9	75%	184.2	75%	171.4	76%	-7%	5%
Regulated customers sales…………………….	41.5	19%	51.3	21%	48.9	22%	-5%	18%
Spot market sales………………………………..	12.8	6%	11.2	5%	6.1	3%	-45%	-52%
Total revenues from energy and capacity sales	**217.3**	88%	**246.7**	91%	**226.4**	90%	***-8%***	***4%***
Gas sales…………………………..	3.7	1%	1.9	1%	2.2	1%	17%	-40%
Other operating revenue……………………….	25.8	10%	23.1	8%	23.1	9%	0%	-10%
Total operating revenues………………….	**246.8**	100%	**271.7**	100%	**251.7**	100%	***-7%***	***2%***
Physical Data (in GWh)								
Sales of energy to unregulated customers (1)……	1,685	75%	1,631	74%	1,587	74%	-3%	-6%
Sales of energy regulated customers……	471	21%	479	22%	485	23%	1%	3%
Sales of energy to the spot market…………….	91	4%	82	4%	76	4%	-8%	-17%
Total energy sales………………………….	**2,247**	100%	**2,193**	100%	**2,148**	100%	***-2%***	***-4%***
Average monomic price unregulated customers(U.S.$/MWh)(2)	**98.9**		**114.0**		**106.8**		***-6%***	***8%***
Average monomic price regulated customers (U.S.$/MWh)(3)	**88.3**		**107.1**		**100.8**		***-6%***	***14%***

(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$226.4 million in the third quarter, representing a US$20.3 million or 8% decrease from the second quarter, due mainly to lower revenues in the unregulated segment: (i) the Radomiro Tomic power supply contract expired in August; (ii) reduction-emission costs passed through to prices decreased, and (iii) power capacity sufficiency reliquidations resulted in lower net revenues. In physical terms, demand from the Radomiro Tomic mine decreased by 57 GWh due to the end of the contract, and this was partly offset by greater demand from El Abra (+11 GWh) and Antucoya (6 GWh), among others.

When compared to the third quarter of 2016, unregulated clients' power demand decreased due to the end of the Radomiro Tomic PPA in August 2017 (-60 GWh) and the Cerro Colorado PPA in September 2016 (-75 GWh), while Codelco also reported lower demand. Greater demand from certain clients including Alto Norte and Antucoya partially offset this decrease.

In the third quarter, sales to distribution companies, or regulated clients, amounted to US$48.9 million, a two-digit increase compared to 3Q16 due to higher prices. The average Henry Hub index used in the calculation of the Emel tariff increased from US$2.05/MMBtu used in the April 2016 tariff setting process to US$3.08/MMBtu used in the April 2017 tariff setting process. Furthermore, the Henry Hub index rose by more than 10%, triggering a tariff increase effective December 2016. The April 2017 tariff, which became effective in May, added to a 1% physical sales increase, explained the 10% sales increase in this segment in the second quarter when compared to the first quarter of 2017. However, in the third quarter, an adjustment had to be made to a provision in Chilean pesos to account for the differential between the tariffs in effect and the tariffs being effectively paid by the distribution companies. This differential had its origin in the delay of the publication of the Average Node Price decrees for the six-month periods starting January 1, 2017, and July 1, 2017, which did not occur until October, 2017. This FX adjustment was the main reason for the decrease in regulated sales as compared to the second quarter.

Physical sales to the spot market reached 76 GWh in the third quarter, a slight decrease compared to both the 82 GWh sold in the second quarter of 2017 and the 91 GWh sold in the third quarter of 2016. The spot market sales and purchase items also include the retroactive annual sufficiency capacity tariffs and monthly energy adjustment payments per the reliquidations made by the system's coordinator.

Gas sales during the third quarter have remained at low levels, similar to the second quarter and slightly below those of the third quarter of 2016. The most relevant items in the 'Other operating revenue' account are sub-transmission tolls and regulatory transmission revenues, which accounted for 63% of the total amount in 3Q17. In addition, this account includes port and maintenance services, among others.

Operating Costs

Quarterly Information (In US$ millions)

	3Q 2016		2Q 2017		3Q 2017		% Variation	
Operating Costs	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**	**QoQ**	**YoY**
Fuel and lubricants………………………………	(75.4)	37%	(87.5)	38%	(85.7)	38%	-2%	14%
Energy and capacity purchases on the spot market……………………………	(32.4)	16%	(60.3)	26%	(50.4)	22%	-16%	56%
Depreciation and amortization attributable to cost of goods sold……………………………	(33.6)	16%	(33.0)	14%	(34.0)	15%	3%	1%
Other costs of goods sold……………………	(55.3)	27%	(43.1)	19%	(46.5)	21%	8%	-16%
Total cost of goods sold……………….	**(196.8)**	96%	**(223.9)**	97%	**(216.7)**	96%	**-3%**	**10%**
Selling, general and administrative expenses…	(8.4)	4%	(7.0)	3%	(10.7)	5%	52%	27%
Depreciation and amortization in selling, general and administrative expenses…………	(1.2)	1%	(1.0)	0%	(1.0)	0%	-1%	-18%
Other operating revenue/costs………………………	1.2	-1%	0.6	0%	1.7	-1%		
Total operating costs…………………	**(205.2)**	100%	**(231.3)**	100%	**(226.7)**	100%	**-2%**	**10%**
Physical Data (in GWh)								
Gross electricity generation								
Coal…………………………………………	1,660	80%	1,294	83%	1,286	83%	-1%	-23%
Gas…………………………………………..	401	19%	234	15%	236	15%	1%	-41%
Diesel Oil and Fuel Oil…………………….	7	0%	13	1%	7	0%	-45%	-2%
Hydro/Solar……………………………………….	14	1%	13	1%	13	1%	-3%	-6%
Total gross generation…………………	**2,082**	100%	**1,555**	100%	**1,542**	100%	**-1%**	**-26%**
Minus Own consumption………………..	(152)	-7%	(122)	-8%	(121)	-8%	-1%	-20%
Total net generation……………………	**1,930**	**82%**	**1,433**	**63%**	**1,421**	**64%**	**-1%**	**-26%**
Energy purchases on the spot market………..	414	**18%**	842	**37%**	795	**36%**	-6%	92%
Total energy available for sale before transmission losses………………………	**2,344**	**100%**	**2,275**	**100%**	**2,215**	**100%**	**-3%**	**-5%**

Gross electricity generation decreased 26% year-on-year and remained relatively unchanged compared to the second quarter of 2017. The sharp year-on-year decrease in total gross generation was largely explained by the commissioning of base-load coal and gas-fired plants in the system, which displaced older, higher-cost plants in terms of dispatch priority. Gas generation decreased its proportion in the generation mix, when compared to last year, but remained even compared to the previous quarter.

