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BRAZIL

**Conditional Credit Line for Investment Projects (CCLIP) for Financing Productive and Sustainable Investments**

**(BR-O0001)**

**First Program under the CCLIP: Financing Program for Sustainable Energy**

**(BR-L1442)**

**Economic Analysis**

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1. Introduction
   1. The Financing Program for Sustainable Energy (BR-L1442), the first program under the Conditional Credit Line for Investment Projects (CCLIP) for Productive and Sustainable Investments (BR-O0001), has the objective of promoting investments in sustainable energy projects so as to contribute to meet Brazil’s goal of diversifying its energy matrix and efficient use of energy, minimizing GHG emissions in Brazil.
   2. As described in the Proposal for Operation Development (POD), the problem that the CCLIP aims to address is the lack of adequate financing for those private investments more likely to stimulate productivity and sustainability in Brazil. By increasing access to medium and long-term financing, the CCLIP would enable firms to increase their investment,[[1]](#footnote-1) with focus on three strategic areas (infrastructure investments, clean energy investments and productive investment of SMEs) where a potential for contributions to long-term growth has been identified and a counter-cyclical intervention is considered more valuable.
   3. The CCLIP is conceived as a flexible instrument with the general goal of promoting productive and sustainable investment in Brazil by channeling long˗term financing for private projects in different sectors. The first program will consist of a single component under which the *Banco Nacional de Desenvolvimento Econômico e Social* (BNDES) –the largest state-owned development bank and the main source of long-term financing in the country– will use IDB funding along with its own resources to provide financial support to private developers of sustainable energy projects through direct/indirect sub loans. More specifically, projects to be financed include: (i) electricity generation from Alternative Renewable Energy (ARE) sources[[2]](#footnote-2); and (ii) medium to large Energy Efficiency (EE) investment projects, including cogeneration, in industry.
   4. The program shall be able to provide a financial instrument that is adequate to the needs of these types of projects. By channeling IDB resources, BNDES increases its capacity to provide the longer terms these projects require due to the high levels of costs and risks involved, the need to match their cash flow profiles and return rates that can guarantee proper implementation of these ventures.
   5. The proposed CCLIP will use US$2,400 million from IDB’s ordinary capital. The first program under the CCLIP consists of a global credit loan operation for US$750 million and co-financed with an additional US$150 million from BNDES. BNDES will use long term resources from the IDB to diversify its sources of funding in order to better respond to the financing needs of private investors in sustainable energy infrastructure in Brazil. The total amount of resources from the IDB will be channeled to end users by BNDES directly, or indirectly, through the intermediation of other financial institutions (second tier transactions). Resources will ultimately be used to provide direct loans to finance new ARE or EE projects that are deemed eligible based on the conditions established in the Operating Regulations (OR) of the program. The program is designed to allow for the use of funds based on actual demand for credit; no quotas are established for ARE or EE projects, or for particular technologies in each group.
   6. The beneficiary and the executing agency of the CCLIP and the first program will be BNDES, with the Federal Republic of Brazil serving as guarantor. BNDES will ensure the necessary administrative and control mechanisms to provide and maintain a transparent and effective administration of the program are in place. Previous experiences of BNDES working with the IDB, along with their leading position in the sector of clean energy over the past decade, makes them a suitable partner with strong will to continue developing the sector.
   7. The intended beneficiaries of the program will be private developers of ARE and EE projects. End users of electricity infrastructure added to the system, be them firms or households, will also indirectly benefit from an enhanced provision of the service. In addition, Brazilian population will indirectly benefit from positive externalities associated with the environmental and economic impacts of the program.
   8. In order to present evidence of the economic viability of the program, the proposal is supported by a cost benefit analysis which quantifies ex ante a monetary value for the net economic benefits of the program. The following sections present the methodology, assumptions, results and conclusions of this analysis. Benefits are measured on an assumed portfolio of projects incorporated to the system via support from BNDES[[3]](#footnote-3). Environmental externalities are also accounted for based on a valuation of GHG emission reductions.
   9. Using the standard IDB discount rate of 12%, the program shows a positive net present value of US$496.26 million and remains robust even when stressing some important variables in the sensitivity tests.
2. Methodology and Assumptions
3. A. Proposed methodology
   1. The program consists of a global credit loan operation for US$750 million and co˗financed with an additional US$150 million from BNDES. The total amount of US$900 million will be used entirely for the provision of medium and long term loans to private firms developing ARE and EE projects.
   2. The economic evaluation of the program compares estimated costs and benefits for the scenarios “with” and “without” the program, assuming a portfolio of the projects financed by the program. To the extent possible, a valuation of the externalities associated with the development of such projects is included. This model serves as a practical tool to quantify ex ante the economic value of the aggregated incremental benefit of the program. The details and assumptions of the methodology for this exercise are presented in the following sections.
   3. From an economic perspective, project analysis requires assessing changes in costs and benefits that would result from carrying out a particular investment. In the case of energy projects, such costs and benefits have to further consider the existence of externalities, the most significant being an overall reduction of CO2 emissions. The negative effects of greenhouse gas emissions on the environment from the use of fossil fuels is also one of the reasons why the government and the Bank promote the diversification of the energy matrix towards the use of ARE and the implementation of EE measures in firms and households. Additionally, in the case of Brazil, the current profile of the electricity generation matrix (over 60% hydro) implies vulnerability and potential instability of the electricity supply, which in turn could affect the economy, as dependence on fossil fuel imports to maintain energy supply in dry years can impose high costs on the economy, particularly in situations of increased prices of oil and gas in international markets.
