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Energy InfraSAP

Final Report

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EAE



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Table of Contents

List of Figures.....	iii
List of Tables.....	iv
Abbreviations.....	iv
Acknowledgements.....	1
Executive Summary.....	2
1 Overview of Sri Lanka’s Power Sector.....	24
2 Energy Investment Plans and Financing Needs.....	257
3 Binding Constraints to Financing.....	388
4 Roadmap to Address Key Constraints.....	554
Annexes.....	69
References.....	118

List of Figures

Figure 1: Average Power Generation Cost from Current Sources	18
Figure 2: Co2 emissions per capita	19
Figure 3: CO2 Savings in Base Case Compared to Reference Case	20
Figure 4: LNG Import Prices	22
Figure 5: Base Case Capacity Addition as per LTGEP 2018-2037 (MW).....	25
Figure 6: Capital Investment as per LTGEP 2018-2037 Base Case	26
Figure 7: Potential Sources of Investment for Power Sector.....	32
Figure 8: CEB Profitability Ratios	40
Figure 9: CEB’s Cash Flow Analysis	40
Figure 10: CEB’s Debt (2016)	41
Figure 11: Average Weighted Prime Lending Rate	44
Figure 12: Debt Trading Statistics in Sri Lanka	46
Figure 13: Government Bond’s Maturity Profile	46
Figure 14: Government Debt (% of GDP).....	48
Figure 15: Government’s Fiscal Deficit (% of GDP).....	48
Figure 16: FDI Inflows (% of GDP)	49
Figure 17: Government Spending on Power Sector	49
Figure 18: Green Bond Structure	65
Figure 19: Power Sector Structure.....	69
Figure 20: Power demand evolution	71
Figure 21: Sector wise power consumption	71
Figure 21: Installed capacity evolution	71
Figure 23: Power generation mix.....	72
Figure 24: Cost of power is higher than end user pricing.....	72
Figure 25: Average cost of power from existing generation sources	73
Figure 25: Transmission and Distribution Licensees.....	73
Figure 27: Transmission Network Evolution	75
Figure 28: Distribution Network Evolution	76
Figure 28: CEB’s Transmission and Distribution Losses	76
Figure 30: Transmission Charge	80
Figure 31: Average Tariff by Indian State Distribution Companies (US Cents / kWh)	80
Figure 32: CPC Facing Operational Losses due to Regulated Oil Pricing.....	85
Figure 33: LECO Distribution Losses.....	86
Figure 34: LECO’s Profit Margins	87
Figure 35: IMF Program – Key Objectives	94
Figure 35: Political Risk Insurance for Equity Investment.....	109
Figure 37: PRG Arrangement	110
Figure 38: Liquidity PRG Agreement.....	111
Figure 39: Bujagali Project Structure	113
Figure 40: Kribi Project Structure.....	113

List of Tables

Table 1: NCRE Projects Implemented, by Technology (as of February 2017)	15
Table 2: Financiers of Select NCRE Projects.....	16
Table 3: CO2 Emissions in Base Case and Reference Case of LTGEP 2018-2037	19
Table 4: Capital requirements of Power generation segment.....	26
Table 5: Capital requirements of Power Distribution Segment.....	29
Table 6: Total capital requirements for the Energy Sector.....	30
Table 7: Required Financing and Potential Funds available from Government Stakeholders	34
Table 8: Potential financing available from Domestic Banks.....	34
Table 9: Review of Proposed Capacity Additions and Actual Capacity Additions	35
Table 10: CEB’s Balance Sheet Snapshot	41
Table 11: Risk Allocation Framework.....	50
Table 12: India Sri Lanka TL - Estimated Cost of Alternative 1.....	78
Table 13: India Sri Lanka TL - Estimated Cost for Alternative 2	79
Table 14: NDC unconditional target estimation (GWh) based on BAU case of LTGEP 2013-2032.....	83
Table 15: Projected ORE development based on base case of LTGEP 208-2037 (GWh).....	84
Table 16: CPC Financials.....	85
Table 17: Sri Lanka’s Domestic Financial System.....	97
Table 18: Maturity profile of Domestic Banks’ Assets and Liabilities	97
Table 19: Risk Allocation – Tolling Model	100
Table 20: Risk Allocation – Alternate Tolling Model	101
Table 21: Risk Allocation – Merchant Model	103
Table 22: Risk Allocation – Integrated Supply Side Model	104
Table 23: Standard Risk Allocation Framework	107
Table 24: Tariff Rate (three-tier) All values in LKR / kWh)	117
Table 25: Flat Tariff Rate (All values in LKR / kWh).....	117

Abbreviations

Acronyms	Term
ADB	Asian Development Bank
AWPLR	Average Weighted Prime Lending Rate
BN	Billion
CBSL	Central Bank of Sri Lanka
CCGT	Combined Cycle Gas Turbines
CEB	Ceylon Electricity Board
CEYPETCO	Ceylon Petroleum Corporation
CIF	Cost, Insurance & Freight
CSE	Colombo Stock Exchange
DFI	Development Finance Institutions
DSCR	Debt Service Coverage Ratio

EBIT	Earnings before Interest and taxes
EBITDA	Earnings before Interest, taxes, depreciation and amortization
FCCL	Fiscal commitment and contingent liabilities
FDI	Foreign Direct Investment
FIT	Feed-In Tariff
FSRU	Floating Storage Regasification Unit
GDP	Gross Domestic Product
GoSL	Government of Sri Lanka
HNB	Hatton National Bank
HVDC	High Voltage Direct Current
IDA	International Development Association
IFC	International Finance Corporation
IMF	International Monetary Fund
InfraSAP	Infrastructure Sector Assessment Program
IPP	Independent Power Producer
LCB	Local Commercial Banks
LECO	Lanka Electricity Company (Pvt.) Ltd.
LKR	Sri Lankan Rupee
LTGEP	Long-Term Generation Expansion Plan 2018-37
LTTDP	Long Term Transmission Development Plan
MDB	Multi-lateral Development Bank
MFD	Maximize Finance for Development
MIGA	Multilateral Investment Guarantee Agency
MN	Million
MoF	Ministry of Finance
MoPRE	Ministry of Power and Renewable Energy
NAPPP	National Agency for Public Private Partnership
NCRE	Non-Conventional Renewable Energy (Solar, Wind, Biomass, Mini-Hydro, etc.)
NDC	Nationally Determined Contributions
O&M	Operation and Maintenance
ODSM	Operation Demand Side Management
PCG	Partial Credit Guarantee
PGCIL	Power Grid Corporation of India Limited
PPP	Public Private Partnership
PRG	Partial Risk Guarantee
PUCSL	Public Utilities Commission of Sri Lanka
RFP	Request for Proposals
SLSEA	Sri Lanka Sustainable Energy Authority
SOE	State Owned Entity
SPPA	Standard Power Purchase Agreement

T&D	Transmission and Distribution
TOU	Time of Use
TUA	Terminal Use Agreement
UNFCCC	United Nations Framework Convention on Climate Change
USP	Unsolicited Proposal
WBG	World Bank Group

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Sri Lanka Energy Infrastructure Sector Assessment Program

Executive Summary

Final Draft

February 8, 2019



Executive Summary

The World Bank Group (WBG) undertook the Sri Lanka Energy Infrastructure Sector Assessment Program (Infra SAP) study to assess the future investment needs to develop the energy sector in Sri Lanka. The Infra SAP explored the best potential options to mobilize foreign and domestic capital using limited public finance in the country. The financing landscape for energy infrastructure and the constraints to public and private financing in the country were analyzed as a backdrop to identifying potential financing sources and mechanism. While the study examined the entire energy sector, particular focus was on the development of non-conventional renewable energy (NCRE) and liquefied natural gas (LNG) to meet long-term energy demand in a sustainable and cost-effective manner. Based on the analysis and extensive stakeholder discussions, the WBG has developed a recommended roadmap for maximizing financing for the sustainable development of the energy sector by leveraging commercial financing.

The Energy Sector in Sri Lanka – A Snapshot

Sri Lanka’s power sector has made commendable progress in several areas in the last 10 years. Some of its achievements include near 100% electrification, low transmission & distribution losses and meeting increased electricity demand with new power generation. The country has also been able to stimulate the growth of Non-Conventional Renewable Energy (NCRE) and rooftop solar projects with financing from domestic banks and investors.

To meet growing energy needs, Sri Lanka will need to look beyond publicly financed projects and increase the share of commercial financing and encourage greater private sector participation. Electricity demand continues to grow at an annual rate of 5.6% and the Long-Term Generation Expansion Plan (LTGEP) indicates that capacity additions of some 8,341 MW will be needed by 2037. Public financing has historically been the primary source of financing for power plants owned by the Ceylon Electricity Board (CEB). Larger Projects (>10 MW) developed by independent power producers (IPPs) on a Build-Own-Operate-Transfer (BOOT) scheme have been able to mobilize international financing, but this financing has typically required a guarantee for CEB’s payment obligations from the Government of Sri Lanka (GoSL).

Despite initial success, the renewable energy sector is yet to scale up and achieve its potential. NCRE projects up to 10 MW have been successful in attracting private investment from domestic developers and lenders without government financing support. Such projects have contributed considerably to installed generation capacity in the country with about 400 MW of mini hydro¹, 128 MW of wind², 51 MW land mounted solar, 17 MW biomass, and 120 MW of rooftop solar. However, apart from a few recent competitive outcomes, the country has not yet been able to develop utility scale NCRE projects at tariffs comparable with other projects globally or in the region or to tap into commercial financing and private sector participation in larger scale projects. As part of the preparation of the InfraSAP, two pre-feasibility assessments for potential large scale NCRE park sites were conducted for sites in Pooneryn and Moneragala, respectively, totaling about 500 MW of potential generation capacity.

The natural gas sector in the country has been slow to develop and the exploration of domestic gas basins is uncertain. The focus has now shifted to procurement of LNG to fuel the power sector, but there is lack of clarity on the demand for LNG beyond the power sector. In the power sector, LNG is expected to fuel about 700 MW of old oil-fired power plants to be converted to gas-fired plants, and about 1,600 MW of new gas plants are

¹ Significant initial impetus to the development of mini hydro in Sri Lanka was provided by the World Bank Renewable Energy for Rural Development Project, which supported about 260 such projects.

² A 100 MW wind project is under implementation in Mannar, financed by the ADB

also planned in the LTGEP. However, LNG procurement methodologies and their cost effectiveness is yet to be examined in detail³. The country has recently received government to government proposals and unsolicited bids for supply of LNG, but given the take-or-pay nature of LNG contracts which would impose significant financial commitments on GoSL's balance sheet, it would be prudent to tender and competitively procure gas so as to try and minimize such commitments.

Development of the energy sector faces major challenges that, if not addressed, could bring into question its sustained long-term viability. Sri Lanka needs to develop and adopt a dynamic roadmap and innovative financing mechanisms and structures to efficiently and effectively develop the power sector moving forward.

Structural challenges

- Significant share of Sri Lanka's power generation is based on imported liquid fuels. Expensive oil-based generation is often used to compensate for low hydropower generation during adverse monsoon seasons, which have become increasingly frequent. CEB expenditure for liquid fuels has been close to USD 0.5 BN per year and could increase further. This has led to high average cost of power generation compared with other countries in the region (~ 8.5 US cents / kWh in 2016, compared to ~ 5.5 in India and ~ 6.5 in Bangladesh).
- Fuel prices in the country are "administered" and have typically not been cost-reflective. As a result, the state-owned Ceylon Petroleum Corporation (CPC) has been racking up losses weakening its balance sheet, impacting operations, and hindering its ability to raise capital. However, the Cabinet has recently approved a fuel pricing formula linked to a 3-month average of the Singapore Platts index and this could help ameliorate the situation, if the formula is consistently and transparently implemented.
- Electricity retail tariffs are not cost-reflective which is essential for long-term viability of the sector. In 2017, the average selling end user tariff was US cents 11.4 / kWh while the cost incurred for generation and transmission of the power to selling point was US cents 13.8 / kWh. Similar mismatch in 2016 has led to a cumulative subsidy requirement from CEB to GoSL of about USD 900 million (MN) for 2016 and 2017. However, while GoSL has not made direct subsidy payments to CEB, it has undertaken to service CEB's debt for projects where funds were on-lent from the government to CEB. This is a non-transparent and unsustainable cyclical arrangement. The inability of CEB to fully recover costs, in particular in years of low monsoon, has also resulted in delayed payments to suppliers including CPC.
- The approved tariff adjustment methodology, which would help adjust tariffs to be more cost reflective, has not been fully implemented. The establishment of a physical Bulk Supply Transaction (BST) Account, with separate costs and revenues for all CEB licensees, will be critical for the proper functioning of the tariff setting mechanism. However, this has not been established.
- Given the constraints in the government's ability to provide loans and guarantees to CEB moving forward, the existing energy sector framework will need to be restructured so that it can mobilize domestic and international commercial capital to meet the future investment needs of the sector.
- In the absence of cost-reflective tariffs and subsidy payments from GoSL, CEB and CPC are not creditworthy and, as such, will not be able to mobilize financing based on the strengths of their balance sheets.

Macro-fiscal challenges

- GoSL has limited fiscal space to make subsidy payments to CEB and CPC, which are necessary if it wishes to continue with below market energy prices.

³ Assuming LNG is procured only to meet gas demand in the power sector, it is estimated that Sri Lanka would need to contract LNG supplies worth about USD 7 BN over the 2018-37 period.

- Sri Lanka's international credit rating of B+ (S&P) is four notches below investment grade rating. In 2017, public debt was 77.6% of GDP, while the fiscal deficit was 5.4% of GDP. Currently, debt repayments account for more than 90% of the government's tax revenues. Sri Lanka is working with the IMF to improve the current fiscal situation, but IMF guidelines will further restrict the GoSL's ability to provide subsidized guarantees for foreign currency borrowings. This tenuous macro fiscal situation will, at least for the short to medium term, further hinder continued public financing of energy projects.
- Currency depreciation is a major risk for foreign investments in the energy sector since receivables will mostly be in local currency. Sri Lanka lacks a developed hedging market to mitigate foreign currency risk and the maximum tenor available in the domestic market for cross currency swaps is one year, which is insufficient for energy infrastructure loans with tenors of 10+ years. Previously, the Central Bank had offered currency swaps for certain projects of national importance, but it has recently made a policy decision to stop providing such swaps, thus requiring the market to hedge its own risks. There is currently no program to catalyze a long-term currency swap market.
- Foreign Direct Investment (FDI) investments in the power sector has seen a consistent decline over the past four years from USD 44.9 MN in 2013 to USD 1.1 MN in 2017. FDI has been declining primarily due to policy uncertainty, which the GoSL has tried to address with the New Inland Revenue Act (effective since April 1, 2018), which moves the incentive regime from profit-based incentives (such as tax holidays) granted under multiple laws, to a performance-based incentive (based on actual investment). The domestic banking sector needs strengthening and does not have adequate liquidity to finance the significant needs of the energy sector. In addition, the capital markets, which could help mobilize financing are currently limited and underdeveloped in Sri Lanka.

Lack of a robust and supportive enabling environment

- Power sector objectives and targets have not been fully aligned among sector stakeholders. After long deliberation among sector stakeholders, the 2018-37 long-term generation plan was approved in June 2018. A lack of alignment among sectoral entities may continue to delay project implementation and hinder mobilization of commercial finance.
- Processes for generation planning and tariff setting do not always follow institutional guidelines and mandates, and the planned LNG procurement has not been fully transparent; these factors exacerbate weaknesses in the power sector.
- Procurement procedures do not always follow leading global practice and there is a perceived lack of efficiency and transparency in the procurement process, which has led to project delays⁴. For example, the tender for 300 MW CCGT plant at Kerawalapitiya was delayed due to a less than transparent bid award process. The international bidders have disputed the tender results. The bid, which was initially awarded to CEB's subsidiary Lakdanavi, was ultimately awarded to a foreign private sector entity based on decision from the Procurement Appeal board. Until the transparency is improved, it would be extremely challenging to attract professional investors to invest in an environment which is perceived to be highly inefficient and with governance challenges.
- The Public Private Partnership (PPP) policy implementation needs strengthening in line with the two adopted Cabinet papers on PPPs. To attract private and foreign investment, the country needs to develop bankable project structures that allocate risks consistent with international best practices and mitigate those key risks related to political economy, change in law, payment security, currency risks and termination provisions. The proposed new PPP policy introduces equity, transparency and good

⁴ For instance, the tender for a 10 MW solar project has been extended three times with no clear information to the bidders on the reasons for the delay, and the last competitive tender for a wind project was released in December 2015. The GoSL has also received unsolicited bilateral proposals for supply of LNG from various countries and the terms of these bids have not been made public.

governance and clearly articulates the roles and responsibilities of parties whilst providing clarity on the process that would allow the GOSL to ensure value for money.

- Delays in procuring land for NCRE projects deters investment. The perceived lack of transparency in the allocation and valuation of publicly owned land is a hindrance. The multi-tiered approvals and licenses required from various agencies is also a constraint to investment.

Investment Needs in the Power Sector total USD 7 billion by 2026

To meet the projected demand for electricity in 2026⁵, Sri Lanka will need to mobilize capital investments of about USD 5.0 BN in generation, USD 1.1 BN in transmission, USD 229 MN in distribution, and USD 512 MN in planned DSM programs⁶. Including contingencies of about USD 102 MN, it is estimated that total cumulative funds of about USD 7 BN will be needed up to 2026.⁷

Potential Financing Sources to meet Capital Requirements and the Investment Gap

The estimated cumulative investment of about USD 7 BN in the power sector for the period up to 2026 will have to come from both the government, commercial banks, and the private sector, and tap both domestic and foreign sources of capital.

Financing Capacity of Key Stakeholders and Domestic Banks

CEB: CEB has historically financed projects through a) direct loans from DFIs and commercial banks backed by a guarantee from the MoF, and b) concessionary loans from DFIs and donors on-lent to CEB by the GoSL and guaranteed by the government. CEB is not presently able to raise significant additional debt itself on its balance sheet which has been weakened by the high use of expensive oil-based generation and absence of cost-reflective tariffs. In fact, in lieu of tariff adjustments, the government is repaying some of CEB's debt. Given the state of CEB's finances, it may only be able to raise about USD 300 MN through 2026 from domestic banks, provided it can still obtain government guarantees. However, if cost-reflective tariffs were to be approved, CEB could potentially leverage around USD 2 to 2.5 BN of additional debt by 2026, while minimizing the need for direct and indirect support from the government.

LECO: Lanka Electricity Company (LECO), a state-owned distribution company, is debt free and can finance capital investments in distribution projects from its cash accruals and other receivables. It is estimated that LECO could mobilize up to USD 150 MN of debt on its balance sheet through 2026 to meet its investment needs.

GoSL: The government's budget expenditure on power sector infrastructure project investments has been decreasing from about USD 55 MN in 2017 to USD 5.5 MN for 2018. Assuming an average annual budget of USD 30 MN over the medium term, GoSL may be able to invest up to USD 240 MN by 2026.

Local banks and local capital markets: Domestic banks have supported multiple project finance transactions for small-scale NCRE IPP projects up to 10 MW. The banks have provided funding either through direct lending or through credit lines secured from DFIs. International banks have also funded projects in the power sector,

⁵ As per capacity projected under LTGEP 2018-37 Base Case Plan and LTTDP

⁶ Section 3 (Growth Plan and Financing Needs) of the main report provides details of investment needs

⁷ In addition to these investment needs, if LNG were to be procured as a new fuel option to meet the demand for gas in the power sector, an additional USD 7.0 BN will be needed to contract LNG supply over the period 2018-37⁷. Furthermore, the Government is planning an investment of up to USD 2.0 BN for the refurbishment and expansion of the country's only oil refinery facility.

either directly or via credit lines to local banks⁸. Preliminary analysis indicates that domestic banks could potentially finance up to USD 2.6 BN through 2026. However, current infrastructure financing by the local banks is limited⁹ and this potential could only be unlocked if a range of significant constraints are addressed, including limited availability of long term debt, small average size of banks, single borrower limits, ability to syndicate loans, and still limited project finance experience and capability. Similarly, the local capital markets are still under-developed and hampered in their ability to finance infrastructure by an illiquid and inefficient long-term bond market (> 10 years) and impediments to institutional investors entering into the infrastructure sector.

The Funding Gap and Sensitivity Analysis

It is estimated that sector stakeholders and domestic banks could potentially finance up to USD 3.3 BN through 2026. Given the cumulative investment need of USD 7 BN, the shortfall would be about USD 3.7 BN. However, the gap would remain larger if the domestic banking sector and capital market constraints are not addressed, as noted above.

Leveraging commercial financing from foreign sources and alternative financing structures will be essential to meet the high investment needs of the power sector. However, to do this, Sri Lanka will need to address structural and macro-fiscal challenges as well as improve the enabling environment to help sustainably develop the energy sector.

Source	Total USD million
Planned Investments Through 2026 for entire power sector	6,984
Government budget, CEB & LECO current financing capacity	690
Domestic Banks	2,580
Institutional investors/capital markets	<i>To be mobilized</i>
<i>Additional Investment Needs (from foreign sources of financing)</i>	<i>3, 714</i>

However, in particular absent the implementation of the measures recommended in this report, there is limited ability to mobilize finance in Sri Lanka given the weak financial state of Ceylon Electricity Board (CEB) and Ceylon Petroleum Corporation (CPC), weak fiscal situation, limited foreign currency reserves, governance challenges, and under-developed banking sector and capital markets. It would therefore be challenging to raise the required capital from stakeholders' own sources, development finance, foreign and domestic private capital, and capital markets.

With view to these challenges, a sensitivity analysis was done as part of the analysis. It found that even if it assumed that (i) the financing needs are 50% lower than the projected requirements through 2026, and (ii) the entire capital available with domestic banks could be mobilized efficiently, state entities and domestic banks would not be able to meet the entire sector financing needs. This points to the importance of implementing the measures recommended by this report to strengthen sector entities – only with strengthened financials

⁸ HSBC, Standard Chartered and ANZ were lead arrangers in several of the internationally financed PPP/IPP transactions closed in Sri Lanka. For AES Kelanitissa, a 163 MW diesel-fed combined independent power plant closed in 2001, financing was arranged by ANZ and featured a USD 26 MN direct commercial loan and a USD 52 MN Partial Risk Guarantee (PRG) from the ADB.

⁹ Based on historic data, the total exposure of domestic banks to the infrastructure sector is in the range of 6 – 7% of their total investable assets. Assuming infrastructure lending would continue at historic levels and 30% of it goes to energy sector (as indicated by the World Bank PPI database) the domestic banks are currently poised to contribute ~ 1.5 USD BN through 2026.

would they be able to mobilize more finance, including from commercial sources. In addition, the sensitivity analysis highlights the critical importance of increased role for foreign sources of commercial finance and private sector participation and investment, in particular in the generation sector.

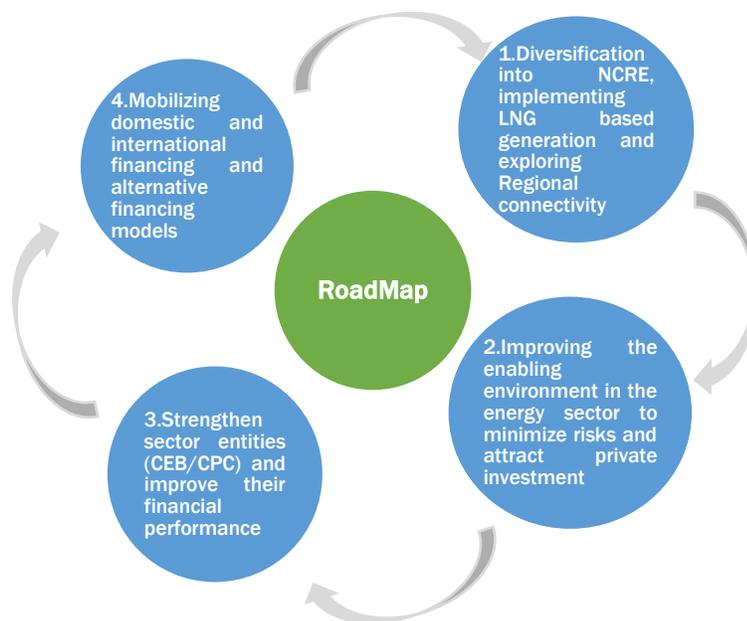
Given these findings, another scenario – considered to be realistically achievable – analyzed the historic average investments in the power sector; in 2010-2018 the average investment was estimated at approximately \$440 million. It was furthermore assumed that they could be increased by 10% each year going forward, through 2026. With these assumptions total funding of about USD 5.5 BN could be mobilized, leaving a shortfall of USD 1.5 BN compared to the total power sector investment needs/plans. To fully close the gap a year on year growth rate of 15% over historic levels would be needed. Given the limited fiscal space available on the books of the government it is unlikely that the government will continue to invest at the historical rate, and hence, this scenario also emphasizes the need to mobilize commercial / private finance in the sector.

Prioritizing the investment requirements

The capital investment required for meeting the sector targets is significantly higher than what could potentially be contributed by the state stakeholders. Given the same, it will be prudent for CEB and sector stakeholders to prioritize and invest the amounts available in sectors and flagship projects with strategic and national importance. For example, the power transmission segment and refinery expansion could be given priority for maintaining state ownership, while private participation can be maximized in power generation segment, especially NCRE. CEB can also explore divestment in certain generation assets as a way to raise additional capital to meet the needs in the power sector.

A Roadmap for the Future of the Power Sector

Based on the findings of the analysis, a prioritized roadmap of key recommendations for the short to medium-term has been developed to address some of the challenges facing the power sector and mobilize the required investment capital. The role of institutions in implementing the roadmap is also highlighted as relevant. A more comprehensive and detailed roadmap, including medium to longer term actions, is provided in section 4. The roadmap can be structured into four interdependent pillars:



1. Diversification through utility-scale NCRE, LNG, and regional connectivity

Key recommendation 1: To lower generation costs and mobilize private sector expertise and finance, launch a multi-project competitive NCRE procurement program starting by end of 2019 with a flagship project.

Sri Lanka should increase NCRE (particularly utility scale solar and wind projects) to optimize cost of power generation, diversify the energy mix and reduce dependence on oil-based generation, lower environmental impacts, and help Sri Lanka meet its climate change mitigation objectives. Cost of power around US cents 6 / kWh from NCRE could potentially be achieved through competitive tenders, even on commercial finance terms. The procured NCRE-based power can be used to replace expansive oil-based power which in 2017 averaged ~ US cents 17 / kWh. Given the financial constraints of sector stakeholders and fiscal constraints of the government, the objective should also be to maximize the private sector participation in the NCRE generation segment to the extent possible, while conducting the procurement in a transparent and efficient manner to optimize tariff outcomes. The shared infrastructure (access roads, water supply and drainage, telecommunications, pooling stations inside the parks, transmission lines and substations) benefiting all of the private generators in such NCRE park sites could be implemented by the public sector. The program should start with projects at the Pooneryn and Moneragala sites, on which pre-feasibility studies were completed as part of the InfraSAP. Structuring of a competitive tender is already under way with IFC support for the Pooneryn site.

As part of the development of the Government's NCRE program, SEA and CEB should prepare feasibility studies for NCRE sites consistent with the final LTGEP and development of the common infrastructure required by all generators at the NCRE parks. The capacity of the power grid to integrate and dispatch NCRE also needs to be assessed and as needed, strengthened through various means, potentially including energy storage. National Agency for Public Private Partnerships (NAPPP) should take the lead on advising on PPP best practices including transparent processes, bankable Power Purchase Agreements (PPAs)/contracts, appropriate contractual protections to investors, transparent evaluation, adherence to timelines, etc. Sri Lanka Sustainable Energy Authority (SLSEA) should coordinate closely with relevant GoSL agencies to procure land for NCRE projects before tenders are launched to minimize risks for investors. The capacity of SLSEA to act as a one-stop-shop for permitting should also be enhanced.

Key recommendation 2: To Ensure that LNG is procured in line with projected demand and at globally competitive prices and terms, develop and implement a LNG procurement strategy with clear institutional roles and transparent principles.

GoSL should prepare LNG procurement guidelines following global best practices; NAPPP has started work in this regard. This should be complemented by assigning clear roles and responsibilities to institutions involved in the entire process of procuring and retailing LNG. To ensure that the sector entities can deliver on their mandates, capacity building programs should be implemented for the relevant institutions. Prior to evaluating the multiple unsolicited proposals received, the state needs to undertake comprehensive due diligence on supply options and demand (including potential industrial and other uses) for LNG, bring further clarity on issues relating to siting of the terminal and finalize a viable procurement strategy. An assessment undertaken as part of the InfraSAP preparation indicates one floating LNG terminal would be sufficient to meet foreseeable demand. Subsequently, all the LNG supply and regasification proposals should be assessed against global benchmarks to obtain optimal pricing and contract terms. In general, global experience shows that international competitive bid approach would yield best results.

Key recommendation 3: To tap into both cost effective supply and potential export opportunities in regional power markets, evaluate the feasibility, appropriate business models and financing structures for the proposed Sri Lanka-India transmission line and initiate project development.

The Government should re-evaluate the feasibility of the Sri Lanka-India transmission line for importing power¹⁰ cost effectively in the short term, and initiate project development if found feasible. In the medium to longer run, the interconnection could be utilized to export power to India. To this end, CEB should also evaluate the feasibility of off-shore wind power in the northern part of the country.

2. Improving the enabling environment to minimize risks and attract private investment

Key recommendation 4: To ensure sufficient reserve capacity at all times and to accurately assess investment and financing needs and to improve outcomes, prepare a short- and medium-term implementation and financing plan based the LTGEP with prioritized investments

The LTGEP provides the basis to start the process of diversifying the generation mix and reducing the use of high cost fuels. To speed up LTGEP implementation, a continuously updated LTGEP implementation plan with measurable targets should be prepared, including prioritization of investments, implementation modality (public, private, PPP models), a procurement plan and timeline, and a financing plan. The implementation of the LTGEP and the prioritized short-term plan should be continuously monitored and reported on to the Government. The plan should seek to ensure that there is sufficient reserve capacity meet demand at all times, including during periods of low rainfall and years of low monsoon. In this context and in the preparation of the subsequent LTGEPs and implementation plans, the demand growth scenarios need to also be periodically re-assessed.

Key Recommendation 5: To improve institutional alignment and ensure successful implementation of investment and procurement programs, establish a coordination mechanism for planning and implementation review.

Ministry of Power, Energy and Business Development should implement measures to strengthen coordination and cooperation among government institutions, for instance, through a standing coordination committee. Collaborative processes should be put in place to finalize LTGEP and other sectoral plans and programs, and periodically review their implementation progress. It would also be important to strengthen governance oversight of the CEB and CPC by the Government as their majority shareholder.

3. Strengthen sector entities (CEB/CPC) and improve their financial performance

Key recommendation 6: To improve financial standing of CEB, as cost-effective sources of supply are added in the system, progressively move to cost reflective tariffs. As a transition arrangement, consider a transparent direct subsidy to CEB instead of Government repayment of debt.

It is critical that a cost-reflective tariff regime is adopted (while ensuring that tariff affordability and the resulting social impacts are analyzed and mitigated e.g. through well targeted direct support to poorest consumers) to improve the financial performance of the sector. Achieving cost parity becomes easier if cost effective sources of supply (see key recommendations 1 and 3 above) can be added. The government should adopt a cabinet decision to operationalize an automated electricity tariff setting mechanism as per the IMF program. To promote timely implementation of cost reflective tariffs, CEB should establish a physical Bulk

¹⁰ The last feasibility study undertaken by Power Grid of India was based on prices in 2012.

Supply Transaction Account (BSTA in compliance with the tariff methodology and seek approval for cost-reflective tariffs. PUCSL should engage with CEB for timely audit of required data and approve tariff adjustments to achieve cost reflectiveness. Currently, as a way to provide financial relief to CEB, the government has agreed to repay part of the on-lent debt on CEB's books. Such measures, while do ameliorate the impact of the non-cost reflective tariff regime, are temporary and non-transparent. Instead, until the time a cost reflective regime is implemented, a transparent and structured subsidy program should be put in place to provide coverage of losses, currently being borne by the CEB transmission licensee.

Key recommendation 7: To improve performance and encourage participation by private/foreign counterparts, create cost-and profit centers within CEB, and develop transparent financial management and reporting tools and practices of both CEB & CPC

CEB & CPC should seek technical assistance from DFIs to build capacity and develop financial management tools for financial projections, liability management, reserves for fuel price adjustments and low monsoons, etc. with a focus on efficiency, cost control and cash management. Both entities should improve transparency in reporting and do more detailed and timely data publication and audits. The Government should consider creating independent cost/profit centers within CEB structure to improve efficiency and to ensure accountability, transparency and ability for potential financiers to assess credit quality of CEB. Improved transparency of CEB and CPC would help encourage participation from private/foreign investors and financiers.

4. Mobilizing domestic and international financing and alternative financing models

Key Recommendation 8: To mobilize long-term domestic financing, develop bond instruments and increase participation of pension and insurance funds in infrastructure.

Mobilizing domestic finance will be critical for meeting the financing needs in the energy sector. It is therefore imperative to develop financial products such as tradable long term corporate and government bonds and ensure efficient bond pricing mechanisms to support long term financing typically required for infrastructure. It should be supported by increased liquidity through reforms of the financial sector and increased participation of market makers, including pension and insurance funds. The mandates of such funds should be amended as necessary and appropriate to allow investments in infrastructure projects.

Key recommendation 9: To improve the bankability and viability of planned investments, develop innovative financing models and structures and enhance the domestic banks' project finance capacities.

Various innovative financing models should be explored to help mobilize the necessary capital. A sector-level stapled financing structure may be explored wherein the entire procurement process is supported by pre-approved financing and/or credit enhancement structures (guarantees, risk insurance) in conjunction with GoSL support. Global financial institutions could also provide credit enhancement products (e.g. subordinated debt or a guarantee) to support a sector entity (such as CEB) issue a bond (domestic / offshore) to raise capital. It may also be possible to attract concessional financing and climate finance from financial institutions (FIs) for a sector level NCRE procurement program. It is also important to strengthen the project finance capacity of domestic banks on best practices, currency hedging instruments, security packages and arrangements (assignment and step in rights, credit enhancement packages), waterfall mechanisms, and project due diligence. In this regard Ministry of Finance and Central Bank of Sri Lanka (CBSL) need to coordinate with domestic banks to build capacity of banks with the assistance of international project finance professionals.

1 Overview of Sri Lanka's Power Sector

The Sri Lankan economy has grown at an average growth rate of around 6.4%¹¹ p.a. over the last 10 years. Electricity demand, in line with the economy's growth rate, has also grown at an average annual rate of around 6% over the past 10 to 15 years and the trend is expected to continue in the foreseeable future.

In recent years, Sri Lanka's power sector has made commendable progress in achieving stated renewable energy targets¹², near-universal electrification¹³, and reducing transmission and distribution losses¹⁴. However, sustaining these achievements and keeping pace with demand from a growing economy while meeting the envisaged power sector development needs, will require large sums of new investment. They include large investments in renewables and LNG/gas-based generation. If those investments are not forthcoming, it will further increase Sri Lanka's reliance on imported fossil fuel (oil and coal) based power to meet its future energy needs. This would have substantial negative environmental, health, climate change and economic impacts.

This section introduces the key regulation and reforms that have taken place in the power sector. It also provides an overview of the NCRE and LNG/gas sectors, previous project transactions and expected developments in the foreseeable future. A more comprehensive description of the power sector structure, power demand, generation, transmission and distribution is provided in annex 1.

The power sector in the country is currently dominated by hydro power plants, and fossil fuel-based generation from coal and liquid fuels. However, the government of Sri Lanka, through the envisaged renewable energy targets and projected generation planning, has been pursuing a shift toward clean generation, including both NCRE and LNG based generation. Accordingly, this report highlights the constraints and opportunities for diversifying the generation mix towards NCRE and LNG based generation.

1.1 Key Regulations in Power Sector

The power sector in Sri Lanka has witnessed reforms in two phases.

Phase 1: The first phase of reforms was implemented from 1983 to 2008. As early as 1983, the state-owned distribution company, Lanka Electricity Company (LECO) was established, to distribute power in Western coastal regions of Sri Lanka. In 1996, private sector participation in generation commenced with the development of two small scale Hydro power plants in 1996 (total capacity of 1 MW). In 1997, three oil fired thermal power stations with cumulative capacity of 42 MW were added¹⁵.

In 2000, CEB was divided internally into six divisions — one for generation, one for transmission, and four for distribution. This was done through an administrative CEB decision, without effecting the legal or financial separation of these divisions within the CEB structure.

In 2002, the first power sector reform came about with the enactment of the Electricity Reform Act. The act proposed restructuring of CEB by breaking the CEB to several independent state-owned companies to carry out generation, transmission and distribution. This was followed with the creation of the Public

¹¹ Assessment of Sri Lanka's power sector 2017 - ADB

¹² 10% generation share from NCRE & mini-hydro was achieved in 2015, a target set under National Energy Policy

¹³ Electrification rate of 99.3% in 2016 (CEB Statistical Digest 2016)

¹⁴ Refer Annexure 1 for details

¹⁵ Source: http://www.ceb.lk/index.php?aam_media=38068

Utilities Commission of Sri Lanka (PUCSL) as the power sector regulator, effective July 2003. However, before PUCSL could exercise its mandated powers over the power sector, the Electricity Reform Act failed to get implemented owing to opposition from various parties, including CEB.

Phase 2: Phase 2 included two key reforms – implementation of the Electricity Act 2009 and PUCSL’s tariff methodology for the power sector.

Electricity Act 2009. This legislation allowed PUCSL to finally operate as the power sector regulator. However, it authorized less restructuring of the CEB than had been originally proposed in the 2002 Electricity Reform Act. A single-buyer model was introduced, with the CEB transmission entity as the single buyer. In contrast to what is usually done in an unbundling reform, the business units or divisions within the CEB were not spun off as separate entities with independent ownership structure and management.

Tariff Reform. Prior to the Electricity Act 2009, the end user electricity pricing was done in an ad-hoc manner by various governments. This resulted in financial losses and accumulated debt for CEB. In 2009, the PUCSL initiated a tariff reform to address these issues. The new tariff methodology¹⁶ was designed based on two key principles:

- The tariff methodology should reflect separately the costs of each generating, transmission, and distribution licensees; and
- The tariff methodology should permit each licensee to recover all reasonable costs incurred.

However, the implementation of the tariff adjustments for both customer and bulk supply has encountered considerable delays, due to limited adherence to guidelines by sector stakeholders. This has eroded public confidence in the tariff-setting process.

1.2 Overview of NCRE Sector

Renewable Energy Targets

The energy policy, in 2010, highlighted targets for NCRE, as follows:

- To achieve 10% share of generation from NCRE by 2015. The target was successfully achieved in 2015.
- To achieve 20% share of generation from NCRE by 2020.

Post the energy policy, there has been a continuous disagreement amongst key entities in the sector, over the renewable energy targets. The energy development plan 2015-25, highlighted the following targets for the Sri Lanka power sector:

- Increase the share of electricity generation from renewable energy sources (hydro + NCRE) from 50% in 2014 to 60% by 2020.
- Meet the total power demand from renewable and other indigenous energy resources by 2030 (energy self- sufficiency).