The fuel cost item increased 14% year-on-year and decreased 2% compared to the second quarter of 2017. When compared to the third quarter of last year, the fuel-cost item increased by US$10.3 million mainly due to higher coal prices and the accrual of the new CO_2 taxes beginning January 1, 2017. Starting the third quarter, hydrated lime costs have stabilized since the new emission norm had already become effective in all of EECL's production complexes in July 2016.

The spot electricity purchase cost item decreased by US$9.8 million compared to 2Q17 because of a 13% drop in marginal costs and a 6% decrease in physical purchases. As compared to the third quarter of 2016, the spot electricity purchase cost item increased by US$18 million due to increased physical energy purchases, which almost doubled, partially offset by a 26% decrease in average marginal costs.

Depreciation costs in the costs-of-goods-sold item increased slightly compared to both the 2Q17 and 3Q16 due to depreciation of assets related to the U16's overhaul.

Other direct operating costs included, among others, operating and maintenance costs, transmission tolls, insurance premiums and cost of fuels sold. This item increased by US$3.4 million from the second quarter mainly due to transmission toll reliquidations and third-party maintenance services. It reported an US$8.8 million improvement compared to 3Q16 due to lower transmission tolls and cost saving initiatives, including reduced insurance premiums.

SG&A expenses, excluding depreciation, increased by US$3.7 million compared to 2Q17 mainly due to the payment of land rental fees to the Ministry of National Goods, IT services, and project development costs. The year-on-year comparison shows a US$2.3 million increase mainly due to the land rental payments.

The Other operating revenue/cost item includes water sales and miscellaneous income as well as recoveries and provisions, and its value is relatively low.

Electricity Margin

Quarterly Information (In US$ millions)

	2016				2017			
	1Q16	2Q16	3Q16	9M16	1Q17	2Q17	3Q17	9M17
Electricity Margin								
Total revenues from energy and capacity sales………	**212.6**	**222.5**	**217.3**	**652.4**	**238.3**	**246.7**	**226.4**	**711.4**
Fuel and lubricants…………………..	(85.9)	(74.4)	(75.4)	(235.7)	(88.2)	(87.5)	(85.7)	(261.4)
Energy and capacity purchases on the spot market……	(21.0)	(41.0)	(32.4)	(94.4)	(54.7)	(60.3)	(50.4)	(165.5)
Gross Electricity Profit	**105.7**	**107.1**	**109.4**	**322.3**	**95.3**	**99.0**	**90.3**	**284.6**
Electricity Margin	*50%*	*48%*	*50%*	*49%*	*40%*	*40%*	*40%*	*40%*

In the third quarter, the electricity margin, or the gross profit from the electricity generation business, decreased by US$8.7 million when compared to the immediately preceding quarter, remaining even at 40% in percentage terms. This was mainly due to a slight decrease in physical sales volumes, lower revenue from capacity reliquidations, and lower spot sales. This was partly offset by lower spot purchase costs explained by an 11% decrease in average realized spot prices. The above resulted in a US$20.3 million revenue decrease, partially compensated for by a US$11.6 million cost decrease.

The year-on-year comparison shows a US$19.1 million decrease in the electricity margin (US$9.1 million revenue increase and US$28.3 million cost increase). The increase in fuel prices, particularly coal, was the main reason behind the 9% average realized price increase (US$105/MWh in 3Q17 vs. US$97/MWh in 3Q16), which combined with a 4% decrease in physical sales, resulted in a 4% increase in energy and capacity revenues. On the costs side, fuel costs increased by US$10.3 million despite the lower generation (-510 GWh). Electricity purchases increased by US$18 million as physical spot purchases increased by 91% or 375 GWh, while realized purchase prices fell 18%. In sum, (i) lower energy sales volumes, combined with (ii) greater provisions and lower revenue related to sufficiency capacity reliquidations, and (iii) new green taxes (US$3.8 million) contributed to explain the year-on-year decrease in the electricity margin.

Operating Results

Quarterly Information (in US$ millions)

EBITDA	**3Q 2016** Amount	**3Q 2016** % of total	**2Q 2017** Amount	**2Q 2017** % of total	**3Q 2017** Amount	**3Q 2017** % of total	**% Variation** QoQ	**% Variation** YoY
Total operating revenues………………………	246.8	*100%*	271.7	*100%*	251.7	*100%*	*-7%*	*2%*
Total cost of goods sold……………………	(196.8)	*-80%*	(223.9)	*-82%*	(216.7)	*-86%*	*-3%*	*10%*
Gross income…………………………	**50.0**	*20%*	**47.8**	*18%*	**35.1**	*14%*	***-27%***	***-30%***
Total selling, general and administrative expenses and other operating income/(costs).	(8.4)	*-3%*	(7.4)	*-3%*	(10.0)	*-4%*	*35%*	*19%*
Operating income…………………	**41.6**	*17%*	**40.4**	*15%*	**25.1**	*10%*	***-38%***	***-40%***
Depreciation and amortization……...…………	34.8	*14%*	34.0	*13%*	35.0	*14%*	*3%*	*1%*
EBITDA………………….………………	**76.4**	*31.0%*	**74.4**	*27.4%*	**60.1**	*23.9%*	***-19%***	***-21%***

3Q17 EBITDA reached US$60.1 million, an US$14.3 million decrease compared to the immediately preceding quarter. This was due to the above-explained US$8.7 million electricity margin decrease and an increase in operating costs and administrative expenses. While the US$3.4 million increase in operating costs was mainly due to reliquidations of transmission tolls and third-party maintenance services; the US$3.7 million increase in SG&A expenses included land rental fees, IT system upgrade expenses, and project development costs. All this was slightly offset by an increase in other operating income.

EBITDA decreased by US$16.3 million year-on-year due to the US$19.1 million electricity margin decrease, a US$2.3 million increase in SG&A expenses, and lower gas and other operating revenues. The above was offset by an US$8.8 million decrease in operating costs including renegotiation of service contracts, among others.