   4. The economic evaluation is based on the comparison of two scenarios:
      1. In the scenario “with” the program, the funding of BNDES allows the investment of a portfolio of clean energy projects (wind, solar and energy efficiency). The cost for energy supply incurred in this scenario is expressed as: (i) investments costs; and (ii) operation and maintenance costs (O&M) disaggregated for each type of technology. Investment costs occur during the investment phase, while maintenance costs occur during the life of the projects. These costs reflect the economic cost of supplying clean energy. Energy efficiency projects are exemplified as cogeneration projects, and allow the reduction of energy consumption, and have also investment and O&M costs. In this scenario, emissions are reduced, both from clean generation, and from energy efficiency. Total costs are costs for all investments are considered, incorporating all sources of financing.
      2. In the alternative scenario (“without program”), it is assumed that the clean energy portfolio of the program is not implemented – without financing from the BNDES, no wind or solar developer has the capacity to finance 100% of these investments by themselves and other sources of financing are not currently available. As a result, the equivalent amount of energy that would have been produced by these projects must be provided to the system by a mix of traditional sources (small hydro, thermal), and the cost of providing this energy is assumed to be the average marginal cost of the system.[[4]](#footnote-4),[[5]](#footnote-5) It is assumed that in this scenario, energy has the average emissions rate of the current electricity matrix. This is a conservative assumption[[6]](#footnote-6), given that in the absence of ARE projects, and with the difficulty of large hydro developments, the energy might actually be provided only by additional fossil fuels that may be implemented in the short-term, with higher emissions instead of at the rate of emissions of the current energy matrix[[7]](#footnote-7). Furthermore, in the without project scenario there are no energy savings from energy efficiency projects.
   5. Benefits and costs for each scenario are calculated following the principles below:
      1. Economic benefits for the Program derive from the difference between the expected energy supply costs of the scenario with program, and the expected energy supply costs of the scenario without program.
      2. The cost of energy supply from ARE projects, in the scenario with program are calculated considering the investment and O&M costs, determined based on the total additional capacity (in MW) that is expected to be installed and become operative as a result of the program, and the energy generated and injected to the system by these projects (GWh) during their life time, assuming an average capacity factor for each type of technology[[8]](#footnote-8).
      3. The energy supply costs in the scenario without the program are determined based on the energy that would need to be provided (GWh) to the system, at the average marginal cost of the system, in the absence of the ARE projects[[9]](#footnote-9). Projections of the comparison of these two scenarios are made for a period of 20 years. Additionally, the externalities associated with the reduction of GHG emissions are also included as an economic benefit of the program[[10]](#footnote-10). As the marginal cost of the system is subject to different stochastic variables (rain patters, fuel prices, demand growth, etc.), different assumptions are explored in the sensitivity analysis (see Annex I for detail).
      4. EE investments will be evaluated over the base of the amount of energy saved in the projects financed by the program. Benefits are represented by the foregone costs that are implied by saving such amounts of energy instead of consuming them from the electricity grid plus the abated costs associated to the reduction of GHG emissions also resulting from savings of electricity that would have been provided by the grid. The value of these foregone-costs in the scenario without program shall be zero, as no savings in energy are expected in the absence of an EE technology in place. Projections will be made for a period of 20 years[[11]](#footnote-11).
      5. Total new ARE capacity and energy saved by EE projects is determined based on a tentative pipeline of projects provided by BNDES, including the programming in which those projects are expected to be approved for financing and start operations.
   6. The program will also have the benefit of reducing exposure to climate and/or fuel price shocks. Nonetheless, quantifying potential benefits in the form of lower volatility of energy prices and increased energy security and resilience of the electricity grid to droughts would need to consider a general equilibrium model of the country’s energy policy and a model of the electricity system as a whole, over a much more extensive period of time. Considering that the program affects only a part of the energy policy, mainly promotion of ARE, the expected benefit of reduced economic vulnerabilities of the current energy matrix is not accounted for in this analysis. Therefore, results of this economic evaluation represent a lower bound of the expected economic benefits of the program.
   7. A Net Present Value (NPV) is calculated by projecting the net economic flows over the estimated useful life of each type of projects (see ¶2.4), and discounting them at a rate of 12%.[[12]](#footnote-12) The NPV of the program is obtained as a key indicator to determine its economic viability.
   8. A sensitivity analysis is then carried out on the main calculation parameters used in the core analysis, estimating the impact of these variations on the NPV under each different sensitivity scenario.
4. B. Identification and quantification of economic costs and benefits
   1. Resources from the proposed program will be allocated entirely in the financing of individual projects. Sub loans are expected to be distributed by type of projects with approximately 90% of resources going to ARE projects and 10% to EE projects. Due to the different nature of these two groups, including the different ways in which benefits are estimated, some considerations on assumptions, identification and quantification of benefits for each group will be described separately.
   2. It is assumed that the sum of funds (US$840 million) to be used in ARE investments will finance 24 projects a total of 600MW of wind capacity and 120MW of solar capacity. The remaining 10% of funds (US$60 million) will finance four mid-sized EE investments.[[13]](#footnote-13) Such new additions to the system will be developed gradually, based on an assumed programming for project readiness and closing of deals by BNDES.
   3. Based on the program’s conditions as per the OR, the main characteristics of the eligible projects and information on loan portfolio from BNDES, standard parameters have been established for the typical sub projects expected to be financed under the program. This has been produced for each technology and is presented in Table 2.2.