¹⁶ Refer Annexure 5 for details on the PUCSL’s Tariff Methodology

The target of achieving energy self-sufficiency by 2030 was heavily debated amongst the stakeholders. It was subsequently agreed that achieving self-sufficiency by 2030 is an unrealistic target. In an endeavor to embrace renewables, Sri Lanka at the 22nd UNFCCC Conference of Parties in Marrakech, Morocco, announced a target to use only renewable energy for electricity generation by 2050 (100% RE by 2050¹⁷).

The LTGEP 2018-37, prior to its approval, was heavily debated amongst the Government, CEB and PUCSL over the contribution of coal and renewable energy in the long run, and alignment of LTGEP with the 100% renewable energy target up to 2050.

Cabinet's policy decision on the generation plan: The cabinet has recently approved a policy paper on the power generation mix in Sri Lanka, which envisages the following key points:

- a) Considering the renewable energy as prime development policy, meeting 50% of electricity generated by major Hydro and NCRE based generation.
- b) Developing the NCRE sector to the maximum feasible limit (up to 2,500 MW by 2030), meeting ~ 1/3 of the energy requirement of the country by 2030.
- c) To ensure energy security, meeting 2/3rd of the energy requirement by firm power sources such as LNG, coal, fossil fuel and large hydro.
- d) Maintaining the firm capacity mix as following: 30% of the firm capacity mix to be thermal, 30% LNG, 25% Hydro and the remaining 15% as fuel and NCRE

Given the above, CEB estimates a requirement of about 900 MW of additional coal plants by 2030. Based on the approved LTGEP, the Base Case includes development of 1,500 MW of Coal capacity up to 2030. While the Base Case may not reflect the cabinet's policy decision in entirety, it is the closest to the approved cabinet decision plan and has been utilized for estimating the capacity and investment needs in this report.

The 'Base Case' under the LTGEP 2018-37 envisages the following capacity additions for the NCRE sector:

- Development of around 1.4 GW of Solar power projects up to 2037, and
- Development of around 1.2 GW of Wind power projects up to 2037.

Utility Scale NCRE: While the FIT scheme for mini-hydro was introduced in early 1990s, an emphasis on commercial development of the solar and wind power was initiated in 2011. In 2011, FIT was provided for solar, wind and biomass projects with up to 10 MW generating capacity. The FIT scheme was introduced with the aim of increasing investor participation in the sector. Tariffs were cost based and technology specific, and the developers had the option of selecting either a three-tier tariff¹⁸ or a flat tariff. The tariff was valid for a period of 20 years and extendable by mutual consent.

For projects larger than 10 MW and up to 25 MW capacities, the tariffs were to be based on negotiations with the government (and expected to be lower than FIT rates).

For projects of capacity greater than 25 MW, the electricity act¹⁹ states that the government should hold at least 50 % shares or no. of shares as determined by the secretary to the Treasury and Ministry

¹⁷ ADB report - Assessment of Sri Lanka's Power Sector 2017

¹⁸ Refer Annexure 14 for details on the three tier and flat tariff under FITs

¹⁹ http://www.pucsl.gov.lk/english/wp-content/themes/pucsl/pdfs/electricity_act_2009.pdf

of Finance. While there have been projects of greater than 25 MW capacity, for e.g. the recently awarded 300 MW CCGT, tendered without any requirement for government participation, the above clause could potentially restrict the development of large scale NCRE projects, as envisaged under the long-term generation plan.

The FIT scheme received a decent response from local investors and domestic banks alike and led to an influx of domestic developers supported by local financing. As the sector developed, the government introduced competitive bidding for tariffs for solar and wind projects. The first tender for a utility scale wind project was released in 2015 (10 MW), while the first tender for a utility scale solar project (10 MW) was released in 2016. The bidding-based tariffs have reduced to ~LKR 12.29 per kWh (~ US cents 8 / kWh, for wind projects) and ~LKR 11.79 per kWh²⁰ (~ US cents 7.7 / kWh, for solar projects). These tariffs are about 50% lower than under the FIT scheme, and more than 50% lower than the cost of power generation from oil-based power plants in Sri Lanka.

Table 1: NCRE Projects Implemented, by Technology (as of February 2017) 21

Technology	No. of Projects	Installed Capacity (MW)
Solar Power	7	41.36
Wind Power	15	123.45
Others (Biomass)	9	22.10
Total Land mounted NCRE	31	186.91
Mini Hydro	178	349.64
Roof-Top Solar	~8,000	119.00

Rooftop Solar Net Metering Scheme: Net metering for rooftop solar power projects was introduced in June 2010. The consumer generates electricity on their rooftops using solar panels, connected to the grid through a net metering system. The consumer pays only for the net amount of electricity consumed. If solar production exceeds the consumption of the premises, the balance amount can be carried forward to future use for up to 10 years. No fee will be paid to the consumer for the excess electricity produced.

In September 2016²², two additional options were introduced:

- **Net Accounting** – If generation is more than own consumption, the consumer is paid for the net amount of electricity exported to the grid (total generation - own consumption). The consumer is paid for exported electricity at LKR 22 per kWh (US cents 15 per kWh) for 7 years, and LKR 15.5 per kWh (US cents 10 per kWh) thereafter for the contract period of 20 years.
- **Net Plus** – Consumers can install roof top solar PV plants that are equivalent or less than their contract demand. They can then export the total generation to national grid at LKR 22 per kWh (US cents 15 per kWh) for 7 years, and LKR 15.5 per kWh (US cents 10 per kWh) thereafter

²⁰ Tariff achieved in recent solar and wind bids, based on market feedback

²¹ LTGEP 2018-37

²² Source: http://www.pucsl.gov.lk/english/wp-content/uploads/2017/09/Consultation-doc_-rooftop.pdf

for the contract period of 20 years. This option uses two separate meters: existing meter measures consumption, new meter exports.

Program for 1 MW Projects: In 2016, government launched the ‘Surya Bala Sangramaya’ program which focuses on installation of 60 solar power projects of ~ 1 MW each; for both ground mounted and rooftop projects. The program aims to add 200 MW of solar electricity to national grid by 2020 and 1,000 MW by 2025. The first round of the auction was conducted in 2017. In this round 63 bids were received for 1 MW plants²³, but less than 25 were qualified. The maximum purchase price was kept at US cents 12 per unit (LKR 18.37 per unit), but bids were received for as low as US cents 7.14 per unit (LKR 11 per unit).

In 2018, the government plans to launch the second round of the program and auction 90 MW of solar projects. Bidding conditions followed in stage one of the program have been revised to ensure more bids are received. For example, unlike the first bid round where only one proposal per bidder was entertained for 60 projects of 1MW each, bidders can now tender for any quantity of power up to 90 MW. Similarly, the land requirement under the selection criteria has been broadened to give more flexibility to bidders. Stage one of the project required the proposals to provide proof of ownership of a five-acre plot for the generation plant. The new condition has revised the extent to three acres. However, the maximum purchase price per unit of power will remain at US Cents 12 per unit (LKR 18.37 per unit). In September 2017, ADB approved a USD 50 million loan to help fund ~50 MW of rooftop solar for the second round of the ‘Surya Bala’ program.

Details of Select Solar and Wind Projects: Most of the Solar and Wind projects in Sri Lanka are financed by domestic lenders and developed by domestic investors. The primary reason for this is the small-scale of NCRE projects and the risk allocation under the PPA which seems more acceptable to domestic investors compared to international investors. International lenders including DFIs have considered financing these projects but have not been able to finance them for this reason other than small equity or quasi-equity investments in some isolated cases though even that has been challenging due to the small size of transactions/ projects and associated transaction costs. The table below highlights the financiers of select NCRE projects installed in Sri Lanka.²⁴

Table 2: Financiers of Select NCRE Projects

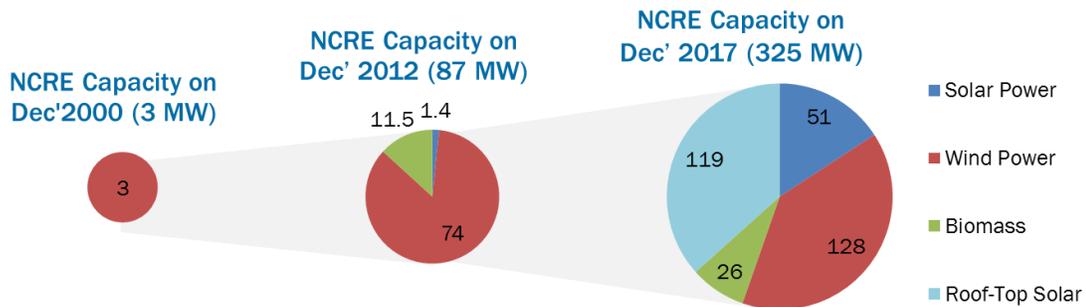
Project Type	Location	Capacity	Developer	COD	Lenders
Solar	Hambantota	10 MW	Sagasolar Power	Dec-16	DFCC Bank, Bank of Ceylon, Hatton National Bank, EIB
Solar	Barutakanda, Hambantota	10 MW	Laugfs Holdings	Oct-16	DFCC Bank

²³ <http://www.ft.lk/news/90-more-solar-projects-in-the-offing-by-CEB/56-641814>

²⁴ Source: PFIE and IJ Global Database

Project Type	Location	Capacity	Developer	COD	Lenders
Solar	Barutakanda, Hambantota	10 MW	Laugfs Holdings	Oct-16	Sampath Bank
Solar	Vavuniya	10 MW	Wind Force	Jul-17	Hatton National Bank
Wind	Mannar	100 MW	CEB	Expected in 2020	ADB
Waste to Energy	Kerawalapitiya	10 MW	Aitken Space PLC	Expected in 2019	HNB, People's Bank, DFCC, Bank of Ceylon

Capacity Evolution of Solar and Wind Projects

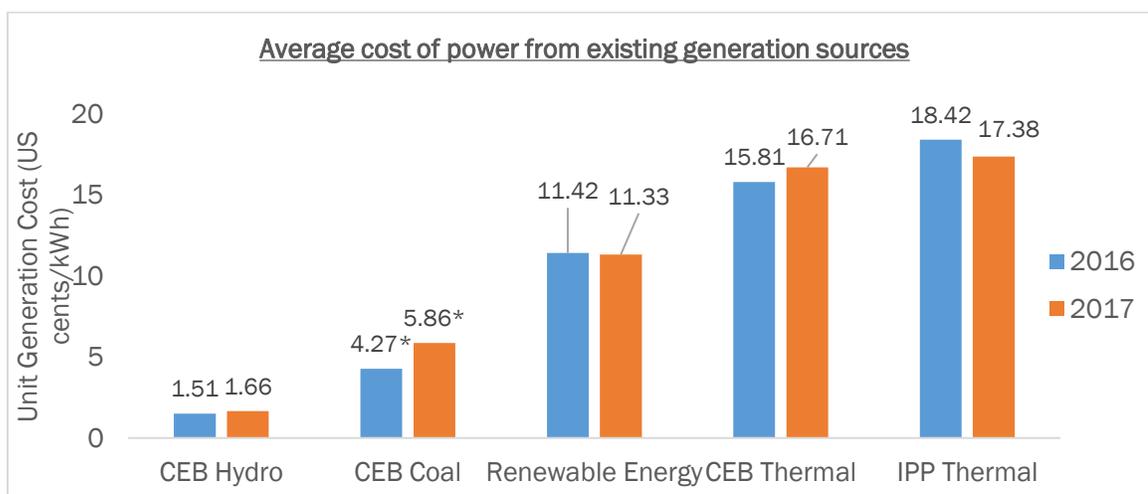


Optimized cost of power from Solar and Wind sources

The Solar and Wind power has the potential to further optimize the cost of power in the country. In line with what is being witnessed across the globe (i.e. low tariffs in solar and wind based generation), it seems reasonable to assume that by opening the sector to international players with adequate incentives and risk mitigation mechanisms in place, a significant reduction in cost of power could be achieved in Sri Lanka²⁵. The solar and wind based generation could be potentially used to replace some of the expensive imported oil based power, which is currently utilized to offset the low availability of hydro resources.

²⁵ Potentially a tariff of US cents 6 / kWh (~ LKR 9 / kWh) is achievable from solar and wind based power. In 2016, the average cost of power generation from oil based generators was ~ US cents 17 / kWh. Refer Annexure 1 for details

Figure 1: Average Power Generation Cost from Current Sources



*Does not include financing, environmental / health costs

Actual cost of power generation from the coal plant

The actual cost of power generated from Coal is currently being debated amongst PUCSL and CEB. While CEB estimates the cost of power from coal in 2017 in the range of US cents 5.86 / kWh (the calculations do not include the financing cost of the plant), PUCSL has estimated the cost of Coal to be ~ US cents 11 / kWh (LKR 18.60 / kWh²⁶, inclusive of financing cost). While there are differences in the assumptions used by PUCSL and CEB for calculating the cost of coal (for example, PUCSL has estimated the financing cost to be LIBOR + 4.5%, while CEB has excluded the financing cost of Coal in its calculations. In 2009, Sri Lanka received a concessional loan for 900 MW Coal plant from China government at an average all-in cost of 2.7%²⁷), the cost of Coal is highly driven by the Coal prices, which are on the rise over the past few years. The coal prices have increased from ~ USD 50 / MT at start of 2016 to ~USD 100 / MT in June 2018²⁸. Based on the current Coal prices and low cost of financing procured on MOFs books, the coal power prices could potentially be in the range of *US cents 9 – 10 / kWh*. Given the above, coal ceases to be the least cost source of power generation, as cost of power from LNG and NCRE could potentially be lower than US cents 9 / kWh. It may be noted that none of the above estimates include the environmental and health costs associated with Coal.

Environmental Benefits of NCRE

Greenhouse gas (GHG) emissions in Sri Lanka have seen rapid growth over past 25 years due to the shift in power generation mix towards fossil fuel-based generation. Sri Lanka's per capita CO2 emissions, while still comparatively low, have been increasing fairly rapidly with electricity demand

²⁶ http://www.ceb.lk/index.php?aam_media=33317

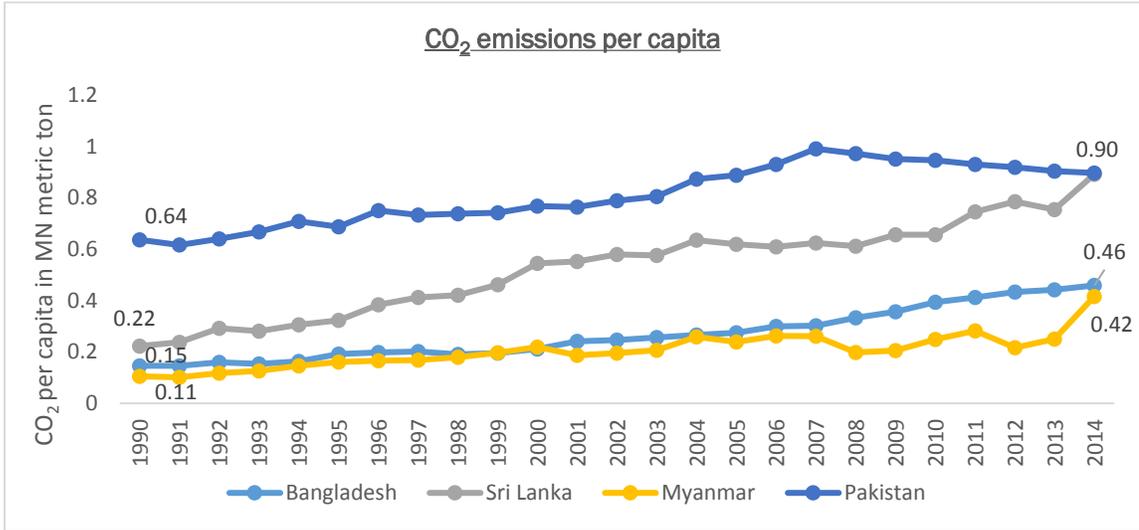
²⁷ Source: 150 million was provided at 6%, while the remaining amount of 741 million was procured at 2%.

<https://china.aiddata.org/projects/33463?iframe=y>

²⁸ World Bank Database for Commodity Prices

growth, and addition of fossil fuel based (oil and coal) sources at a pace that outstrips the pace of NCRE additions.

Figure 2: Co2 emissions per capita



According to the planned augmentation in generation capacity as per LTGEP 2018-2037, increase in NCRE & mini-hydro sources of power generation will lead to significant savings in CO₂ emissions, compared to the scenario with no NCRE & mini-hydro additions (“Reference Case”), as highlighted below. Planned NCRE & mini-hydro additions, if implemented, will be a significant step on climate change mitigation and towards Sri Lanka’s nationally determined contributions (NDCs) to the Paris Climate Agreement²⁹.

Following analysis shows potential CO₂ savings in various scenarios:

- 1) Base Case: Capacity addition as per LTGEP 2018-2037
- 2) Reference Case: No increase in NCRE & mini-hydro capacity; capacity addition is done only through committed major hydro plants, and thermal power generation

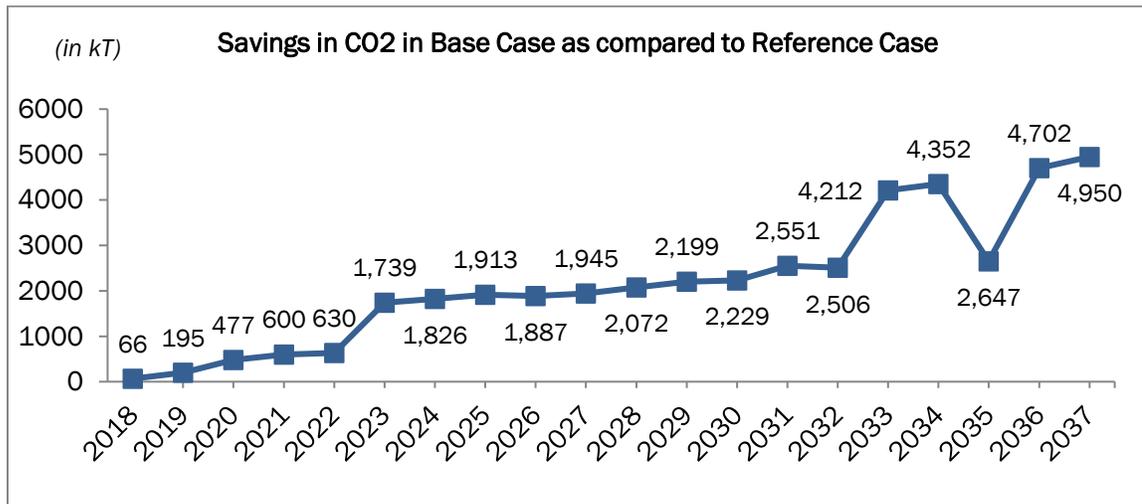
Table 3: CO₂ Emissions in Base Case and Reference Case of LTGEP 2018-2037

Cumulative CO ₂ Emissions (in million Tons)	Up to 2020	Up to 2026	Up to 2037
Base Case	14.46	50.03	205.02
Reference Case	15.20	59.36	248.72
Difference (CO₂ Cumulative Savings)	0.738	9.33	~ 43.70

²⁹ Detailed in the annexure 4

As highlighted in the below graph, approximately 43.70 million tons of CO₂ will be saved from projected NCRE & mini-hydro development of 2897 MW as per LTGEP 2018-2037 plan.

Figure 3: CO₂ Savings in Base Case Compared to Reference Case



1.3 Overview of LNG Sector

Natural Gas is considered a potentially important source of power generation by the Government of Sri Lanka. The LTGEP 2018-37 envisages ~1905 MW of capacity addition for gas power over the next 20 years. However, currently, there is no commercially developed gas field in Sri Lanka.

The possibility of introducing indigenous gas from Mannar Basin should be considered in the medium to long term. However, the quantity and the pricing would be the key determinants for ensuring the upstream investments are feasible.

Development of the natural gas resources in the Mannar Basin is still at very early stages. In 2011, Cairn India discovered natural gas reserves in the well it drilled in the Mannar basin of Sri Lanka. However, the company exited the basin after the expiry of the exploration period in October 2015, as the discoveries were assessed to be unviable.³⁰ In February 2017, the government has once again invited interest for exploration in the offshore Block M2 in the Mannar basin.

In the short-medium term, considering rising power demand, the concern around rising cost of oil imports, and the need to reduce reliance on hydro as the dominant base load generation source, LNG is being pursued as a viable option. As noted in LTGEP 2018-37, gas sources in India and Bangladesh are located far from Sri Lanka, which makes cross border pipeline projects economically unattractive. Hence, natural gas transport by means of shipping LNG seems to be a better option for Sri Lanka. Globally, multiple emerging economies (for example, Bangladesh, Pakistan, etc.) have entered the LNG

³⁰ Media articles - <https://www.thehindubusinessline.com/companies/cairn-india-to-exit-sri-lankan-gas-block/article7757402.ece>

market, meeting the domestic gas demand through long-term and/or spot contracts, and implementing project structures reflective of the regional landscape and gas demand³¹.

Unsolicited Proposals for LNG procurement: The government has recently received multiple government to government proposals to supply LNG on an unsolicited basis. Some of the proposals include long term LNG supply as well as construction of floating / onshore infrastructure to support the regasification of LNG. The government has also announced its intention to go for a Swiss challenge process based on one of the proposals. A brief summary of the proposals is as follows:

1. JV between India, Japan and Sri Lanka: In September 2017, it was announced that Petronet LNG (India's biggest importer of gas), will partner with Japan's Mitsubishi and Sojitz Corp and Sri Lankan Government to set up Sri Lanka's first FSRU LNG terminal at Kerawalapitiya on the western coast of Sri Lanka, in close vicinity of Colombo. Petronet will be the largest shareholder in the Joint Venture.
2. South Korea Proposal: government has received a bid to supply LNG and develop LNG infrastructure in Sri Lanka from the South Korean Government-backed SK E&S Company—an integrated gas and power company. The government also intends to go for the Swiss Challenge method³² for procurement of LNG, based on the South Korean proposal. The proposal includes a free-of-charge floating Liquefied Natural Gas (LNG) terminal tied to an annual order of 1 million MT of LNG for two decades at international market prices.
3. LNG gas to power proposal from China: The Governments of China and Sri Lanka have taken steps to implement a joint project to establish a 400 MW Liquefied Natural Gas (LNG) power plant in Hambantota. The project will be implemented with the prime objective of providing electricity to the industrial zone proposed to be constructed at Hambantota and to overcome the power scarcity that may occur in the future. The USD 500 million project has been approved³³ to be implemented as a Joint Venture between the China Machinery Engineering Corporation (CMEC), nominated by the Government of China and the Ceylon Electricity Board.

With regard to such Government-to-Government proposals, PUCSL approval of the LTGEP 2018-37 was subject to (i) accommodation in the LTGEP of the Cabinet approved Government-to-Government proposals, totaling 1,400 MW and (ii) the Transmission Licensee negotiating and ensuring that the generation plants built on Government-to-Government basis meet all the technical and economic parameters under the Grid Code and that they are least cost. While further clarity is required on the expected timelines for these power projects, the government needs to ensure that the USPs are assessed independently prior to their implementation.

Indicative cost of LNG based power generation in Sri Lanka: As part of the InfraSAP preparation, a preliminary analysis of the indicative cost of LNG based power generation was done. It used the following assumptions.

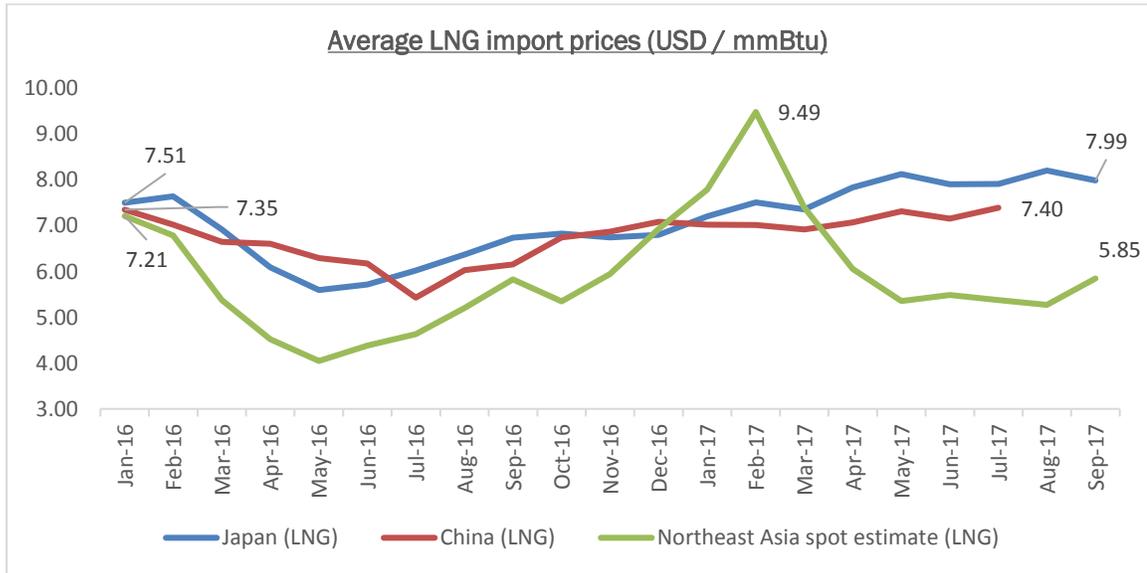
1. LNG Import prices: Based on the recent pricing of LNG imports across Asia, spot to long term import prices may range from ~ 7.00 USD / MMBtu up to 10.00 USD / MMBtu, as highlighted below.

³¹ LNG Project Structures are highlighted as part of Annexure 8.

³² Details of a Swiss challenge process are included later in this section

³³ Industry stakeholders and Media Articles - <https://in.reuters.com/article/sri-lanka-china-lng/sri-lanka-approves-500-million-lng-plant-near-chinese-controlled-port-idINKbillion1I60GH>

Figure 4: LNG Import Prices³⁴



2. **LNG Regasification Costs:** The LNG regasification costs are typically driven by the contracted volumes. The increase in committed volumes tends to drive down the per unit regasification prices. Given the same, the LNG regasification costs in Sri Lanka may range from 1.00 USD / MMBtu up to 1.80 USD / MMBtu³⁵
3. **Power Generation Costs:** Based on the assumptions on the import prices and regasification costs, as well as energy and capacity charges, the indicative cost of power generation from LNG is estimated:
 - a. Fuel Costs = LNG import + Regasification cost = 8.00 USD / MMBtu up to USD 11.80/MMBtu
 - b. Energy charge (with a Heat rate assumption of 7300 KJ/kWh³⁶) ~ US cents 5.50 / kWh up to US cents 8.10 / kWh
 - c. Capacity charge ~ US cents 2.50 / kWh to US cents 3.25 / kWh
 - d. **Power Generation costs ~ US cents 8.00 / kWh up to US cents 11.35 / kWh**

Key Benefits of LNG base load generation: Based on the indicative costs of LNG based power generation, it can be observed that the cost of power from LNG is significantly lower than that from oil-based generation (cost of power from oil based generation is ~ 17 US cents / kWh³⁷, while the same for LNG could potentially be optimized to ~ 8.00 US cents / kWh³⁸). Apart from the low-cost advantage, LNG may also act as a feasible option to complement hydro power or other intermittent power in base load generation, thereby reducing reliance on oil in cases of adverse monsoons. Furthermore, LNG is considered a cleaner fuel as compared to coal and oil³⁹, and may contribute to meeting climate change mitigation and clean energy targets of the country.

³⁴ IHS Markit Reports

³⁵ Estimated on 70% plant load factor

³⁶ Precedent transactions in the regions

³⁷ Refer Annexure 1 for details on average cost of power in Sri Lanka

³⁸ Refer Section 1.2 for details pertaining to potential cost of power from LNG

³⁹ Refer Section 2 for details on potential environmental benefits of NCRE & mini-hydro and LNG based generation

Key Concerns around procurement of LNG: Based on the recently received proposals and government's intention to move ahead with them, several concerns may be highlighted:

1. **Unsolicited Proposals and Swiss Challenge Process:** As highlighted, the government is engaged in discussions on multiple unsolicited proposals from India, Japan, China and South Korea. Prior to analyzing the viability of the proposals, or committing to an import capacity, government would benefit from conducting a feasibility assessment. This should include, among others, a demand estimation of LNG for power generation in Sri Lanka, evaluating various procurement methods, required capacity building of sector stakeholders, and defining the roles and responsibilities of various sector stakeholders during the procurement.

A Swiss Challenge process entails an initial unsolicited proposal, based on which other proposals from the market are invited. If the proposals received from the market include better terms than the initial unsolicited proposal, the government gives the initial bidder an opportunity to match the terms received from the market. When the initial bidder can match other competitive bids it significantly deters other bidders from investing time and money to make a competitive bid. Moreover, this process assumes that the original bidder's design and specifications is indeed the most suitable for the country. Given this, Swiss challenge procurement may not yield the desired results. Based on global precedents, and in absence of a pricing formula in the country, it may be more prudent to design a transparent, efficient and competitive procurement process to boost industry participation, for importing LNG in the country.

Pricing: There is an inconsistency on pricing of imported LNG across geographies. This is because there is still limited clarity on an international pricing index. In Asia, long term LNG pricing has been typically linked to a standard mark-up over crude, while spot pricing has been based on indices like Platts JKM ("Japan Korea Marker") and Sling (Jointly developed by Singapore Exchange (SGX) and Energy Market Company (EMC), the SGX LNG Index Group – or Sling). Given the prevalence of unsolicited proposals in Sri Lanka, it will be crucial to ensure that the pricing achieved for long term LNG imports is transparent and in line with adequate pricing benchmarks, because international market prices in the LNG space is still an evolving concept and very difficult to transparently adjust for site conditions.

2. **LNG Demand:** The current near-term demand for LNG (in the power sector) is limited to ~ 400 MW of oil-fired plants (that the government plans to convert into gas fired⁴⁰) and the proposed 300 MW CCGT plant at Kerawalapitiya, expected to be online by 2020. To meet the stated demand, procurement of a single FSRU (a 3.75 MMtpa FSRU typically can meet power demand up to 3000 MW) may suffice. However, based on the unsolicited deals highlighted above, there is a possibility that the government may find itself in a situation where actual demand is lower than the take or pay volumes under the import contracts. Such a situation could impose a significant burden on the government finances due to the high take or pay obligations under LNG import contracts.

1.4 Regional Connectivity - India Sri Lanka Transmission line

Presently, no bilateral power exchange exists between Sri Lanka and India. Plan for a transmission interconnection between India and Sri Lanka has been under consideration since 1970. A pre-

⁴⁰ Based on interaction with industry stakeholders

feasibility study was conducted in 2002 by United States Agency for International Development, followed by the recent study by Power Grid Corporation of India Ltd (PGCIL).

Both these studies point to the feasibility of a short-term link of 500 MW and a medium and long-term link of 1,000 MW between the two countries.

Key benefits of Sri Lanka – India Interconnection includes:

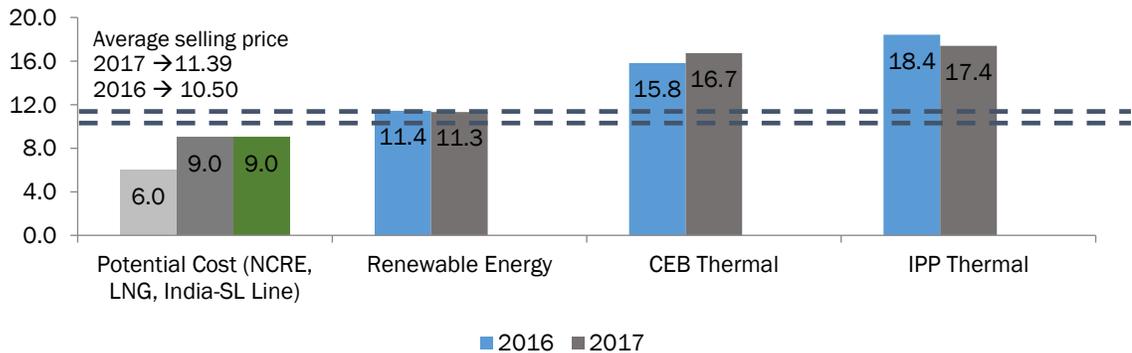
- Opportunity to enter India Power Exchange for energy trading.
- Reduction in operational cost through better resource management.
- Meeting growing power demand with imported power.
- Potential for export of surplus base load power.
- Improves supply profile (base / peaking).

Two alternative routes have been identified for interconnection:

- Alternative 1: Sub-marine Cable from Panaikulam in India to Thirukketiswaram in Sri Lanka
- Alternative 2: Sub-marine Cable from Dhanushkodi in India to Talaimannar in Sri Lanka

The preliminary investment cost estimates for the different alternatives ranges from USD 669 MN to USD 1.1 BN. As per the estimations highlighted in annex 2, the total cost to Sri Lanka for the import of power from India, is estimated to be from US cents 8.76 – 8.95 / kWh. The cost to import power from India could potentially bring in significant optimization in the cost of power, which currently stands at ~ US cents 13.8 / kWh⁴¹.

Potential benefit in cost of power through diversification (US cents / kWh)



The current cost of power to end customers in Sri Lanka stands at US cents 11.4 / kWh⁴². This cost of electricity, despite being subsidized, is on the higher side as compared to the regional peers, i.e. Bangladesh⁴³ (average cost of electricity is US cents 9.20 / kWh), India⁴⁴ (National average power purchase cost for open access customers was US cents 5.4 / kWh for 2017), Pakistan (NEPRA power purchase prices US cents 4.6 / kWh).

⁴¹ Average cost of power at selling point in 2017

⁴² Average selling price for power in 2017. Refer Annexure 1 for details.

⁴³ <http://corporate-downloadables-tips.s3.amazonaws.com/1478573661.68b4d11ba9cb3ccb30e91c6edd66b6c9.pdf>

⁴⁴ <https://defence.pk/pdf/threads/electric-power-rates-in-india-and-pakistan.541115/>

2 Energy Investment Plans and Financing Needs

The long-term generation plan is prepared by CEB and vetted by PUCSL every two years, and is a comprehensive document which identifies the required generation over the next 20 years. The LTGEP 2018-2037 was released in April 2017, and approved in July 2018. PUCSL has approved the LTGEP 2018-37 but with three conditions:

1. Accommodation of Cabinet's policy decision⁴⁵ in the plan,
2. Accommodation of the Cabinet approved Government-to-Government proposals, totaling 1,400 MW, and
3. the Transmission Licensee is required to negotiate and ensure that the generation plants built on Government-to-Government basis meet all the technical and economic parameters under the Grid Code and that they are least cost.

The approved LTGEP 2018-37 includes the development of 705 MW of gas-based plants up to 2026 and 1.6 GW of gas based plants up to 2037. It is still to be clarified if the proposed gas-based plants are inclusive of the three power plants approved by the Cabinet to be developed under collaboration with other governments. In case the approved plants are planned in excess to the capacity envisaged under LTGEP 2018-37, there may be a risk of oversupply of LNG and a situation where the government is obligated under take or pay contracts to pay even for the LNG in excess of the domestic demand.

Similar to the LTGEP, Government has also published a Long-Term Transmission Development Plan (LTTDP), which includes projected investment needs in the transmission segment up to 2027.

In this section, based on the LTGEP's generation projections and the LTTDP's transmission projections, cumulative investment needs of entire sector have been estimated. Investment estimates include the capital investment required for the development of sector, while recurring costs like operations and maintenance costs and fuel purchases are not considered. A separate analysis has been included in the annex 8 to estimate the LNG take or pay obligations.

2.1 Generation Expansion Plan

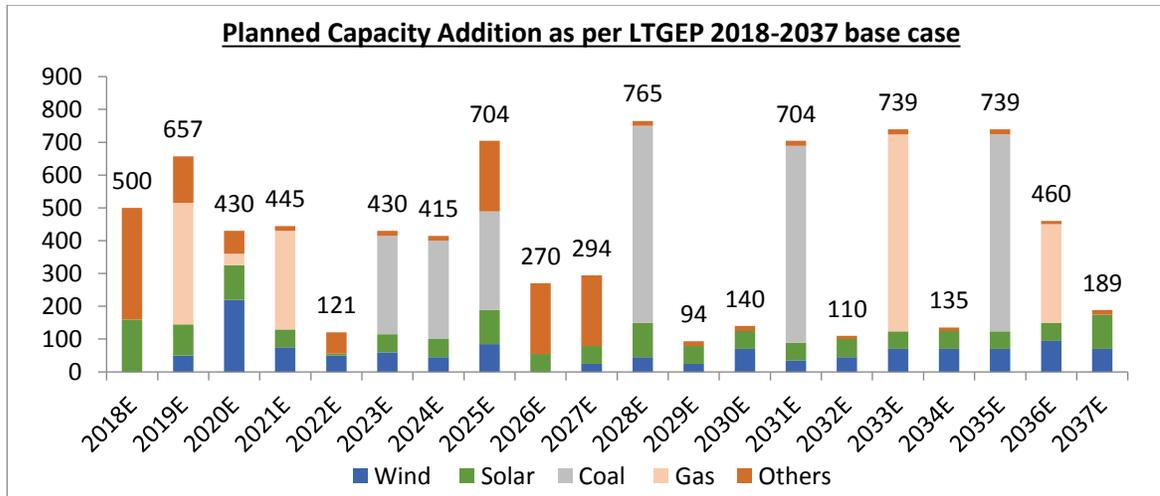
LTGEP 2018-2037 focuses on diversifying the power mix and increasing reliance on renewable energy projects and gas-based projects. Base case under the LTGEP 2018-2037 envisages:

- 1,035 MW of wind (270 MW), solar (360 MW) and gas (405 MW) projects by 2020,
- 1,980 MW of wind (585 MW), solar (690 MW) and gas (705 MW) projects by 2026, and
- 4,199 MW of wind (1205 MW), solar (1389 MW) and gas (1605 MW) projects by 2037

Additionally, base case also estimates installation of 215 MW of mini hydro, 85 MW of biomass, 822 MW of major hydro, 2.7 GW of coal and 320 MW of oil-based generators up to 2037.

Figure 5: Base Case Capacity Addition as per LTGEP 2018-2037 (MW)

⁴⁵ <https://www.dailynews.lk/2018/05/09/local/150426/cabinet-fixes-sri-lankas-energy-mix?page=2>



Capital investment requirement is estimated based on the power generation expansion plan. Total capital requirement includes capital costs expected to be incurred for setting up the generation plants (including both conventional and renewables). Additional investment will be required for operating plants and for fuel related expenditure.

Total capital required for generation expansion plan up to 2037: Total capital requirement for generation expansion plan as envisaged under the LTGEP is ~ USD 9.59 billion. Out of the total requirement ~ USD 1.76 billion is required in the short term (up to 2020) and USD 5.04 billion in the medium term (up to 2026).