Financial Results

Quarterly Information (In US$ millions)

Non-operating results	**3Q 2016** Amount	**3Q 2016** % of total	**2Q 2017** Amount	**2Q 2017** % of total	**3Q 2017** Amount	**3Q 2017** % of total	**% Variation** QoQ	**% Variation** YoY
Financial income………..………………………	0.5	*0%*	0.9	*0%*	0.0	*0%*	*-98%*	*-96%*
Financial expense…………….…………………	(6.8)	*-3%*	(3.3)	*-1%*	(2.3)	*0%*	*-31%*	*-67%*
Foreign exchange translation, net…………..	1.3	*1%*	(1.4)	*-1%*	1.5	*0%*		
Share of profit (loss) of associates accounted for using the equity method	0.3	*0%*	(0.2)	*0%*	0.2	*0%*	*-181%*	*-44%*
Other non-operating income/(expense) net…	0.9	*0%*	10.1	*4%*	0.5	*0%*		
Total non-operating results…………….	**(3.7)**	*-2%*	**6.1**	*3%*	**(0.1)**	*0%*		
Income before tax……………………. ………	37.9	*16%*	46.4	*19%*	25.0	*3%*	***-46%***	***-34%***
Income tax………………………………………	(10.2)	*-4%*	(12.5)	*-5%*	(6.2)	*-1%*	*-51%*	*-39%*
Net income from continuing operations after taxes …	27.7	*12%*	33.9	*14%*	18.8	*2%*	*-44%*	*-32%*
Net income attributed to controlling shareholders…….	**27.0**	*12%*	**31.5**	*13%*	**18.1**	*2%*	***-42%***	***-33%***
Net income attributed to minority shareholders……….	0.7	*0%*	2.4	*1%*	0.7	*0%*	*-71%*	
Net income to EECL's shareholders	**27.0**	*12%*	**31.5**	*13%*	**18.1**	*2%*	***-42%***	***-33%***
Earnings per share……………………..	**0.026**		**0.030**		**0.017**			

The interest income item was virtually null in the third quarter since US$0.6 million in interest income was offset by the mark-to-market valuation of fuel hedges. For this reason, interest income was lower compared to both the 2Q17 and 3Q16.

Interest expense decreased by US$1.0 million compared to 2Q17 and decreased by US$4.6 million when compared to the third quarter of 2016. These changes depend on the pace of interest capitalization of the company's existing debt, which is made in proportion to the IEM capital expenditures made in each quarter.

Foreign-exchange income reached US$1.5 million in the quarter, which compares positively with a foreign-currency loss reported in the 2Q17 and a gain in the 3Q16. This is explained by the effect of exchange-rate variations on 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. During 2016, the company had accounts receivable from TEN in Chilean pesos, which reported a foreign-exchange gain. This receivable was fully repaid in December 2016.

The account labelled 'Share of profit (loss) of associates accounted for using the equity method' showed a small profit due to the proportional result in the jointly-controlled TEN project company. TEN reported moderate profits due to foreign-exchange results, which offset SG&A expenses that cannot be accounted for as capital expenditures. The year-on-year comparison shows a slight profit decrease; however, this account is immaterial as TEN is still in its construction stage.

The 'Other net non-operating income' account included a positive amount (US$1.3 million) corresponding to insurance reimbursements associated to a loss at CTM3. In the second quarter, this item included US$10 million resulting from the partial recognition of insurance recoveries on the U16 loss reported at year-end 2016. The year-on-year comparison is unfavorable as in the third quarter of 2016, this item included income on the sale of the company's corporate offices.

Net Earnings

The applicable income tax rate for 2017 is 25.5%, up from 24% in 2016.

In the third quarter of 2017, the company reported after-tax net income of US$18.1 million, a decrease compared to the 2Q17's US$31.5 million, due to lower operating results and the US$10 million insurance recovery accounted for in the second quarter. This effect was softened by lower income taxes. The year-on-year comparison also shows some deterioration due to a US$16.5 million decrease in operating income, in part compensated for by a US$4.6 million interest-expense reduction. Despite the higher income-tax rate, the lower pre-tax results explained the US$4 million decrease in the income tax provision.

9M 2017 compared to 9M 2016

Operating Revenues

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

	9M 2016		9M 2017		Variation	
Operating Revenues	Amount	% of total	Amount	% of total	Amount	%
Unregulated customers sales…………………..	485.4	*74%*	540.1	*76%*	*54.7*	*11%*
Regulated customers sales…………………….	133.1	*20%*	146.9	*21%*	*13.8*	*10%*
Spot market sales……………………………..	33.9	*5%*	24.4	*3%*	*-9.4*	*-28%*
Total revenues from energy and capacity sales……	**652.4**	*91%*	**711.4**	*91%*	***59.0***	*9%*
Gas sales…………………………..	6.1	*1%*	5.4	*1%*	*-0.7*	*-11%*
Other operating revenue……………………….	59.4	*8%*	65.4	*8%*	*6.0*	*10%*
Total operating revenues………………….	**717.9**	*100%*	**782.2**	*100%*	***64.3***	*9%*
Physical Data (in GWh)						
Sales of energy to unregulated customers (1)……	5,113	*74%*	4,818	*74%*	*-295*	*-6%*
Sales of energy regulated customers……	1,430	*21%*	1,441	*22%*	*11*	*1%*
Sales of energy to the spot market……………	368	*5%*	246	*4%*	*-122*	*-33%*
Total energy sales………………………….	**6,911**	*100%*	**6,505**	*100%*	***-406***	*-6%*
Average monomic price unregulated customers(U.S.$/MWh)(2)	**94.7**		**111.5**		***16.7***	*18%*
Average monomic price regulated customers (U.S.$/MWh)(3)	**93.1**		**102.0**		***8.9***	*10%*

(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$711.4 million in the first nine months of 2017, representing a 9% increase compared to the first nine months of 2016, due to the price indexation to increasing fuel prices. As a reference, average international European coal prices climbed 41%, while the Henry Hub gas index reported a 29% increase. Sales to both regulated and unregulated clients increased, as opposed to spot sales, which exhibited a decrease.

Physical energy sales decreased 6% basically due to decreases in the unregulated segment and spot sales. The decrease in physical sales to unregulated clients was primarily explained by the end of the Cerro Colorado and the Radomiro Tomic PPAs in September 2016 and August 2017, respectively, and decreased demand from El Abra and Codelco. This was partly offset by increased demand from Antucoya, Altonorte, Esperanza and El Tesoro, among others.