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| --- |
| Table 2.2. Parameters for a typical project by technology |

|  | Wind | Solar | Cogeneration |
| --- | --- | --- | --- |
| Average capacity (MW)[a] | 30 | 30 | 30 |
| Production factor[b] | 0.38 | 0.20 | -- |
| Investment costs (MUSD/MW)[b] | 1.8 | 1.5 | 1.0 |
| O&M costs (USD/kW)[b] | 20 | 6.2 | 0.01 (USD/kWh) |
| Efficiency factor versus conventional plant[c] | -- | -- | 0.80 versus 0.45 |
| Average electricity rate for industry (USD/MWh)[d] | 101.77 | | |
| Average marginal generation cost (USD/MWh)[e] | 104.4 | | |
| Exchange rate (USD/R$) | 0.31 | | |

[a] Data for project size is based on BNDES portfolio since 2012 and tentative pipeline

[b] [Financiamento de energias renováveis alternativas no Brasil](http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=40661714) (2016) and [Review of CHP Technologies](http://www.distributed-generation.com/Library/CHP.pdf) (Office of Industrial Technologies, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, 1999). Investment and operating costs may vary widely (depending on the plant size, location, local electric system, etc.). Using averages is only aimed for practical purposes of this analysis.

[c] Center for Climate and Energy Solutions (C2ES). The typical method of separate centralized electricity generation and on-site heat generation has a combined efficiency of about 45% whereas cogeneration systems can reach efficiency levels of 80%.

[d] *Média das tarifas da classe Industrial* as of October 2015, *Associação Brasileira de Distribuidores de Energia Elétrica* (ABRADEE).

[e] The system’s marginal generation cost is calculated from the Average Spot Price (PLD) from September 2011 to August 2016, using constant 2016 prices. *Preço Médio* from the *Câmara de Comercialização de Energia Elétrica* (CCEE). See Annex I.