Figure 6: Capital Investment as per LTGEP 2018-2037 Base Case

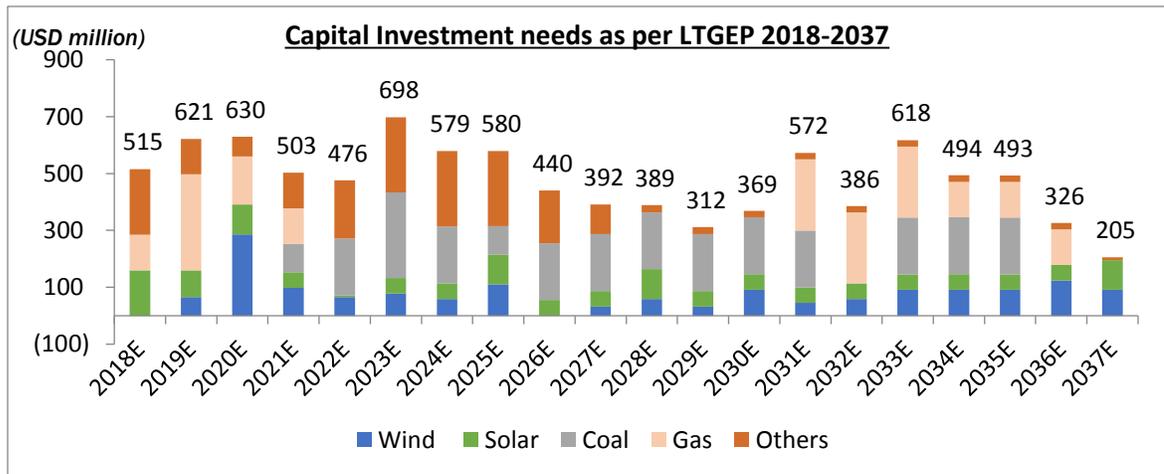


Table 4: Capital requirements of Power generation segment

All values in USD million	Power Generation					
	Solar	Wind	Gas	Coal	Others ⁴⁶	Total
Short Term (till 2020)	360	351	631	-	424	1,767
Medium Term (cumulative up to 2026)	690	761	756	1,100	1,724	5,041
Long Term (cumulative up to 2037)	1,389	1,567	1,881	2,700	2,056	9,594

Key assumptions used for the calculations are highlighted below:

Timeline Assumptions: Construction period for wind, solar and gas turbine projects is assumed to be 1 year each, for mini hydro and biomass it is assumed to be 2 years each, for CCGT and coal projects it is assumed to be 3 years each, and for major hydro it is assumed to be 5 years each⁴⁷ with uniform investment distribution over the construction period.

Cost Assumptions: It may be noted that cost estimates for each project shall vary with the kind of technology, location, timeline and the size of individual project, but for the sake of simplicity, standardized cost assumptions have been used for this exercise. The following cost ranges have been observed in select precedent projects in the similar emerging geographies:

- Wind: USD 1.30 to 1.57 million per MW
- Solar: USD 1.00 to 1.42 million per MW
- Combined cycle: USD 1.25 to 1.63 million per MW
- Gas turbine: USD 1.25 to 1.53 million per MW
- Coal: USD 1 million to USD 2.1 million per MW
- Mini/Major Hydro: USD 2 to 3 million per MW
- Biomass: USD 1 to 3 million per MW

For the purposes of this analysis, the low end of these cost ranges was used. This is based on an assumption that if well structured, competitive tenders are organized and well qualified investors – including international ones – participate in the tenders the costs would be brought down. Naturally, if such outcomes are not achieved, the financing needs would be even higher.

⁴⁶ Includes Mini Hydro, Major Hydro, Biomass and Oil

⁴⁷ As per industry benchmarks

2.2 Transmission Segment

As part of the transmission development plan, CEB estimates following for the power sector up to 2027:

1. Transmission line (new construction): The plan envisages construction of 100 kms of 400 kV lines, 907 kms of 220 kV lines and 867 kms of 132 kV lines.
2. Transmission line (capacity enhancement): The plan envisages enhancement of 100 kms of 220 kV lines, and 544 kms of 132 kV lines.
3. Grid substations (new construction): The plan envisages following enhancements:
 - 4300 MVA of 220/132 kV substations
 - 1647 MVA of 220/33 kV substations
 - 320 MVA of 220/22 kV substations
 - 2391 MVA of 132/33 kV substations
 - 1026 MVA of 132/11 kV substations
4. Grid substations (augmentation): The plan envisages augmentation of 327 MVA of 132/33 kV station, and 63 MVA of 132/11 kV station.

Total capital required for transmission segment up to 2027: Total capital requirement for transmission segment as envisaged under the LTTDP is ~ LKR 279 billion (USD 1,811 million⁴⁸). Out of the total requirement ~ 39% of capital has already been committed (with expected financing from ADB and JICA), thus additional capital required up to 2027 is LKR 170.2 billion (~ USD 1,105 million).⁴⁹

It is reasonable to assume that by 2027 a basic transmission infrastructure would be established in the country. Hence, going beyond 2027, the expected capital required for transmission would be limited. Given this, to estimate the expected capital required for transmission in the country beyond 2027, it is assumed that capital required for transmission would comprise ~ 10% of the capital required for power generation segment.

2.3 Power Distribution

Sri Lanka's distribution network is divided into 4 divisions. Each of the division prepares its distribution network expansion plan, and these plans are rolled out every 2 years. Below table shows the requirement of the distribution network based on the distribution expansion plans of these divisions.⁵⁰

Short term proposals include Completion of ongoing Distribution Network Reinforcements, Re-arrangement of feeding, 11 kV to 33 kV conversions (short lengths), MV Line Augmentation (short lines), and short MV line interconnections.

Long Term Proposals include new MV lines, gantries, MV line conversions, new / augmentation of primary substations, 11kV/33kV UG cables, 11kV ring substations, auto-reclosers, load break switches,

⁴⁸ Converted at constant USD/LKR of 154

⁴⁹ Given the early stages of development of the Sri Lanka – India interconnection and that no reliable investment costs estimates for it yet exist, it is not included in these estimates. It is also worth noting that investment into the interconnection could reduce needed investments in generation somewhat.

⁵⁰ Due to unavailability of DD1's distribution plan, the capital needs for DD1 have been estimated based on other divisions requirement using the area wise weighted average

fault Indicators and new / augmentation of grid substations. The total capital requirement is estimated at USD 169 MN through 2020 and USD 230 MN through 2026.

Table 5: Capital requirements of Power Distribution Segment

All values in USD million	Power Distribution				
	DD1	DD2	DD3	DD4	Total ⁵¹
Short Term (till 2020)⁵²	72.2	54.1	32.8	9.9	169
Medium Term (cumulative up to 2026)	95.5	71.2	43.6	19.2	229.5

2.4 Demand Side Management (DSM) Program

Government puts emphasis on efficient energy utilization, and its National Energy Policy (NEP) formalized in 2005 highlights the need for efficient management of energy while also ensuring efficient utilization and conservation of energy. By enacting the Sri Lanka Sustainable Energy Authority Act of 2007, Government created Sri Lanka Sustainable Energy Authority (SLSEA), which governs the energy efficiency improvement and conservation (EEI&C) activities of Sri Lanka.

SLSEA estimates a total capital requirement of LKR 97.65 billion (USD 634 million) by 2020, for the proposed Operation DSM. The planned DSM program consists of nine sub-programs for lighting bulbs and fixtures, chillers, refrigerators, motors, fans, air conditioning, green buildings, and smart homes. The program is expected to save ~ 1,895 GWh of energy up to 2020. The SLSEA has already secured grants from the government for LKR 18.77 billion (USD 122 million). Therefore, additional capital requirement for DSM is LKR 78.87 billion (USD 512 million).

2.5 Capital Requirements for Rehabilitation of Hydro Power Plants

Generation Division of CEB plans to implement several rehabilitation projects through which selected hydro power plants are to be refurbished. Hydro plants targeted for refurbishment post 2016 were Polpitiya (Samanala) Power Station, Udawalawe Power Station and Victoria Power Station. This has been done to minimize their maintenance/repair costs and improve efficiency and reliability of the machines. Obsolete equipment will be replaced with modern counterparts to ensure efficient performance in the years to come. As per CEB, most of the rehabilitation programs are already completed, and there may be limited requirements for additional rehabilitation at least through 2026.

⁵¹ Does not include LECO's distribution needs, as LECO can fund its need independently from its cash accruals

⁵² Although USD 26.5 million funds were committed for distribution segment under the ADB project, but in this analysis it is assumed that these funds were used for 2016 and 2017 requirements, and thus additional funds are required for requirements post 2017

2.6 Overall Capital Requirement for the Power Sector

The table below summarizes the capital investments envisaged in the power sector. Post 2020, the estimates also include a 5% contingency amount⁵³, as a conservative measure to assess the unplanned capital investment needs.

Table 6: Total capital requirements for the Energy Sector

All values in USD million	Generation	Transmission	Distribution	Operation DSM	Contingency	Total
Short Term (till 2020)	1,767	625	169	~ 512	-	3,073
Medium Term (cumulative up to 2026)	5,041	1,105	229	~ 512	~ 102	6,989
Long Term (cumulative up to 2037)	9,594	~ 1,525	229	~ 512	~313	12,173

2.7 Refinery Expansion

As highlighted in annex 4, the current refinery at Sapugaskanda is of 50,000 bpsd capacity and can meet only the 40% of the country's needs, with a ~35% utilization rate. To further enhance the capacity, improve the utilization and increase the fuel quality, the government is planning refurbishment of the Sapugaskanda oil refinery. The Ministry of Petroleum is drafting specifications for a tender to expand the refinery, and has stated they plan to maintain ownership, take on debt to finance the refurbishment, and conduct a public and transparent tender process.

According to a government estimate, the proposal to refurbish and double the capacity of Sri Lanka's only refinery in Sapugaskanda will draw in USD 2 billion in financing in the short term (through 2020) and this program would see the capacity at the Sapugaskanda refinery double to 100,000 barrels per day⁵⁴. Although the government estimates that the proposed refurbishment will yield a profit of USD 400 million annually, it still needs to be seen how the financiers value the proposed refurbishment. Given the current fiscal situation of the government, it would be critical for the government to precisely evaluate the impact of the additional debt amount for financing the proposed refurbishment program.

As there is limited clarity on how or when the proposed refurbishment will take place the capital needs of the refinery are excluded when calculating the capital needs for power sector.

⁵³ 5% of power generation capital requirements

⁵⁴ <http://www.dailymirror.lk/article/Sapugaskanda-refinery-revamping-to-draw-US-bn-in-foreign-investments-124800.html>

2.8 Existing Financing Models Adopted by Key Stakeholders

CEB: CEB is the sole integrated power utility in Sri Lanka, and was the sole power generating entity up to the late 1990s, post which the sector was opened to IPPs. Although the sector was open to participation from international players, the participation was limited to select oil/diesel fired plants⁵⁵, and CEB continued to be the leading power generating entity. Historically, CEB owned projects have been financed by one of the two following methods:

- **Loans to Government on-lent to CEB:** The loans were borrowed by the Government (primarily in the form of concessionary loans from donors/IFIs), which lowered the cost of financing. The same loans were then on-lent to CEB, albeit at a margin, but still concessional compared to the then available financing in the market. This increased the quantum of direct liabilities on the Government's balance sheet, and increased CEB's liability towards the government.
- **Loans to CEB backed by Government:** Commercial loans were borrowed by CEB primarily from international commercial banks/DFIs for its own projects, and these loans were backed by a MoF guarantee. Debt raised by CEB through this structure (e.g. from AFD, ICBC) was not concessional as compared to market benchmarks and was made bankable with the MoF guarantee.

These financing models have started to face sustainability issues given the high levels of public sector debt. The MoF guarantees, while not considered part of public debt, are included as contingent liability on government's books and capped at 10% of average GDP for past three years. Based on the above cap, the government can accrue contingent liabilities up to USD 8.32 billion while the current contingent liabilities (at 2017 end) are ~ USD 4.24 billion⁵⁶. Although this gives the government sufficient room to provide guarantees to the foreign financiers for incoming loans to SOEs like CEB, providing guarantees to back loans on CEB's books is unsustainable given CEB's current financial status.

In 2013, the Government converted part of CEB's debt to equity. Post 2013 equity conversion, CEB was able to procure more debt on its own balance sheet from local commercial banks and DFIs, with reduced support from the Ministry of Finance⁵⁷. Due to inability of the government to adjust end tariffs, CEB has again accumulated losses on its books, which has resulted in its inability to repay its obligations. The CEB has been delaying payments to CPC and has entered into an arrangement with the government under which the loans on CEB books shall be repaid by the government. Given the unsustainability of such an arrangement, there is an imminent requirement of adjustment in the end user tariff to make CEB function independently without government intervention.

IPPs: For IPPs, local banks have supported multiple project finance transactions for small scale NCRE projects. These banks have provided funding either through direct lending or through credit lines secured from international finance institutions⁵⁸. Major local banks involved in power sector projects include HNB, DFCC, Peoples Bank, etc. Table 2 highlights major lending by local banks in NCRE segment.

⁵⁵ Asia Power (51 MW, Oil Powered), AES Kelanitissa (163 MW, Diesel Powered), ACE Power Embilipitiya (100 MW, Oil Powered), West Coast (300 MW, Oil Powered), Northern Power (38 MW, Oil Powered)

⁵⁶ MOF Annual report 2017

⁵⁷ Local commercial banks - Peoples bank, NSB, HNB, International DFIs – AFD, ICBC, The USD 200 million loan from ADB to CEB for Mannar Wind farm is also backed by sovereign guarantee, but the loan was approved in 2017 and the terms are yet to be disclosed in CEBs statements.

⁵⁸ IFC and European DFIs. Source:

<https://ifcextapps.ifc.org/ifcext/pressroom/ifcpressroom.nsf/0/AE94CFA8C7D58EF385258177002DD38A>,
<http://www.combank.lk/newweb/en/news/9-press-releases/posts/390-commercial-bank-partners-eib-credit-line>

International banks have also funded projects in the power sector, either directly or via credit lines to local banks. HSBC, Standard Chartered and ANZ were lead arrangers in several of the internationally financed PPP/IPP transactions closed in Sri Lanka. For AES Kelanitissa, a 163 MW diesel-fed combined independent power plant, closed in 2001, financing was arranged by ANZ and featured a USD 26 million direct commercial loan and a USD 52 million Partial Risk Guarantee (PRG) extended by ADB. Similarly, Asia Power, a 51 MW diesel fired plant constructed in 1998 (Sri Lanka's first IPP), was financed by IFC at the back of a government undertaking⁵⁹. For other IPPs less information on the financing details is publicly available.

LECO: With a continuously expanding customer base and decreasing distribution losses, LECO is a benchmark model to be followed in Sri Lanka. LECO has managed to remain debt free and continues to invest more than LKR 1 billion (USD 6.8 million⁶⁰) annually in expanding the distribution network. Capital requirements of LECO continue to be funded either by internal cash accruals from operations, or by receivables from outstanding loans to CEB and other sector stakeholders⁶¹.

Cash flow from operations generated by LECO (in 2016⁶²) stood around LKR 3,345 million (~ USD 21.7 million). Assuming a debt servicing coverage ratio (DSCR) of 1.3⁶³, and maximum leverage of 1, LECO can potentially source up to USD 150 million debt on its books in the short to medium term (through 2026)⁶⁴. LECO has prepared its distribution network plan, within which the expected capital requirements are USD 2.25 million over the short term⁶⁵ (through 2020). Given the past investment pattern, and the financial ability of LECO, it can fund the required needs from its own cash accruals.

CPC: As detailed in annex 4, CPC has funded its capital needs in the past⁶⁶ by procuring loans from local banks, primarily People's Bank and Bank of Ceylon. As of 2014, CPC had accumulated ~ USD 1.5 billion of losses on its books. Although the company has realized operational profits in 2016 and 2017⁶⁷, the profits were primarily due to a drop in international oil prices. The recently approved fuel pricing formula is expected to ameliorate the situation for CPC, by linking the fuel prices in the country to global prices. Going forward, the expected improvement in CPC's financial situation and the profitability estimates⁶⁸ from refinery expansion, CPC could potentially finance the refinery on its own books, with adequate government support in form of direct / indirect guarantees.

2.9 Potential Financing Sources to Meet Capital Requirement

As highlighted above, the cumulative investment needs of the power sector are estimated to be ~ USD 7 billion till 2026. Potential ways in which these investment needs may be met are highlighted below:

Figure 7: Potential Sources of Investment for Power Sector

⁵⁹ <http://www.bwsc.com/Sapugaskanda-Power-Plant-Sri-Lanka.aspx?ID=214>

⁶⁰ Average capex in 2015 and 2016.

⁶¹ CEB has received 'related party loans' from LECO of ~ USD 20 – 25 million. In 2015, LECO financed select assets from outstanding loan receivables due from CEB.

⁶² From LECO's audited accounts

⁶³ Typically for long term infrastructure projects, the lenders require a minimum DSCR of 1.3

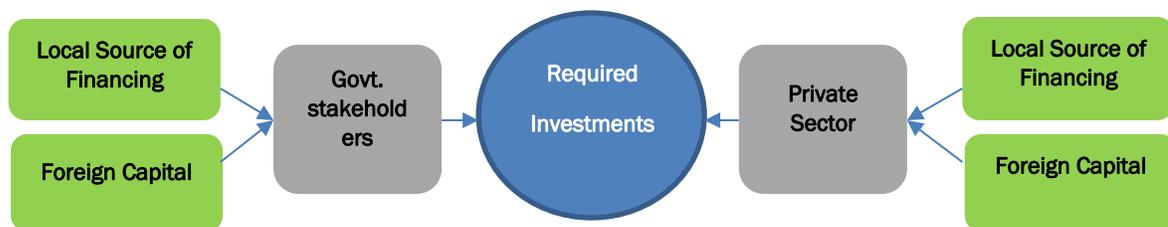
⁶⁴ It is assumed that in the short – medium time frame, the cash flow profile would remain similar to its current levels and no further equity injected in LECO

⁶⁵ Medium term proposals although mentioned in LECO's distribution plan are not considered as firm, and their cost is thus not considered in the plan

⁶⁶ CPC Annual Reports FY 13 and FY 14

⁶⁷ MOF's Annual report FY 17

⁶⁸ The government estimates USD 400 million annual profit from the proposed refinery expansion



To assess the possibility of meeting the financing needs from various sources in the short to medium run (through 2026), a preliminary analysis is conducted below. A similar analysis for long run investment needs is not detailed as the financing sources in the long run shall depend on multiple macro factors like fiscal stability, development in the domestic financing markets and developments in other sectors.

Possibility of raising financing from government and private investors

CEB – Given the current debt on CEBs books, CEBs cash flow profile, and an assumption that the existing debt shall be repaid by CEB from its own revenues, it might be possible for CEB to additionally bear ~ USD 300 million of debt on its books in the medium term (through 2026)⁶⁹. It is assumed that in the short to medium term the cash flow profile of CEB⁷⁰ will remain at similar levels, and the additional debt is procured from the local banks with government providing guarantee for the loans. As this amount is comparatively lower than the required capital needs, it may be prudent for CEB to prioritize and invest the amounts in transmission and development segments, while promoting private sector participation (PPPs, IPPs) in the generation segment.

Currently, given that the tariffs are not being adjusted by PUCSL to ensure cost-reflectiveness, CEB has accumulated losses amounting to ~ USD 900 million in 2016 and 2017, and have requested the government to subsidize this. The above analysis is based on the fact that government is not providing any cash subsidies to CEB, to offset these losses. Assuming the tariff regime becomes cost reflective / CEB receives the required subsidies, CEB could potentially leverage ~ USD 2 to 2.5 billion of additional debt on its own books by 2026, while minimizing the need for direct / indirect support from the government.

Due to inability of the government to provide subsidy to CEB, there is an interim arrangement between the government and CEB wherein the on-lent loans are repaid by the government from tax revenues, as opposed to CEB’s revenues. This is an unsustainable cyclical arrangement, wherein CEB’s ability to take additional debt will eventually be offset by the losses due to low end tariffs and will require another government intervention.

LECO – Similar to above, based on the current cash flow profile and debt service obligations, it would be possible for LECO to raise up to USD 150 million for meeting the distribution segment needs in the medium term (through 2026)⁷¹.

Government – A detailed assessment of required support from government is conducted in section 4.5.1 (“government’s ability to fund power sector needs”). The government’s expenditure on power sector

⁶⁹ As later highlighted, CEB may not be able to source additional debt on its books from international sources, but local banks might be willing to lend to CEB on the back of government guarantees. The assumption here is that CEB could potentially avail debt up to meeting the projected DSCR of 1.0, at the back of government guarantees.

⁷⁰ CEB’s operating profits have further deteriorated to negative 319.7 USD million in 2017 primarily due to a reduced Hydro base (Hydro declined to 21.17% in 2017 compared to 24.52% in 2016)

⁷¹ The operational performance of LECO is included as part of Annexure 4

was ~ USD 55 million in 2017 and its approved expenditure for 2018 is USD 5.5 million. Although the budget allocated to power sector has consistently been decreasing, this analysis assumes an average annual budget of USD 30 million over the short to medium term. Given the above, in the medium-term government may be able to invest up to USD 240 million (a budgeted capital investment of USD 30 million annually up to 2026).

The table below indicates the amount that would be required in addition to the amounts raised by sector stakeholders. It is estimated that out of ~ USD 7.06 billion required in the medium-term (through 2026), only ~ USD 540 million could be sourced by the government stakeholders. The additional capital required could either be sourced by private sector participation, or by exploring alternate financing structures⁷². As highlighted before, the current calculations used to estimate the ability of sector stakeholders to raise financing assume existing financing models going forward. If the tariff regime becomes cost reflective, or CEB received the required subsidies from the government, CEB can potentially source USD 2 – 2.5 billion of debt on its books in the medium term (through 2026).

Table 7: Required Financing and Potential Funds available from Government Stakeholders

All values in USD MN	Total
Required Financing needs in medium term	6,989
- Government	240
- CEB	300
- LECO	150
Additional financing required	6,299

Possibility of raising financing from domestic lenders

Based on preliminary analysis, around USD 220 million (USD 0.22 billion) is potentially available with Sri Lanka’s domestic banks to invest in the energy sector. Table below shows the assumptions and calculations using which the available funds to energy sector from domestic banks were estimated.

Table 8: Potential financing available from Domestic Banks

Estimation of Financing Available for Energy Sector from Domestic Banks	LKR (Billion)	USD (Billion)
Licensed Commercial Banks – asset base 2017	8,926.19	57.96
Licensed Specialized Banks – asset base 2017	1,366.2	8.87
<i>Total Investable Bank Assets – 2017 (A)</i>	10,292.40	66.83
Y-O-Y increase in Investable asset base	5%	5%
<i>Total Investable Bank Assets – 2018 (B)</i>	10,807.02	70.17

⁷² The alternate financing models are highlighted as part of section 4.1.

Share of Energy Sector in total investable assets	3%	3%
<i>Total Investable Assets available for Energy Sector (C)</i>	324.21	2.11
Average Loan Tenor (Years) (D)	9	9
<i>Available financing to Energy Sector in 2018 (C/D)</i>	36.02	0.23

Total asset base of banks in 2017 is LKR 10,292.40 billion (USD 66.83 billion) and is assumed to grow by 5% year-on-year basis, reaching LKR 10,807.02 billion (USD 70.17 billion) in 2018. Historically, domestic banks have invested ~ 6-7% of their investable assets in infrastructure. Potentially, if the constraints in the domestic financing markets are removed, the banks could contribute up to 10% in infrastructure sectors. As per World Bank's PPI database, investments in energy have historically been ~ 30% of investments in infrastructure. Given the above, ~ 3% of investable assets (LKR 324.21 billion/USD 2.11 billion)⁷³ are assumed to be potentially available for investment in the energy sector. Assuming a 9-year average tenor on loans, it was calculated that around LKR 36.02 billion (USD 0.23 billion) would be repaid each year and are assumed to be available to be deployed again in infrastructure assets.

Based on the above assumptions in the medium term (through 2026), domestic banks can potentially cumulative fund up to ~ USD 2.58 billion. This would require that banks are able to syndicate large ticket loans and that entire asset base is optimally utilized to fund the investments. Given that such optimization is not readily possible, the annual financing contribution from the domestic banks will be significantly lower and requirements from other foreign sources may be significantly larger.

As highlighted in the section 2.8, the cumulative needs of power sector could reach up to USD 7 billion in a similar time frame. **Hence, to meet the financing requirements, ~ USD 4.4 billion worth of capital needs to be mobilized in the medium term (up to 2026).** If CEB, LECO and the Government can finance additional USD 0.690 billion, another USD 3.7 billion would need to be mobilized, either from foreign sources or through the domestic capital markets. The funding gap would be considerably narrowed if cost reflective tariffs were introduced, which would enable CEB to leverage significant additional debt on the strength of its own balance sheet.

2.10 Implementation of past LTGEs

This section evaluates how successfully Government has managed to implement the LTGE's proposed in the past. For this evaluation LTGE 2013-2032 and LTGE 2015-2034 were considered, and actual capacity additions from 2013 till now with the proposed additions in respective LTGEs were compared. Following table details capacity additions which were proposed in LTGE 2013-2032, along with their status, whether they have been commissioned or are still in pipeline or have been cancelled.

Table 9: Review of Proposed Capacity Additions and Actual Capacity Additions

Proposed Plant	Capacity	Status	LTGE 2013-2032	LTGE 2015-2034	LTGE 2018-2037
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⁷³ Assumption based on World Bank PPI database

			Proposed Commissioning Year	Proposed Commissioning Year	Proposed Commissioning Year
Chunnakum Extension	24 MW (3X8)	Operational	2014	2013	2013
Puttalam Coal Stage II	600 MW (2X300)	Operational	2014	2014	2014
Broadlands HPP	35 MW	Not Complete	2016	2017	2020
Uma Oya HPP	120 MW	Not Complete	2016	2017	2019
Gas Turbine	105 MW	Not Complete	2017	2018 (2x35 MW) /2019 (1x35 MW)	2019 (2x35 MW) /2020 (1x35 MW)
Trincomalee Coal Power plant (Sampur)	500 MW (2X250)	Cancelled	2018	2020	-
Moragolla Plant	27 MW	Not Complete	2018	2020	2022
Mannar Phase 1	100 MW	Not Complete	-	2018	2020

Of all the proposed capacity additions in LTGEP 2013-2032, only two have been commissioned till date. Both were additions to existing plants, and major capacity contribution came from only one coal project. Based on the analysis, it is clear that actual capacity addition significantly lags the additions proposed in LTGEP. Going ahead, it would be crucial that actual capacity addition timelines adhere to the proposed ones to ensure that Sri Lanka efficiently meets its proposed energy targets.

Historical investments in the Energy Sector

As highlighted, the country has missed the LTGEP targets in the past. Analyzing the historical investments in the country, it is observed that on an average there has been an annual private investment of ~ USD 138 MN⁷⁴ in the electricity sector. Additionally, the government on an average has invested ~USD 300 MN p.a. in the energy and water sectors.⁷⁵ Combined, up to ~ USD 438 MN have been invested on an annual basis in the sector, with the government having contributed more than triple the amount invested by the private sector. Assuming that a similar investment trend continues, the total investments through 2026 will be limited to about USD 3.5 BN or ~ 50% of the total funding requirement for the sector through medium term.

Comparing with the total funding requirement of USD 7 BN up to 2026, it can be concluded that continuing with the historical investment trend will not suffice to meet the required investment.

⁷⁴ World Bank PPI database for Sri Lanka for the period 2010-2018

⁷⁵ CBSL reports - Capital expenditure incurred in 'Energy and Water' sector by the government averaged USD 400 MN in 2010-2018. The capex amounts are converted at an exchange rate of USD / LKR of 154. For the purposes of this illustrative analysis it was assumed that 75%, or USD 300 MN of the capex incurred is in energy sector.

Additional USD 3.5 BN funds need to be mobilized to meet the funding shortfall. Given that the government has historically invested significantly more than private sector and in light of the current fiscal constraints, it is reasonable to assume that majority of the additional funding requirement needs to be mobilized through commercial finance and private sector counterparts.

2.11 Sensitivity Analysis of Financing Shortfall

As highlighted, the generation planning in the LTGEPs has not been timely implemented, with majority of the projects experiencing delays due to political, environmental and other non-financial reasons. Given such a situation, it is highly likely that the actual financing needs in the medium term are lower than what has been projected in the LTGEP 2018-37. This section intends to assess the financing shortfall in the following cases-

- a) *If the actual financing needs reduce by 25%, 50% and 75% compared to those projected in the LTGEP 2018-37, LTTDP and other sector plans.*

Actual Financing Needs(as a % of total projected needs in Medium Term, i.e. USD 6,989 MN)	Financing potential of Domestic Lenders and state stakeholders (USD MN)	Financing required from foreign sources (USD MN)
75% (5,242)	3,270	1,972
50% (3,495)	3,270	225
25% (1,747)	3,270	-

It can be seen that even if the actual financing needs are lowered by 50% of the projected requirements in the next 8 years (through 2026), the state entities and domestic banks will not be able to potentially meet the entire sector needs. This analysis assumes that the entire capital available with domestic banks could be mobilized efficiently to fund the infrastructure needs which in real terms is constricted by many factors like low syndication capabilities, limited maturity and high cost of funding, low project finance know-how, etc. and hence overstates the contribution from domestic banks.

- b) *If the historic investment levels can be grown at a 10% annual growth rate*

As highlighted above, if future investments continue to be at historical level there would be roughly a 40% shortfall compared to the investments required to implement sector plans in medium term. But it is likely that the country is able to mobilize funds with a 10% year on year growth rate, in particular if recommendations included in this report are implemented. A scenario where investments increase at a 10% year-on-year growth rate above the historical level is highlighted below.

Investment estimate through 2026 ⁷⁶	Funds needed to meet LTGEP targets through 2026
USD 5.5 BN	USD 7.0 BN

Under the above scenario total investments through 2026 will be about USD 5.5 BN, which is USD 1.5 BN short of the USD 7.0 BN funding required to implement the power sector expansion and investment plans through the medium term. To close the gap an annual growth rate of 15% over historic levels would be needed. While this does provide a more encouraging picture, it is critical to see this in the light of the current fiscal limitations of GoSL. The historical investments are based on an annual average investment of USD 300 MN from the government/public sector, while the government’s budget expenditure on power sector infrastructure project investments has decreased from about USD 55 MN in 2017 to USD 5.5 MN for 2018. This highlights the dual importance of strengthening the key sector players like CEB / CPC for mobilizing funds on their books and increasing the participation of commercial and private finance in the sector.

3 Binding Constraints to Financing

As highlighted in section 2.9, there is an imminent need to mobilize USD 4.4 billion of financing in the medium time frame (through 2026), to meet the required financing needs of the sector.

Foreign investment can be attracted by addressing key binding constraints that have resulted in limited influx of foreign capital in the country. To understand these key constraints, following questions have been addressed in the subsequent sub-sections:

- Can the main sector stakeholders (CEB/CPC) secure financing for the entire investment needs, across generation, transmission and distribution segments? If not, why?
- Can the domestic financial institutions fund the required investments?
- Why is there limited participation from international players and financiers to support the sector?

3.1 Constraints to CEB’s Ability to Mobilize Financing⁷⁷

It is imperative for CEB to have strong financial capability. First, the creditworthiness of CEB directly impacts the payment risk/credit risk that the private sector IPPs would perceive under the PPA arrangement with CEB. Second, the financial capability of CEB is directly linked to the amount of capital that CEB can leverage on its own books for meeting the desired investment requirement.

Based on the current small scale NCRE projects procured under SPPAs, domestic sponsors and lenders seem to be broadly comfortable with potential delay in tariff payments, the current weak financial situation of CEB, and the risk allocation mechanisms under the SPPA. However, considering the long-term investment needs of the sector, these characteristics of the Sri Lankan power market are not conducive to attracting international investors. Financing from international investors will be essential if Sri Lanka’s power generation needs are to be met. Indeed, based on global practice, investors would

⁷⁶ Average investment in the sector in 2018 assumed to be USD 438 MN (refer section 2.10 for details). The average investments are assumed to grow at a 10% year on year growth rate through 2026.

⁷⁷ The constraints to other government stakeholders are not highlighted separately, as the scope of other stakeholders is very limited.

assess credibility of the off-taker (CEB). In the absence of an international investment grade CEB credit rating, coupled with CEB's low financial soundness, these investors would typically need robust security mechanisms to cover the payment risk.

It is important to note that role of CEB is not limited only to off-taking the power generated by IPPs. CEB also dominates Sri Lanka's power generation segment with more than 72% of the installed capacity owned and operated by CEB. CEB in addition plays a critical role in defining the long-term generation plan. Therefore, to grow in its role as a developer/equity holder in the power generation segment, and to meet the transmission and distribution requirements on its own, CEB needs to have adequate financial capability.

Given the above, this section highlights key constraints faced by CEB when it comes mobilizing and meeting its investment needs. Indeed, CEB's cash flows have a high element of variability which disincentives lenders from relying on CEB's cash flow profile for debt servicing. With reduced support from Ministry of Finance, CEB is even further constrained in its ability to raise additional local/domestic financing.

3.1.1 The country's low credit rating limits CEB's ability to borrow internationally

Recently assigned credit ratings for CEB are the following:

- **CEB's National Long-Term Rating:** AAA (Stable) - Fitch
- **Sri Lanka Long-Term Foreign Currency Issuer Default Rating:** B+ (Stable) - S&P, Fitch

Based on the financial condition of CEB (highlighted in the next section), the AAA national rating may come as a surprise. However, key drivers for this rating, as highlighted by the Fitch rating agency, are:

1. **Strong Linkages with the State:** Strong linkages between CEB and the state reflected by high ownership and management control, explicit guarantees⁷⁸, and financial support through equity infusions and debt funding.
2. **Monopoly Status in the Power Sector:** Sole integrated utility across power generation, transmission and distribution. Considering rising power demand, electricity sales are bound to rise significantly.

Consequently, although the national credit rating of CEB is AAA, the international credit rating of CEB may be, in practice, capped at the country's credit rating. Sri Lanka's credit rating at B+, which is four notches below investment grade, is a concern for international financiers. They would therefore require additional credit enhancement instruments to enhance the credit rating of the transaction. CEB does not currently have any international rating as an entity. However, if it was to be rated, International financiers might rate CEB be even lower than the country, based on CEB's volatile cash flow profile and overall financial situation.

⁷⁸ In light of the current macro situation, the Government has reduced the amount of guarantees to be provided to SOE's. But a sovereign guarantee has been provided for Mannar Wind farm. Source: <https://www.adb.org/news/adb-boosting-renewable-energy-sri-lanka-100-mw-wind-park>

3.1.2 Volatile financial performance, exposed to weather and fuel prices

It is critical to analyze CEB’s financial capability to pay-off its fixed obligations in a timely manner (to the IPPs and to service the debt on its own balance sheet). CEB’s income statement mirrors the challenge CEB is currently facing in Sri Lanka: adverse monsoons in 2014, 2016 and 2017 have led to low generation from hydro plants, and subsequent high utilization of expensive oil-based generation to meet demand. This situation is reflected in CEB’s volatile and decreasing profitability. As can be seen in Figure 8, CEB’s profit margins follow a pattern similar to the monsoons. The profit margins are adversely impacted during periods of low generation from hydro power (2014, 2016 and 2017) and pick up in periods with favorable monsoon. This inconsistency in margins is viewed negatively by lenders, as it subjects the future debt servicing capability to variable climate conditions and international fuel prices. This would tend to limit the availability of international financing or increase its cost.

Figure 8: CEB Profitability Ratios⁷⁹

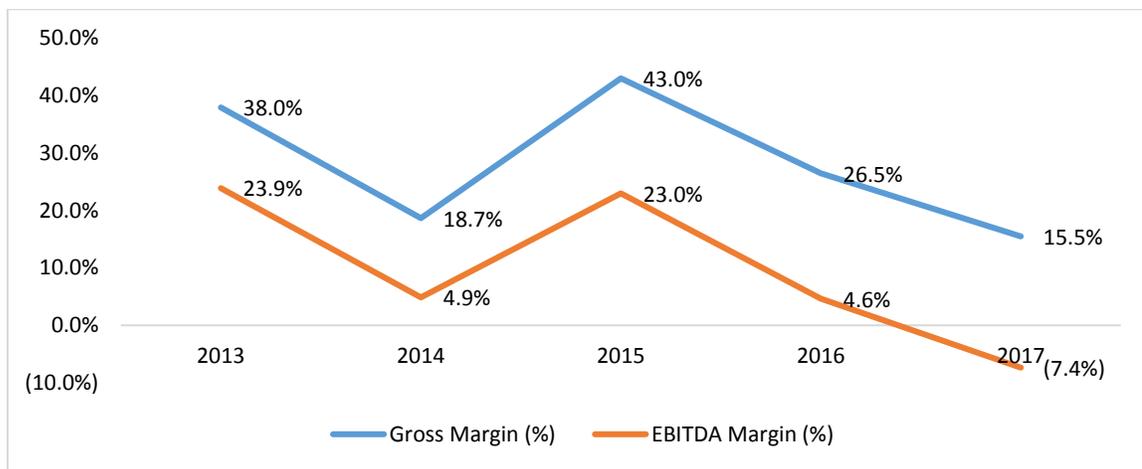


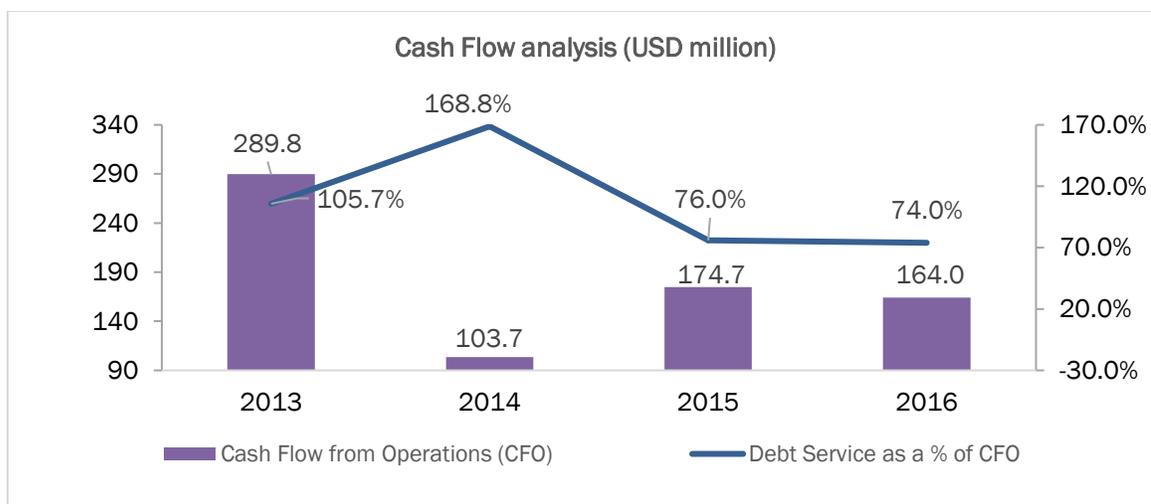
Figure 9 below reflects impact of the inconsistent cash flows on CEB’s debt service capability.⁸⁰ It can be seen that CEB’s cash flow profile is in correlation with the contribution of hydro power plants towards overall generation. In 2013 and 2014, due to adverse monsoons and reduced utilization of hydro power plants, the cash flow generated from operations was not sufficient to service the debt.

Figure 9: CEB’s Cash Flow Analysis⁸¹

⁷⁹ Source: CEB Financial Statements, where Gross margin = Gross Profit / Revenue, and EBITDA margin = Earnings before interest depreciation and amortization / Revenue

⁸⁰ In 2014, the debt service obligation was additionally impacted due to conversion of ~ USD 1.2 billion of debt to equity by Government

⁸¹ Source: CEB Financial Statements



3.1.3 Weak balance sheet and high debt service obligations

CEB's balance sheet is significantly weak for a utility company, owing to its inability to maintain profitability. Government in 2013 converted ~ USD 1 billion of CEB's debt into equity. Post 2013, thanks to its reduced liabilities after the equity conversion, CEB was able to source additional debt on its own balance sheet, primarily via local commercial banks and DFIs.