Sales to distribution companies, or regulated clients, amounted to US$146.9 million, representing a 10% increase compared to the first nine months of 2016, as a result of higher prices. The average Henry Hub index used in the calculation of the EMEL tariff increased from US$2.80/MMBtu and US$2.05/MMBtu through the first nine months of 2016 to US$2.52/MMBtu and US$3.08/MMBtu through the first nine months of 2017.

Physical sales to the spot market decreased 33% due to the CTA maintenance. The spot market sales and purchase items also include the retroactive annual sufficiency capacity price and monthly energy adjustment payments per the re-liquidations made by the SING dispatch center.

Small gas sales volumes were reported in both periods. The most relevant item in the Other operating revenue account is composed of sub-transmission tolls and regulatory transmission revenues, which accounted for almost 73% of this item. In addition, this item includes port and maintenance services and connection rights, among others.

Operating Costs

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

	9M 2016		9M 2017		Variation	
Operating Costs	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Fuel and lubricants……………………………	(235.7)	*39%*	(261.4)	*38%*	*25.7*	*11%*
Energy and capacity purchases on the spot market…	(94.4)	*16%*	(165.5)	*24%*	*71.0*	*75%*
Depreciation and amortization attributable to cost of goods sold…	(100.7)	*17%*	(99.4)	*15%*	*-1.3*	*-1%*
Other costs of goods sold…………………….	(150.1)	*25%*	(132.6)	*19%*	*-17.4*	*-12%*
Total cost of goods sold………………..	**(580.9)**	*96%*	**(658.8)**	*96%*	***78.0***	***13%***
Selling, general and administrative expenses…	(20.3)	*3%*	(26.1)	*4%*	*5.7*	*28%*
Depreciation and amortization in selling, general and administrative expenses…	(3.0)	*0%*	(3.1)	*0%*	*0.1*	*3%*
Other operating revenue/costs……………………….	1.1	*0%*	3.8	*-1%*	*-2.7*	*249%*
Total operating costs….……………….	**(603.1)**	*100%*	**(684.1)**	*100%*	***81.0***	***13%***
Physical Data (in GWh)						
Gross electricity generation						
Coal………………………………………….	5,302	*80%*	3,834	*83%*	*-1,468*	*-28%*
Gas…………………………………………..	1,243	*19%*	746	*16%*	*-497*	*-40%*
Diesel Oil and Fuel Oil…………………….	25	*0%*	23	*1%*	*-2*	*-8%*
Hydro/Solar……………………………………….	36	*1%*	43	*1%*	*7*	*18%*
Total gross generation………………….	**6,606**	*100%*	**4,646**	*100%*	***-1,960***	***-30%***
Minus Own consumption………………..	(505)	*-8%*	(373)	*-8%*	*131*	*-26%*
Total net generation…………………….	**6,102**	***85%***	**4,273**	***64%***	***-1,829***	***-30%***
Energy purchases on the spot market………..	1,060	***15%***	2,452	***36%***	*1,392*	*131%*
Total energy available for sale before transmission losses………………………	**7,161**	***100%***	**6,724**	***100%***	***-437***	***-6%***

The commissioning of new base-load plants in the system during 2016 (Cochrane and Kelar) and new renewable capacity led to an important decrease in our own electricity generation in the first nine months of 2017 and an increase in our energy purchases on the spot market.

The increase in international fuel prices resulted in an 11% increase (US$25.7 million) in the fuel cost item in the first nine months of 2017, despite the decrease in generation. The fuel cost increase is explained mainly by higher coal costs, the enactment of CO_2 taxes, and hydrated lime costs in the Mejillones complex, effective since July 2016. This was partially offset by lower LNG costs.

The spot electricity purchase costs item increased 75% since physical purchases more than doubled, while average realized spot prices dropped by 24%.

Depreciation costs decreased by US$1.3 million as a result of asset write-offs related to the failure of the U16 in late 2016 and Central Tamaya, which ceased to be depreciated in March 2016.

Other direct operating costs included, among others, operating and maintenance costs, cost of fuel sold and sub-transmission tolls related to the EMEL contract, with the latter covered by revenues from sub-transmission tolls. This item, as a whole, decreased by US$17.4 million when compared to the first nine months of 2016, mainly due to cost-saving initiatives involving renegotiations of procurement contracts and insurance policies, among others, as well as lower demurrage and fuel handling costs.

SG&A expenses increased by US$5.7 million, in part due to a low comparison base explained by the reversal of a legal cost provision in 2016, and also due to the reorganization of working teams, the appreciation of the Chilean peso (CLP654/USD in 9M17 vs CLP680/USD in 9M16), and the payment of land rental fees. Lower IT, travel and consulting expenses achieved in the context of a cost-saving plan partially offset these effects.

The Other operating revenue/cost item includes water sales, services and office rentals as well as the proportional result in TEN. The latter improved mainly due to foreign-exchange results, which offset TEN's pre-operating expenses.

Operating Results

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

EBITDA	**9M 2016**		**9M 2017**		**Variation**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Total operating revenues………………………	717.9	*100%*	782.2	*100%*	*64.3*	*9%*
Total cost of goods sold……………………	(580.9)	*81%*	(658.8)	*84%*	*78.0*	*13%*
Gross income……………………….	**137.0**	*19%*	**123.3**	*16%*	***-13.7***	***-10%***
Total selling, general and administrative expenses and other operating income/(costs).	(22.2)	*3%*	(25.3)	*3%*	*3.1*	*14%*
Operating income…..………………	**114.8**	*16%*	**98.1**	*13%*	***-16.7***	***-15%***
Depreciation and amortization……...…………	103.6	*14%*	102.4	*13%*	*-1.2*	*-1%*
EBITDA……………….….…………….	**218.4**	*30.4%*	**200.5**	*25.6%*	***-17.9***	***-8%***

EBITDA reached US$200.5 million in the first nine months of 2017, 8% below the EBITDA reported in the first nine months of 2016. As explained earlier, the US$37.7 million decrease in gross electricity profits explained by lower physical sales, the effect of green taxes, higher hydrated lime costs, and sufficiency capacity reliquidations, was partially offset by a US$17.4 million decrease in operating costs and higher toll income. All this led to a decrease in gross income.

SG&A expenses increased during the first nine months of 2017 because of both provision reversals reported in 2016 and greater project development costs, which contributed to the EBITDA decrease.