* 1. For each of these categories, the time required for fully implementing the construction of a project this size is estimated to be one year from the date of approval of the financing. Projects are expected to start operations and produce benefits (associated to the production and/or savings of energy) the year after the end of the installation of the system is completed.[[14]](#footnote-14) Likewise, operation and maintenance costs are considered to start from the beginning of operation of the projects. From then on, lifetime of projects is assumed to be standard and equal to 20 years.
  2. Costs of the program are composed by the initial investment costs plus the operating and maintenance (O&M) costs of the sub projects. Investment costs are accounted for entirely at the time of start of implementation of each project; the assumption is that these will cover the initial costs of starting up and deployment of the ARE plants/EE technologies. O&M costs will be included yearly starting from the year in which each project begins operations (see ¶2.12).
  3. The abovementioned investment costs are assumed to be fully covered by financing from the program (including BNDES counterpart) plus the private funding complementing this financing (equity and/or additional financing from sources other than BNDES).
  4. Economic benefits, as aforementioned, include three main elements: (i) reduced energy supply costs by new ARE projects; (ii) foregone energy costs (energy savings) by EE; and (iii) abated costs derived from the difference between future GHG emissions of a "no change" energy system and the future emissions of an energy system characterized by an expansion of ARE and EE systems financed by the program[[15]](#footnote-15) (see ¶2.4).

**Economic benefits (USD) = Foregone energy supply costs from ARE + Savings from EE + Abated emissions**

* 1. The first measure of benefits is obtained considering the difference between the energy supply costs for providing ARE projects (investment and O&M costs), versus the cost of providing this same amount of energy at the electricity systems’ marginal cost). The analysis is performed for each technology over a period of 20 years, minimum expected lifetime of the projects financed.

Foregone energy supply costs from ARE = Cost of elect prod from ARE – Cost of elect prod at average marginal cost

Cost of electricity supply from ARE = Investment costs ARE + O&M costs ARE

Cost of electricity supply at average marginal cost =Electricity prod (MWh) x average marginal cost (USD/MWh)

Electricity prod (MWh) = Installed capacity (MW) x 24 x 365 x production factor

* 1. Benefits from energy efficiency (cogeneration) are calculated by estimating the average energy savings of beneficiaries and assessing the costs that will be avoided by covering these energy needs with the new efficient systems, instead of using the grid electricity. Energy savings are determined by the higher efficiency in energy power generation provided by the cogeneration systems installed. Industry utility rates are used to obtain these savings for a period of 20 years.

Energy saved (Mwh) = Installed capacity x 24 x 365 x (efficiency factor of cogeneration - efficiency factor of conventional plant)

Savings from EE **=** Energy saved (MWh) x Electricity rate (USD/MWh)

* 1. A third portion of benefits (abated costs) uses a monetary value of GHG emissions reduced by the projects financed, determined by the unit price of a metric ton of C02 in the international market. This value is based on information about carbon pricing around the world (emissions trading systems, ETS, and carbon taxes), which has been substantially increasing since 2012. The existing carbon prices vary significantly—from less than US$1 per tCO2e to US$130 per tCO2e, with the majority of emissions (85%) priced at less than US$10 per tCO2e. The analysis will use a unit price of US$5 per tCO2e, conservatively and along the lines of existing or potential instruments in other emerging economies (including Korea, China, Mexico and Chile)[[16]](#footnote-16). The use of this reference price is an interpretation of the evaluation exercise of the various economic, local and global, current and future costs of negative externalities associated to less clean technologies displaced. International carbon pricing provides us with a publicly available resource for monetization of this aspect of the analysis.
  2. The conversion factor which is specific to Brazil’s electricity grid – used to determine displaced (reduced) emissions from the plants commissioned – is 115kgCO2/MWh (*Empresa de Pesquisas Energeticas, EPE*, 2014). This value – generally calculated by the corresponding energy-related agencies of the countries based on CDM practices – corresponds to a default CO2 emission factor for the displacement of electricity generated by power plants in an electricity system.[[17]](#footnote-17). Considering that the emissions factor represents an average emissions factor for the existing electricity system in Brazil (which is 60% hydro and already has a high share of renewable energy), this benefit’s estimation is very conservative. A more realistic estimation would be obtained by assuming that in the absence of the program the energy would be supplied by thermal power plants with much higher potential for reduction in emissions (they have an emission factor of 300-400 kgCO2/MWh).