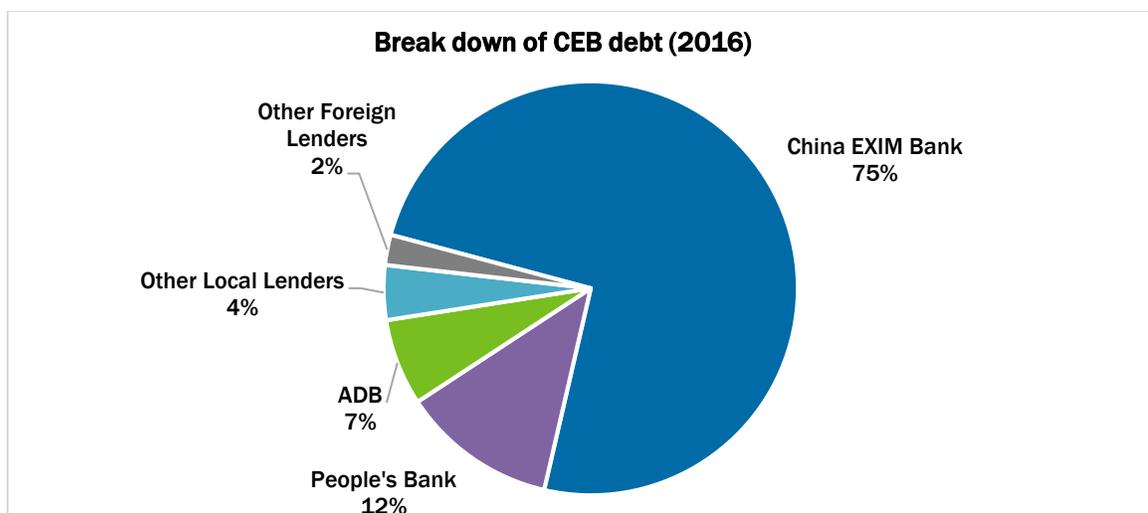
Table 10: CEB's Balance Sheet Snapshot

(Dec Year End LKR BN)	2013	2014	2015	2016
Liabilities				
Equity	226.7	394.8	428.2	411.9
Non-Current Liabilities				
Interest Bearing Debt	334.5	202.8	198.3	201.8
Other Non-Current Liabilities	95.5	83.3	89.3	97.9

Figure 10 below highlights key loans on CEB's books. Majority of the loan book is provided for by China EXIM bank, for 900 MW Puttalam coal project. The ADB loans are for the transmission and distribution projects. Contribution of local lenders to CEB's balance sheet is minimal. Local loans from the People's Bank and others are primarily utilized to meet working capital requirements. The local banks lending to CEB may perceive less of a re-payment risk on their loans and require less collateral as they assume the loans to be secured through an implicit government guarantee.

Figure 10: CEB's Debt (2016)⁸²

⁸² Source: CEB Financial Statements



Based on CEB's 2016 financial statements, CEB's debt service obligations are more than 70%⁸³ of the operational cash flows, leaving no room for procuring any additional debt on its books from international sources. However, at the back of government guarantee, local banks could potentially provide additional debt to CEB, irrespective of CEB's financial performance⁸⁴.

The inability of the government to raise the tariffs in line with the cost of power has weakened CEB's ability to service the ongoing debt service obligations. Given this, there is an interim arrangement between the CEB and the government, whereby the government will service the China EXIM loan from tax revenues. Although this is expected to reduce CEB's debt service obligations in the near term, it is not a sustainable arrangement. CEB's increased ability to source additional debt on its books will eventually get offset by the accumulated losses due to low end user tariffs, which will require another government intervention to clean the slate. Given government's fiscal space, it is prudent if the situation is supported by required adjustments in the end user tariffs, or in the interim, supported by a transparent and structured direct subsidy mechanism to CEB transmission licensee.

3.1.4 Lack of CEB financial transparency contributes to non-cost reflective tariffs

Prior to the electricity act in 2009, tariff setting mechanism was unclear and the government used to set tariffs in an ad-hoc manner. The inability to charge cost reflective tariffs resulted in financial losses for CEB. As already highlighted, tariff methodology adopted by PUCSL⁸⁵ in 2009 entails following benefits to all the licensees:

- Tariff schedule will reflect separately the costs of each generating, transmission, and distribution licensee providing electricity at specified times of the year.
- Tariff schedule will permit each licensee to recover all reasonable costs incurred in carrying out its authorized activities on an efficient basis.

⁸³ Equivalent to operational DSCR of 1.35 (in 2016). This DSCR does not consider the China EXIM loan repayments, as they are serviced by the government from tax revenues. Given the current scenario, international lenders would require a much higher and a consistent DSCR if CEB takes debt on its own books & without a government guarantee to finance upcoming investments.

⁸⁴ The potential debt that CEB could leverage on its books at the back of government guarantee from local banks is estimated to be ~ USD 300 MN. The assumption is that CEBs cash flows remain the same at 2016 levels, and local banks potentially fund up to a projected DSCR of 1, at the back of government guarantee.

⁸⁵ Refer Annexure 5 for details on the tariff methodology

However, there has been limited clarity from CEB on costs and revenue streams pertaining to its transmission and distribution licensees. Hence, tariffs continue to be non-reflective of actual costs incurred.

Setting up of a Bulk Supply Transaction Account is a key element under the PUCSL's tariff methodology. While the CEB transmission licensee has prepared a notional Bulk Supply account and submits information on transactions to the PUCSL, it has not set up a separate account to settle transactions with the distribution licensees. The cash collected from the distribution licensees is directly credited into the CEB's central corporate account⁸⁶.

CEB maintains that it has been disclosing all cost related information required to adjust the tariffs and as requested by PUCSL. The PUCSL has been requesting separate accounts of all licensees, which CEB may construe as a step towards unbundling the utility. According to CEB, if the utility is unbundled, it might not be feasible for licenses to raise additional capital, given the limited asset base of resulting individual entities. CEB's understanding of the license requirements is that there is no need to establish separate physical accounts and it is complying with the PUCSL's request to provide information for each distribution licensee. Payment vouchers are used to show the required transactions even if physical cash transactions do not take place due to the shortfall in revenues collected from customers. As part of the disclosure pertaining to the Bulk Supply account, CEB transmission licensee has shown accumulated losses in 2016 and 2017 and requested subsidies from the government amounting to about USD 900 million. The government has not made subsidy payments to CEB. According to CEB, the rationale for not raising tariffs is motivated by reasons other than its adherence to the tariff methodology.

The PUCSL, on the other hand, has requested CEB to set up separate accounts for each of the licensee in the interest of greater transparency in the use of receivables and bring in more clarity on the actual cash transactions between the various CEB licensees. PUCSL also believes that the generation dispatch is not audited in a transparent manner. The audited data is delayed by as much as 2 years, which makes it difficult for PUCSL to verify the actual data with the forecasted data.

The last tariff adjustment was implemented in 2014, where the end user tariffs were reduced by ~ 25%⁸⁷, in anticipation of reduced cost of power from the 900 MW Coal plant. Post 2014, the PUCSL has taken a policy decision to not entertain any tariff requests from CEB until a physical bulk supply account is established by the CEB transmission licensee. Limited disclosure and non-adherence to guidelines has resulted in the tariffs continue being non-reflective of the underlying costs and has eroded public confidence in the tariff setting process.

3.2 Constraints to Mobilizing Financing from Domestic Financial Institutions

Sri Lanka's domestic financing market has developed over the years as highlighted in annex 7. However, it requires further deepening to seamlessly provide a market for large ticket, long tenor loans typically required for infrastructure projects. This section highlights the key constraints faced by the banking sector in Sri Lanka when it comes to funding the required investments in the energy sector.

⁸⁶ Refer Annexure 5 for details on the current transactions amongst CEB licensees

⁸⁷ Based on interaction with sector stakeholders

3.2.1 Limitations of the Domestic Banking System

Limited Availability of Long Term Debt: Currently, the average tenor of the loans being provided by banks is in the range of 7 - 10 years. Domestic banks do not generally have the capacity to fund such long tenor loans on a regular basis due to asset-liability mismatch. Given that power sector projects, due to their size and nature⁸⁸, typically require long term debt, mobilizing such debt from the domestic banking sector is likely to be a big challenge.

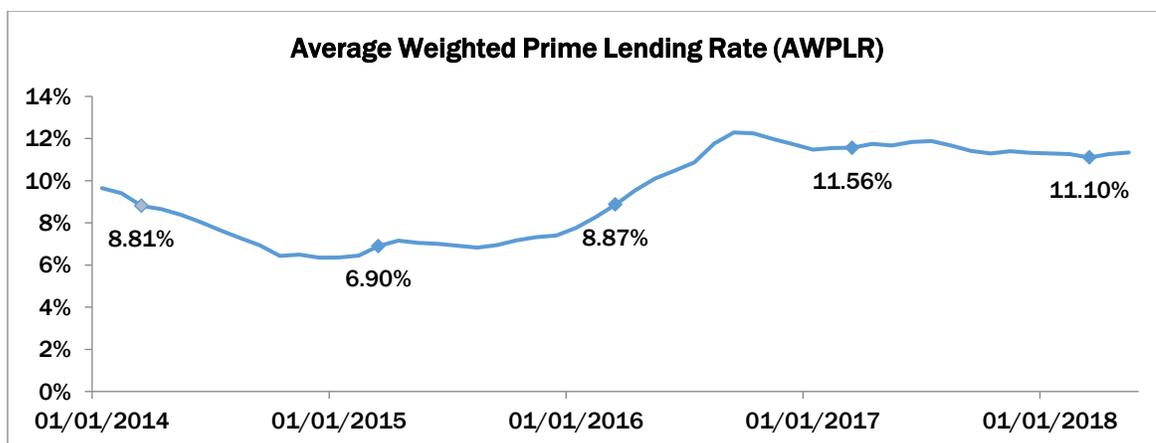
Limited Size of the Banking System: Sri Lanka's banking system does not have enough liquidity to support the amount of infrastructure investment required, particularly when it comes to large individual power projects. The sector is relatively fragmented with many small banks which do not have the capacity to fund large projects, given their limited asset base. Even the 6 - 8 large players can individually fund only up to USD 25-30 million on average per project. Given this, theoretically, in a syndicated transaction the total debt available to a project could be in the range of USD 150 - 200 million. In practice there has been no substantial syndicated deals (involving more than 2-3 lenders).

Single Borrower Limits: Under existing regulations, banks can incur a single-borrower exposure equivalent to 30% (40% for corporate groups) of shareholder funds. However, in practice, commercial banks set their own internal credit limits. They are often lower than the limits imposed by the regulator. Assuming local banks limit their single-obligor exposure to a more prudent 15% of shareholder funds, the top six banks could incur a combined exposure of only USD 382 million for major borrowers (of which around USD 153 million would come from the two largest banks). Thus single-borrower limits could also constrain the amount of infrastructure lending that local banks are able to extend. There have been instances in the past where some of the renewable projects have been exempted from the borrowing limits. CBSL should continue this practice for the upcoming investments, as it would enable international players to expand in the local market.

High Cost of Borrowing: Current cost of local financing is on the high side (~13%-15% in LKR terms) with pricing typically at a margin to the Average Weighted Prime Lending Rate. Primary reason for high borrowing cost is the high cost of funding for the local banks. Local banks in Sri Lanka are dependent on deposits/foreign loans/foreign bonds as source of funds. In case of foreign loans/bonds, overall cost of funds is high as it also includes the cost for hedging the currency risk. Due to lack of a developed hedging market in Sri Lanka, CBSL assists the banks in converting USD based loans to LKR, and the hedging cost comes to ~ 6%-7%. Lenders believe that hedging cost has room for optimization and the cost would come down to 3%-4% once hedging market is developed. Additionally, Average Weighted Deposit Rate has continuously increased from April 2015, leading to an upward pressure on the cost of funds. Due to the limited availability of long tenor funds and associated higher cost of funding, loan margins are primarily influenced by the cost of funding and the relationship with borrowing entity, and less by the credit risk and underlying project cash flow.

Figure 11: Average Weighted Prime Lending Rate

⁸⁸ A typical project finance transaction for a large scale power project would be funded at a significant high Debt to Equity ratio (at least 60% debt). To repay the large amount of debt, and simultaneously maintaining the minimum DSCR requirements of lenders (which is typically in the range of 1.2/1.3), a long tenor loan is required. The tenors can range from 10-17 years for a project life of 20 years.



Limited Project Finance Capability: A major concern amongst local lenders is that CEB pays revenue payments directly to the developer. Lenders believe that there is no substantial recourse in case the developer does not abide by the repayment schedule. Hence, banks believe that there is need of an arrangement between CEB, developer and the banks, whereby the lenders get first right on the project cash flows, after the tax and O&M payments are made. Typically, as an international practice in project finance transactions, the off-taker makes payment to a revenue account of the project company. Payments from the revenue account (for example O&M payments, taxes) are monitored by the bank, and paid out in the order of rights on the project cash flows. Any change in the payment rights needs to be approved by the banks. Additionally, the project company enters into standard security arrangements, including assignment rights of all the project accounts and agreements to the banks. Typically, a direct agreement is executed between the lenders and the off-taker to acknowledge the step-in rights of lenders in case of events of default. The local banks have limited know-how about these structures and have become comfortable with the existing mechanism. While this may be workable in case of small scale projects, for large scale projects the banks would need to adopt standard practices to ensure bankability in the transactions.

3.2.2 Under-Developed Local Capital Markets

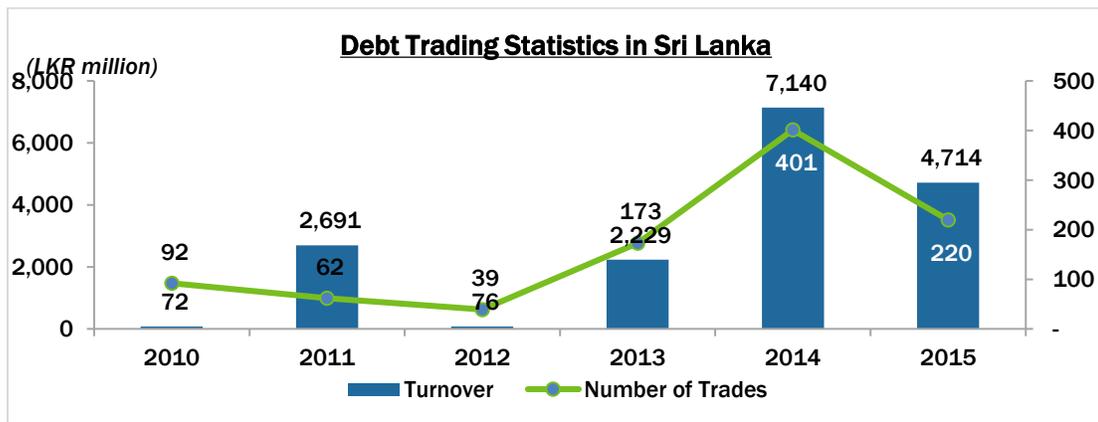
Despite its potential, Sri Lanka's capital market is at a nascent stage of development. In 2015, stock market capitalization stood at USD 19.6 billion accounting for 26.3% of GDP, relatively smaller than comparable countries such as Thailand (88% of GDP) and Malaysia (129% of GDP). Importantly, almost all the securities in the market are Treasury bills and bonds. Corporate bonds are limited to around 0.75% of GDP (2015) and are mostly held to maturity. The World Bank 2015 Financial Sector Assessment Program (FSAP) highlighted that some conglomerates have reached single obligor limits with commercial bank and can look to the corporate bond market for financing requirements. Because of the generous tax incentives, there was a significant increase in the number of listed corporate bond issues in 2013 and 2014, but these were issued by financial institutions only.⁸⁹ This situation reversed in 2015 and 2016 with reduction in corporate bond issuance, primarily due to tax uncertainty.

⁸⁹ In 2016, out of the 17 debentures issued, 15 were by either banks or finance companies. In 2015, out of the 25 issued, 19 were by either banks or finance companies. In 2014, out of the 20 debentures issued, 16 were by either banks or finance companies. In 2013, out of the 30 debentures issued, 23 were by either banks or finance companies.

Capital markets in Sri Lanka may be considered underdeveloped and not liquid enough to support the large amount of investment required in the power sector. Key constraints to development of capital markets are highlighted below.

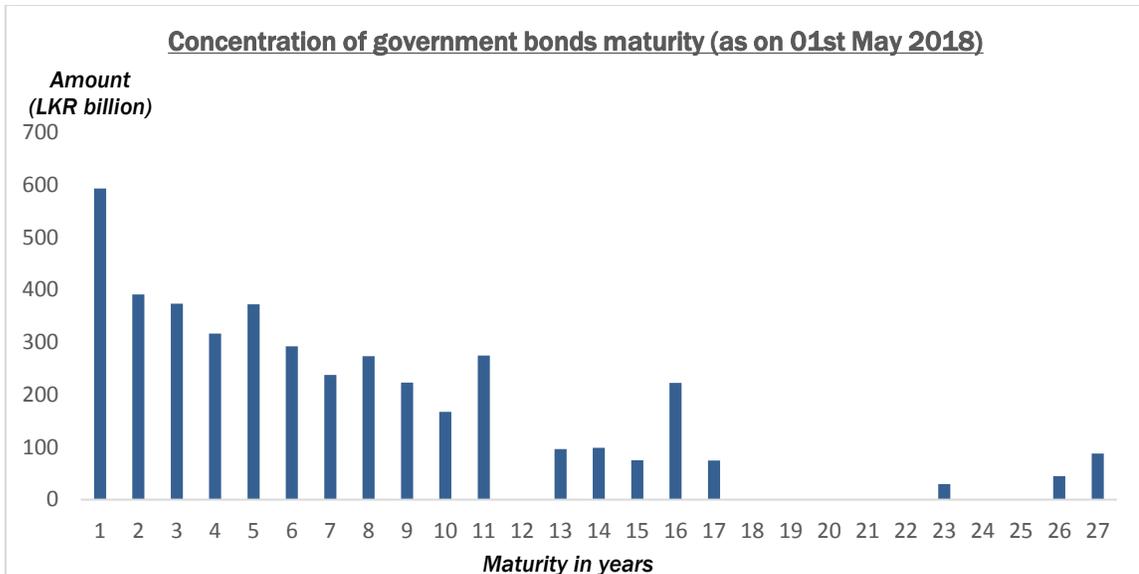
Limited number of trades: Number of trades as well as number of bonds traded has been very low, reflecting the preference for domestic institutional investors to hold corporate bonds till maturity. A vast majority of investors in corporate bonds are institutional investors such as unit trusts, banks, pension funds and insurance funds. Given the small size of listed corporate debt market and the large size of these institutional investors, their holding of corporate debt is very small in absolute values and relative to their portfolios. Therefore, there is no fundamental portfolio rebalancing or cash flow need for institutional investors to trade their corporate debt holdings. This inhibits other potential investors to invest in the secondary market due to lack of liquidity, which in turn reduces primary market demand for corporate debt, limiting the ability for companies to raise funds through debt issuance. Illiquidity in the market can be observed from the fact that there were only 220 bond trades executed in 2015 (ADB, 2018) (figure 12 below), with total value of LKR 4.71 billion (USD 30.58 million).

Figure 12: Debt Trading Statistics in Sri Lanka



Inefficient pricing of government bonds: Limited number of long-term government bonds (with maturity over 10 years) hampers developing a reliable benchmark yield curve for transparent pricing of corporate bonds. Also, secondary market trading in government bonds is limited, particularly in longer maturity government bonds. This is primarily because vast majority of bonds are held by institutional investors who tend to hold them till maturity. Most secondary market yields are just bid and ask quotes from primary dealers, and do not represent actual transaction yields (ADB, 2018).

Figure 13: Government Bond's Maturity Profile



No market making mechanism for corporate bonds: There is no formal market maker mechanism in the Colombo Stock Exchange (CSE). Debt trading members are only obligated to act as intermediaries to transactions between buyers and sellers and are allowed to trade on their own portfolios.

Legal and Regulatory Impediments to Increasing Funding from Institutional Investors: Charter documents of Employee Provident and Employee Trust Funds (EPF and ETF), as well as of insurance companies, typically restrict the type of investments that they can make. As such, most funds invest majority of their assets in government securities. Although investment guidance to EPFs mentions they can potentially invest in capital intensive sectors and assist the development with their long-term source of funds, EPFs need special approval to invest in non-listed companies. This is an issue as PPP projects are typically developed through an unlisted special purpose vehicle structure. However, these investors can be a critical source of financing for power projects. It will be important to educate them of potential benefits of long term investments and alignment with their investment mandates.

3.3 Constraints to Mobilizing Financing via International Financial Institutions

As already highlighted, Sri Lanka may face an annual average shortfall of ~ USD 150 million (or more) within its own financial system to fund the estimated power sector requirement of USD 4.4 billion by 2026. To successfully develop the power sector as envisaged, and absent the development of the capital markets, this amount would need to come from foreign participants. To achieve this, key constraints highlighted below will need to be adequately addressed and mitigated to create a supportive enabling environment for international investors.

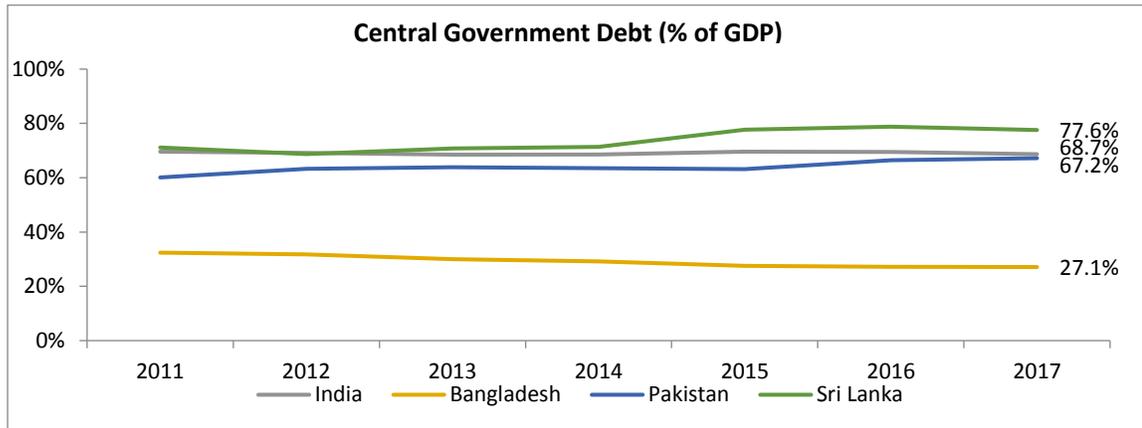
3.3.1 Macro-Fiscal Constraints

Fiscal Constraints: To date, capital investment needs have been largely supported by the government through international loans from multilaterals and donor funds. This has led to high level of debt on the books of the government. This has burdened the treasury and resulted in a situation where debt service payments are more than 90% of the government's tax revenue.⁹⁰ The public debt statistics of

⁹⁰ Source: CBSL Annual report

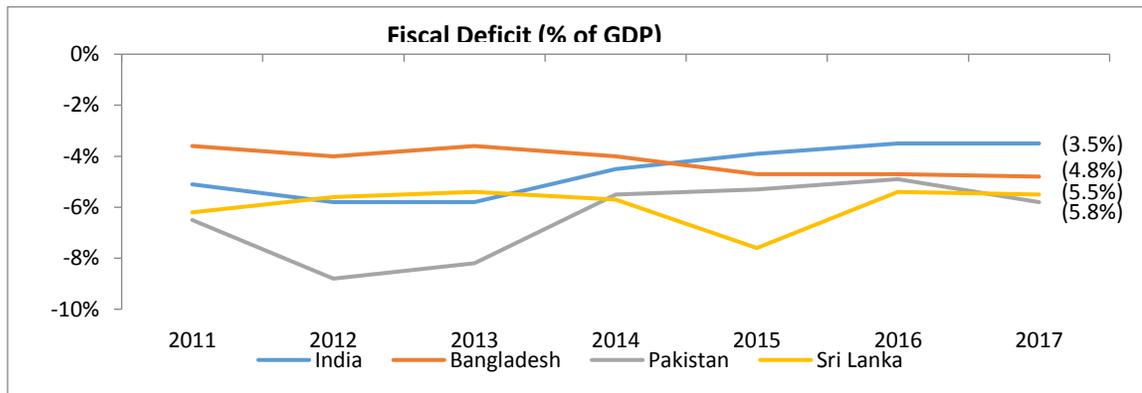
Sri Lanka are weak compared to regional peers (India, Bangladesh and Pakistan). High public debt (77.6% of GDP in 2017, figure 14, (World Bank data, 2018)), among other factors, contributes to high credit risk / low sovereign credit rating for a country. This is one of the key risks that typically require robust credit enhancements for incentivizing international commercial financing in a country.

Figure 14: Government Debt (% of GDP)



In addition, Sri Lanka’s fiscal deficit to GDP ratio among regional peers is on the higher end, as highlighted in the figure 15 (World Bank data, 2018)). High fiscal deficit typically limits government’s ability to backstop on-going payment obligations of the state utilities. This again is considered to be a critical risk by international investors in infrastructure, particularly for those countries that have sub-investment grade credit ratings.

Figure 15: Government’s Fiscal Deficit (% of GDP)



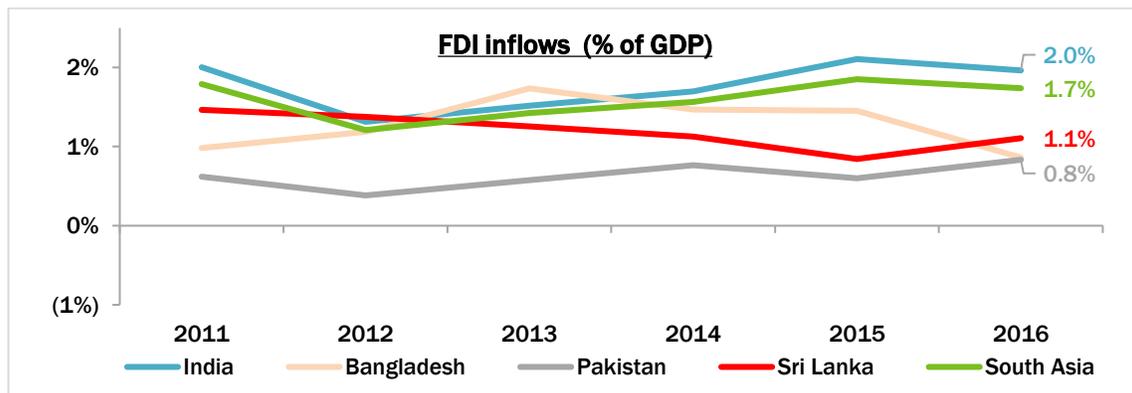
Constraint to Foreign Direct Investment (FDI) Inflows: FDI investments in Sri Lanka have been lower compared to other countries in the region, and when FDI has come in, it has typically focused on tourism, manufacturing and real estate sectors. Furthermore, FDI in power sector has seen consistent decline over the past 4 years, from USD 44.9 million in 2013 to USD 1.1 million in 2017.⁹¹ Given the power sector investment requirement from foreign sources, it is critical to create an enabling

⁹¹ Source: https://www.cbsl.gov.lk/sites/default/files/cbslweb_documents/publications/annual_report/2017/en/14_Appendix.pdf

environment for foreign participation in the sector. Section 4 highlights key policy and governance level measures that the sector stakeholders should implement to successfully meet investment needs.

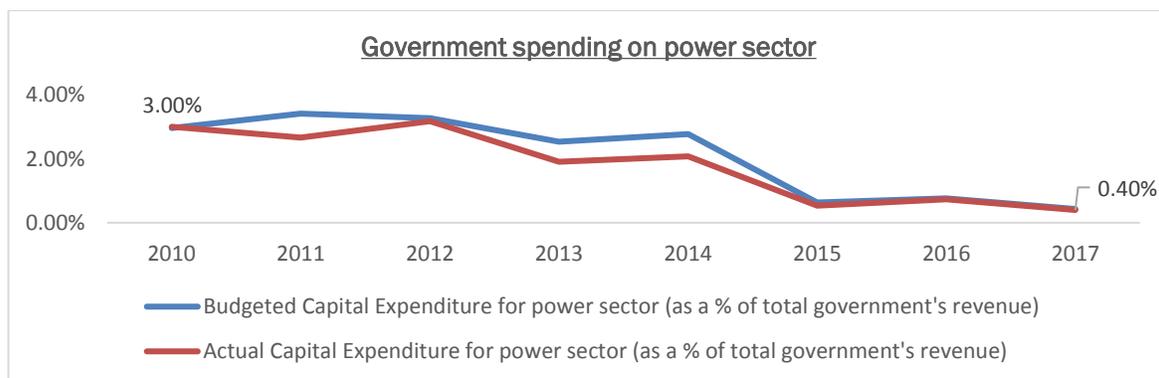
FDI has been declining primarily due to the policy uncertainty, which Government has in part tried to address by New Inland Revenue Act, effective since April 2018. The act has moved the incentive regime from profit-based incentives (such as tax holidays) granted under multiple laws to a performance-based incentive (based on actual investment). As a result, new incentive regime is expected to better balance revenue and FDI considerations. Following graph (World Bank data, 2018) presents FDI net inflows of Sri Lanka and comparable peers. As can be seen, FDI flows are below the regional average.

Figure 16: FDI Inflows (% of GDP)



Government’s ability to fund power sector needs: Budgetary allocations by the government to the power sector have consistently reduced (both recurrent and capital budgets), as highlighted in the graph below.

Figure 17: Government Spending on Power Sector



In 2017, the government’s actual expenditure for capital requirements in power sector was ~ USD 52 million, which when compared with the average annual capital investment requirements of power sector (~ USD 870 million⁹²), falls short by a significant amount.

⁹² Section 2 estimates total investment requirement of USD 7 billion over the 8 year period. On an average the amount comes to approximate 870 million annually.

The current government debt outstanding on the books of CEB is the on-lent loans from the treasury. Given CEB’s financial situation and the arrangement between CEB and the government, there is limited possibility in the near term of CEB repaying the debt via internally generated cash. Accordingly, it would be imperative for the government to prioritize the limited public finance at the disposal of power sector. The government would benefit by investing the limited finance in creating an attractive investment destination for the international investors. The government could potentially provide back-end support, rather than directly investing in the capital-intensive power projects, e.g. in the following form:

- Engage with sector stakeholders for direct investments in segments where private participation is expected to be limited, for example, transmission and distribution segments.
- Engage with stakeholders in creating an enabling environment for incoming investors in the generation segment. This may include support in form of providing guarantees / counter-guarantees to international financiers. While this may result in increased off-balance sheet contingent liabilities, it will not impact the direct liabilities on the government’s books.
- Invest in developing a land acquisition framework (highlighted in section 4.2.4) and ancillary infrastructure for the projects. This may include development of NCRE parks, strengthening the framework for development of projects, etc. While ensuring optimal utilization of limited public finance, it will mitigate the existing risks on land, and approvals currently faced by the developers.
- Given the current ambiguity on LNG development, the government may also assist the sector stakeholders in engaging with LNG experts and organizing knowledge transfer and capacity building programs.

3.3.2 Lack of Internationally Bankable Project Structures

Risks in PPP projects can be generally categorized as commercial, legal and political. Commercial risks typically include financial and market risks, for instance, increase in the costs of PPP project due to rise in the cost of capital, raw materials, inflation, and other payment risks. Legal and political risks relate to amendments in the legal and regulatory framework, including taxation policies and political uncertainties.

Risks are typically allocated to the party which is best placed to manage that risk. Since the risks borne by developer are priced in the proposals submitted, an appropriate risk allocation ensures that developers provide a competitive tariff. Risk allocation is also a key requirement for making a project bankable and allowing developers to raise financing at competitive cost.

Key elements of a standard risk allocation structure, followed internationally for solar projects, are highlighted below⁹³. It is compared to the risk allocation under the current SPPAs in Sri Lanka in the NCRE sector.

Table 11: Risk Allocation Framework

	Power Purchase Agreement	Standard Risk Allocation Framework	Sri Lanka Standard PPA (SPPA for up to 10 MW)
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⁹³ A detailed standard risk allocation framework is included as part of Annexure 10

		Project Company	Off-taker	Project Company	Off-taker
Construction Risk	Construction Risk	✓	✗	✓	✗
Operations Risk	Currency Risk	✗	✓	✓	✗
	Payment Risk	✗	✓	✓	✗
	Operation Risk	✓	✗	✓	✗
Common Risks	Change in law	✗	✓	✓	✗
	Political Force Majeure	✗	✓	✓	✗
	Termination	✗	✓	✓	✗

Key risks under the PPA, like Payment security risk, Political risks and Termination risks are allocated to the developer under the SPPA. It is understandable that a simpler structure has been designed for SPPAs to attract domestic investors, but given international best practice, such a risk allocation would likely be perceived to be un-bankable. Further, CEB needs to agree to certain international provisions under the security structure, for example, the lender’s direct agreement⁹⁴, appropriate assignment rights under the PPA, and international arbitration provisions. Some of the standard risk allocation provisions were included under the Project Agreements in the recently tendered 300 MW CCGT but have been absent in the SPPAs in the NCRE sector.

Currency fluctuations represent a significant risk for international investors in long term infrastructure projects, as they typically look for fixed returns in a hard currency (for example, USD). Sri Lankan Rupee (LKR) has depreciated at a Compound Annual Growth Rate (CAGR) of 3.5% to USD over the 2013-2018 period. Currency risk protection was provided in the recently tendered 300 MW CCGT, which witnessed significant international participation, but is absent in the recent NCRE SPPAs. Indeed, investors would typically want the currency risk to be protected by the government. If the currency risk remains uncovered, investors tend to build cushions in their bids that may make the resultant cost of power uncompetitive.

3.3.3 Underdeveloped Local Derivatives Market

The derivatives market, especially with respect to cross currency swaps and interest rate swaps is underdeveloped in the country. Given that there is insufficient liquidity in the domestic market to fund large sized power projects, it will be important to source financing from foreign banks which will usually be USD denominated. As the revenue source from NCRE projects are predominantly LKR denominated (current tariffs are denominated in LKR), a currency risk component arises which will need to be hedged through currency swaps. However, the maximum tenor available in the domestic market for cross currency swaps is 1 year, which is insufficient for loans with tenors of 10+ years.

⁹⁴ A direct agreement acknowledges the lender’s step-in rights, typically in an event of default

Previously, the Central Bank has offered currency swaps for certain projects, but it has recently made a policy decision to stop providing such swaps, thus requiring the market to hedge its own risks. This policy stance may need to be reviewed, considering the urgent need to raise private sector finance to invest into infrastructure.

Given the long-term nature of infrastructure projects, hedging of floating interest rates through an interest rate swap is a common mitigation strategy. However, in Sri Lanka, the interest rate swap market is practically non-existent and as such, most loans are floating rate loans. This adds another layer of risk onto a project.

3.4 PPP Framework Related Constraints

Currently, implementation of PPPs in the energy sector in Sri Lanka faces several constraints. There have been delays in finalizing the sector targets and project pipelines, setting up of PPP projects, and proliferation of sub-optimal procurement practices. Therefore, the government needs to develop a comprehensive and consistent framework for PPP projects, agreed to by all government stakeholders. The major PPP related constraints are detailed below.

Lack of Consistency in PPP Policy: Currently, Sri Lanka needs a comprehensive PPP Policy. Lack of a clear policy may jeopardize the PPP effort and / or lead to government agreeing to less favorable conditions under a specific PPP project (due to the additional risk perceived by the private sector and particularly foreign investors). Secondly, there appears to be a lack of consistency in terms of risk allocation, and the contractual terms being offered within the same sector differ from project to project. This overall lack of predictability and consistency in government policy has often constrained private sector appetite to pursue investments.

An example of this inconsistency is the difference in risk allocation under SPPAs for NCRE projects and the PPA for the 300 MW CCGT tendered by CEB. The risk allocation under the NCRE projects and the CCGT project is significantly different. Notably, key risks like currency risk, termination related payments, etc. under the SPPAs is not aligned with standard international practice. It is understandable that a simpler structure has been designed (for SPPAs) to attract domestic investors, but the current structure may not be bankable if the government wants to scale up NCRE and attract foreign capital.

Limited Transparency in Procurement of PPPs/PPPs and lack of industry best practices: There is a perceived lack of transparency in the project procurement process. The last bid for a wind project was released in December 2015. Additionally, the bid for a 10 MW solar project has been extended three times, with no clear information to the bidders on the timelines. To promote private participation, a clear procurement process with a fair and transparent set of tender rules is required to maximize process efficiency. Also, a multi-year pipeline of projects should be maintained to continuously engage investors for development of the sector.

As already highlighted, there have been issues pertaining to transparency in procurement during the 300 MW CCGT tender, which led to a 24-month delay in the tender award from tender launch. The bid, which was awarded to CEB's subsidiary Lakdanavi, has been challenged by the other international bidders, and is now pending decision from the Procurement Appeal board.

There needs to be an adequate knowledge exchange program structured for the sector stakeholders, to highlight the procurement related best practices, including the importance of transparency throughout the process.

Reliance on Unsolicited Proposals: Unfortunately, it appears that inconsistent and unclear policies, combined with limited coordination and oversight, has contributed to a proliferation in the number of unsolicited proposals (USPs) being considered for implementation. A major example of this is the three large-scale USPs that are being planned for LNG import in the country. Evidence from around the world shows that, unless strictly regulated and controlled, USPs rarely maximize value for money. More importantly, USPs have been associated with corrupt business practices, used as a way of bypassing normal procurement rules to award projects to related parties. Given this, USPs can not only adversely impact the perception of PPPs/IPPs but also deter private sector investors from bidding for projects.

3.5 Governance and Institutional Constraints

The power sector in Sri Lanka is faced with multiple governance related constraints. This has created an environment of uncertainty which reduces the attractiveness of the sector for private financiers. Significant effort is needed to align stakeholders in resolving these constraints and to successfully achieve the desired power sector targets. An example of the lack of a robust and widely agreed policy is the tussle on the power sector targets. As highlighted earlier, there have been multiple power sector targets established by various entities. The Government has recently approved a policy paper for the generation mix which is expected to be the lynchpin for future generation plans. The major constraints are detailed below.

Limited coordination among various entities, complicated by Overlapping Mandates: At present, coordination and cooperation mechanisms between the sector stakeholders is limited. It is evident in the delay in flow of information amongst the various entities. For example, the stakeholders have limited and fragmented information pertaining to domestic gas exploration, and Government's plans on the unsolicited proposals for LNG procurement. Similar lack of information flow was observed in finalization of the sectoral targets as part of LTGEP discussions.

In addition, decision-making tends to be inefficient as the various line ministries typically tackle their own challenges and problems in isolation. Such a fragmented structure is likely to impede a rational and efficient allocation of resources and investments. Overlapping functions also add to potential inefficiency and confusion. Currently the stakeholders seem to have limited clarity on their role and responsibilities relating to the proposed Swiss challenge for LNG procurement. For example, which entity would be responsible for the procurement process, which entity will lead the evaluation and negotiations of proposals and which entity will act as a state-owned buyer of LNG.