Financial Results

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

	9M 2016		**9M 2017**		**Variation**	
Non-operating results	**Amount**	**% of total**	**Amount**	**% of total**	**Amount**	**%**
Financial income………..………………………	1.7	*0%*	1.9	*0%*	*0.2*	*11%*
Financial expense…………..…………………	(22.6)	*-3%*	(10.0)	*-1%*	*12.6*	*-56%*
Foreign exchange translation, net……………	2.4	*0%*	0.4	*0%*	*-2.0*	*-84%*
Share of profit (loss) of associates accounted for using the equity method	53.8	*7%*	0.6	*0%*	*-53.2*	
Other non-operating income/(expense) net…	180.6	*25%*	10.2	*1%*	*-170.5*	
Total non-operating results…………….	**215.9**	*30%*	**3.1**	*0%*		
Income before tax……………………. ………	330.7	*46%*	101.1	*13%*	***-229.6***	***-69%***
Income tax……………………………………	(68.3)	*-10%*	(26.2)	*-3%*	*42.1*	
Net income from continuing operations after taxes …	262.4	*37%*	74.9	*10%*	*-187.5*	*-71%*
Net income attributed to controlling shareholders…….	**260.6**	*36%*	**69.3**	*9%*	***-191.3***	***-73%***
Net income attributed to minority shareholders……….	1.8	*0%*	5.6	*1%*	*3.8*	*207%*
Net income to EECL's shareholders	**260.6**	*36%*	**69.3**	*9%*	***-191.3***	***-73%***
Earnings per share…………………….	**0.247**		**0.066**			

Financial income increased slightly due to higher interest rates and discounts made on advanced payments to certain suppliers.

Interest expense decreased by US$12.6 million given the capitalization of interest in the IEM project.

Foreign-exchange profits reached US$0.4 million in the first nine months of 2017, which compares negatively with the US$2.4 million foreign-exchange gain reported in the first nine months of 2016, which at that time resulted from advances in local currency to TEN.

The 'Share of profit (loss) of associates accounted for using the equity method' account reported a small profit, which compares to exceptional income in 2016 related to the fair valuation of EECL's remaining 50% shareholding in TEN.

Other net non-operating income reached US$10.2 million due to insurance recoveries associated to the U16 loss reported in the last quarter of 2016. In the first nine months of 2016, this item included non-recurring income of US$180 million, explained almost entirely by the following non-recurring ítems: (i) Income from the sale of 50% of TEN's shares (US$187 million); (ii) sale of a converting substation to SQM (US$13 million); (iii) Tamaya fuel-oil plant impairment (US$18 million); and, (iv) expensing of project development costs (US$3 million).

Net Earnings

The applicable income tax rate for 2017 is 25.5%, up from 24% in 2016. The heavier income tax provision in the first nine months of 2016 is mainly attributed to the income on the sale of 50% of TEN.

In the first nine months of 2017, net income after taxes reached US$69.3 million, down from last year's exceptional US$260.6 million. For comparison purposes, when isolating the non-recurring effects, net income would have been US$60.9 million, a 3% decrease compared to the US$62.8 million recurring income in the first nine months of 2016. This is mainly explained by lower EBITDA combined with lower financial expenses.

Liquidity and Capital Resources

As of September 30, 2017, EECL reported cash balances of US$87 million. This amount compares with a total nominal financial debt[1] of US$825 million, with US$75 million of debt maturing within one year. The company has a US$270 million committed revolving credit facility to support its liquidity in times of active investment in capital expenditures. This facility has been provided by five international banks: Mizuho, BBVA, Citibank, Caixabank, and HSBC and matures on June 30, 2020. It remained undrawn as of September 30, 2017.

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

Cash Flow	**2016**	**2017**
Net cash flows provided by operating activities…	151.1	177.0
Net cash flows used in investing activities………	(49.9)	(415.9)
Net cash flows provided by financing activities..	(91.2)	46.6
Change in cash…………………..………….	**9.9**	**(192.3)**

(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.

Cash Flow from Operating Activities

In the first nine months of 2017, cash flow generated from operating activities reached approximately US$252.6 million, which after income tax payments (US$57.6 million) and interest expense (US$18 million), amounted to US$177 million. It should be noted that cash interest payments amounted to US$40.6 million, US$22.6 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 2017, cash flows from investing activities resulted in a net cash expenditure of US$415.9 million, mainly due to the investment in the IEM (US$319.3 million) and port (US$35.6 million) projects, plant and transmission assets maintenance (US$40.8 million) and contributions into TEN (US$21.4 million). By contrast, in the first nine months of 2016, net investment flows reached only US$49.9 million since capital expenditures were partially offset by cash flows from asset sales (50% of TEN and the SQM substation).

Capital Expenditures

Our capital expenditures in the first nine months of 2017 and the first nine months of 2016 amounted to US$395.7 million and US$273.7 million, respectively, as shown in the following table.

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

CAPEX	**2016**	**2017**
CTA ……………………………………………….	1.0	1.0
CTA (New Port) …………………………………..	50.4	35.6
CTH ………………………………………………	0.2	0.5
IEM …………………………………………………	186.4	319.3
Overhaul power plants & equipment maintenance and refurbishing…………………	2.5	17.2
Environmental improvement works………………	2.0	0.1
Solar plant………………………………………………..	9.1	0.0
Overhaul equipment & transmission lines …………………	7.8	16.0
Others……………………………………………	14.2	6.0
Total capital expenditures……………………….	**273.7**	**395.7**

Cash Flow from Financing Activities

Financing cash flows in the first nine months of 2017 include two items: (i) dividend payments totaling US$28.4 million, which included US$15.6 million paid to the minority shareholder in Inversiones Hornitos (CTH), and (ii) new one-year bank loans taken by EECL for an aggregate of US$75 million.

Contractual Obligations

The following table sets forth the maturity profile of our debt obligations as of September 30, 2017.

Contractual Obligations as of 09/30/17

Payments Due by Period (in US$ millions)

	Total	**< 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Bank debt……………………………	75.0	75.0	-	-	-
Bonds (144 A/Reg S Notes)………	750.0	-	-	400.0	350.0
Deferred financing cost…………..	(19.8)	(0.5)		(4.6)	(14.7)
Accrued interest…………………	7.6	7.6	-	-	-
Mark-to-market swaps	0.0	0.0	-	-	
Total	**812.8**	**82.2**	**-**	**395.4**	**335.3**

On July 20, 2017, EECL took two one-year loans with BCI for US$60 million and Banco de Crédito del Perú (BCP) for US$15 million. Both loans are in US dollars, accrue a fixed interest rate and are documented by simple promissory notes (*"pagarés"*) reflecting the payment obligation on the due date, with no operational or financial restrictions and prepayment option at any time with no penalties for the company.