TM CO2 displaced = Conversion factor (kgCO2/kWh) x [Electricity prod from ARE (kWh) + Energy saved from EE (kWh)] / 1000

**Abated costs** = TM CO2 displaced x Price per TM CO2 (USD)

1. Other Considerations
   1. It is assumed that despite the current recession context, the country will maintain a fairly stable framework and conditions conducive to sustaining investment and promoting financial instruments to support it. Due to the current economic environment, the program is not expected to generate a crowding out effect – either in terms of value added or in terms of employment – since it is assumed that the current demand exceeds supply and the intervention of BNDES rather responds to a countercyclical role (at least in the short to medium term). Likewise, it is considered that the Program will not have a considerable effect on the marginal generation cost, spot market prices, and on the grid emission’s factor.
   2. The financing of ARE developments is typically based on the existence of long term contracts with the Brazilian Electricity Regulatory Agency ([*Agência Nacional de Energia Elétrica*](http://www.aneel.gov.br/), ANEEL), awarded via a formal bidding process based on price, which allows for a stable framework within which private developers can analyze the financial viability of specific projects. Hence, voluntary participation of the private sector under market conditions and at a bidding price is indicative that the expected value of these projects will result in net financial profits (i.e. financial costs are lower than financial benefits from a private perspective). In this sense, the financial viability of the Program is guaranteed[[18]](#footnote-18).
   3. The implementation of activities under the proposed program is part of a more comprehensive solution to broader institutional and structural problems that hinder the development of productive sectors in Brazil, particularly the energy sector. The limited scope of the program does not allow for addressing all these problems. In that sense, it should be considered that a quantification of each and every element that may affect the development of the sector is not incorporated in this analysis.
   4. The analysis is very conservative, as it leaves out a number of positive externalities which are not possible to quantify accurately. These additional benefits include: (i) generating direct and indirect jobs during construction; (ii) contribution to the competitiveness of the country’s economy; (iii) reduction of the risk of volatility of prices and balance of payments[[19]](#footnote-19); (iv) reducing the vulnerability of the system to dry seasons, and the resulting energy shortages (which are valued at > R$3000/MWh by EPE’s planning exercises). Hence, the benefits should be considered as a lower bound estimate.
2. Results of the Analysis
   1. Based on the considerations described in the sections above, projections were built for a cash flow structure of aggregated annual benefits and costs for the program. The discounted value of these cash flows, this is to say the net present value of the program is US$496.26 million. A table with the detailed calculations for the period of analysis is shown in annex II.

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Table 5.1.- Summary of results | | | | |
|  |  |  |  | **Value** |
| Net Present Value (USD) |  |  |  | **496.26** |
| Internal Rate of Return |  |  |  | **18.3%** |