To cite another example, PUCSL, the power sector regulator, seems to have limited authority in practice, to exercise its mandates and approve the generation plan with the target to achieve 100% RE by 2050. PUCSL and CEB debated the LTGEP 2018-37 for more than a year, prior to its approval in 2018. The approval provided by PUCSL is contingent on meeting of three conditions. One being that the plan needs to adopt the generation mix approved by the cabinet in its entirety. Second condition requires the LTGEP to include the Cabinet approved Government-to-Government proposals, totaling 1,400 MW. The third condition requires the Transmission Licensee is to negotiate and ensure that the generation plants built on Government-to-Government basis meet all the technical and economic parameters under the Grid Code and that they are least cost.

Delays in land acquisition: Limited land availability as well as delays in securing the necessary land have emerged as important constraints that have often deterred the private sector from investing. Majority of the land is publicly owned, but the ownership structure is unclear. The various agencies that own the land mass are Mahaweli authority, forest department, wildlife authority, cashew corporation, and the private sector (ownership of private sector is in patches across the country). The land in the central part is highly fertile and the agencies are not willing to give up agricultural land for solar projects. The land on the outskirts is usually bush/scrubs and infertile land, but the ownership is divided amongst several entities with different objectives. This makes it difficult to secure a large mass of land, a critical requirement to set up projects larger than 10 MW.

The land lease framework is also unclear. In past projects, the authorities have been charging a nominal lease of 4% of the commercial value of the land as the lease from private sector developers. Recently, however, the land authorities have started demanding land lease to be a percentage of the revenues from the project, which has disproportionately increased the lease amount.

The perceived lack of transparency in the allocation and valuation of state land have become important issues. Since land will likely be required for most PPP projects, it is important that land valuation is dealt with in a consistent and transparent manner. It is also important that the private sector has full and legally transferable rights to use the land, whether through a direct sell or lease, and that the process of transferring land from the state to the private sector is made more efficient.

In the past, developers were assigned the responsibility to procure land, under the FIT scheme. This was an example of inefficient risk allocation which resulted in delays in project development as the bidders were unable to procure land within required timelines. Under the current power purchase agreements (SPPAs) for tendered solar and wind projects (up to 10 MW), the public sector undertakes to identify and acquire the project sites, which are then leased to the project company for project development. However, while this is an improvement to the process, various developers have still faced delays in their project timelines due to issues pertaining to site selection and negotiated pricing of land.

Limited government support on approvals: Once a solar / wind project is awarded to the developer, there are multiple government approvals that are required. They include environment, land usage, and archeology related approvals. The SLSEA was instituted to act as a one stop shop for all the related approvals for NCRE projects, but the on-ground support has been limited. Project developers observe that there is lack adequate support from the government to complete the approval processes within the stipulated timelines. This leads to delay in construction of project and adversely impacts the return profile for developer.

4 Roadmap to Address Key Constraints

Based on the analysis of the sector investment plans and needs, as well as the constraints to mobilizing financing, this section presents a roadmap of recommended actions and methodologies to mobilize financing and meet the sectoral targets. The roadmap is focused on the short to medium time frame (2 – 8 years).

The short to medium term measures need to also be aligned and consistent with the development of socially, environmentally and economically sustainable power sector infrastructure in Sri Lanka in the long run. These long run objectives that need to be addressed for the short- and medium-term measures to be sustainable may be divided into the following:

Macro and Fiscal stability. As highlighted, the government of Sri Lanka needs to manage the macro parameters and fiscal commitments, to move to a more stable macro fiscal environment. There is no unique set of thresholds for each macro variable between stability and instability. Rather, there is a continuum of various combinations of levels of key macro variables (e.g., growth, inflation, fiscal deficit, current account deficit, foreign reserves) that could indicate macroeconomic instability. The key fiscal parameters that Sri Lanka may focus on in the long run are:

- Manage fiscal commitment and contingent liabilities (FCCL; fiscal debt and deficits, current account deficits, contingent obligations, etc.) and maintain the commitments as a % of GDP within a reasonable level.
- Developing a minimum level of foreign exchange reserves to enable the country to deal with foreign currency movements.

The macro-fiscal parameters of Sri Lanka will not solely be governed by the macro and fiscal policies but also on the development of key sectors like banking and infrastructure. To enhance macroeconomic stability, Sri Lanka needs to support the policies with structural reforms that strengthen and improve the functioning of these sectors.

Development of Domestic Financing Market Sri Lanka needs to develop its domestic financing market to finance most of its infrastructure needs in the domestic private-capital markets. This would mean seamless availability of long tenor and large sized loans in the domestic market. In this regard, it can learn lessons from regional peers like Malaysia and Thailand. Key considerations should be given to the following:

- Support developing debt markets, strengthen central banking, and establish financial infrastructure that can be a foundation for building public confidence in the financial system.
- Develop an institutional investor base that generates long-term finance and risk capital by way of supporting the development of capital markets, including subnational debt markets and enhancement of access to long-term finances.
- Promote and support improvement of macro- and micro-prudential regulation and supervision of financial institutions and markets with a view to enhancing accountability and transparency.

The macro-economic and financing markets objectives highlighted above need to be complemented by multiple measures required to drive energy sector financing in the near to medium term.

4.1 Diversification in to NCRE, LNG, and exploring regional connectivity

Given the current high cost of power in the country, there is an imminent need to initiate diversification into NCRE and LNG based generation, in order to offset the cost and environmental impact of the imported oil-based generation.

4.1.1 Diversification into NCRE and LNG – Procurement programs

Key Entities Responsible – CEB, NAPPP, SLSEA, Other stakeholders, as decided, for LNG procurement

As highlighted, the key benefits that the government of Sri Lanka may realize through diversification include optimization in cost of power, alignment with clean energy targets and reduced reliance on imported fossil fuel-based generation.

NCRE segment: The LTGEP 2018-37 projects development of ~ 1.5 GW of wind and solar projects up to 2026 and ~ 2.5 GW of wind and solar projects up to 2037. Specific to NCRE segment, Sri Lanka would benefit (in form of increased participation from the market and competitive tariffs leading to low cost of power) from revamping of certain policies. For example, the involvement of the private sector on a standalone basis in projects with capacity over 25 MW needs to be allowed, to benefit from economies of scale. Secondly, the PPP related constraints need to be addressed in a structured and sustainable manner. For example, the government should plan sectoral targets in a well-organized manner. This would involve identifying priority projects that are suitable for IPP/PPPs and publishing a time line for their procurement based on a clear and standardized process. Transparent flow of information to the market covering the project pipeline for 2-3 years would further provide comfort to the investors planning to enter the Sri Lankan market. To ensure expansion of NCRE segment at the desired pace, the following need to be considered.

- *Park vs non-park based procurement:* A park-based procurement has distinctive advantages over non-park based, or procurement on an individual project basis. In line with the ambitious growth targets for NCRE and the need for attracting foreign capital, the government may draw from park-based success stories from countries like India and develop an enabling environment that supports the mobilization of international private capital.
- *Procurement best practices:* As highlighted under section 5.1.2, to provide an enabling environment to leverage access to international capital, the procurement process needs an overhaul in terms of transparency in processes, roles/responsibilities of sector stakeholders, alignment with international best practices, support on approvals, and efficient land acquisition process.

Pooneryn and Moneragala are the two sites identified for the park based NCRE development. The feasibility study for Pooneryn site has been completed, and the study estimates 100 MW solar power and 150 MW wind power potential at the site. The site study for Moneragala is expected to be finalized shortly. CEB should continue to pursue the development of these sites in the short term (up to 2020), to meet the projected power needs in the generation plan. In addition, in line with the long term generation plan, CEB should also initiate the pre development / development activities of other power plants.

To address key challenges to a successful procurement program for NCRE, CEB should engage and coordinate more closely with other stakeholders. For example, to address the concern on the requirement of the land, CEB should engage with SLSEA to develop a strategy and implement a

program to procure land for NCRE projects to minimize risks for investors, e.g. by securing land before the tender documents are issued.

Additionally, in order to successfully incorporate PPP related best practices during the procurement of the envisaged power assets, CEB should be adequately supported by NAPPP. NAPPP may take the lead to advise CEB and other stakeholders on various aspects including procurement process, bankable contracts, transparent evaluation and overall procurement timelines, and also conduct engagements with international experts to successfully align the entire process with the procurement objectives.

LNG segment: As discussed, import of LNG has been envisaged to meet the required gas demand in the power sector. The LTGEP envisages development of ~ 1.9 GW of CCGT and gas fired plants up to 2037. To ensure development of the LNG segment at the required pace, the following need to be considered:

- *Demand Assessment:* In the near term, the demand for gas from the power sector is expected to comprise ~ 700 MW of converted oil-fired plants, including the 300 MW CCGT plant, expected to come online by 2020. Based on this, the near-term demand of the country may be easily met by a single FSRU (3.5 MMtpa). Currently, based on the number of unsolicited proposals received by the Government, it is imperative to assess the demand of LNG in the country before getting locked in to take-or-pay payments typical to LNG contracts. Such obligations could have a huge financial impact on the government.⁹⁵
- *Procurement best practices:* The government is currently engaged in multiple (at least three) unsolicited proposals and is considering using one of the proposals as a basis for a Swiss Challenge procurement process. Given the above, there are multiple constraints that need to be addressed for successful procurement of LNG. The first constraint is the limited know-how amongst the sector stakeholders on LNG. There needs to be adequate capability enhancement to ensure the sector stakeholders are aware of the latest know-how in the LNG sector. Secondly, there is limited clarity on the roles that the government will play in the procurement. Based on global precedents, there could be multiple procurement structures⁹⁶ for LNG import. The government needs to evaluate the structure that may be best suited for importing LNG in the country and assign specific roles to appropriate parties. A knowledge transfer program may be initiated inviting global experts to assist the entire development process.
- In addition, as there is limited clarity on pricing (with no existing pricing formula in the country), it will be imperative to benchmark the terms of the proposals received, with market benchmarks. The benchmarking exercise should ensure optimal pricing and other terms (including risk allocation) in line with global industry practice.

4.1.2 Exploring the feasibility of India Sri Lanka Interconnection line

Key Entities Responsible – CEB

As highlighted in section 1.3, a significant optimization in the cost of power could be achieved through power connectivity to India, based on the calculations of the proposed transmission line at 2012 price levels. The all-in cost to import power from India, which is estimated to be ~ US cents 8.95 / kWh⁹⁷ (at 2012 price levels) could potentially bring in significant optimization in the cost of power, which

⁹⁵ A power sector LNG demand assessment is under way as part of the LNG case study prepared within the scope of the Energy InfraSAP analysis.

⁹⁶ Details on LNG import project structures is highlighted in Annexure 8

⁹⁷ The detailed estimation of potential cost of power import from India is included as part of Annexure 2

currently stands at US cents 13.8 / kWh⁹⁸. Given the above, CEB may re-assess the feasibility of the proposed transmission line in the present context.

It needs to be highlighted that establishing a new interconnection between two separated power systems involves much more than just a new transmission line between the two closest substations. There are several issues that will be required to be addressed:

- Adequate estimation of the costs and returns from the project
- Amount of power that needs to be exchanged in each direction
- Reliability requirements to ensure all standards are met
- Other technical requirements such as appropriate method of transmission interconnection (under-sea cable vs. an overhead line) and High voltage DC vs. AC with back-to-back DC
- Political considerations between the two countries

Sri Lanka also possesses a strong potential in its offshore wind resources in the northern part of the country. The offshore wind resources need to be studied as a potential power resource, which if developed, could potentially be utilized to export the excess power to India via the interconnection line. Going forward, in the medium term (through 2023), CEB may also explore the potential of the offshore wind resources.

4.2 Good governance and Institutional Alignment

4.2.1 Alignment amongst sector stakeholders on processes, targets, and roles

Key Entities Responsible – MOPRE, NAPPP, CEB and PUCSL

As highlighted, it would be useful to design the consultation process for PPP projects (from planning to execution) such that NAPPP gets more involved in advising the government on key decision-making process at each stage, with adequate consideration given to inputs and comments from CEB and other sector stakeholders.

Secondly, on the long-term generation planning for the sector, PUCSL and CEB should start engaging frequently in order to finalize the generation planning, in line with the cabinet policy decision.

For the proposed LNG procurement, the government should establish clearly demarcated roles and responsibilities for various stakeholders. Adequate technical assistance should be provided to the stakeholders to ensure desired knowledge transfer and capacity building.

The MoPRE should focus on strengthening the coordination and cooperation amongst the sectoral entities (for example, a standing committee may be created to conduct timely meetings amongst all stakeholders, and ensure alignment on key decisions), and oversee / monitor the decision-making processes, including the generation planning and implementation of PPP guidelines.

4.2.2 Build institutional capacity

Key Entities Responsible – MOPRE, NAPPP

⁹⁸ Average cost of power at selling point in 2017

Highlighted in section 4.6, the limited know-how of procurement best practices has been partly responsible for the slow and small-scale implementation of NCRE projects as well as the indecisiveness and lack of coordination in LNG procurement. NAPPP may be expected to lead in advising on the preparation of key contracts (PPA, Implementation agreement, etc.), designing the bid / proposal evaluation process, deciding the procurement timelines, and ensuring timely communication with the market / bidders.

To complement NAPPP advisory, it will be important to conduct capacity building programs and adequate expert engagement to ensure that CEB/SLSEA, and the relevant public institutions for LNG procurement receive the necessary technical guidance, and the procurement is conducted in line with the global PPP best practices.

4.2.3 Land / Ancillary Infrastructure Allocation

Key Entities Responsible – SLSEA, Land owning state corporations

Land acquisition has been a consistent issue constraining the successful procurement of power projects across the country. Three elements may be considered to ensure a better functioning land acquisition process:

- Simple and comprehensive framework for land acquisition with identified/selected land parcels. Currently there is limited clarity on the location and amount of land that may be considered suitable for development of infrastructure projects. SLSEA should initiate identification of the potential land parcels across the country.
- A pricing formula for selected land parcels for public procurement. Given the ad hoc pricing of land charged by different owners, a possible way is to segregate the land parcels region wise, area wise, and category wise (for example, residential, business, agriculture, etc.). The compensation for the land can be structured in line with market prices.
- Responsibility of acquiring land taken up by the Government. Under the recent SPPAs the risk has been taken up by the government, but as highlighted above, issues in pricing and land selection still result in a delay in the entire process.

These elements would standardize the process for land acquisition and lead to optimization in timelines. A standard framework with pre-agreed pricing would lower the risk profile for private sector investors and will be reflected in the resulting cost of power.

Given that the government is exploring park-based procurement, similar to India, it will be imperative to assist the park development by providing for ancillary infrastructure required. For example, in India, the solar parks are developed by a park implementation agency (typically a state-owned entity, with private partnership), which is responsible for providing the ancillary infrastructure such as land, grid connectivity, water supplies, etc. The state is best suited to provide the ancillary services because the incoming developer may not have the expertise to procure the ancillary infrastructure on its own and will typically price this risk while quoting the tariffs for the projects.

The solar park structure has enabled India to develop more than 20 GW of solar power capacity, a target set for 2022, but achieved in 2018, with resultant cost of power going as low as US cents 3.75 / kWh. Given the above, and intention of the government of Sri Lanka to explore park-based procurement, it may be imperative that state provides for land and ancillary infrastructure to the developers in a timely manner.

4.2.4 Support in Approval Process

Key Entities Responsible – SLSEA, NAPPP, CEB

As highlighted in section 3, there has been limited support from the government in completing the required approvals, specifically for NCRE projects, within the stipulated timelines. To mitigate this uncertainty, there needs to be a pre-determined framework on the approval timelines. Adequate cost and time-based incentives/penalties may be linked to ensure adherence to the pre-agreed timelines both for the Government and the private sector. For example, under the PPA, delay damages could be structured, payable to the private sector in case there are any delays from the stipulated timelines by the government and vice versa. This would further incentivize the government to provide support in getting approvals.

4.3 Regulatory Reforms

As highlighted previously, currently there is limited clarity on the policies and framework around NCRE projects and the proposed LNG import scheme. A stable and NCRE/LNG -focused policy regime is crucial to help the target sectors take off in the desired manner. Policies should be consistent in nature and should work towards dis-incentivizing fossil-based generation.

At a policy level, the government needs to work on bringing clarity along key areas as described below:

4.3.1 Development of a clear and transparent PPP policy

Key Entities Responsible – NAPPP, MOPRE

As highlighted, Sri Lanka aims to increase the generation capacity at an annual CAGR of 5.5% in the medium term (through 2026) and will require an estimated 4.4 USD billion from foreign sources. To enable international players to enter the market who have the experience and expertise, and bring along significant economies of scale, the PPP framework for NCRE and LNG projects needs redesigning to incentivize international participation.

The PPP policy should clearly enlist the procurement rules for development of various sectors. The procurement rules should encourage true and open competition in tendering and contract award, equitable and fair distribution of information, effective monitoring and auditing of all processes and implementation activities. Decision-making criteria at all stages must be clear, justifiable and objective minimizing the room for discretion at any time, especially in the evaluation and comparison of the bids. In addition to developing the PPP framework, the government should also ensure the implementation of the framework. NAPPP should advise the government on PPP projects including preparation of bankable contracts, designing a transparent evaluation process, deciding the procurement timelines, and other critical aspects for a successful implementation of PPP practices in the sector.

4.3.2 Transparent disclosure and adherence to PUCSL's tariff methodology

Key Entities Responsible – CEB and PUCSL

As highlighted in section 4.3, because of the limited disclosure from CEB on the costs and revenue streams of all licensees, tariffs have not been adjusted adequately to cover costs, and financial instability persists in the industry. The CEB is saddled with losses accumulated⁹⁹ from not being allowed to charge cost-reflective tariffs. As a dominant player in the power sector, adequate disclosure from CEB is imperative to assess and address the key issues resulting in financial losses.

Aligning incentives/penalties with disclosure: The Government could require the adherence to the tariff methodology in a step by step manner, with milestones linked to target dates and adequate penalties for non-adherence to the timelines. Non-adherence to the targeted timelines could be made to result in direct penalties being levied on the defaulting entity. Given CEB's financial condition, further penalties could act as an incentive to abide by the guidelines, which may lead CEB to disclose the revenue and cost streams in the required manner.

Establishment of a Bulk Supply transaction account by March-2018 and automatic electricity pricing mechanism by September 2018

The highlighted tariff methodology developed by PUCSL entails development of a Bulk supply transaction account, which is critical to ensure transparency in the generation, transmission and distribution segments, and is imperative for tariffs to become cost reflective. The actual implementation of BST has been extended multiple times from December 2016 to March 2018.

CEB construes establishing a separate BSTA as a step towards unbundling of the utility. Given that PUCSL requires CEB to establish a physical Bulk Supply account, to adjust the tariffs in line with the methodology, CEB and PUCSL should engage in finding a way to bring in transparency in the system. CEB needs to understand the importance of the BSTA, while PUCSL needs to comfort CEB in the fact that establishment of a BSTA is necessarily not a step towards unbundling. Going forward, even if the BSTA is established, CEB could function as a single entity, with more transparency in the system.

A direct and structured subsidy mechanism in absence of a cost reflective tariff mechanism

As highlighted in section 3.1.3, currently there is an interim arrangement between the CEB and the government, whereby the government will service the China EXIM loan from its tax revenues. This arrangement is entered to offset some of the losses to CEB TL from the non-cost reflective tariffs. Although this is expected to reduce CEB's debt service obligations in the near term, it is neither a transparent nor a sustainable arrangement. The government should structure a direct subsidy mechanism to CEB TL, as a way to compensate for losses incurred on regulated end user tariffs.

Up to 2011/12, the PUCSL's tariff orders used to have a provision for government to compensate the CEB TL for such losses. CEB, to date, highlights the losses made by it on the end user tariffs and includes the required subsidy amounts in its bulk supply transaction statements.

Given the above, the government should consider to move away from the adhoc arrangements such as repayment of CEB's debt, and design a transparent and a direct subsidy mechanism in line with the losses incurred by CEB TL in absence of cost reflective tariffs. The subsidy mechanism can be dissolved or cancelled once cost reflective tariff regime is implemented in the country.

⁹⁹ At 2016 end, CEB has around 2 USD billion long term debt on its books, at a Debt: Equity of ~73%. This is in addition to ~ USD 1.2 billion debt converted to Government's equity in 2013.

4.3.3 Implementation of the revised fuel pricing mechanism

Key Entities Responsible – CPC, PUCSL

As highlighted earlier, CPC has been incurring losses on the purchase of fuel, due to the multiple taxes on the fuel purchases levied on CPC, and regulated pricing of fuel in the country with limited consideration towards cost recovery for CPC. The recently approved fuel pricing formula links the fuel prices to a 3-monthly weighted average of the Singapore plats index; the fuel purchased by CPC is also linked to the same index. Although further clarity is required on the exact pricing formula that has been approved, it is a positive development considering that the fuel prices in the country were entirely administered, without any linkage to the international prices. Going forward, it may be critical to ensure that the mechanism is implemented without any further delay and CPC is able to recover its reasonable costs incurred, including any taxes that may be levied on fuel purchases.

4.4 Strengthening of sector stakeholders (CEB / CPC)

Key Entities Responsible – CEB, CPC, PUCSL, MOPRE

CEB needs to focus on few key areas to improve the financial viability of CEB up to acceptable levels.

- Firstly, it needs to diversify the generation mix and reduce reliance on expensive oil-based generation. This will entail integration of low cost RE and gas-based generation in the system.
- Secondly, to sustain its operations independently i.e. without periodic support from the government, cost reflective tariff regime needs to be implemented. CEB is required to establish a physical bulk supply tariff account (BSTA)¹⁰⁰ and disclose costs related to all licensees as per the PUCSLs tariff setting methodology. As highlighted before, CEB provides PUCSL with data as required under the methodology but has not yet established the BSTA leading PUCSL to disapprove tariffs adjustments. The inability of CEB to fully recover costs has also resulted in delayed payments to suppliers including CEYPETCO.
- Finally, CEB needs to engage in prudent financial management including cost control, working capital management, cash management and development of long term financial management tools like financial projections, etc.

As the cost of power reduces and the variability in the cash flow profile decreases due to diversification in the generation mix, the end user tariffs become cost reflective (with proper disclosure as required by PUCSL), and with prudent financial management, CEB should be able to achieve a minimum acceptable level of financial soundness, and improvement in its credit risk.

CPC: As highlighted, currently CPC's financial position is weak due to accumulated losses and increasing short term loans on its books. To ensure that CPC recovers, and is able to act as an independent functioning unit, following measures are proposed:

- Firstly, the approved fuel pricing formula needs to be implemented, in line with the objective of making the fuel prices cost reflective for CPC. This would enable CPC to realize positive profit margins on its books and can gradually recover from the existing financial situation.

¹⁰⁰ A detailed note on the Bulk Supply Transaction Account is included as part of Annexure 5

- CPC has procured high amounts of short term loans on its books, primarily to pay import bills. Given the fuel pricing formula is implemented timely, CPC needs to resort to prudent working capital management, and ensure reduction of such short-term loans from its books.

Given the large capital investments required, it is imperative that CEB and CPC are financially sound and start working as an independent unit, without any government support, to ensure that going forward, a significant amount of financing needs of the power sector is successfully met by these entities.

4.5 Bankable Project Structures

Key Entities Responsible – NAPPP, CEB

It is important for the Government to balance risk allocation between the public and the private sector. To meet the desired investment needs of the power sector, it is critical that the risk allocation under the project agreements is standardized and in line with international best practice, to make the sector attractive for both domestic and foreign investors.

Risks such as site availability, change in law, and other matters within control of the Government should be borne by the public sector. Risks arising from the construction, operation and maintenance of the project (i.e. those matters for which the public sector has approached the private sector for its skills and expertise)) should be borne by the private sector.

As part of a bankable project structuring, currency risk and political/country's credit risk are the major constraints that would need to be addressed to mobilize international commercial finance. A country's international credit rating plays a significant role in the risk perception of foreign financiers. The current credit rating of Sri Lanka stands below investment grade, and further sustained efforts from the government and state utilities as highlighted below is required to incentivize the desired participation from international investors.

4.5.1 Managing Currency risk - A Government-sponsored currency hedging facility

Key Entities Responsible – MOF, MOPRE

Typically, investors look towards the government/state entities to ensure that currency risk is mitigated. Reducing the cost of foreign debt by reducing the currency hedging cost can mobilize foreign capital and spur investments in renewable energy and LNG segments by reducing the cost of capital. Given this, it would be necessary for the Government to manage the currency risk by designing a suitable hedging facility.

The design of such a facility would be a significant undertaking that should be carefully considered, given that currency movements can be uncertain and volatile. In providing currency hedging for renewable energy projects, the Government would need to consider the following questions:

- What are the expected costs and risks of providing such hedging?
- How can the government cover unexpected and extreme movements in foreign exchange rates?
- And what is the market risk premium for taking currency risks?

Under a foreign exchange hedging facility, the government can provide project developers or off-takers (depending on the power purchase agreement) a currency hedging solution through a standalone fund that covers debt / equity payments for underlying USD investments.

There are ways for the government to manage the risks to which the foreign exchange hedging facility is exposed. In line with what is being done in multiple countries (for e.g. Pakistan, Bangladesh, India, etc.) is passing the currency risks in the end user tariffs by periodic adjustments. Indeed, this solution stands viable if the currency devaluation is in line with expectations. The additional risk arises in cases of severe disruptive events, leading to large variations in underlying currency. One way to protect against the risk of unexpected and extreme movements in foreign exchange rates, and to ensure that the foreign exchange hedging facility does not default, is a capital buffer, or a contingent reserve.

A contingent amount may be carved out from the government revenues, to support the foreign exchange hedging facility. An alternate way to expedite creation of a reserve is by charging a marginal surcharge to the end users. Typically, multiple economies like Australia, UK have included additional costs in their electricity pricing mechanism. For example, in Australia and UK, the customers are charged 5.6% and 6.1%¹⁰¹ respectively, in their price of electricity to finance the development of renewable energy projects. A similar structure could be formulated in Sri Lanka, to finance the development of the hedging facility. Due to an increasing customer base, the individual impact of such a surcharge would likely be minimal, simultaneously assisting the government in establishment of a currency hedge reserve.

4.5.2 Managing Political risk - Credit Enhancement Instruments

Key Entities Responsible – CEB, MOPRE

Credit enhancement products supporting energy investments are usually issued by public entities such as governments and international finance institutions to address key political, policy, credit and currency risks. By addressing various risks, guarantee instruments can improve the structure and quality of an investment, making projects more attractive to private investors. The involvement of multilaterals, such as the WBG, ADB and others, can also provide a 'halo' effect, which increases the creditworthiness of the project as perceived by international investors.

Guarantees offer an efficient way of leveraging private investment with limited public capital. The major guarantee products offered in the market by various DFIs are highlighted in Annex 12. There are guarantee / insurance products available for solely protecting the equity investments of private sector counterparts from the political risks. The credit enhancement products could be provided on a project basis or could be utilized at a sectoral level. Globally, credit enhancements have been utilized in multiple developing / under-developed geographies to promote private financing. Select examples of energy projects where credit enhancements have been utilized to make the project bankable are highlighted as part of annex 12.

As most guarantee products require a counter-indemnity agreement with the host government (such agreements, while not resulting in direct liabilities for the government, do increase the contingent off-balance sheet liabilities), the applicability and actual impact of such products needs to be assessed by the government. The guarantee products can be structured for a complete or partial

¹⁰¹ Source: <https://www.businessjuice.co.uk/energy-guides/what-makes-up-your-electricity-price/>,
<https://www.auroraenergy.com.au/your-home/bills-and-payments/your-bill-explained/electricity-cost-breakdown>

coverage of potential losses¹⁰², thereby reducing the contingent liabilities on the host government and simultaneously enabling required enhancement of the credit risk of the transaction. Given the above, the Government would need to manage its fiscal commitments in a prudent manner, to be able to provide adequate support in form of indemnities / counter-guarantees.

4.6 Exploring alternate financing models at a sector level

Key Entities Responsible – CEB, MOPRE

To incentivize foreign capital in the short term, the target sectors may further benefit by exploring non-conventional financing at a sectoral level. The instruments could be supported by credit enhancement products to ensure partial/complete coverage of political risks, thereby leveraging private capital. Some of the instruments that may be explored are highlighted below.

4.6.1 Foreign currency bonds

Similar to the 2017 USD bond issue (as highlighted under annex 11), Sri Lanka can tap the international market and the interested investor base for rolling out sector or project specific bonds. The prime investor base for USD bonds issued in 2017, i.e. international fund managers, could be tapped to conduct a market assessment of a proposed sector level issuance (green bonds). Details on Green bonds can be found in annex 13.

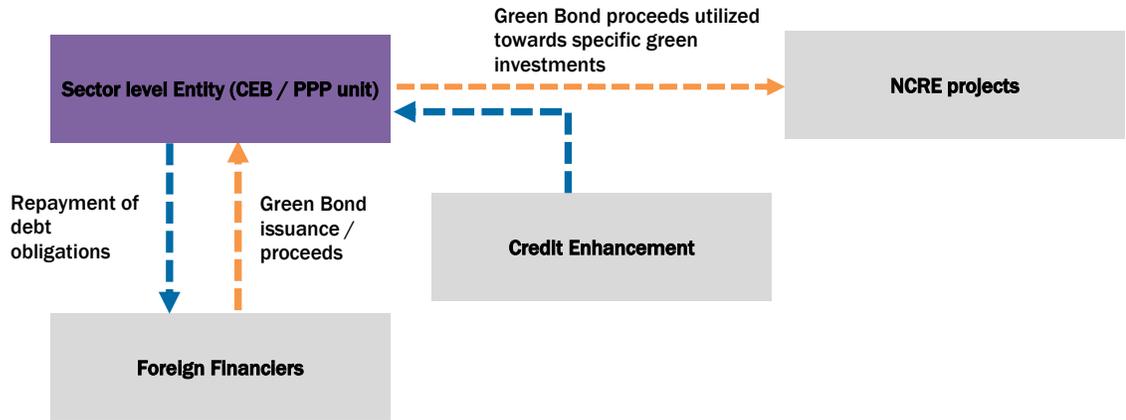
Foreign currency bond issuance in 2017: The bonds CBSL issued in 2017 have already received positive response from the international market. The bond issue in 2017 achieved an oversubscription ratio of over 7 times, spread across 500 participating accounts. The positive reaction from the international markets reflected investor's confidence in the efforts being channelized under the IMF program and overall Sri Lanka growth story. By the investor type, 83% of the credit was issued by fund managers, 9% by banks, and 5% by insurance and pension funds. Geographically, 58% of the final allocations went to US, and only 20% to Asia. Further, compared to the 2016 spread between US Treasury 10-year yield and 10-year Sri Lanka bonds yield, 2017 spread has substantially declined indicating a reduction in the risk premium demanded by the investors.

Proposed Structure: The structure highlighted below entails a sector level entity raising foreign financing via green bonds. A similar issuance specific to NCRE segment could be rolled out in the form of green bonds. In case the bond issuing entity is a sector level entity (for example, CEB) with no international credit rating and limited creditworthiness, the structure may necessitate utilization of a credit enhancement product to increase the creditworthiness of the issue and reduce the cost of bond capital. For example, a DFI guarantee (Partial Risk Guarantee¹⁰³ /Partial Credit Guarantee) may be utilized (typically backed by a counter-guarantee agreement from the host government) to raise the credit worthiness of the bond issue, leading to favorable financing terms (margin and tenors). Another way to enhance the credit rating of the issuance is to subordinate the repayment of a high rated debt (for example, another loan from a DFI like World Bank) to the repayment of the green bond.

Figure 18: Green Bond Structure

¹⁰² Refer Annexure 12 for project cases that have utilized partial / complete coverage from credit enhancements

¹⁰³ Standardized guarantee products provided by DFIs like WBG. Details are included in annexure 12



4.6.2 Concessional Financing

Blended concessional finance for private sector projects is one of the significant tools that Multilateral Development Banks and other development finance institutions can use to increase finance for important private sector activities, address development goals, and mobilize private capital.

Depending on the transaction, a concessional financing facility can be concessional either from a cost perspective, or from a risk perspective. This means that concessional financing can be utilized to reduce the cost of capital (by being concessional from a cost perspective), as well as enable the project to utilize higher leverage (by being concessional on the risk side, similar to sub-debt facilities).

The concessional financing on a project is typically provided by IFIs and requires that the financed asset is in adherence to their development mandates. A moral hazard may arise because a concessional loan may provide the buyer with a counterproductive incentive to engage in riskier behavior, undermining its purpose to guard against risk. To dispel moral hazard and reward projects that are financially viable, concessional financing is issued usually only after comprehensive due diligence and screening.

The concessional financing opportunities could be explored at a sectoral level in Sri Lanka. This will require aligning the country's power sector goals with the development mandates of the donors/DFIs. Sri Lanka can take examples from regional peers like Cambodia, where ADB is supporting the country with a concessional financing structure for development of a solar park project.

4.6.3 Sector Level Staped Financing Structures

A sector level development program, supported by DFIs and MDBs, could be considered in the Sri Lankan context. It would mean the entire procurement process is supported by pre-approved financing and credit enhancement structures in conjunction with the government. It will have two advantages:

- A stapled financing¹⁰⁴ that would be available with an option of exploring financing outside of the pre-approved structure, and will remove the risk of financing for the bidders
- Involvement of DFIs in the tender process provides the ‘halo’ effect, leading to increased participation from international players

The World Bank Group has been instrumental in the development of the solar power sector in multiple geographies in Africa through its Scaling Solar Program. The Program is “one stop shop” program aimed at creating viable markets for solar power in each client country by making privately funded grid-connected solar projects operational within two years at competitive tariffs. The Scaling Solar program has been supported by International Finance Corporation (IFC) and World Bank (WB), and includes stapled financing where IFC provides a credit approved financing term sheet for the project, as part of the RFP package. However, bidders are free to explore financing outside IFC financing. WB has also provided support to the Projects in terms of liquidity PRG (Partial Risk Guarantee).

4.7 Development of domestic financing market

In line with the objective of sustainable development, Government may initiate steps in the near term to ensure development of domestic market in the long run. This may include, but not limited to the following:

4.7.1 Introduce hedging instruments in the domestic market

Key Entities Responsible – MOF / Government

As highlighted in section 3, the domestic financing market in Sri Lanka lacks hedging instruments to hedge currency and interest rate risks. To ensure seamless influx of foreign capital to meet the required power sector needs, it is imperative for the government to protect the incoming investors from macroeconomic risks such as currency fluctuations and interest rate fluctuations. The same could be done either by government bearing these risks directly or providing a domestic market where the risks could be mitigated. While the Central bank has provided currency hedges in the past, it has taken a policy decision to not provide any hedges anymore. It may be critical for the government to initiate development of a hedging market in the country. Sri Lanka could introduce some hedging products by engaging with international institutions with potential demand for local currency (if any). Such an arrangement could be backed by adequate government guarantees to protect the international counterpart.

4.7.2 Develop adequate project finance capability

Key Entities Responsible – CBSL

As highlighted, the domestic banks lack the know-how of best practices in project finance. This has led to sub-optimal terms in the financing arrangements which exposes lenders to additional risks. While this may work for ongoing small-scale transactions, it may be a cause of concern for bigger players when dealing with transactions at a large scale. The domestic banks may need to further develop their

¹⁰⁴ A typical stapled financing would include committed term sheets from a lending institution floated as part of RFP package

know-how on the security arrangements (getting well accustomed to the assignment rights, and step in rights in the project), waterfall mechanisms¹⁰⁵ and due diligence of projects.

¹⁰⁵ A cash waterfall mechanism is the basis on which the various entities have the rights on the project cash flows in a project finance transaction. The lenders monitor the project accounts and ensure that payments are made in line with the waterfall mechanism.

Annexes

Annex 1. Overview of Power Sector in Sri Lanka

The section provides an introductory overview to the power sector in Sri Lanka, delineating key aspects of power generation, transmission and distribution segments, spelling out the dynamics of fuel imports and highlighting the need for diversification in the power mix. The section also provides an overview of the ongoing energy efficiency program in Sri Lanka.

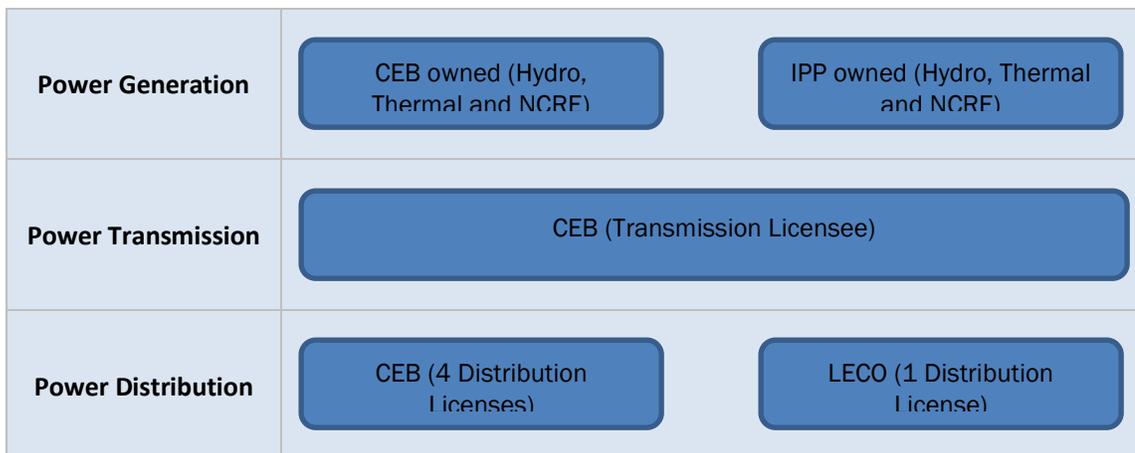
1.1 Sri Lanka Power Sector Structure

The electricity sector in Sri Lanka is largely managed by state-owned corporations, with private sector participation limited to power generation.

CEB is a state-owned vertically integrated utility engaged in power generation (accounting for ~72% of the total installed capacity in Sri Lanka in 2016), power transmission (single entity responsible for entire transmission system in Sri Lanka) and power distribution. Independent Power Producers (IPPs) also engage in power generation (accounting for ~28% of the total installed capacity in Sri Lanka in 2016). In addition to CEB, LECO¹⁰⁶ (state-owned distribution company) is responsible for power distribution. LECO purchases bulk power from the CEB Transmission Licensee and distributes to around 500,000¹⁰⁷ customers in south western coastal belt of the country.

There are two regulatory agencies involved in the electricity sector, the Public Utilities Commission of Sri Lanka ('PUCSL') and Sri Lanka Sustainable Energy Authority ('SLSEA'). Below figure depicts the key entities in the generation, transmission and distribution sector in Sri Lanka.

Figure 19: Power Sector Structure



¹⁰⁶ Formed in 1983 and started operating in June 1984

¹⁰⁷ Around 8.5% market share

Key players in Sri Lanka's energy sector include:

1. **Ministry of Power and Energy (MOPE)**'s mandate is to

- Formulate and implement policies, programs, and projects pertaining to power and energy, and all subjects that come under the purview of institutions within MOPE,
- Provide all public services that come under the MOPE's purview,
- Reform systems and procedures, and, ensure efficient conduct of business,
- Monitor, investigate, plan, and develop electricity facilities, including hydropower, thermal power, mini hydro, coal, and wind power,
- Extend rural electrification,
- Develop a sound, adequate, and uniform electricity policy for controlling, regulating, and utilizing energy resources,
- Develop indigenous renewable energy resources while promoting energy efficiency.