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.

On June 30, 2015, EECL signed a long-term senior unsecured revolving credit facility agreement with five international banks (Mizuho, BBVA, Citibank, Caixabank and HSBC), that will allow the company to draw loans in a flexible manner in an aggregate amount of up to US$270 million with maximum maturity date of June 30, 2020. The execution of this revolving credit facility represented the fulfillment of the first milestone of the company's announced financing plan, and will provide EECL with financial flexibility to finance its expansion in the transmission and generation businesses. The facility draws a commitment fee on the unused portion of the line and a floating interest rate equal to 90-day LIBOR plus a margin on any drawn amounts. As of September 30, 2017, the committed amount remained fully available as EECL had not made any disbursements under this facility.

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, the size of our available cash balance and anticipated financing requirements for capital expenditures and investments in the following years. The dividend payment proposed by our Board is subsequently approved at a Shareholders' Meeting as established by law.

On April 25, 2017, at the Annual Ordinary Shareholders Meeting, our shareholders approved the Board's proposal to pay a final dividend of US$12,849,087.20 (US$0.012198773 per share) to be paid on May 18, 2017, in Chilean pesos using the peso-dollar observed rate published by the Official Gazette on May 15.

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

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, a Risk and Insurance Committee, responsible for the risk matrix review, analysis and approval as well as the proposal of risk mitigation measures, has been established. The risk matrix is updated and reviewed quarterly, while the monitoring of action plans is effected on a permanent basis. The company's risk management performance is presented to the company's board on an annual basis.

The company's financial risk management strategy is geared at safeguarding EECL's operating stability and sustainability in a context of risk and uncertainty.

Hedging Policy

Our hedging policy intends to protect the company from certain risks to which we are exposed, 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 is 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 may experience; and, (iii) our inability to perfectly match at all times our fuel cost mix with the tariff indexation in our PPAs, 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. In late 2016, we defined and executed a financial hedging strategy to cover our residual exposure to international commodity price risk in 2017. Therefore, we have taken financial swap contracts to further 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. A percentage of the advances made to our TEN affiliate in 2015 and 2016 was made in local currency; nevertheless, all of these loans were repaid with proceeds of the project financing in December 2016. In the specific case of the EMEL contract, the price is calculated in dollars and is currently converted to pesos at the average monthly exchange rate; therefore, the foreign currency exposure related to this contract has been substantially reduced. 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 as a result of foreign currency fluctuations out of management's control. In the last quarter of 2015 and through 2016 EECL made some advances to TEN denominated in UF (an inflation-linked Chilean peso unit), which were exposed to foreign-exchange fluctuations and gave birth to foreign-exchange differences. However, all of these advances were paid on December 16, 2016.

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, 2017, 100% of our financial debt, for a principal amount of US$825 million, was at fixed rates, including the US$75 million short-term loans with interest rates fixed for one year at the time of disbursement. Loans under the 5-year revolving credit facility will draw a variable interest rate based on 90-day LIBOR. As of this date, EECL has not requested any drawings under this facility.

As of September 30, 2017

Contractual maturity date (in US$ millions)

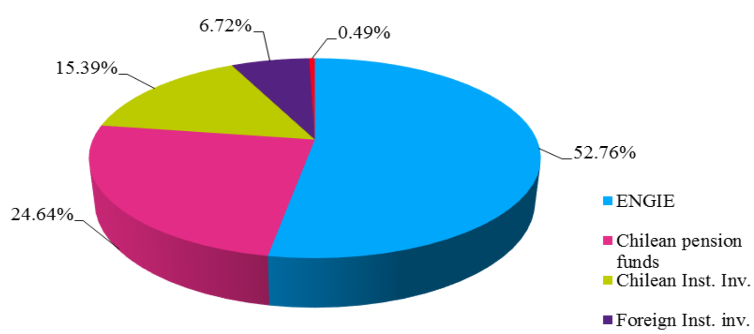
	Average interest rate	2017	2018	2019	2020	Thereafter	Grand Total
Fixed Rate							
(US$)	5.625% p.a.	-	-	-	-	400.0	400.0
(US$)	4.500% p.a.	-	-	-	-	350.0	350.0
(US$)	1.525% p.a.	-	75.0	-	-	-	75.0
Total		**-**	**75.0**	**-**	**-**	**750.0**	**825.0**

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 the sole regulated client in the SING, which provides electricity supply to residential and commercial clients in the region. 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 we have individual counterparty limits to manage our exposure.

OWNERSHIP STRUCTURE AS OF SEPTEMBER 30, 2017

Number of shareholders: 1,830



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

APPENDIX 1

PHYSICAL DATA AND SUMMARIZED QUARTERLY FINANCIAL STATEMENTS

Physical Sales

Physical Sales (in GWh)

	2016				2017			
	1Q16	**2Q16**	**3Q16**	**9M16**	**1Q17**	**2Q17**	**3Q17**	**9M17**
Physical Sales								
Sales of energy to unregulated customers.	1,737	1,691	1,685	5,113	1,600	1,631	1,587	4,818
Sales of energy to regulated customers	483	476	471	1,430	476	479	485	1,441
Sales of energy to the spot market………	109	168	91	368	88	82	76	246
Total energy sales…………………………	**2,328**	**2,336**	**2,247**	**6,911**	**2,164**	**2,193**	**2,148**	**6,505**
Gross electricity generation								
Coal………………………………………….	1,893	1,749	1,660	5,302	1,253	1,294	1,286	3,834
Gas…………………………………………..	499	343	401	1,243	277	234	236	746
Diesel Oil and Fuel Oil…………………….	7	11	7	25	3	13	7	23
Renewable……………………………………….	12	10	14	36	17	13	13	43
Total gross generation………………….	**2,411**	**2,114**	**2,082**	**6,606**	**1,550**	**1,555**	**1,542**	**4,646**
Minus Own consumption……………..	(191)	(162)	(152)	(505)	(130)	(122)	(121)	(373)
Total net generation……………………	**2,220**	**1,952**	**1,930**	**6,102**	**1,419**	**1,433**	**1,421**	**4,273**
Energy purchases on the spot market………..	178	468	414	1,060	821	842	795	2,458
Total energy available for sale before transmission losses………………………	**2,397**	**2,420**	**2,344**	**7,161**	**2,240**	**2,275**	**2,215**	**6,730**