1. Sensitivity Analysis
   1. A sensitivity analysis is included in this section, where deviations on key variables used for the base analysis are simulated in order to determine their impact with regards to the potential benefits and/or costs. In other words, assumptions are modified in order to verify the tolerance of the program to variations on the conditions that may have an impact on the results established above.
   2. While all variables used in this analysis (and assumptions related to them) may be affected by factors out of the control of the program execution, the selection of parameters to be included in this section was determined on account of their criticalness in the quantification of sub project results. Following is a list of the parameters analyzed and a brief description of the tested scenario. In all cases, extreme values for the parameters have been used in order to make the analysis more robust:
      1. O&M costs were increased for all technologies under analysis. A reference value for this increase is difficult to determine based on existing information, as ARE costs vary widely among different countries. However, a 25% increase is considered a highly unlikely potential scenario given that since 2009 the cost of all RE has decreased between 29% and 78% worldwide, depending on the technology[[20]](#footnote-20), and local factors affecting prices (inflation, exchange rate) should be partially offset by declining evolution in international prices. Moreover, both in the case of ARE as in the case of EE, O&M costs represent a small portion of total costs, with the investment costs representing the most important fraction.
      2. The sensitivity of the program to the marginal cost of generation was verified by using two different scenarios: (i) the 10 year historical average of the system marginal generation cost (71.3 US$/MWh) – Scenario 1, and (ii) the long term [marginal expansion cost](http://www.epe.gov.br/geracao/Documents/NT-EPE-DEE-RE-010-2016-r0.pdf) for a 50/50 mix of small hydro and gas fueled power generation (65.9 US$/MWh) – Scenario 2 (See Annex I, paragraphs 8.1 to 8.3, for more detail).
      3. The industrial electricity rate is replaced by the minimum value existing for all distributors listed in the [*Média das tarifas da classe Industrial*](http://www.abradee.com.br/setor-de-distribuicao/tarifas-de-energia/tarifas-de-energia) as of October 2015, *Associação Brasileira de Distribuidores de Energia Elétrica* (ABRADEE). This reduces the energy savings benefit, as the foregone costs of consuming this energy will be lower. Nonetheless, as in recent years tariffs have been increasing (15% only in 2016), this risk is considered low.
      4. The time required for construction is made longer. Assuming there are a series of factors than can affect construction (other than availability of resources) and produce delays, we consider a scenario in which 50% of the projects take twice as much time to start operations. It is worth noting that, in general, a big portion of delays occurring with these projects is associated to acquiring the licenses necessary for construction to begin, which in the case of the program is a requirement for eligibility of the financing, hence this risk is mitigated.
      5. Projects that may not evolve successfully and are not implemented (for instance, due to default) are considered for the last scenario. This implies an assumption that after the investment is made and the financing is approved, some of these projects do not become operative and enter into default. This scenario assumes that 20% of projects default, which is considered extreme as BNDES is characterized by its high quality credit portfolio, with default rates of 0.06% in 2015, well below the average for the Brazilian national financial system (3.4%). In 2014, these values were 0.01% and 2.8%, respectively.
      6. Given that the demand for EE projects is less guaranteed than that of ARE, the assumed allocation of funds (90% ARE, 10% EE) is varied to test the impact of having less EE projects in the mix, making it 100% ARE. Based on a revision of BNDES pipeline of projects in the timeframe of the program, it is not likely that EE projects will have a larger share of financing from the US$900 million. Nonetheless, it is worth noting that in the unlikely scenario that the share of EE projects is higher, the NPV and IRR would increase as compared to the base scenario (the contribution of EE projects to the NPV is higher than that of ARE projects).
   3. Table 5.1 presents a summary of the results of the sensitivity analysis. For each parameter the table shows the test value under the changed scenario, the variation (in %) with respect to the value used in the core analysis (base scenario) and the adjusted NPV and IRR under the modified scenario.[[21]](#footnote-21)

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| Table 5.1: Summary of sensitivity analysis\* |

| Parameter | Initial value | Test value | Var (%) | Program NPV (MUSD) | Program  IRR (%) |
| --- | --- | --- | --- | --- | --- |
| a. O&M costs (all technologies) (US$) | wind: 20  solar: 6.2  cogen: 0.01 | wind: 25  solar: 7.8  cogen: 0.013 | +25% | **472.33** | **18.0** |
| b.1 Energy supply cost without program (US$/MWh) – Scenario 1 | 104.4 | 71.3 | –22% | **75.98** | **13.0** |
| b.2 Energy supply cost without program (US$/MWh) – Scenario 2 | 104.4 | 65.9 | –28% | **7.41** | **12.1** |
| c. Electric industry tariff (US$) | 101.77 | 54.9 | –46% | **409.49** | **17.3** |
| d. Time of construction (all technologies) (years) | 1 | 2 | +100% | **410.76** | **16.9** |
| e. Projects not completed (all technologies) (number) | wind: 0  solar: 0  cogen: 0 | wind: 4  solar: 1  cogen: 1 | +20% | **168.16** | **14.2** |
| f. ARE/EE mix | 90% ARE  10% EE | 100% ARE  0% EE | n/a | **424.07** | **17.2** |

* 1. The results of the sensitivity analysis show that the net economic benefit of the program is particularly elastic to the energy supply cost in the alternative scenario, that considers that there are no investments in ARE projects, and that a mix of traditional generation sources will provide the electricity to the system. That means that the economic value of the program depends largely on which technologies would be implemented in the absence of the program (to cover the same amount of energy), and their generation costs. The break-even marginal generation cost of the counterfactual scenario for the program to be viable is 65.71 US$/MWh. This value is lower than the 10 year average generation marginal cost (Scenario 1), and similar to the long-term expansion cost of a 50/50 mix of small-hydro and gas power (Scenario 2). This means that compared to a scenario that would behave like the last 10 years of the system (Scenario 1), or an scenario in which the same amount of energy is provided by a traditional mix (gas and small hydro power plants in this case, Scenario 2), the program is still viable from an economic point of view.
  2. Although it is possible to construct other alternative scenarios of generation mixes, which in turn would result in different marginal generation costs, the analysis must consider that, in the absence of ARE investments, the most likely technology to be deployed in the short-term to cover energy supply are gas power plants, particularly for their short times of implementation (6-9 months) and because they require less capital investments upfront. Gas power plants have a long-term marginal price of 235 R$/MWh – US$73 US$/MWh (defined by EPE in 2016), and have a higher CO2 emissions than ARE. Therefore, the sensitivity analysis of Scenario 2, which is conservative in its assumptions, supports the robustness of the program.
  3. Potential delays in construction, O&M costs and electric rates used for EE projects show a much lesser impact on the NPV. A slightly higher impact is shown when assuming some of the projects do not materialize. In this last scenario, investment costs are accounted for in full while no benefits are considered for the failed projects; still, the project retained a positive NPV.