2. **Ceylon Electricity Board (CEB)**, a state-owned corporation, was established on 1 November 1969 under the Ceylon Electricity Board Act No. 17 of 1969. CEB is the sole vertically integrated player in Sri Lanka's power market. It is engaged in power generation, transmission and distribution, serving about 4.5 million customers across four distribution regions. CEB generation division caters to 72% of the installed capacity in Sri Lanka, and its distribution licensees have around 92% share in Sri Lankan market. Additionally, CEB is empowered to acquire assets, and to appoint and promote its officers, following the pre-approved procedures.

3. **Lanka Electricity Company (LECO)**, a state-owned distribution company, is the only player in the distribution sector, other than CEB. It was formed in 1983 and started operations in June 1984. LECO holds around 8% market in the distribution segment, and purchases power in bulk from the CEB Transmission Licensee. LECO serves around 500,000 consumers in the western and coastal belt townships between Negombo and Galle. CEB and the Ministry of Finance (on behalf of the state) are major shareholders in LECO, with other shareholders also being state entities.

4. **Public Utilities Commission of Sri Lanka (PUCSL)** was established in July 2003, with the mandate to act as economic, technical, and safety regulator for the electricity industry, as well as for petroleum and water industries of Sri Lanka under the purview of the PUCSL Act No. 35 of 2002. Later, PUCSL was empowered to regulate the generation, transmission, distribution, supply, and use of electricity through the passage of Electricity Act No. 20 in 2009.

5. **Sri Lanka Sustainable Energy Authority (SLSEA)** was established in October 2007, through the Sri Lanka Sustainable Energy Authority Act No. 35 of 2007. SLSEA currently functions under the purview of the Ministry of Environment and Natural Resources. SLSEA's mandate is to

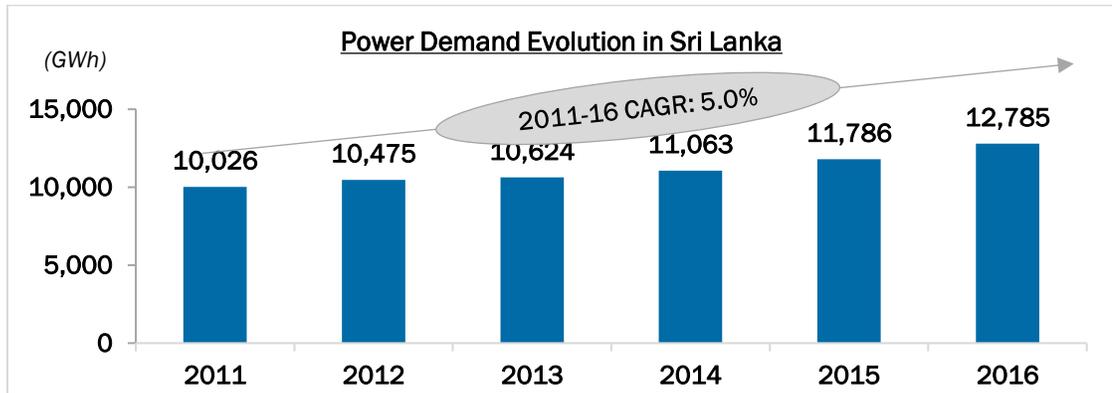
- Assist in developing the national policy on energy,
- Implement policy for renewable energy, and for energy efficiency and conservation,
- Promote development of renewable energy projects through private investment, and
- Conduct research on the development of indigenous energy resources.

1.2 Power Demand – Supply in Sri Lanka

The total power demand in Sri Lanka was 12,785 GWh in 2016 increasing at a CAGR of 5.0% during 2011-16 period. CEB has estimated power demand to grow at a CAGR of around 5.0% to 36,613 GWh by 2037 (LTGEP 2018 -37, 2018).

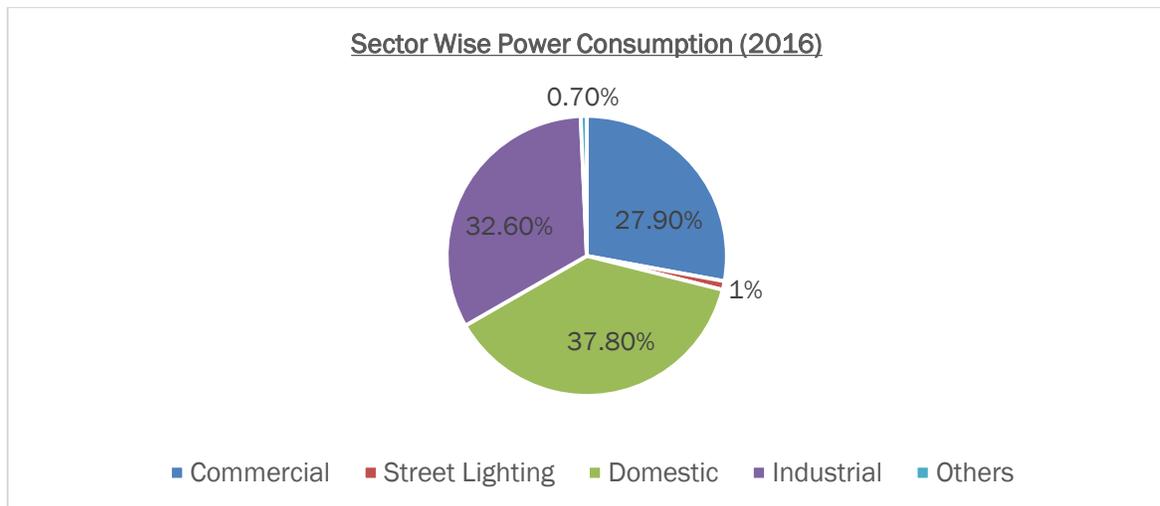
The per capita electricity demand has also increased to 602 kWh per person in 2016 from 141 kWh per person in 1990, reflecting both rising incomes and greater access to the national grid (in 2016, Sri Lanka had an electrification rate of 99.3%).

Figure 20: Power demand evolution



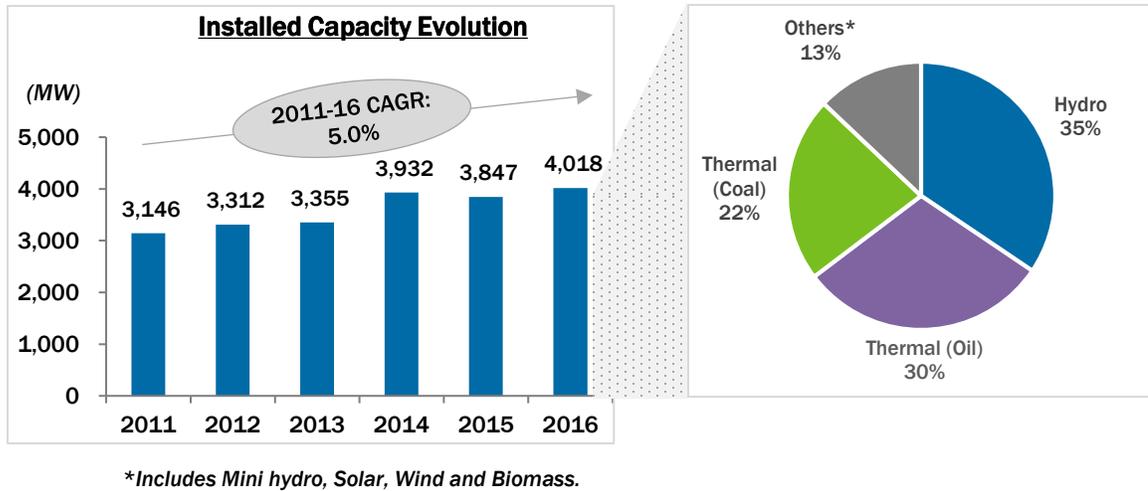
The sectoral contribution to the existing demand is highlighted below. It is observed that the industrial and commercial (general purpose, hotel, government) sectors' consumption together is more than the consumption in the domestic sector.

Figure 21: Sector wise power consumption



In early stages the electricity demand of the country was mainly supplied by hydro generation and the contribution from thermal generation was minimal. With time, thermal generation has become prominent. At present, thermal installed capacity share is much higher than that of hydro. Additionally, the other renewable energy generation from mini hydro, wind, solar, dendro (woody biomass), etc. is also increasing.

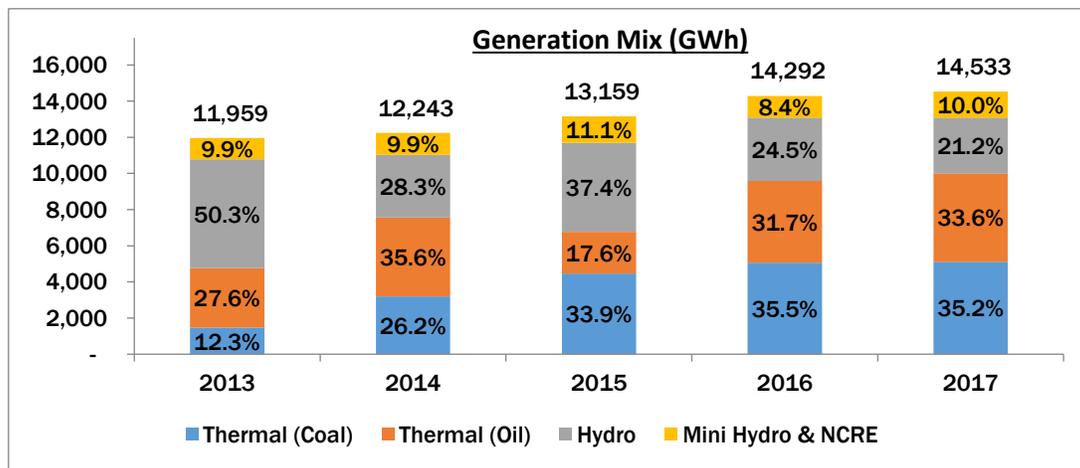
Figure 22: Installed capacity evolution



1.3 Power Generation

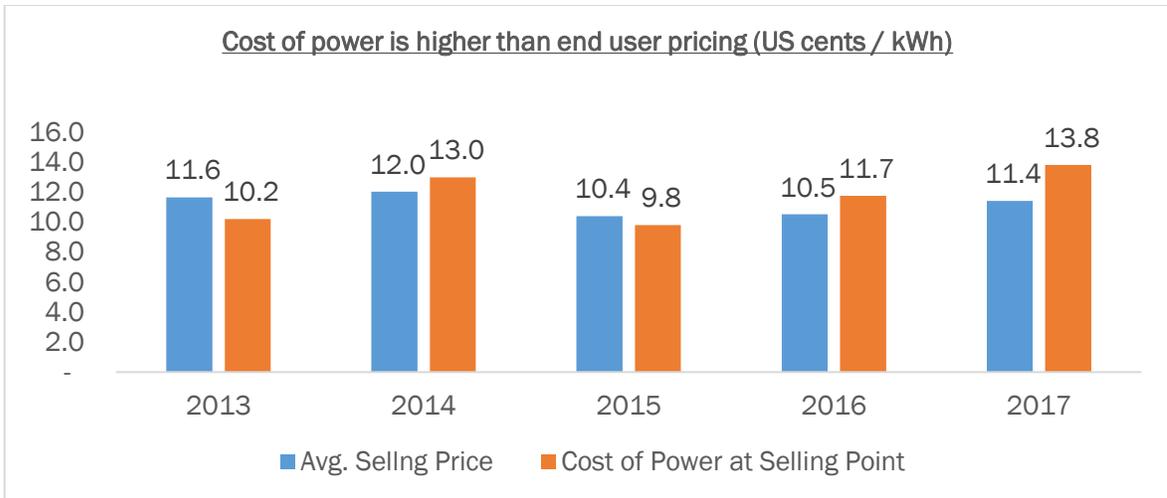
The power sector is dominated by Hydro plants in the country, primarily run-of the river projects with limited storage capacity. This typically leads to a crisis situation in periods of adverse monsoons, during which the country has to resort to expensive imported oil-based generation. The graph below highlights the generation mix in the country from 2013 to 2017.

Figure 23: Power generation mix



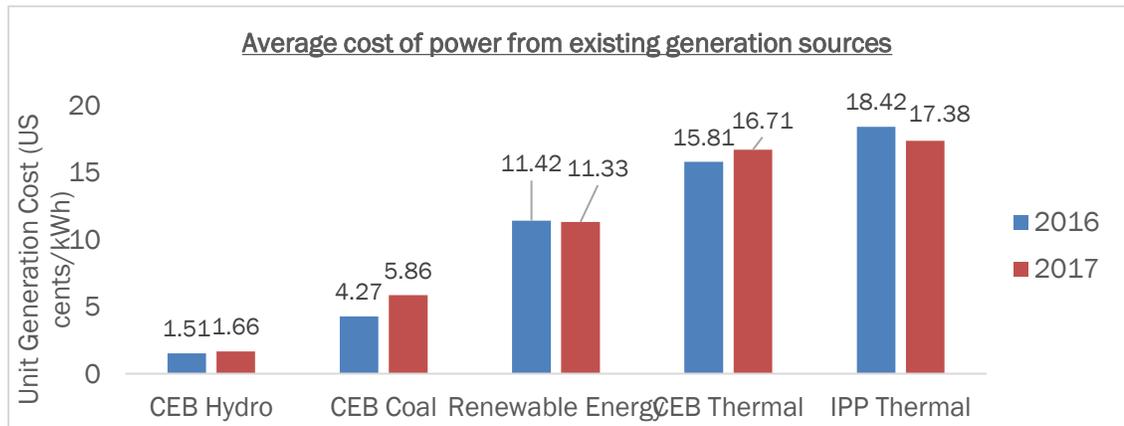
In periods of low Hydro contribution (leading to an increased contribution of oil-based generation), the cost of power exceeds the regulated end user pricing. This typically results in operational losses for CEB, which is recovered by procuring additional short-term debt.

Figure 24: Cost of power is higher than end user pricing



On comparing the cost of power generated via existing source, it is observed that even at existing tariffs for NCRE based power generation (which potentially can further be optimized¹⁰⁸), the cost of power generated by NCRE is significantly lower than that generated by thermal power methods. The figure below represents the average cost of power in the country, compared to the cost of power from various existing sources.

Figure 25: Average cost of power from existing generation sources



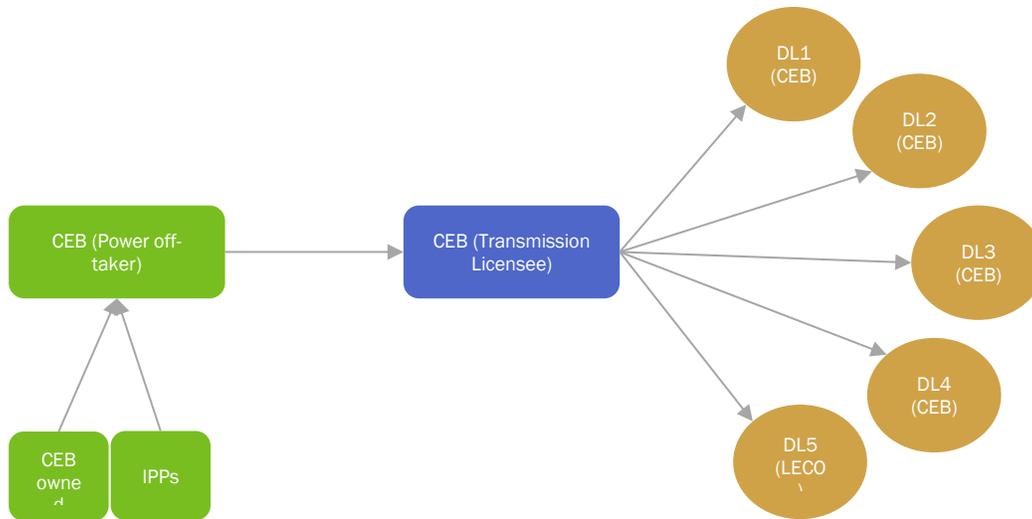
- In 2017, the average cost of power generated from Thermal is ~ 40% to 50% higher as compared to power generation from NCRE sources.

1.4 Power Transmission and Distribution

The section summarizes the power T&D segment in Sri Lanka. The power flow diagram for the entire power sector is highlighted below.

Figure 26: Transmission and Distribution Licensees

¹⁰⁸ Refer Annexure 9 for details



The T&D segment is dominated by CEB, with limited participation from LECO. The sole transmission license is held by CEB, while the Distribution Licenses (DLs) are held by CEB (4 out of 5) and LECO (1 out of 5).

The transmission licensee is responsible for transmission of power from generators to distribution points, and for Bulk Supply Operations to Distribution Licensees. The distribution licensees are responsible to supply electricity to end users and collect revenue from the end users.

Sri Lanka's T&D sector has been developed in a well phased manner, with sufficient reach (current electrification rate is ~ 98%) and decreasing network losses (cumulative T&D losses for Sri Lanka have dropped from 13% in 2010 to below 10% in 2016). The pressing requirement in the sector is to incentivize investments to expand the T&D network and upgrade the existing network to ensure a seamless integration of the envisaged NCRE based generation. As per the Grid Frequency Stability Analysis¹⁰⁹, few initial observations have been made pertaining to integration of NCRE in Sri Lanka's grid system:

- Integration of wind and solar technologies in the existing grid system would result in frequency / voltage instability, which needs to be avoided to transmit the power seamlessly.
- **Frequency Instability:** Unlike conventional synchronous generators, wind turbines and PV units have inverters that do not naturally respond to frequency events. This can cause larger dips in the first frequency swing after a disturbance, such as the trip of a large generator.
 - To mitigate this, most modern wind turbines come with a control functionality that can emulate the "inertial response" of a synchronous generator. If the expected wind and PV penetration in the CEB system is significantly large, having wind turbines provide "inertial response" may reduce the exposure to load shedding. Some wind turbines also have governor functionality that can be used for improving the frequency stability of the CEB 2020 system.
 - CEB system can seamlessly accommodate ~540 MW of solar capacity up to 2020, and still maintain a frequency within 1% band of 50 Hz, as required by CEB, assuming that solar parks (of not more than 60 MW) are geographically distributed.

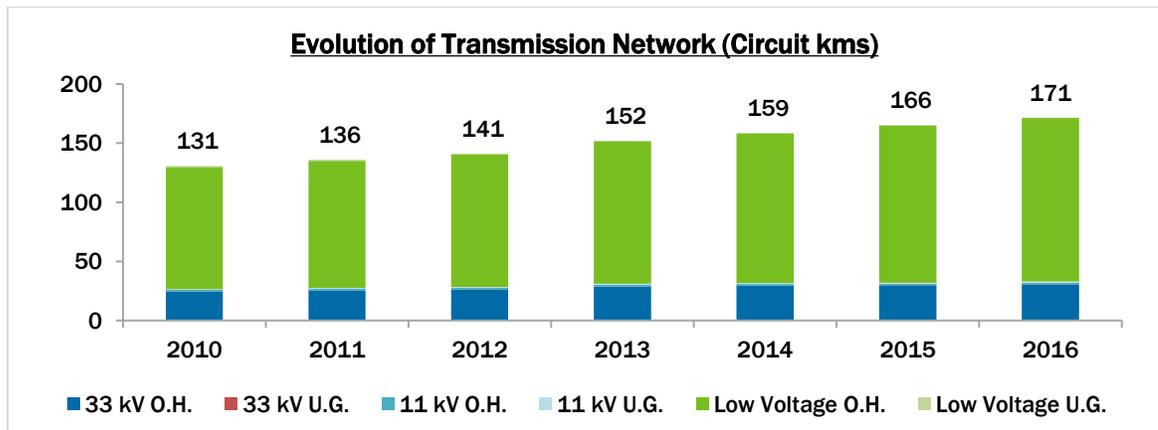
¹⁰⁹ Grid Frequency Stability Analysis of VRE in the CEB System by Siemens PTI

- **Voltage Instability:** Currently, the solar and wind projects utilize a tap changing transformer to regulate bus voltage in a steady state. On Load Tap Changing (OLTC) transformers are needed if the plants do not have voltage control ability, which are lot more expensive. Most PV and wind turbines manufactured today can control voltage, and in such a scenario OLTC's may not be necessary.
- Battery energy storage is another option that can be used for improving frequency and/or voltage stability of the grid. The batteries can provide both active and reactive power support to the grid. Because inverters are used in PV systems, the responses are quick and can be controlled accurately, thereby enhancing the overall system stability.

Power Transmission

The transmission network in Sri Lanka is operated at 220kV and 132kV to transport electricity from generation points to distribution bulk supply points, within a frequency range of $50 \pm 1\%$ Hz.

Figure 27: Transmission Network Evolution



- **Transmission Losses:** Transmission loss is calculated by taking the difference between total electrical energy received from the generating plants and the total energy supplied to all bulk supply distribution licensees. CEB, as the sole transmission licensee has been able to keep the transmission losses at a low level.

Total Energy Loss in Sri Lankan Transmission Network in 2014 was ~ 2.7 %, while the same figure was ~ 3.6% during first half of year 2015 (PUCSL, 2018).

- **System Availability:** Further to assess the reliability of the system, the availability of the transmission system needs to be assessed. The availability of the transmission system components depends on the number of faults which occur and on the number of outages taken to allow maintenance and construction work to be undertaken. System availability is reduced whenever a circuit is taken out of operation for either planned purposes or as a result of a fault.

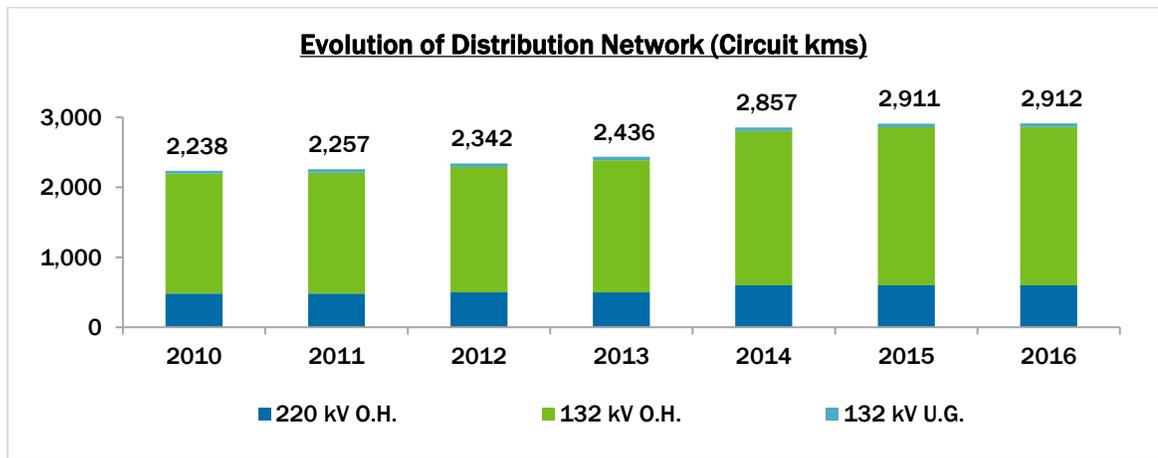
Total unavailability of the transmission network in 2014 was ~ 0.08%, while the same figure was ~ 0.22% in first half of 2015 (PUCSL, 2018).

- **Interruption Duration:** The interruption duration measures the average time duration per reported period where a single transmission line circuit is not available in service. The Index has been designed to measure the ‘Duration’ of the electricity disruptions and made sure would not go beyond the stipulated and accepted margin, which is 24hours per annum. Interruption Duration in the first half of year 2014 was ~ 2.78 hours, while the same duration in the first half of year 2015 increased to ~ 9.54 hours (PUCSL, 2018).

Power Distribution

The distribution network comprises 33 kV and 11 kV medium voltage (MV) lines and 400 V low voltage (LV) lines taking power from the 132 kV and 220 kV transmission systems through grid substations (GSS).

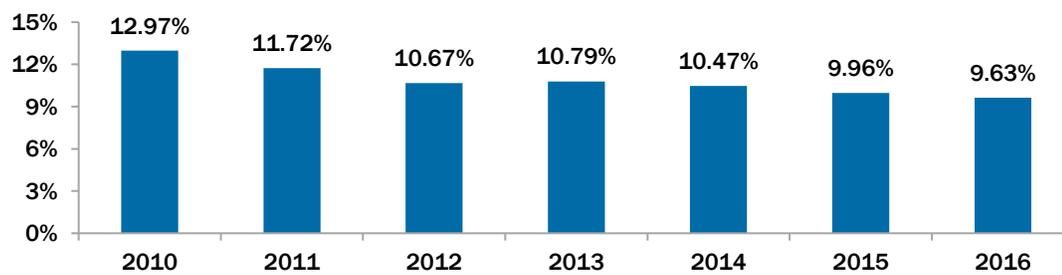
Figure 28: Distribution Network Evolution



The transmission and distribution losses for CEB are highlighted below. It is observed that the total T&D losses are optimal as compared to other South Asian peers (In 2014, the T&D losses for India were ~ 19%, Pakistan 17% and Bangladesh ~ 11%) (World Bank data, 2018), although there is further room and continuous efforts by industry regulator and stakeholders to further optimize the system.

Figure 29: CEB’s Transmission and Distribution Losses

Transmission and Distribution Losses (CEB)



Annex 2. India Sri-Lanka Interconnection Line

Presently, no bilateral power exchange exists between India and Sri Lanka. Plan for a transmission interconnection between India and Sri Lanka has been under consideration since 1970. A pre-feasibility study was conducted in 2002 by United States Agency for International Development, followed by the recent study by Power Grid Corporation of India Ltd (PGCIL). Both the studies observe that an electrical interconnection can be developed with minimal technical challenges due to the proximity of the two countries. Only feasible connection with India is through a HVDC marine cable. This interconnection would be different from any other electricity interconnections planned in the South Asia Region.

Both these studies point to the feasibility of a short-term link of 500 MW and a medium and long-term link of 1,000 MW between the two countries.

Key benefits of Sri Lanka – India Interconnection includes:

- Opportunity to enter into India Power Exchange for energy trading.
- Reduction in operational cost through better resource management.
- Meeting growing power demand with imported power.
- Potential for export of surplus base load power.
- Improves supply profile (base / peaking).

Two alternative routes have been identified for interconnection:

- Alternative1: Sub-marine Cable from Panaikulam in India to Thirukketiswaram in Sri Lanka
- Alternative 2: Sub-marine Cable from Dhanushkodi in India to Talaimannar in Sri Lanka

Alternative1: Below provided is the detail route for alternative 1 along with responsibility of building infrastructure:

- **Indian Territory (Scope: PGCIL) Madurai (India) to Panaikulam (India)**
 - Establishment of new HVDC / 400kV AC substation at Madurai
 - 400kV D/c line (twin lapwing) from Madurai (New) to Madurai: 48 km
 - HVDC overhead line from Madurai (New) to Indian Sea Coast (Panaikulam): 130km
 - 2x500 MW HVDC terminal to be built in two stages at Madurai (New)
- **Sea Route (Scope: PGCIL) Panaikulam (India) to Thirukketiswaram (Sri Lanka)**
 - HVDC line (Submarine Cable) from India Sea Coast (Panaikulam) to Sri Lankan Sea coast (Thirukketiswaram): 120 km
- **Sri Lankan Territory (Scope: CEB) Thirukketiswaram to Anuradhapura: 110km**
 - Establishment of new HVDC / 220kV AC substation at Anuradhapura
 - HVDC overhead line from Sri Lankan Sea Coast (Thirukketiswaram) to Anuradhapura: 110km

Table 12: India Sri Lanka TL - Estimated Cost of Alternative 1¹¹⁰

Description	Project Cost	
	Conventional HVDC	VSC Based HVDC

¹¹⁰ Cost based on February 2012 Price Level.

Stage 1	1X500 MW Monopole	(USD 669 million)	(USD 716 million)
Combined Stage-I & Stage-II	2X500 MW Bi-pole	USD 1,031 million	USD 1,110 million

Alternative 2: Provided below is the detail route for alternative 2 along with responsibility of building infrastructure:

- **Indian Territory (Scope: PGCIL) Madurai (India) to Dhanushkodi (India)**
 - Establishment of new HVDC / 400kV AC substation at Madurai
 - 400kV D/c line (twin lapwing) from Madurai (New) to Madurai: 48 km
 - HVDC overhead line from Madurai (New) to Indian Sea Coast (Dhanushkodi): 180km
 - 2x500 MW HVDC terminal to be built in two stages at Madurai (New)
- **Sea Route (Scope: PGCIL) Dhanushkodi (India) to Talaimannar (Sri Lanka)**
 - HVDC line (Submarine Cable) from Dhanushkodi (India) to Talaimannar (Sri Lanka): 40 km
- **Sri Lankan Territory (Scope: CEB) Talaimannar to Anuradhapura: 150 km**
 - Establishment of new HVDC / 220kV AC substation at Anuradhapura
 - HVDC overhead line from Talaimannar to Anuradhapura: 150km
 - Looping in and looping out of New Anuradhapura – Puttalam 220kV D/c line (AAAC 400, twin) at New Anuradhapura : 1km
 - Looping in and looping out of New Anuradhapura – Kotmale 220kV D/c line (Zebra) at New Anuradhapura : 1km
 - 220kV D/c line with twin zebra conductor from New Anuradhapura – New Habarana: 50 km
 - 2x500MW HVDC Terminal to be developed in two stages at New Anuradhapura

Table 13: India Sri Lanka TL - Estimated Cost for Alternative 2¹¹¹

Description		Project Cost	
		Conventional HVDC	VSC Based HVDC
Stage 1	1X500 MW Monopole	USD 359 million	USD 385 million
Combined Stage-I & Stage-II	2X500 MW Bipole	USD 515 million	USD 564 million

Evaluation of Sri Lanka – India Interconnection

Indicative Levelized Transmission Charges have been calculated to assess the viability of the alternative transmission interconnections. Levelized Transmission Charge estimates the cost per kWh of power transmitted through the interconnection that is necessary to recover the investment cost of each

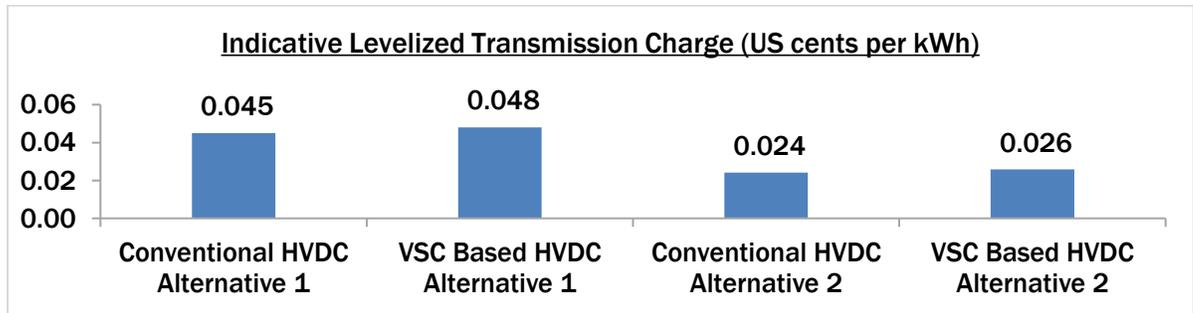
¹¹¹ Cost based on February 2012 Price Level.

alternative, plus provide an adequate return on the investment. The assessment has been done for Stage 1 as we believe completion of Stage 1 more likely given the current power dynamics in Sri Lanka.

Key parameters used for the assessment of each of the alternatives include:

- Availability of Transmission Line: 85%
- Debt/Equity ratio: 75:25
- Interest rate: 6% (all-in)
- Return on Equity: 16%
- Construction Duration: 3 years
- Debt tenor: 18 years (door-to-door)
- O&M Cost: 5% of the project cost

Figure 30: Transmission Charge

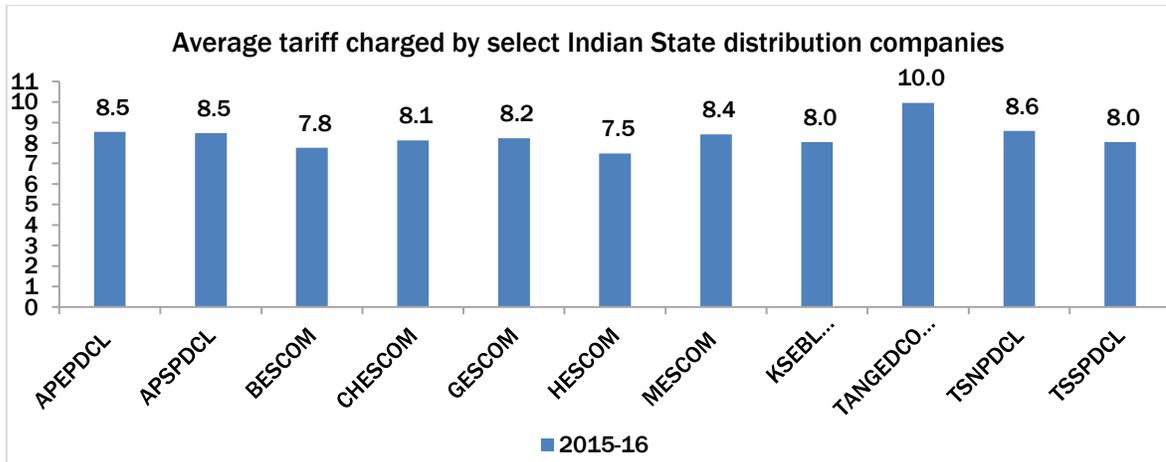


The current tariff as charged by select state distribution companies¹¹² in India is highlighted below.

Figure 31: Average Tariff by Indian State Distribution Companies (US Cents / kWh)

¹¹² Source:

http://www.pfcindia.com/DocumentRepository/ckfinder/files/Operations/Performance_Reports_of_State_Power_Utillities/1_Report%20on%20the%20Performance%20of%20State%20Power%20Utillities%202013-14%20to%202015-16.pdf



Given the above, the average tariff from state distribution companies is assumed to be US cents 8.5 / kWh and the total cost to Sri Lanka for the import of power from India, is estimated to be:

- *Conventional HVDC Alternative 1: US cents 8.95 / kWh*
- *VSC based HVDC Alternative 1: US cents 8.98 / kWh*
- *Conventional HVDC Alternative 2: US cents 8.74 / kWh*
- *VSC based HVDC Alternative 2: US cents 8.76 / kWh*

The cost to import power from India could potentially bring in significant optimization in the cost of power, which currently stands at US cents 13.8 / kWh¹¹³.

It needs to be highlighted that establishing a new interconnection between two separated power systems involves much more than just a new transmission line between the two closest substations. There are several issues that will be required to be addressed:

- Amount of power that needs to be exchanged in each direction
- Reliability requirements to ensure all standards are met
- Other technical requirements such as appropriate method of transmission interconnection (under-sea cable vs. an overhead line) and High voltage DC vs. AC with back-to-back DC

¹¹³ Average cost of power at selling point in 2017

Annex 3. Measures to mitigate environmental impact

Government has actively participated in the global efforts to minimize GHG emissions within the framework of sustainable development and principles enshrined in the United Nations Framework Convention on Climate Change (UNFCCC) and Kyoto Protocol (KP). Some of the key measures that Government has initiated towards this endeavor are:

Clean Development Mechanism (CDM):

The Clean Development Mechanism (CDM) helps industrialized countries meet their emission reduction targets, by allowing the trade of Certified Emission Reduction (CER) credits earned by developing countries. The Clean Development Mechanism incentivizes the developing countries to participate in emission reduction projects and earn CER credits. The energy sector has been identified as having the highest potential to take up emission reduction projects.

Sri Lanka currently has 20 registered renewable power CDM projects, totally 183 MW in potential capacity. Only one of these, Broadlands Hydropower, is a large-scale hydropower project, the others are all small-scale hydropower or other renewable energy technologies. Twelve of these projects have issued CERs and so are definitely operational, but many of the other eight may not have been commissioned. In fact, most of these projects have not communicated with the UNFCCC Secretariat in several years, so it is unlikely that they are operational.

Title	Status	Type	Total issuance (kCERs)	Date of registration	MWel	Last contact
Hapugastenne and Hulu Ganga Small Hydropower Projects.	Registered	Hydro	406	10/30/2005	13.15	2015m3
10 MW Biomass Power Generation Project - Tokyo Cement, Trincomalee	Registered	Biomass	239	10/26/2009	10	2017m4
Small Hydropower Projects at Alupola and Badulu Oya.	Registered	Hydro	121	10/30/2005	8.2	2015m3
Magal Ganga Small Hydropower Project	Registered	Hydro	113	10/30/2005	9.9	2015m7
Adavikanda, Kuruwita Division Mini Hydro Power Project	Registered	Hydro	70	8/24/2010	6.5	2016m12
Mampuri Wind Power Project	Registered	Wind	52	12/21/2012	10	2016m12
Mampuri Wind Power Project 2	Registered	Wind	32	11/20/2012	10	2016m12
Lower Kotmale Oya Mini Hydro Power Project	Registered	Hydro	24	5/13/2013	4	2017m3
Kiriwaneliya Mini Hydro Power Project	Registered	Hydro	23	9/25/2013	4.65	2017m4
"Coconut shell charcoaling and power generation at Badalgama, Sri Lanka"	Registered	Fugitive	22	3/28/2009	5.8	2013m9
Sanguhar and Delta Small Hydro Power Projects	Registered	Hydro	20	12/11/2006	3.2	2014m10
Mampuri Wind Power Project 3	Registered	Wind	19	9/23/2014	10.5	2017m4
Grid connected hydro power project (Power Hub)	Registered	Hydro	0	10/9/2012	6.6	2013m1
Broadlands Hydropower Project	Registered	Hydro	0	12/27/2012	35	2016m9
Municipal Solid Waste to Energy Project by Western Power Company (Pvt) Ltd	Registered	Landfill gas	0	5/14/2013	12	2013m9
Kithulgala Small Scale Hydropower CDM Project	Registered	Hydro	0	10/21/2013	7.3	2015m7
Denawaka Ganga Mini Hydro Power Project	Registered	Hydro	0	12/23/2013	7.2	2015m7
Kirkoswala Small Scale Hydro Power CDM Project	Registered	Hydro	0	12/31/2013	4	2017m4
5 MW Biomass Gasification based power project by FEPL	Registered	Biomass	0	1/10/2014	5	2014m3
10.5MW PowerGen Lanka Small Scale Wind Power CDM	Registered	Wind	0	1/28/2014	10.5	2016m5
Forced methane extraction from organic wastewater and power generation by Greenergy Power Pvt. Ltd. at Sevenagala	Validation	Methane avoidance	0	N/A	0	2009m1
Ansell Biomass Boiler Project in Colombo	Validation	Biomass	0	N/A	10.5	2010m9
Methane avoidance by MSW treatment at Kaduwela	Validation	Landfill gas	0	N/A	10	2013m5
Fuel conversion projects at MAS Holdings Pvt Ltd	Validation	Biomass	0	N/A	0	2012m8
K.K.S Large Scale Wind and Solar PV Hybrid Power CDM	Validation	Mixed RE	0	N/A	70	2013m2
Musalpetti Wind Power Project	Validation	Wind	0	N/A	10	2014m6

Nationally Determined Contributions (NDCs)

Sri Lanka has ratified the Paris Agreement on 21 September 2016 and submitted its revised Nationally Determined Contribution (NDC) submitted to the United Nations Framework Convention on Climate Change (UNFCCC) in October 2016¹¹⁴. The NDC commitments for the electricity sector are an unconditional target of 4 percent reduction in CO₂ emissions versus business as usual and a conditional target of 16% reductions. These emission reductions were calculated from the LTGEP 2013-2032 estimate of business as usual emissions from 2020 to 2030, or approximately 195,000 MtCO₂. The NDC states that the unconditional goal would amount to 9.2 MtCO₂ in reductions (actually 4.7%) and the conditional reductions would amount to an additional 30.2 MtCO₂ (15.5%). Sri Lanka's NDC also lists a series of actions that will contribute to these goals, although the NDC does not specify whether and to what extent these actions support the unconditional (by relying on domestic efforts) or conditional (by receiving international support) commitments. The actions include the following:

- Establishment of large scale wind power farms of 514 MW;
- Establishment of solar power plants with a capacity of 115 MW;
- Establishment of biomass power plants with a capacity of 105MW;
- Establishment of mini hydro power plants with the capacity of 176;
- Introduction of Demand Side Management (DSM) activities
- Strengthening sustainable energy related policies with a view to increase the share of renewable energy from the existing 50% to 60% in 2020
- Converting existing fuel oil-based power plants with LNG

In determining to what level of NDC commitment are reflected by Sri Lanka's power sector planning during the period of 2020-2030, it will be useful to understand how much additional OREs are needed to Sri Lanka's conditional and unconditional target. The conditional target of 16% reduction of emissions versus business as usual is four times the value of the unconditional target of 4%. This means that, based on the LTGEP 2013-2032 used to formulate the NDC, if a 4% reduction requires 708 GWh of RE in 2025¹¹⁵, (see Table X below), the conditional target would require an additional 2,832 GWh of RE generation in that year (see table X' below). The incremental ORE generation planned by LTGEP 2018-2037 in 2025 is 2,778 GWh which is very close to what the conditional NDC target aim for.