Quarterly Income Statement

Quarterly Income Statement (in US$ millions)

IFRS								
Operating Revenues	**1Q16**	**2Q16**	**3Q16**	**9M16**	**1Q17**	**2Q17**	**3Q17**	**9M17**
Regulated customers sales………………………	47.7	43.9	41.5	133.1	46.7	51.3	48.9	146.9
Unregulated customers sales…………………..	156.7	165.9	162.9	485.4	184.4	184.2	171.4	540.1
Spot market sales………………………………..	8.2	12.8	12.8	33.9	7.1	11.2	6.1	24.4
Total revenues from energy and capacity sales……………………………	**212.6**	**222.5**	**217.3**	**652.4**	**238.3**	**246.7**	**226.4**	**711.4**
Gas sales…………………………..	0.1	2.2	3.7	6.1	1.3	1.9	2.2	5.4
Other operating revenue……………………….	18.2	15.4	25.8	59.4	19.2	23.1	23.1	65.4
Total operating revenues…………………	**230.9**	**240.2**	**246.8**	**717.9**	**258.8**	**271.7**	**251.7**	**782.2**
Operating Costs								
Fuel and lubricants………………………………	(85.9)	(74.4)	(75.4)	(235.7)	(88.2)	(87.5)	(85.7)	(261.4)
Energy and capacity purchases on the spot	(21.0)	(41.0)	(32.4)	(94.4)	(54.7)	(60.3)	(50.4)	(165.5)
Depreciation and amortization attributable to cost of goods sold..	(33.8)	(33.3)	(33.6)	(100.7)	(32.3)	(33.0)	(34.0)	(99.4)
Other costs of goods sold…………………….	(45.8)	(48.9)	(55.3)	(150.1)	(43.0)	(43.1)	(46.5)	(132.6)
Total cost of goods sold………………..	**(186.5)**	**(197.6)**	**(196.8)**	**(580.9)**	**(218.3)**	**(223.9)**	**(216.7)**	**(658.8)**
Selling, general and administrative expenses…	(6.8)	(5.1)	(8.4)	(20.3)	(8.3)	(7.0)	(10.7)	(26.1)
Depreciation and amortization in selling, general and administrative expenses…	(0.6)	(1.2)	(1.2)	(3.0)	(1.1)	(1.0)	(1.0)	(3.1)
Other revenues………...……………………….	(0.7)	0.6	1.2	1.1	1.5	0.6	1.7	3.8
Total operating costs…..………………	**(194.6)**	**(203.3)**	**(205.2)**	**(603.1)**	**(226.2)**	**(231.3)**	**(226.7)**	**(684.1)**
Operating income…..………………	**36.3**	**36.9**	**41.6**	**114.8**	**32.6**	**40.4**	**25.1**	**98.1**
			0	0				
EBITDA………………..………………	**70.7**	**71.3**	**76.4**	**218.4**	**66.0**	**74.4**	**60.1**	**200.5**
Financial income………..………………………	0.6	0.6	0.5	1.7	1.0	0.9	0.0	1.9
Financial expense…………..…………………	(7.8)	(8.0)	(6.8)	(22.6)	(4.5)	(3.3)	(2.3)	(10.0)
Foreign exchange translation, net……………	0.8	0.2	1.3	2.4	0.3	(1.4)	1.5	0.4
Share of profit (loss) of associates accounted for using the equity method	53.9	(0.4)	0.3	53.8	0.7	(0.2)	0.2	0.6
Other non-operating income/(expense) net……………………..	179.3	0.5	0.9	180.6	(0.5)	10.1	0.5	10.2
Total non-operating results……………	**226.8**	**(7.2)**	**(3.7)**	**215.9**	**(2.9)**	**6.1**	**(0.1)**	**3.1**
Income before tax…………………..………	263.1	29.7	37.9	330.7	29.7	46.4	25.0	101.1
Income tax………………………………………	(49.8)	(8.3)	(10.2)	(68.3)	(7.4)	(12.5)	(6.2)	(26.2)
Net income from continuing operations after taxes …….	213.3	21.4	27.7	262.4	22.2	33.9	18.8	74.9
Net income attributed to controlling shareholders………………	**212.0**	**21.6**	**27.0**	**260.6**	**19.7**	**31.5**	**18.1**	**69.3**
Net income attributed to minority shareholders……………….	1.3	(0.2)	0.7	1.8	2.6	2.4	0.7	5.6
Net income to EECL's shareholders…….	**212.0**	**21.6**	**27.0**	**260.6**	**19.7**	**31.5**	**18.1**	**69.3**
Earnings per share…………………….. (US$/share)	**0.201**	**0.020**	**0.026**	**0.247**	**0.019**	**0.030**	**0.017**	**0.066**

Quarterly Balance Sheet

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

	2016 December	2017 September
Current Assets		
Cash and cash equivalents (1)	278.8	87.1
Other financial assets	2.7	2.8
Accounts receivable	104.6	117.5
Recoverable taxes	36.1	27.6
Current inventories	177.1	166.6
Other non financial assets	34.8	29.2
Total current assets	**634.2**	**430.8**
Non-Current Assets		
Property, plant and equipment, net	2,206.8	2,442.2
Other non-current assets	472.1	474.9
TOTAL ASSETS	**3,313.1**	**3,347.9**
Current Liabilities		
Financial debt	17.4	82.2
Other current liabilities	274.8	212.1
Total current liabilities	**292.2**	**294.3**
Long-Term Liabilities		
Financial debt	731.4	730.7
Other long-term liabilities	283.3	281.4
Total long-term liabilities	**1,014.7**	**1,012.1**
Shareholders' equity	1,922.5	1,966.9
Minority' equity	83.6	74.6
Equity	**2,006.2**	**2,041.5**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,313.1**	**3,347.9**

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

Main Balance Sheet Variations

The main variations between the balance sheet as of September 30, 2017, and December 30, 2016, are the following:

Cash and cash equivalents: The US$191.7 million decrease in cash balances is explained by the use of cash in the company's current intensive capital expenditure program.

Accounts receivable: The US$12.9 million increase is mainly a result of an account receivable from regulated clients arising from the differential between the tariff in effect according to the contract and the tariff being effectively applied to regulated clients according to the Node Price decrees. This differential was caused by the delay in the publication of the Average Node Price decrees, and will be paid over one-year periods following the publication of the decrees. On October 10, 2017, the Average Node Price decrees for the six-month periods starting January 2017 and July 2017 were published.

Recoverable taxes: The US$8.5 million decrease is mainly due to recoverable balances related to taxes paid on income from previous years. These tax recoveries were effectively received during this period.

Current inventories: A US$10.6 millones decrease can be observed in inventory balances due to variations in opposite directions. While inventories of coal and emission-control additives (hydrated lime, limestone and bicarbonate) decreased by US$7.7 million and diesel oil inventories fell US$3.9 million due to lower generation based on fossil fuels, LNG inventories increased by US$10 million as a result of the generation and gas shipment programs. There was also a US$5.3 million reduction in the materials and supplies account and a US$3.3 million obsolescence provision, which contributed to the inventory reduction.

Other non-financial assets – current: The US$5.6 million reduction in this item is explained by lower advances to suppliers. It offset a US$4.6 million increase in the VAT credit account, basically resulting from the high level of capital expenditures in the construction of the IEM and Puerto Andino projects.

Property, plant and equipment, net: The construction of the IEM and Puerto Andino projects primarily explain the net US$235.4 million increase in this item.

Financial debt – current: This item reported a net US$64.8 million increase due to two main factors: (i) the company took US$75 million in short-term debt with BCI and BCP and (ii) interest on the two 144-A/Reg S bonds had accrued a higher amount as of December than as of September given that interest payments are due in the months of January and July of each year.

Other current liabilities: The significant US$62.7 million reduction in this item was a result of the following main variations: (i) A US$38.1 million decrease in income tax provisions explained by the high non-recurring income on asset sales (50% of the TEN project) reported in 2016; (ii) the absence of accounts payable to our LNG supplier, whereas in December there was a US$14 million account payable; (iii) a US$16.7 million decrease in trade payables; (iv) a US$3.7 million decrease in provisions for employee benefits; (v) an US$8 million increase in dividends payable; and (vi) a US$2.3 million increase in unearned income.

Long-term financial debt: This item had no variations during the period.

Other long-term liabilities: This account's main item corresponds to deferred taxes, and it had no relevant variations.

Shareholders' equity: The US$44 million increase in shareholders' equity is made up of (i) US$69.3 million in net income in the first nine months of 2017, minus (ii) US$4.1 million in mark-to-market variations of derivatives taken for hedging purposes and minus (iii) a US$20.7 million dividend payment provision corresponding to 30% of net income in accordance with the company's dividend payment policy.

Minority equity: This account reported a US$9 million decrease due to the payment of retained earnings and dividend payment provisions for an aggregate amount of US$15 million, which exceeded the period's US$5.6 million net income.

APPENDIX 2

Financial information

	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17
EBITDA*	70.7	71.3	76.4	66.4	66.0	74.4	60.1
Net income attributed to the controller	212.0	21.6	27.0	-5.7	19.7	31.5	18.1
Interest expense	7.8	8.0	6.8	4.1	4.5	3.3	2.3

* Operating income + Depreciation and Amortization for the period

	Dec-16	Sep-17
LTM EBITDA	284.8	266.8
LTM Net income attributed to the controller	254.8	63.6
LTM Interest expense	26.7	14.1

	Dec-16	Sep-17
Financial debt	748.9	812.8
Current	17.4	82.2
Long-Term	731.4	730.7
Cash and cash equivalents	278.8	87.1
Net financial debt	470.1	725.7

Financial Ratios

	FINANCIAL RATIOS				
			Dec-16	**Sep-17**	**Var.**
LIQUIDITY	Current ratio (current assets / current liabilities)	(times)	2.17	1.46	***-33%***
	Quick ratio ((current assets - inventory) / current liabilities)	(times)	1.56	0.90	***-43%***
	Working capital (current assets – current liabilities)	MMUS$	342.0	136.5	***-60%***
LEVERAGE	Leverage ((current liabilities + long-term liabilities) / networth)	(times)	0.65	0.64	***-2%***
	Interest coverage * ((EBITDA / interest expense))	(times)	10.66	18.92	***78%***
	Financial debt –to- LTM EBITDA*	(times)	2.63	3.05	***16%***
	Net financial debt – to - LTM EBITDA*	(times)	1.65	2.72	***65%***
PROFITABILITY	Return on equity* (LTM net income attributed to the controller / net worth attributed to the controller)	%	13.3%	3.2%	***-76%***
	Return on assets* (LTM net income attributed to the controller / total assets)	%	7.7%	1.9%	***-75%***

*LTM = Last twelve months

As of the end of September 2017, the current ratio and the quick ratio were 1.46x and 0.90x, respectively, a decrease compared to December 2016 mainly due to (i) a decrease in cash balances as available cash was used to pay for heavy capital expenditures; and (ii) a US$75 million increase in current debt. As a result, working capital, measured as total current assets minus total current liabilities, decreased to US$136.5 million.

The leverage ratio, as measured by total liabilities-to-equity, reached 0.64x as of September 30, 2017, a minimal reduction compared to December 2016's 0.65x, explained by the increase in net worth and minimal variation in total liabilities. The latter was explained by the decrease in non-financial liabilities (mainly tax liabilities), which offset the increase in financial debt.

Interest coverage as of September 30, 2017, was 18.92x, greater than December 2016's 10.66x as a result of a decrease in interest expense explained by the capitalization of interest in the IEM project.

The leverage ratio, as measured by Gross financial debt-to-last-twelve-months EBITDA, increased by 16% due to the combined effect of the 8.5% increase in financial debt and the 6.3% decrease in LTM EBITDA. Net financial debt-to-LTM EBITDA increased further by 65% given the debt increase and the use of available cash (US$192 million) to finance capital expenditures.

Return on equity and return on assets decreased markedly as compared to December 2016, due to exceptionally high non-recurring income reported in the first quarter of 2016 as a result of the sale of 50% of the shares in the TEN Project.

CONFERENCE CALL 9M17

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, 2017, on Tuesday, November 7th, 2017, at 10:00 a.m. (USA-NY) – 12:00 p.m. (Chilean Time)

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

To participate, please dial: **1(412) 858-4609**, international or **1230-020-5802 (toll free Chile)** or 1(866) 750-8807 (toll free US).
To join the conference, please state the name of the conference (**ENGIE Energía Chile**); 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.: 10113236, a conference call replay will be available until Nov 17, 2017.