Table 14: NDC unconditional target estimation (GWh) based on BAU case of LTGEP 2013-2032

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Generation ,2013-32 plan, GWh	864	1,171	1,234	1,289	1,383	1,460	1,519	1,534	1,543	1,590	1,598
Incremental generation for NDC, GWh	0	102	203	305	406	508	544	584	624	664	708
Total RE Generation , GWh	864	1,273	1,437	1,594	1,789	1,968	2,063	2,118	2,167	2,254	2,306
RE % Total	6%	8%	9%	9%	10%	10%	10%	10%	10%	10%	10%

¹¹⁴ Sri Lanka first NDCs:

<http://www4.unfccc.int/ndcregistry/PublishedDocuments/Sri%20Lanka%20First/NDCs%20of%20Sri%20Lanka.pdf>

¹¹⁵ Year of 2025 is selected considering it is a useful reference year for mid-term checking of first NDC period of 2020-2030

Table 15: Projected ORE development based on base case of LTGEP 2018-2037 (GWh)

Year	2018	2019	2020	2021	2022	2023	2024	2025
Incremental program generation (GWh)	509	683	1,434	1,721	1,904	2,171	2,366	2,778
Generation for conditional target (GWh)			2,032	2,176	2,336	2,496	2,656	2,832
Program ER share of conditional target			71%	79%	82%	87%	89%	98%

Note: values are not included for 2018 and 2019 because Sri Lanka's NDC commitment only covers the period 2020 to 2030.

Climate Finance:

Climate finance allows developing countries to mitigate and adapt to climatic changes in the longer run. It enables the transition towards low-carbon, climate resilient growth and development through capacity building.

Climate Finance is delivered through a variety of financial instruments including, grants, results-based carbon finance, loans (concessional and commercial), guarantees & risk-sharing mechanisms, and equity which share the common goals of pushing a development trajectory forward and crowding in other actors and sources of finance to meet the developing countries' climate mitigation and adaptation needs.

Climate finance instruments are normally used:

- in combination with other funds, and to target specific sector/project barriers that need to be overcome:
- when the sector/project requires technical assistance, demonstration/development costs, and similar activities with unclear/broad-based benefits
- where the economic or financial rate of return is low
- technology, counterparty, policy risk is high
- where a large capital investment into enabling infrastructure is needed to unlock the sector

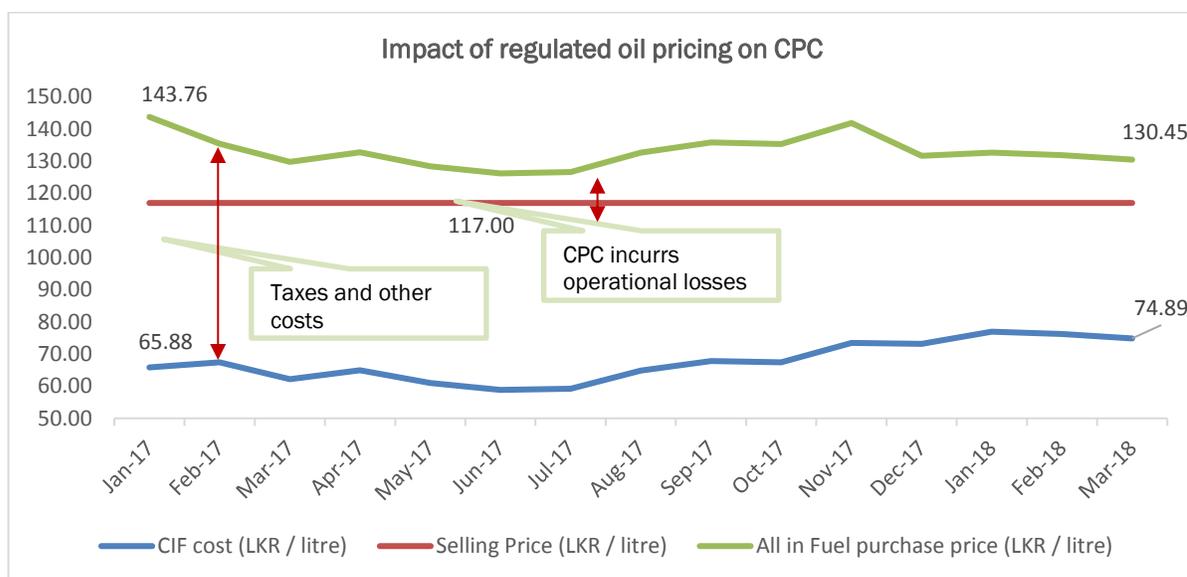
Sri Lanka has been successful in tapping into its hydro resources but still faces challenges in terms of scaling up use of its ORE, especially wind and solar energy, and their integration to the national grid. In the context of meeting the unconditional and conditional targets for the electricity sector in the Sri Lanka's NDC, access to climate finance source like Green Climate Fund, Climate Investment Fund, Global Environmental Facility, World Bank Carbon Finance, Verified Carbon Standards and their effective use is critical for Sri Lanka to address the technical and financial challenges associated with enabling sufficient ORE development. With clear recognition of such needs and operational modality/business models of various climate resources, Sri Lanka may consider utilizing climate finance to support, in a targeted manner, for innovative technology demonstration (i.e. battery storage, off-shore wind, and wave technology), development of new and innovative business models, particularly to support commercial banks/market investor in providing lending, through de-risking the ORE projects, strengthening institutions to become more effective in the regulatory processes to achieve greater electricity sector planning and governance outcomes and etc.

Annex 4. CPC and LECO Financial Performance

CPC: State-owned Ceylon Petroleum Corporation (CPC) is one of the two entities (other being Lanka Indian Oil Corporation, LIOC) responsible for procuring crude and petroleum products in the country. The country imports ~ 60% of the refined fuel consumed domestically, while 40% of the domestic fuel demand is met by Sri Lanka's only refinery at Sapugaskanda, owned and managed by CPC. Existing oil refinery at Sapugaskanda was commissioned in August 1969 to process 38000 bpsd¹¹⁶ (5200 MT / day) of Iranian light crude oil. Current capacity of the refinery is ~ 50,000 bpsd and it runs at a utilization of ~ 35% (CEYPETCO, 2018).

Based on recent developments, a fuel pricing formula is expected to be set up soon, under which CPC will be able to sell the fuel at unsubsidized prices. This is a positive development and is expected to yield positive margins for CPC. Currently, selling price and fuel cost charged to CEB are regulated. They are priced below cost (landed cost and additional overheads) of CPC, which leads to CPC incurring operational losses. The company has not been able to generate operational cash flows¹¹⁷, due to the regulated fuel pricing and high interest costs. Up to now, there was no concrete mechanism whereby CPC could recover the losses from the government or the end customer.

Figure 32: CPC Facing Operational Losses due to Regulated Oil Pricing



CPC Financials:

Table 16: CPC Financials

Profit and Loss For the year ended 31st Dec (in LKR million) ¹¹⁸	2017	2016
Revenue	528,512	435,091
Cost of Sales	(489,230)	(326,441)

¹¹⁶ Barrels per stream day

¹¹⁷ Both in 2013 & 2014 (the latest public data available), CPC has generated negative cash flow from operations.

¹¹⁸ Provisional Data

Finance Cost	(10,531)	(11,405)
Profit (Loss) Before Tax	3,504	69,620

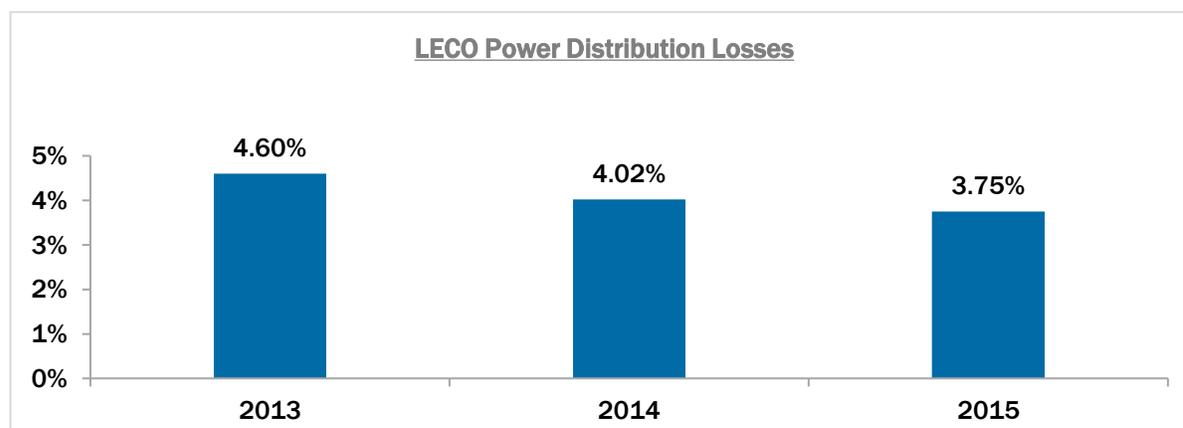
Balance Sheet (LKR million)			
	31.12.14	31.12.13	01.01.13
Equities and Liabilities			
Total Equity	(231,532)	(236,466)	(228,540)
Non - Current Liabilities	1,367	1,888	2,545
Current Liabilities	412,715	421,848	432,231
Total Equity and Liabilities	182,550	187,270	206,236

Based on the publicly available financial statements of CPC, it is seen that CPC has accumulated losses on its books. The primary reason for the consistent losses is the regulated fuel pricing, the taxes on CPC's fuel purchase and the high financial costs. CPC borrows short term loans mainly from Bank of Ceylon and People's Bank to settle its trade balances with the suppliers. These short-term borrowings are major portion of the total loans on CPC books. Most of these borrowings are in USD terms, and since CPC's sales proceeds are mainly in rupee, this leaves CPC exposed to foreign currency risks.

LECO: LECO, the state-owned distribution company, serves around 500,000 customers (with around 8.5% market share) primarily covering the western coastal belt of Sri Lanka. Present shareholders of LECO are CEB, UDA, Government Treasury and four Local Authorities (LAs). The unique achievement of LECO as a successful business venture was its ability in meeting a challenge in attracting foreign funding for the network improvements. LECO with the financial assistance pledge by Asian Development Bank converted a technically run-down network asset to an efficient and profit-making network within a short period.

As compared to CEB¹¹⁹, LECO has been able to restrict the distribution losses to minimal. The figure below highlights the power distribution losses by LECO over the past three years.

Figure 33: LECO Distribution Losses



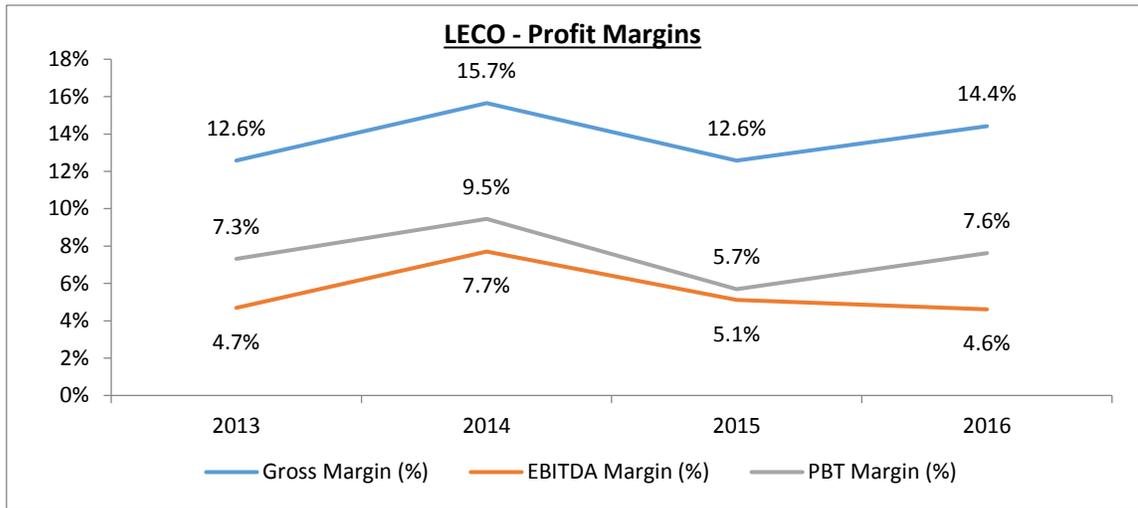
¹¹⁹ CEB's T&D losses for 2016 are 9.63%

LECO Financials

LECO has been a benchmark model to follow in Sri Lanka, with a continuous expanding customer base and decreasing distribution losses. As per LECO's Annual Report 2015, LECO has been able to employ cost control measures which have resulted in a higher gross profit margin for the company.

The Company has been able to remain debt free and continues to invest more than LKR 1 billion (USD 6.8 million¹²⁰) annually in expanding the distribution network. The capital requirements continue to be funded either by internal cash accruals, or receivables due from CEB. Due to high interest / investment income, the PBT margin for LECO is higher than the EBITDA margin (from operations).

Figure 34: LECO's Profit Margins¹²¹



¹²⁰ Average capex in 2015 and 2016.

¹²¹ Gross Margin: Total revenue less cost of goods sold, expressed as a % of revenue

EBITDA Margin: Earnings before interest, taxes, depreciation and amortization, expressed as a % of revenue

PBT Margin: Profits made before taking tax into account, expressed as a % of revenue

Annex 5. PUCSL's Tariff Methodology¹²²

Public Utilities Commission of Sri Lanka (PUCSL) issued a tariff methodology in the Sri Lanka Electricity Act No. 29 of 2009. As per the methodology, tariff has three components: bulk supply tariff, distribution tariff, and retail supply tariff.

5.1 Generation and Transmission Costs—Bulk Supply Tariff

Generation Costs

Generated energy is priced based on individual power purchase agreements that generation licensees have with the transmission licensee (a single buyer). This single buyer determines generation costs that are used to calculate bulk supply tariffs, and these costs are passed to distributor licensees, which in turn pass them through to the end users.

Transmission Allowed Revenues

Transmission licensee is allowed to collect some revenue from the transmission users, excluding the connection charges. This revenue is sum of two components: base allowed revenue and large infrastructure development allowances.

Base allowed revenue is calculated based on a forecast cash flow discounted at the allowed rate of return on capital for the tariff period. Calculation is done considering

- a) Initial regulatory asset base;
- b) Rolling forward of the initial regulatory asset base, with minor capital expenditure for the period;
- c) Depreciation;
- d) Return on capital;
- e) Efficient operational expenditure, and
- f) Taxes.

Revenue regarding capital expenditure is classified as large infrastructure development allowances in the Long-Term Transmission Development Plan and is approved by the PUCSL. This will be collected from transmission system users by adding an allowance to the transmission base allowed revenue time to time.

Determination of Bulk Supply Tariff

Bulk supply tariff (BST) is sum of the following:

- Generation tariff,
- Transmission tariff,
- Bulk supply and operations business tariff.

¹²² ADB, *Assessment of Power Sector Reform in Sri Lanka*

Forecasted BST, which is filed once every 6 months by the transmission licensee, determines the end-user tariff. Filing for this should include

- a) Forecast for the upcoming 6-month period, and
- b) An adjustment factor to compensate for differences between forecasted and actual BSTs for the just completed 6-month period.

Adjustment is needed because actual BST is not passed through to the end-user each month. Through the adjustment, end users are compensated for deviations between forecast and actual BSTs at the end of each 6-month period.

5.2 Distribution Tariff

Distribution and supply licensee is allowed to collect distribution tariff from its users, excluding some charges (connection, reconnection, meter testing, etc.) that are separately regulated. Distribution allowed revenue is calculated based on a multiyear tariff system, and there is a cap on overall revenue during the tariff period. This cap is adjusted with change in the number of distribution users as well as the energy distributed. Adjustment is based on the revenue control formula, and changes in the indexes contained in that formula.

Each distribution and supply licensee makes a tariff filing to the PUCSL. Before the beginning of the tariff period, the filing must be completed, including approval of cost components and revenue control formulas. Once a year after the initial filing, during the tariff period, a simplified filing is made to demonstrate that the revenue control formulas are properly applied.

Like transmission allowed revenue, distribution allowed revenue is also calculated based on a forecast cash flow for the tariff period, considering

- Initial regulatory asset base,
- Rolling forward of the initial regulatory asset base, with forecast capital expenditure for the period,
- Depreciation of assets,
- Return on capital,
- Operating expenses, and
- Taxes.

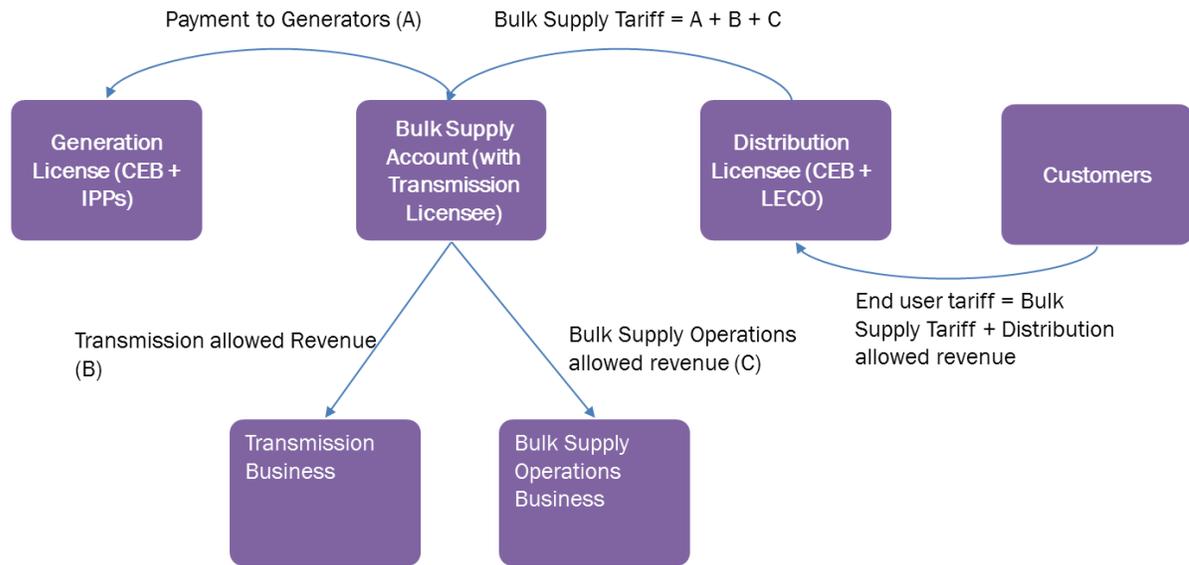
5.3 Retail Tariff

Retail supply tariff has two components, retail service tariff and bulk supply “pass-through” tariff.

Of which, retail service tariff includes costs related to the commercial cycle (meter reading, invoicing, and collection); routine meter testing; and an allowance for bad debt if PUCSL deems such allowance is appropriate.

Again, retail service tariff is calculated based on a multiyear tariff system and is capped during the tariff period. Retail supply customers have to pay bulk supply “pass-through” tariff, which is based on the BSTs and is adapted for retail customers. This “pass-through” tariff consists of two parts: capacity charge and energy charge.

The below figure summarizes the PUCSL approved tariff methodology.



5.4 End user tariff structure and TOU tariff structure

The end user tariff is divided into two parts, capacity charge and energy charge. Typically, capacity charge is a fixed amount charged per month, while the energy charge is a fixed per unit charge. The PUCSL also provides an option to the customers to avail a “Time of Use” (TOU) tariff structure. Under a TOU structure the energy charge is divided into separate time zones, i.e. off-peak, day and peak time zones.

The last tariff approval was done in November 2014, with an objective of reflecting the reduced cost of generation mix, expected to be realized from operations of the 900 MW Coal plant. The table below¹²³ highlights the existing tariff structure for domestic consumer category, approved by PUCSL in November 2014.

Domestic Customers – Tariff Structure		
Consumption per month(kWh)	Energy Charge (LKR/kWh)	Fixed Charge(LKR/month)
0-30	2.50 (~ US cents 1.62 / kWh)	30 (~ US cents 19)
31-60	4.85 (~ US cents 3.14 / kWh)	60 (~ US cents 38)

Consumption per month(kWh)	Energy Charge (LKR/kWh)	Fixed Charge(LKR/month)
0-60	7.85 (~ US cents 5.09 / kWh)	–
61-90	10.00 (~ US cents 6.50 / kWh)	90 (~ US cents 58)
91-120	27.75 (~ US cents 18 / kWh)	480 (~ USD 3.1)
121-180	32.00 (~ US cents 21 / kWh)	480 (~ USD 3.1)

¹²³ <http://www.pucsl.gov.lk/english/industries/electricity/electricity-tariffscharges/>

More Than 180	45.00 (~ US cents 29 / kWh)	540 (~ USD 3.5)
---------------	-----------------------------	-----------------

Optional Time of Use (TOU) Tariff to for Domestic Customers		
Time of Use (TOU)	Energy Charge (LKR/kWh)	Fixed Charge (LKR/ Month)
Off Peak (22:30 – 05:30 hrs)	13.00 (~ US cents 8.4 / kWh)	540 (~ USD 3.50)
Day (05:30 – 18:30 hrs)	25.00 (~ US cents 16.2 / kWh)	
Peak (18:30 – 22:30 hrs)	54.00 (~ US cents 35 / kWh)	

The TOU tariff was limited to consumers having three phase connection and consuming 30 A or more, but in 2017 PUCSL approved the TOU option for domestic consumers with a single-phase connection. The objective of the TOU pricing framework is to shift the power usage from peak¹²⁴ periods to off-peak time periods.

The current tariff structure involve significant amount of cross-subsidization, as can be observed from the large differences in pricing across consumer categories. The government also cross subsidizes the low voltage customers by charging increased tariffs from bulk usage Industrial, hotel and other categories. In addition to the cross subsidization, there is a need of additional subsidies from the government, as the end user tariffs are not reflective of the costs incurred by the licensee. As already highlighted, CEB transmission licensee has requested a cumulative subsidies of USD 900 million for 2016 and 2017.

5.5 Adjusted BST and ongoing cash transactions amongst licensees

The section provides a simplified snapshot of the tariff methodology specified by PUCSL and the current context of tariff setting mechanism in power sector in Sri Lanka.

As highlighted, PUCSL’s tariff setting methodology is based on the principle of cost reflectiveness, i.e. the tariff will enable each licensee to recover the justifiable costs. The methodology requires each licensee to disclose the costs in a transparent manner.

Currently, the end user tariffs are not being set as specified under the methodology. The primary reasons being the following:

- a) The transmission licensee has not yet established a physical Bulk Supply Transaction Account for settling transactions between distribution licensee and transmission licensee (as highlighted below)
- b) The generation dispatch data is not timely and transparently audited, as required by PUCSL.

Given that the current tariffs are not cost reflective, an adjusted methodology is adopted to enable the generation and distribution licensee recover their costs.

¹²⁴ The peak period demand has recently increased due to charging load of the increasing number of EV in Sri Lanka

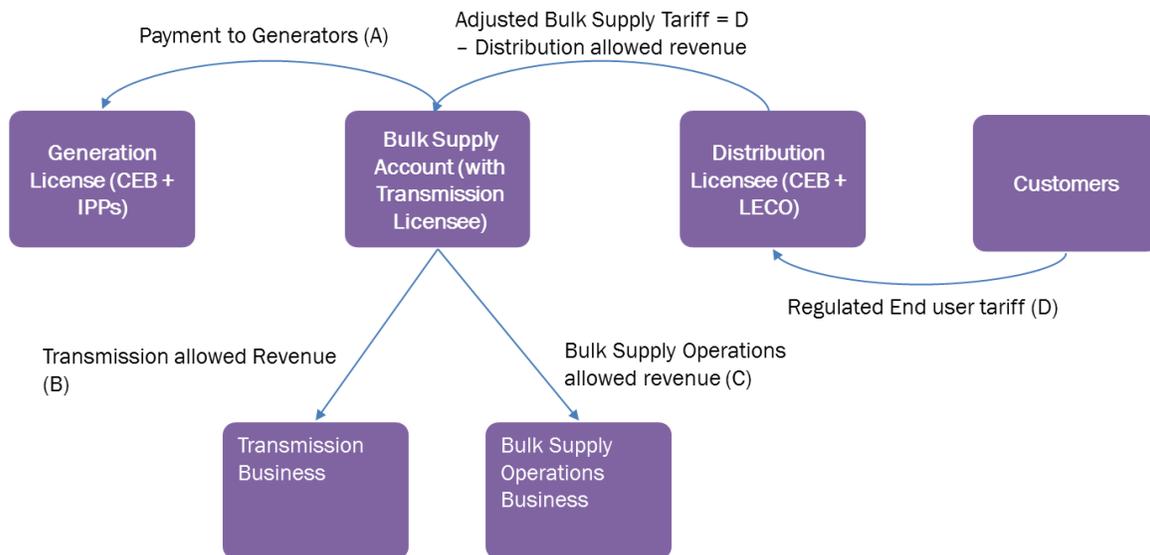
1. Adjusted Tariff Methodology

Under the adjusted methodology, the power from the transmission licensee is purchased at an adjusted Bulk Supply Tariff (as highlighted below), which enables the distribution licensee to recover their costs. The transmission licensee makes the payment to the generation licensee at the contracted power purchase cost.

Given the above, while the distribution licensee and generation licensee are able to recover the allowed revenues, the transmission licensee bears the losses. The loss to transmission licensee equals the difference between Adjusted Bulk Supply Tariff and (A+B+C) as highlighted in the figure below.

While the transmission licensee has started disclosing the statement of a notional Bulk Supply Account to the PUCSL, the physical Bulk Supply Account is not yet established. Given this, PUCSL is not able to audit the statement of accounts furnished by the transmission licensee.

The statement furnished by the transmission licensee illustrates the inability of the transmission licensee to recover costs. This has resulted in transmission licensee incurring ~ USD 900 million accumulated losses in 2016 and 2017. The transmission licensee has requested the government to provide the subsidy for the same amount, but there is no cash subsidy provided as yet to the licensee.

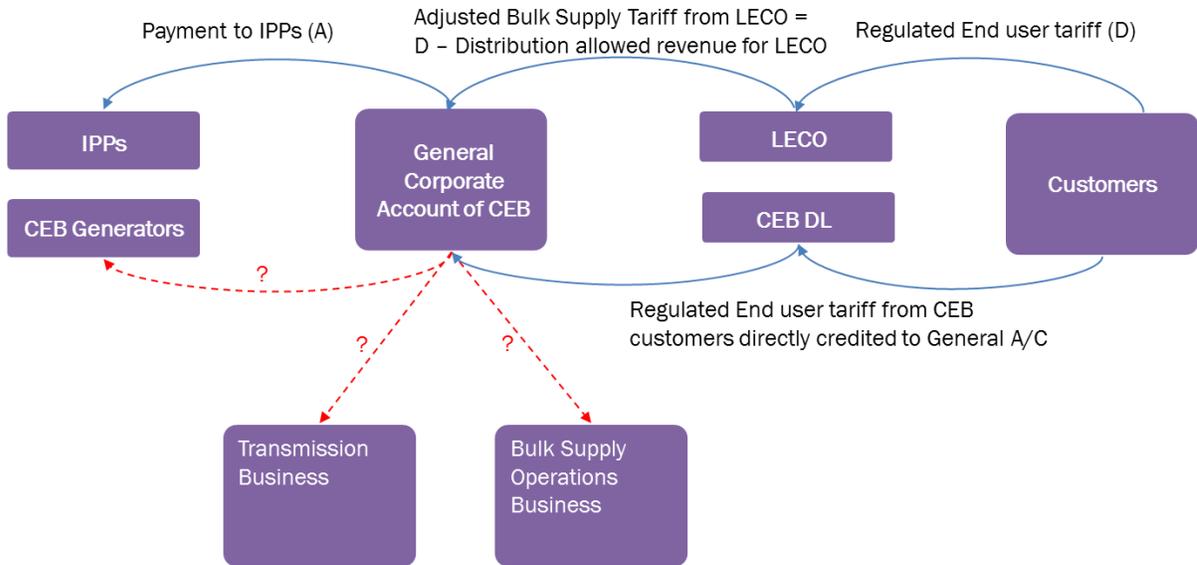


2. Current cash transactions amongst the licensees

Currently, as the physical Bulk Supply Account is not yet established, there is limited clarity on transactions amongst the various licensees. Based on the information gathered from sector stakeholders, the following explains the actual cash transactions amongst the licensees:

- a) LECO, the only non – CEB distribution licensee, purchases the power from transmission licensee at the adjusted Bulk Supply tariff thereby earning the required distribution allowed revenue.
- b) The adjusted bulk Supply tariff provided by LECO, as well as the end customer revenues collected by CEB’s distribution licensee are deposited in the CEB’s general account.

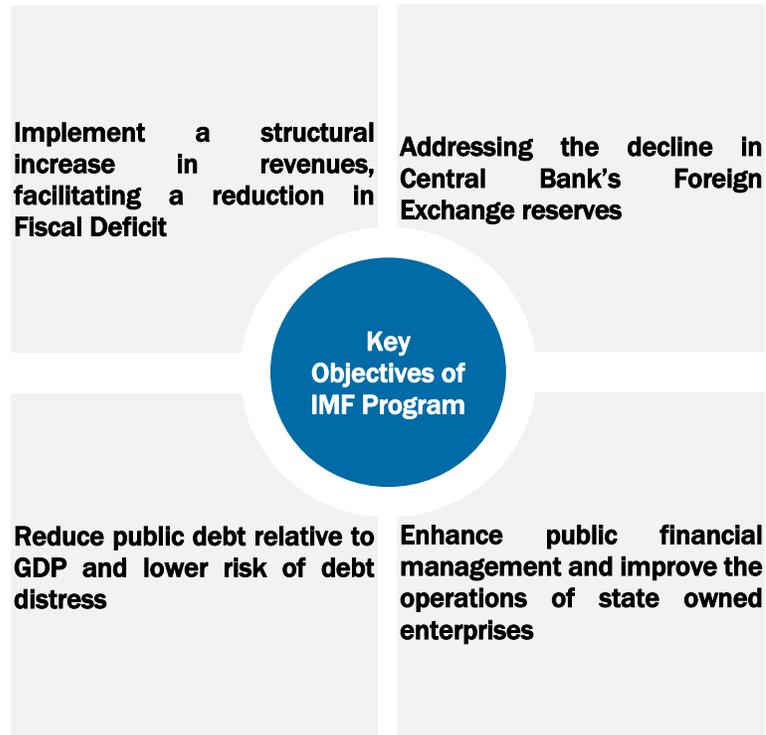
Although the actual payments are made to IPPs from the general account, there is limited clarity if actual payments pertaining to allowed revenues are made to CEB generators, Transmission Business and Bulk Supply Operations Business.



Annex 6. IMF Program

Objectives

Figure 35: IMF Program – Key Objectives



Key Structural benchmarks under the IMF program

In June '17, Government of Sri Lanka, listed out the developments and reform progress so far, and plans and policies of the authorities of Sri Lanka for 2017-19. The key structural benchmarks envisaged to be achieved are highlighted below:

1. Fiscal Policies

- **Fiscal Targets**: The government targets to bring the overall central government deficit down to at least 3.5 percent of GDP by 2020, which should lower the central government debt to about 70 percent of GDP. *The fiscal targeting is the lynchpin of the IMF program*
- **Rationalizing tax incentives**: As an initial step towards rationalizing tax incentives, the Cabinet suspended the Board of Investment Act in May 2016, annulling its capacity to grant tax exemptions, and other preferential treatments.
- **Redrafting the Inland Revenue Act (IRA)**. The new IRA aims to establish a stable, transparent framework, and widens the tax net through the elimination of tax exemptions so that over time, tax rates may be reduced

2. Monetary and Exchange Rate Policy

- Inflation Targeting: To rein in inflationary pressure and curtail the buildup of adverse inflation expectations as well as to control credit growth, the Central Bank raised policy rates by 25 bps in March 2017 and stands ready to further tighten monetary policy in 2017 as warranted.
- Maintaining Flexible Exchange rate regime: The CBSL will take next steps, including establishing price stability as the primary objective of monetary policy and publicly communicating the inflation targets. While the CBSL intends to retain a role for smoothing excessive exchange rate volatility, it will adopt FX intervention policies consistent with a flexible exchange rate regime. The CBSL planned to develop a road map and identify time-bound reform measures to achieve the same, guided by IMF TA, by October 2017.
- Plans to meet NIR (Net Internal Reserves) targets: As a corrective action for missing the NIR target for end-2016, we made a net outright FX purchase of USD 442 million in March and April, with significantly limited FX sales during that period and monetary tightening. Supported by FX purchase and financial inflows, the level of program NIR recovered from a low level at end-2016 to USD 2.3 billion by end-April 2017.

3. Public Financial Management

- Monitoring of government spending: Through modification of the existing IT system and manual reporting from line ministries, the MOF is now capable of tracking spending commitment for each line ministry on a monthly basis.
- ITMIS: The rollout of the new Integrated Treasury Management Information System (ITMIS) should significantly expand Financial Management capabilities, including commitment control, budget preparation, treasury, accounting, and procurement, among others. Full roll-out of ITMIS is expected in 2017 as internal capacity to run the systems is being developed.

4. Financial Sector Policies

- IMF recommendations: The IMF identified issues in the areas of the CBSL's autonomy and governance arrangement (for example, the government's voting representation in the Monetary Board, absence of recapitalization provisions, etc.). The government plans to address these issues with IMF Technical Assistance.
- Additional Measures: The government plans to deploy additional measures to strengthen the financial system, including
 - ✓ Implementation of BASEL III capital standards
 - ✓ Introducing sector specific limits on loan-to value ratio for infrastructure sectors
 - ✓ Initiating resolution mechanism for distressed companies

5. State Enterprise

- Status at start of program: Outstanding obligations of the central government and SOEs totaled LKR 1.36 trillion in end-2015
 - ✓ Obligations of 4 SOEs (CPC, CEB, Sri Lankan Airlines, and the Sri Lanka Port Authority), totaling LKR 1.2 trillion.
- Statements of Corporate Intent (SCI): The SCIs encompass the SOE's mission, high level objectives, and multiyear corporate plan; capital expenditure and financing plans; and explicit financial and non-financial targets. SCIs were signed in March'17.

- Automating Fuel and electricity pricing mechanism: Sequence of steps are being followed to implement an automatic pricing mechanism for fuel and retail electricity prices. These include:
 - ✓ Establishment of a Bulk Supply Transaction account: The account will be used to settle transactions between generators, the transmission operator, and distributors, to be implemented by March 2018
 - ✓ Estimating Cost of non-commercial obligations for fuel and electricity: The government had aimed to complete a report outlining the cost of non-commercial obligations for fuel and electricity by September 2017. Once finalized, the government plans to account for them in the program targets beginning in the third review

IMF conducted the review of the key structural benchmarks for approving disbursements under the EEF. The key highlights of the review are summarized below.

IMF's First Review (Nov'16): IMF completed the first review of Sri Lanka's economic reform program in Nov'16, and approved USD 162.6 million for disbursement.

"Macroeconomic and financial conditions have begun to stabilize, inflation has trended down, and the balance of payments has improved. Meanwhile, international reserves remain below comfortable levels."

IMF's Second Review (Aug'17): IMF completed the second review of Sri Lanka's economic reform program in Aug'17, and approved USD 167.6 million for disbursement.

"Both the end-2016 and end-March 2017 targets were met for the fiscal balance and tax revenues, while both the end-2016 and end-March 2017 targets were missed for net international reserves."

IMF's Third Review (Dec'17): IMF completed the third review of Sri Lanka's economic reform program in Dec'17, and approved USD 251.4 million for disbursement.

"Fiscal performance has been satisfactory and all targets until September were met."

Inflation and credit growth remain on the high side. Maintaining a tightening bias for monetary policy is recommended."

Along with efforts to deepen the foreign exchange market, it is important to further accumulate reserves and enhance exchange rate flexibility"

Annex 7. Domestic financial system in Sri Lanka

Financial system in Sri Lanka has total assets of approximately USD 103 billion (see below), which is around 130% of Sri Lanka's GDP. Of this, 59% or USD 60.4 billion (76% of GDP) are in the banking sector (which comprises of 25 licensed commercial banks (LCBs) and 7 licensed specialized banks (LSBs)).

Public sector dominates the banking industry with eight state-owned banks representing 44.7% of total banking sector assets and 27% of total financial system assets in 2016. Of the eight state-owned banks, two commercial banks, Bank of Ceylon and Peoples Bank are the most significant players.

Table 17: Sri Lanka's Domestic Financial System

Domestic Financial Institutions ¹²⁵	USD billion	%
Central Bank	10.2	9.9
Banking Sector (LCBs & LSBs)	60.4	58.8
Non- banks (Finance, Leasing companies, Cooperatives)	9.0	8.7
Contractual Savings Institutions (EPF, ETF, APPFs & PSPF*)	16.9	16.5
Insurance	3.4	3.3
Financial firms**	2.8	2.8
Total	102.7	100

* *Employees' Provident Fund (EPF), the Employees' Trust Fund (ETF), Approved Pension and Provident Funds (APPFs) and Public Service Provident Fund (PSPF)*

***Financial firms include Primary Dealers, Stock Brokers, Unit Trusts, Market Intermediaries & Venture Capital Companies.*

Banking sector assets have steadily increased in both absolute and relative terms in the last five years (2011-2016), from USD 40.1 billion (58.4% of GDP) to USD 60.4 billion (76.4% of GDP). During the same period, loans and advances have also increased from USD 24.7 billion (36% of GDP) to USD 37 billion (47% of GDP).

Power sector projects in Sri Lanka have mostly been financed by local banks through lending directly to the public / private sector. A limited pool of around 6 - 8 banks has financed infrastructure projects, including Bank of Ceylon, Peoples Bank, Commercial Bank of Ceylon, National Development Bank, Hatton Bank and DFCC Bank. Out of these, HNB and DFCC have recently financed multiple small scale renewable projects.

Unlike some of its regional peers, Sri Lanka's banking sector is relatively stable with low levels of non-performing loans (NPLs), particularly in the case of infrastructure project loans which are often backed by treasury guarantees. Although payments by the government and state-owned entities for infrastructure loans can be delayed sometimes, they are usually regularized within 60 - 90 days, thus preventing the account from being classified as non-performing.

Table 18: Maturity profile of Domestic Banks' Assets and Liabilities

¹²⁵ Total assets as in 2016 CBSL Annual Report

Maturity Bucket	< 1 year	1-3 Years	3-5 Years	> 5 Years	Unclassified	Total
Deposits	37,569	3,080	2,753	4,324	19	47,744
<i>(as a % of Total Deposits)</i>	79%	6%	6%	9%	0%	100%
Loans & Advances	20,951	8,240	5,171	6,195	839	41,397
<i>(as a % of Total Loans & Advances)</i>	51%	20%	12%	15%	2%	100%

Annex 8. Procurement models for LNG import

8.1 Estimating LNG requirements over 20-year period

As envisaged in the LTGEP 2018-37 base case plan, the LNG Supply requirements: Under a heat rate assumption of 7300 KJ/kWh, and a plant load factor of 70%, a 300 MW of gas fired plant would require an annual quantity of ~ 13 million MMBtu of RLNG. An MMBtu of RLNG is assumed to price ~ 10 US cents, for this analysis¹²⁶.

The additional requirement of RLNG as a fuel to operate the projected gas fired and CCGT plants, is estimated to be ~ **USD 9 billion** up to 2037 (under the assumption that the projected CCGT and gas fired plants shall be run entirely on LNG as a fuel).

8.2 Tolling Model

Overview

Contractual Structure: The state-owned entity (SOE), enters into the gas supply agreement with the supplier, a terminal use agreement (TUA) with the terminal company for regasification and sells the re-gasified LNG to the purchaser under the gas purchase agreement. The tolling structure offers an added flexibility of scaling up by aggregating players across the value chain.

Gas Supplier(s): The gas supplying entity is typically an upstream entity (either the gas producer, liquefier or an aggregator), responsible for delivering the LNG to the SOE's delivery point.

Terminal Company: The terminal company may be separately contracted under a TUA by the SOE, or if owned by the SOE, operated by a third-party operator under an O&M contract. The terminal company is responsible for delivering and operating the regasification terminal. A floating terminal may be leased, or purchased by the company whereas an onshore facility may be constructed specifically to cater to the regasification requirements. The terminal company would not hold the title to the gas during the entire process.

Gas Purchaser(s): The SOE sells the re-gasified LNG to the gas distribution company, or if required, directly to the end users.

Precedent Transactions: This structure has been followed in Bangladesh (Moheshkhali FSRU) and Pakistan (Engro LNG Terminal).

¹²⁶ The RLNG pricing is indicated to be in the range of 8 – 11.8 US cents / MMBtu in section 1.2.2, and an average of US cents 10 / MMBtu is applied for the analysis.

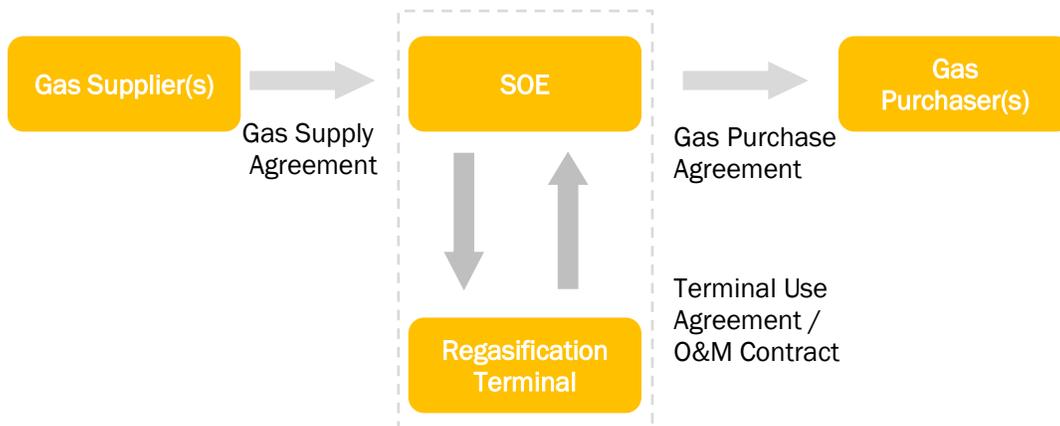


Table 19: Risk Allocation – Tolling Model

Type of Risks	Tolling Model
Supply Risk	<ul style="list-style-type: none"> Under the gas purchase agreement between the SOE and the end user / purchaser, the risk is allocated to the SOE. Typically structured in a back to back manner and allocated to the gas supplying entity under the gas supply contract (vide certain damages for non-adherence to supply standards).
Demand Risk	<ul style="list-style-type: none"> Under the gas supply contract, the demand risk shall be allocated to the SOE. Typically structured in a back to back manner and allocated to the gas purchaser under the gas purchase contract (vide deemed payments for inability to purchase a minimum gas quantity from the SOE).
Regasification Risk	<ul style="list-style-type: none"> May be allocated to the terminal company / O&M operator and mitigated under the TUA / O&M Contract (vide penalties for failure to meet performance standards).
Pricing	<ul style="list-style-type: none"> The SOE has separate contracts for gas supply and terminal usage. This results in an optimized pricing structure for the SOE / procurer, as the payment terms to the suppliers and terminal company are negotiated / competitively procured under the contracts.

8.3 Integrated Demand Side Model / Alternate Tolling Model

Overview

Alternate Tolling Model:

- There could be variants to the Tolling model, based on the integration of the entities across the value chain.
- It is a possibility that the SOE is an entity that has a wider role in the downstream value chain.
- An example of the alternate structure is depicted below, wherein the SOE is also a gas based power producer. If the SOE has high gas demand, the structure can lead to significant benefits by achieving economies of scale.

Contractual Structure: The SOE enters into a gas purchase agreement with the gas supplier for the delivery of LNG and simultaneously enters into a TUA (or O&M Contract, as applicable) with the terminal company for regasification.

Terminal Company: The terminal company would not hold the title to the gas under the alternate structure as well.

Precedent Transactions: The structure has been followed by Tokyo Electric Power Company (TEPCO) - a power generation utility of Japan, which owns and operates 5 LNG terminal.

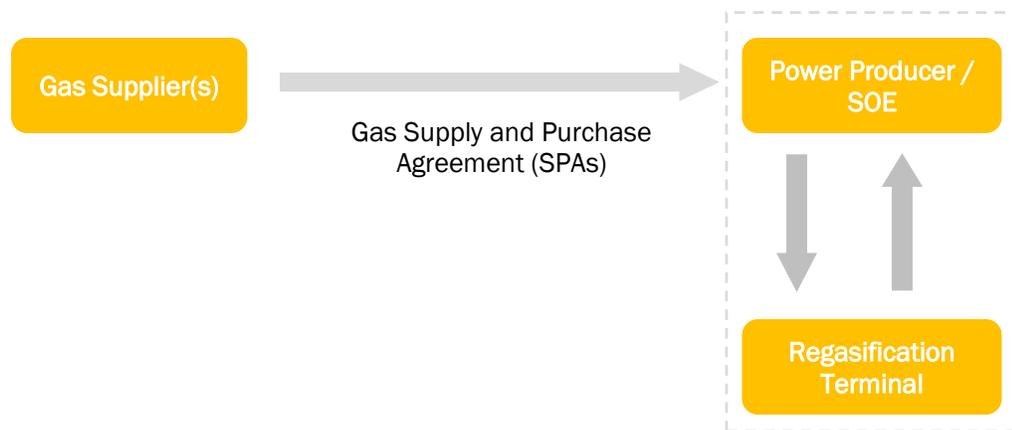


Table 20: Risk Allocation – Alternate Tolling Model

Type of Risks	Alternate Tolling Model
Supply Risk	<ul style="list-style-type: none"> ▪ Allocated to the gas supplying entity under the gas supply contract between SOE and the gas supplying entity (vide certain damages for non-adherence to supply standards).

Type of Risks	Alternate Tolling Model
Demand Risk	<ul style="list-style-type: none"> Allocated to SOE, and may be mitigated by conducting a comprehensive demand assessment of the downstream market.
Regasification Risk	<ul style="list-style-type: none"> May be allocated to the terminal company / O&M operator and mitigated under the TUA / O&M Contract (vide penalties for failure to meet performance standards).
Pricing	<ul style="list-style-type: none"> The SOE has separate contracts for gas supply and terminal usage. This results in an optimized pricing structure for the SOE / procurer, as the payment terms to the suppliers and terminal company are negotiated / competitively procured under the contracts.

8.4 Merchant Model for LNG procurement

Overview

Contractual Structure: SOE enters into the gas purchase agreement with the terminal company, which in turn separately contracts and purchases LNG from a gas supplier.

Gas Supplier: The gas supplying entity is typically an upstream entity (either the gas producer, liquefier or an aggregator), responsible for delivering the LNG to the terminal company's delivery point.

Terminal Company: The terminal company is an independent entity in the value chain, may / may not be controlled by the state. The terminal company purchases the incoming LNG, re-gasifies it, and sells the re-gasified LNG to the SOE (gas distributor) / other gas purchasers. The terminal company holds the title to the gas and undertakes the supply risk (under the gas purchase agreement) which may be allocated to the gas supplier under the gas supply agreement.

Gas Purchaser(s): The SOE or private gas distribution companies enter into a gas purchase agreement with the terminal company.

Precedent Transactions: The structure has been followed in India (Shell's Hazira LNG Terminal)



Table 21: Risk Allocation – Merchant Model

Type of Risks	Tolling Model
Supply Risk	<ul style="list-style-type: none"> ▪ The terminal company undertakes the supply risk under the gas purchase agreement. ▪ Typically structured back to back and allocated to the gas supplying entity under the gas supply agreement (vide damages for non-adherence to supply standards).
Demand Risk	<ul style="list-style-type: none"> ▪ SOE would bear the demand risk under the gas purchase contract (by agreeing to a minimum off-take payments).
Regasification Risk	<ul style="list-style-type: none"> ▪ The terminal company bears the regasification risk independently
Pricing	<ul style="list-style-type: none"> ▪ As the SOE is not a party to supply agreements (which may not reflect competitive prices), the final price of re-gasified LNG to SOE may also be sub-optimal

8.5 Integrated Supply Side Model / Alternate Merchant Model

Overview

Alternate Merchant Model:

- Similar to the Tolling structure, there could be variants to the Merchant model, based on the integration amongst the supply side entities.
- An example of the same is depicted below, where the gas supplying entity also undertakes to re-gasify LNG and deliver the final gas to the gas purchaser.

Contractual Structure: SOE enters into the SPA with the gas supplying (upstream) entity. The gas supplying entity also undertakes to re-gasify the LNG and deliver the final gas to the SOE’s delivery point.

Terminal Company: Similar to the Alternate Tolling model, the terminal company may / may not be separately contracted under a TUA by the supplier. The Terminal Company would not hold the title to the gas (if separately contracted under a TUA) under the alternate structure depicted below.

Precedent Transactions: The structure has been followed by Qatar Petroleum, which owns the Adriatic LNG terminal, near Italy.

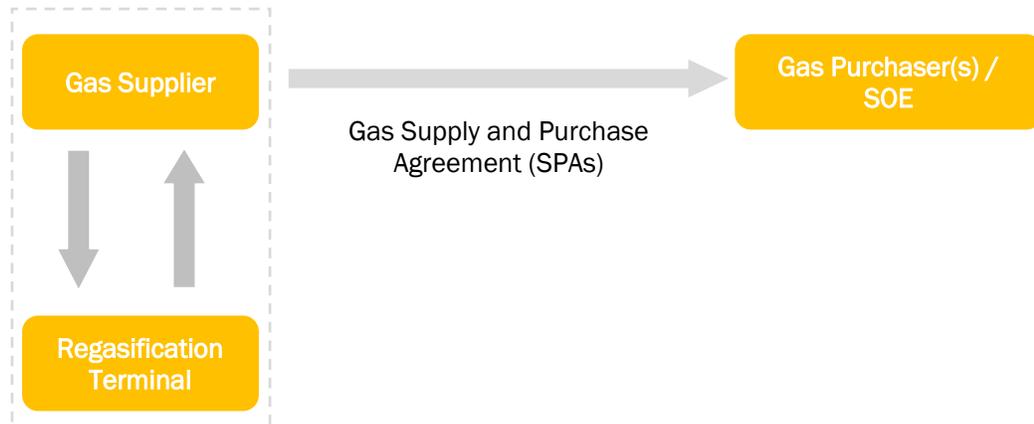


Table 22: Risk Allocation – Integrated Supply Side Model

Type of Risks	Tolling Model
Supply Risk	<ul style="list-style-type: none"> Allocated to the gas supplying entity under the Gas SPA.
Demand Risk	<ul style="list-style-type: none"> SOE undertakes the demand risk which may be mitigated by conducting a comprehensive demand assessment of the downstream market.
Regasification Risk	<ul style="list-style-type: none"> Under the Gas SPA, the supplying entity bears the regasification risk, which may be allocated to the terminal company / operator, as applicable.
Pricing	<ul style="list-style-type: none"> As the SOE is not a party to supply agreements (which may not reflect competitive prices), the final price of re-gasified LNG to SOE may also be sub-optimal

Annex 9. NCRE Tariff Optimization Methodologies

NCRE case study includes analysis of key factors on the project economics in the NCRE sector in Sri Lanka. The analysis has been conducted for a model solar project, with certain standardized assumptions highlighted below.

Based on information at hand, two scenarios are presented – the current scenario and the potentially optimized scenario. The two scenarios differ w.r.t. technical, financing, procurement assumptions.

Current Scenario

The current scenario has been developed based on interaction with the private sector developers, and in line with the cost and timeline assumptions currently applicable in the sector. The current tariff numbers achievable in NCRE power projects are ~ 12-13 LKR / kWh (~ US cents 8.5 / kWh).

Globally, it has been observed that with a well-structured enabling environment and incentives for private sector developers, significant optimization in cost of power is achievable.

Key Tariff Optimization Methodologies

Optimization 1: Financing Terms

In the current scenario, Local financing can be procured at 14% all-in cost (~ 3% margin to current AWPLR) with a tenor of 8 years from COD.

Based on experience in the sector, with the right incentives and project structuring, a USD loan can be procured at LIBOR + 3.5% (with tenors ranging up to 18 years from COD); The USD terms highlighted are the benchmarked terms (based on indicative terms from lenders) that an established international investor would avail in a fairly competitive market, and a bankable project structure.

Optimization 2: PLF optimization

A 16.3% PLF is highlighted under the LTGEP, as the PLF realized currently from solar projects. The 16.3% may be considered a conservative estimate. For the potentially achievable case, a GNI ceiling of 2000 kWh / m² has been assumed for the plant, basis the publicly available GHI parameters for Sri Lanka, and other standard assumptions on technology and availability, leading to a PLF of ~ 24%.

Optimization 3: Construction Timeline

EPC players with limited experience may take as long as 18 months to construct a project (conservative case assumption), whereas a developer / EPC contractor of international repute with significant experience might be able to get the plant running in ~ 6 months.

Optimization 4: Module Prices

The module costs are largely dependent on the negotiating power of the buyer with the contractor. The module price availed currently by some of the developers is ~ US cents 60 cents / Wp (based on interaction with select developers). In a potentially achievable scenario, with participation from

international players, a module price of US cents 35 / Wp may be realized (global players with significant market power have recently availed similar prices in the region).

Optimization 5: Procurement Methodology

- Currently, the projects are procured on a non-park basis, with the following key considerations:
 - Land is procured by the developer
 - Return expected from the sponsors is ~ 18% in LKR terms (standard assumption based interaction with select private sector players)
- To further provide an enabling environment, a park based procurement may be considered, with following considerations (a similar structure has been successfully developed in India, and is being developed in other regional peers like Cambodia, etc.):
 - Land and related infrastructure is provided by the government
 - The project incurs land lease charges and park maintenance charges during the project lifecycle
 - Return expectation from the developers is lower than non-park based procurement (as risks like land allocation, etc. are covered by the government providing sufficient cushion to the investors to price in lower risks): 16% in LKR terms

Potentially Achievable Scenario: Combining all the optimization scenarios

A potentially achievable case is developed by combining the optimization on various factors highlighted in this section. The resultant cost of power (**~ 9.35 LKR / kWh or ~ 6 USC / kWh**) reduces by ~ 20% (from ~ LKR 13 / kWh observed in some of the recently procured NCRE projects).

In line with what is being witnessed across the globe (low tariffs in NCRE sector), it seems reasonable to assume that by opening the sector to international players with adequate incentives and protection mechanisms in place, a significant optimization in cost of power could be achieved in Sri Lanka.

Annex 10. International standard risk allocation framework under the PPA

Table 23: Standard Risk Allocation Framework

	Power Purchase Agreement – Key Risks	Standard Risk Allocation Framework	
		Project Company	Off-taker
Development Phase	Arranging Financing	✓	✗
	Interest Rate Swap Risk	✗	✓
	Delay in FC	✓	✗
Construction Phase	Construction Risk	✓	✗
	Project Cost Overrun	✓	✗
Operation Phase	Off-take risk	✗	✓
	Market Risk	✗	✓
	Payment Risk	✗	✓
	Operation Risk	✓	✗
	Fuel Risk	✗	✓
	Grid Failure Risk	✗	✓
Common Risks	Change in law / tax	✗	✓
	Political Force Majeure	✗	✓
	Natural Force Majeure	✓	✗

Annex 11. Government Foreign Currency Bond issue in 2017

Globally, in addition to traditional commercial and development bank lending, institutional capital has been increasingly active in funding infrastructure debt over the past decade given the long dated, often inflation-linked nature of the asset class. Investment objectives differ by investor type and often project financing solutions require cooperation between several groups of investors. Capital pools from non-bank institutions such as insurers, fund managers and pension funds funded by long-dated savings products have increased significantly over the past decade as compulsory and discretionary saving has developed along with rising consumer affluence.

USD denominated bonds issued in 2017

Sri Lanka has been instrumental in issuing USD denominated notes in the international bond market. In 2017, CBSL issued international bonds for USD 1,500 million maturing in 2027 with a 6.2% coupon. The bond issuance proceeds were allocated primarily towards liability management in lieu of existing debt obligations. This marked the 11th USD benchmark offering in the International bond market by Sri Lanka.

The final order book was in excess of USD 11 billion, achieving an oversubscription ratio of over 7 times, spread across 500 participating accounts. The positive reaction from the international markets reflected investor's confidence in the efforts being channelized under the IMF program and overall Sri Lanka growth story. By the investor type, 83% of the credit was issued by fund managers, 9% by banks, and 5% by insurance and pension funds. Geographically, 58% of the final allocations went to US, and only 20% to Asia. Further, compared to the 2016 spread between US Treasury 10-year yield and 10-year Sri Lanka bonds yield, 2017 spread has substantially declined indicating a reduction in the risk premium demanded by the investors.

Annex 12. Credit Enhancement Products Offered by MDBs and Select Projects

This section examines various types of guarantee that can be used in energy investments. The guarantee instruments discussed in this section are versatile. The instruments are applicable for covering risks for investors across NCRE and LNG segments. They can be used to mitigate investment risks, including political, policy, regulatory, currency, and credit and technology risk.

1. Political Risk Insurance

Investors are highly sensitive to the potential impact of political risk, making the transfer of such risks essential, especially in countries with an unstable political system or inadequate rule of law. Political risk insurance issued by public finance institutions can provide a broad coverage of risks related to government action, building on their strong creditworthiness and government membership.

A member of the World Bank Group, the Multilateral Investment Guarantee Agency (MIGA) is the largest public provider of political risk insurance (PRI) in terms of volume.

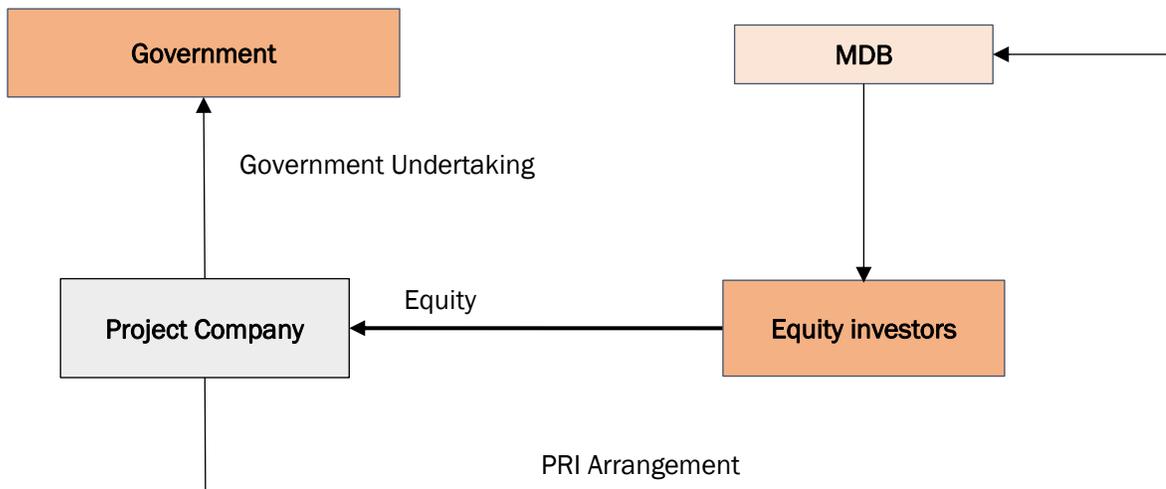
PRI can usually cover both debt and equity investments in a project. This is provided only for a project based investment and where the investment is from offshore investment. It generally covers one or more of the following risks:

- Breach of contract
- Expropriation
- Currency non-convertibility / transferability
- War, civil strife, etc.

Usually, the payments under this product are made only after the arbitration award as per the underlying project agreements.

- For equity investment:
 - It is offered for covering various equity cash-flows like retained earnings, dividend payments, original equity investment, etc.
 - This is priced on the outstanding equity exposure, with a flexibility with the equity investors to vary the amount of cover and duration of the policy
- For debt investment:
 - It can cover up to a certain percentage (usually 95%-97%) of the outstanding debt and interest
 - It is offered only to commercial lenders to the project and can cover the entire debt tenor
 - The policy can be taken by the lender or by the project company

Figure 36: Political Risk Insurance for Equity Investment

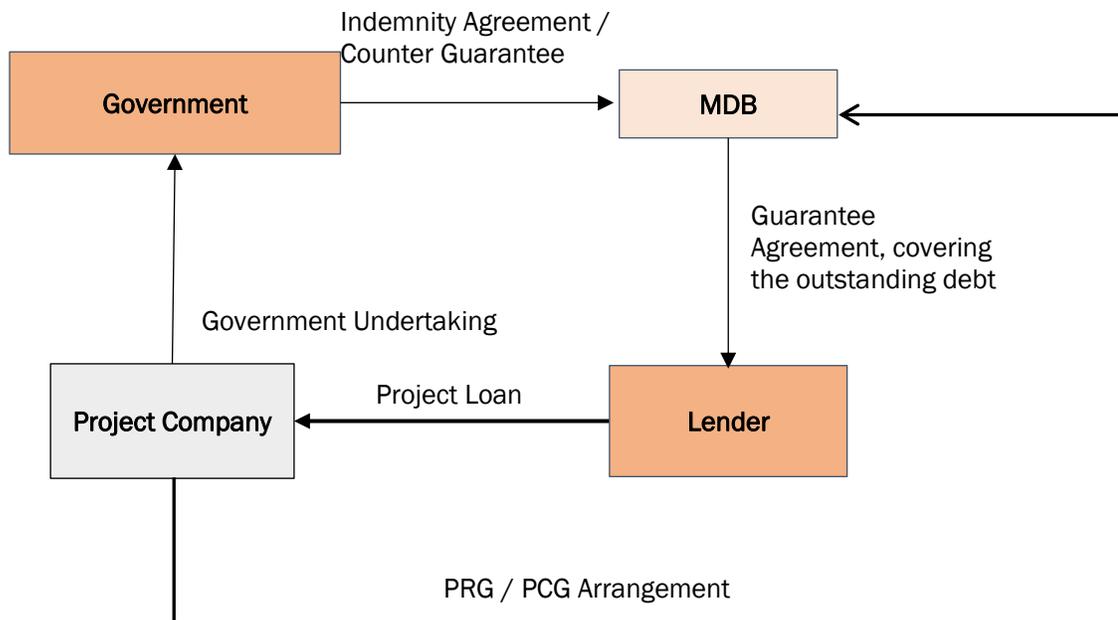


- *The guarantee structure in above diagram covers private sector, equity investors in a transaction*
- *The government has an agreement with the project company (PPA) which includes obligations of government as off-taker*
- *Usually, an acknowledgement may be required from the host government*
- *As and when there is a non-performance by government of its obligations such as breach of contract or currency non-convertibility etc.;*
 - *MDB covers equity investors*
 - *However, any payment under the guarantee is typically made only after an arbitral award*

2. Partial Risk Guarantee / Partial Credit Guarantee

It provides cover to the project's lenders for debt service repayments over life of debt. It also covers termination payment risk for lenders in case of termination by off-taker to protect outstanding principal due to lenders. A similar product is offered to exporters (esp. for exports to neighboring countries) or businesses with foreign currency earnings covering risks for lenders in the project (for example, PRG for enclave projects offered by IBRD). A counter guarantee / indemnity agreement with the host government is usually required.

Figure 37: PRG Arrangement



- *PRG/PCG structure in above diagram covers debt-holders (lenders)*
- *The government provides an undertaking to the project company which includes obligations of government as off-taker*
- *As and when there is a non-performance by government of its obligations such as breach of contract or currency non-convertibility etc.*
 - *MDB covers lenders*
 - *Government has to compensate MDB under the counter-guarantee agreement*

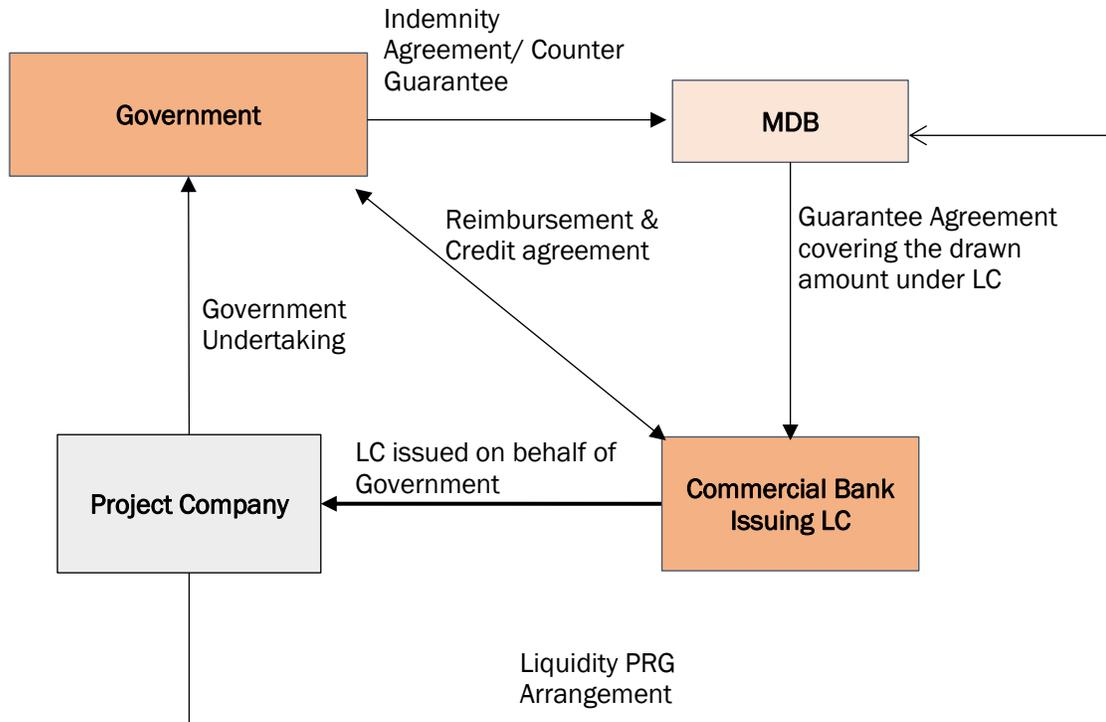
3. Liquidity / Payment Guarantee

It protects project company from liquidity risks for a certain time period (example 3 to 6 months) by covering revenue payments from off-taker (for example, Liquidity PRG offered by IDA).

A slight variation to this structure is the LC based liquidity PRG. This has an additional layer in the form of a LC bank, which results in better responsiveness to the project, thereby fulfilling the basic objective of the structure – to cover the short-term liquidity risk.

A counter guarantee / indemnity agreement with the host government is usually required.

Figure 38: Liquidity PRG Agreement



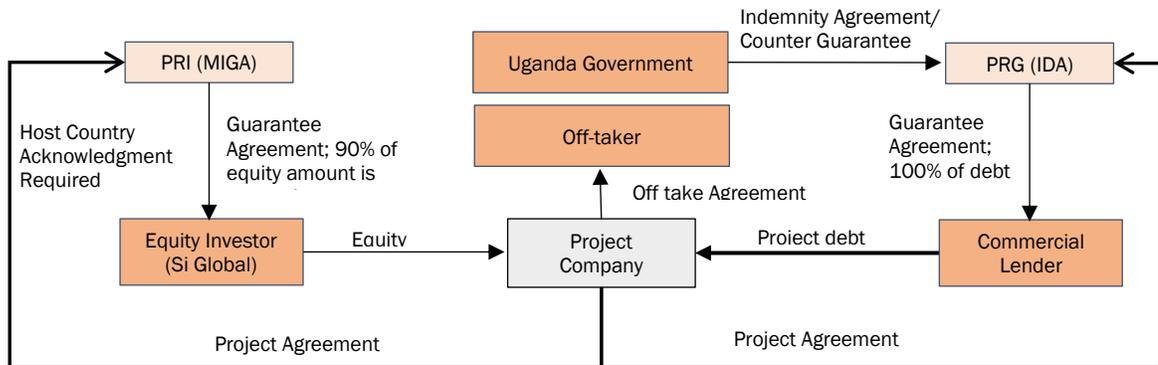
- *Revenues of the Project Company are secured for short term risks under this guarantee structure*
- *In case the off-taker (Government) defaults on the revenue payments to project company,*
 - *The project company draws the LC from the issuing bank*
 - *If the Government defaults on the reimbursement / replenishment of the LC amount to the issuing bank, the bank calls the MDB guarantee to cover for non-payment of LC*

4. Select Projects Made Bankable by WBG Credit Enhancement Products

Bujagali Hydro Power, Uganda (100% Debt Coverage + 90% Equity coverage)

- Bujagali hydro power plant accounted for 67% of total private investment in Uganda between 2003-2012 (World Bank, 2014)
- Key risks in Uganda were identified as – off-taker’s credit rating, country’s lack of track record with private investment, country’s credit rating and currency depreciation
- PRI (MIGA) was used to cover currency depreciation & political risks (90% equity (up to USD 120 million) by Sithe Global was covered)
 - PRG (IDA) was used to cover off-taker risk and enabled commercial lenders to commit financing (covering principal and interest payments of entire commercial loan of USD 115 million)

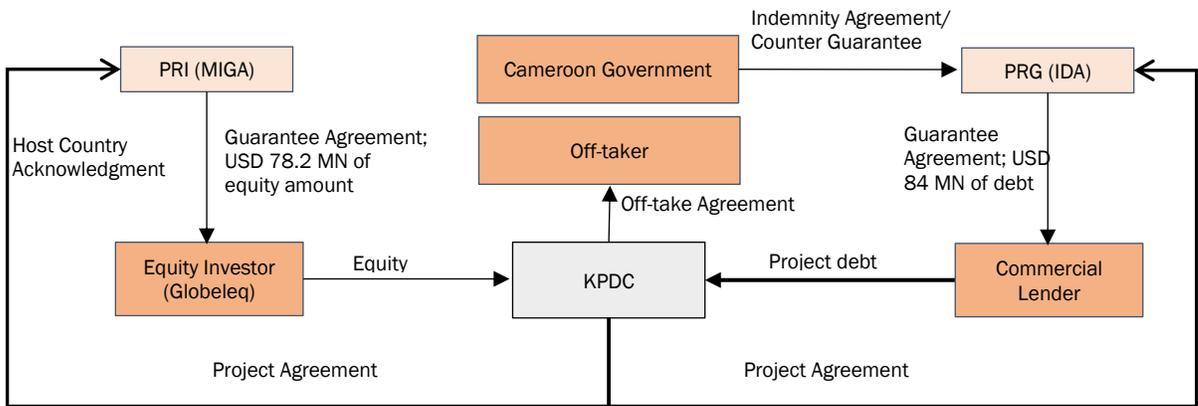
Figure 39: Bujagali Project Structure



Kribi Power Project, Cameroon (Partial coverage of debt and equity)

- Kribi Power Development Corporation, KPDC (project company) owned by AES Corp. and government, started Kribi power plant in 2013
- Key risks in Cameroon were identified as - high corruption, political uncertainty, low investment climate, contractual default by government
- IFC enabled access to local financing (it provided a loan of USD 86 million and acted as a lead arranger for debt of USD 182 million)
- PRG was issued by World bank to extend tenors for their USD 84 million financing, covering off-taker risk (including some government obligations arising out of termination risk)
- MIGA guarantee of USD 78.2 million covered BOC & political risks supporting the equity of Globeleq Energy Holdings (Cameroon) against breach of contract

Figure 40: Kribi Project Structure



Annex 13. Green Bonds – Key Principles

A green bond is a bond whose proceeds are used to fund environment-friendly project such as projects related to clean water, renewable energy, energy efficiency, river/habitat restoration, or mitigation of climate change impacts.

The proceeds from the bond are raised for specific project category (e.g. solar, wind, etc.), rather than specific projects. Thus, the repayment is tied to the issuer, not the success of the projects. This means the risk of the project not performing stays with the issuer rather than investor. The bonds generally attract tax benefits and are considered an attractive investment instrument by the investors. The key benefits associated with issuance of green bonds are summarized below:

- **Positive public Relations:** Green bonds can help in enhancing an issuer's reputation, as this is an effective way for an issuer to demonstrate its green credentials. It displays the issuers' commitment towards the development and sustainability of the environment. Further, this may also generate some positive publicity for the issuer.
- **Investor Diversification:** There are specific global pools of capital, which are earmarked towards investment in Green Ventures. This source of capital focuses primarily on environmental, social and governance (ESG) related aspects of the projects in which they intend to invest. Thus, green bonds provide an issuer the access to such investors which they otherwise may not be able to tap with a regular bond.
- **Potential for pricing advantage:** The green bond issuance attracts wider investor base and this may in turn benefit the issuers in terms of better pricing of their bonds vis-a-vis a regular bond. Currently there is very limited evidence available in this regard; however as demand of green bonds increases it is likely to drive increasingly favorable terms and a better price for the issuer. Further, with increasing focus of the global investor community towards green investments, it is expected that new set of investors will enter into this space leading to lowering the cost of funding for green projects.
- **International Experience:** Issuance of green bonds started in year 2007 and in the initial years Green Bonds were a niche product, pioneered by a handful of development banks. The period of 2007-2012 was featured with the issuance of green bonds by the supranational organizations such as the European Investment Bank and the World Bank, along with few governments etc. However, with growing market appetite for such bonds there is increasing diversification of issuers and investors participating in Green Bonds. An overall growth is witnessed in the fresh issuance of green bonds, with around USD 37 billion issued in 2014

Principles for issuance of Green Bonds (ICMA, Green Bond Principles, 2018): While there are no set guidelines defining the principles for issuance of Green Bonds, International Capital Market Association (ICMA) has however come out with a document called Green Bond Principles (GBP) which outlines a set of principles that delineates good practices for the process of issuing a green bond, which are divided in four components. Brief details of the same are as follows:

Use of proceeds: Issuer shall define and disclose in their offer document, the criteria for identification as 'green' i.e. what projects, assets or activities will be considered 'eligible for financing' and quantum of funds to be spent on the projects/assets/activities.

Project evaluation and selection: The issuer of a Green Bond shall provide the details of decision-making process it will/has followed for determining the eligibility of projects for using Green Bond proceeds. An indicative guideline of the details to be provided is as under:

- Process followed/ to be followed for determining how the project(s) fit within the eligible Green Projects categories;
- The criteria, making the projects eligible for using the Green Bond proceeds; and
- Environmental sustainability objectives.

Management of proceeds: The proceeds of Green Bonds shall be credited to an escrow account, and shall be utilized only for the stated purpose, as in the offer document. The use of proceeds shall be tracked as per an approved internal policy of issuer and such policy shall be disclosed in the offer document/placement memorandum. Utilization of the proceeds may also be verified/supplemented by the report of an external auditor, or other third party, to verify the internal tracking method and the allocation of funds towards the projects, from the Green Bond proceeds.

Reporting: In addition to reporting on the use of proceeds issuers shall also provide, at least on an annual basis, a list of projects to which Green Bond proceeds have been allocated. This may also include the details of the expected environmental impact of such projects. The environmental impact report may provide for qualitative performance indicators and, where possible, quantitative performance measures of the expected environmental sustainability impact of the specific project.

Annex 14. FIT Scheme

Emphasis was given to development of NCRE projects with the introduction of feed in tariff (FIT) scheme for NCRE projects (solar, wind, biomass) up to 10 MW generating capacity. FIT scheme was introduced with aim of increasing investor participation in the sector. The FIT scheme received decent response from local investor and domestic banks alike and led to influx of domestic developers supported by local financing. Tariffs were cost based and technology specific, and the developers had the option of selecting either a three-tier tariff or a flat tariff was valid for a period of 20 years and extendable by mutual consent.

The FIT rates were applicable for projects up to 10 MW capacity. For projects greater than 10 MW and up to 25 MW capacity, the tariffs were to be based on negotiations with the government (and expected to be lower than FIT rates), while projects greater than 25 MW capacity entailed providing free equity shareholding to the government. This limited the participation of private sector players in projects up to 10 MW capacity (MOPRE, 2018). The developers were provided two options of FIT tariff scheme.

Option 1: Three-tier Tariff

Tariff consisted of a fixed rate, escalable Operations and Maintenance (O&M) rate and escalable fuel rate. Tariff for wind projects are given below. Three-tier tariff structure was not applicable for solar power.

Table 24: Tariff Rate (three-tier) All values in LKR / kWh

Technology / Source	Escalable Base O&M rate	Escalable Base Fuel rate	Fixed Rate		
			Year 1-8	Year 9-15	Year 16-20
Wind	1.30	-	22.63	8.58	7.80
Wind Local	1.34	-	23.29	8.83	8.03

Option 2: Flat Tariff

Details for Flat Tariff for wind and solar projects are given below.

Table 25: Flat Tariff Rate (All values in LKR / kWh)

Technology / Source	All-inclusive rate for year 1-20
Wind	20.62
Wind Local	21.22
Solar	25.09

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During the course of the report preparation, Synergy team has continuously explored its internal sources, public and private sources for collating relevant information, illustrated in the presentation. The key sources that have been referred to, are listed below

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