1. Conclusions
   1. The cost benefit analysis shows how the discounted benefits are greater than the discounted costs over the time of analysis, thus resulting in a positive net present value (NPV) of US$496.26 million and an IRR of 18.3%. This assessment is conservative, as all the possible economic benefits of the program were not monetized.
   2. In addition, the sensitivity analysis shows that even when changing the value of the key parameters used for the calculations, the program remains viable for a wide range of values. The sensitivity analysis is relevant as it improves the reliability of the results obtained from the initial assumptions, allowing for more robustness of the conclusions. No significant risks are observed regarding the sustainability of the program in case reasonable changes occur that may affect the main variables on which the benefits are based.
   3. In general, the project team has used plausible and contrasted assumptions, with aims of a rather prudent and conservative approach for the analysis. Based on this, the project team recommends the Bank approves the financing of the proposed program.

**Annex I. Analysis of the marginal cost of generation**

1. **Historical average marginal cost of generation**
   1. This section presents an analysis of the marginal cost of generation, used as an assumption to calculate the cost of supply in the scenario without the program. The analysis is based on the historical series of the market spot price (“PLD”), which is used as a proxy of the marginal cost of generation[[22]](#footnote-22). The PLD price series includes available data for the four submarkets of the national system, from May 2003 to August 2016[[23]](#footnote-23). Data prior to 2003 is not available for the PLD, as the market suffered regulatory changes.
   2. Due to the preponderance of hydroelectric plants in the Brazilian generation park, PLD prices are calculated using complex mathematical models, which aim to find the optimal solution to balance the benefit of present water use and future benefit of hydro storage, measured in terms of the economy expected from the fuel of thermoelectric plants:
      1. From a short-term perspective, the maximum use of hydroelectric power available in each period is the most economical premise, because it minimizes fuel costs. However, this assumption results in greater risk of future deficits (because of lack of stored energy), or future higher energy costs (from thermal generation).
      2. From a long-term perspective, the maximum supply reliability is obtained by keeping the level of hydro reservoirs as high as possible, which means to use more thermal power generation in the short-term, and thus increasing operation costs.
   3. The pricing model optimizes these two perspectives, and determines the merit order for power generation for the period of study, setting the quantities of hydraulic generation and thermal generation for each submarket. This weekly calculation considers: hydrological conditions (reservoir levels, rainfall projections), energy demand, fuel prices, the cost of energy not supplied, the entrance of new projects, and the availability of generation and transmission equipment. As a result of this process the marginal costs of generation for the period of study, for each load level, and for each submarket is obtained. The marginal cost of the system is not necessarily the generation cost of the thermal units, as it also considers the economic value of water-storage, and the reliability provided by hydro power generation.

Table 1. Average PLD (R$/MWh)

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **PLD (R$/MWh)** | **12 months** | **24 months** | **36 months** | **60 months** | **120 months** |
| Average PLD (nominal prices) | 133.19 | 293.76 | 364.71 | 287.16 | 181.76 |
| Average PLD (constant 2016 prices) | 138.12 | 323.80 | 415.20 | 336.77 | 230.10 |

* 1. Table 1 shows the average of PLD prices for the last 12, 24, 36, 60 and 120 months. The analysis also considered transforming historic PLD prices to constant 2016 prices, using the Consumer Price Index from 2003-2015[[24]](#footnote-24), in order to allow for a comparison and aggregation of prices from different years.

Figure 1. PLD prices (constant R$/MWh)

* 1. Figure 1 shows an increase in PLD prices in the last 6-7 years, with peaks of R$800/MWh in 2014 (250 US$/MWh). This increase in PLD prices reflects the current state of the electricity system, including the stress caused by: (i) growth in electricity demand[[25]](#footnote-25); (ii) climate events, particularly droughts; (iii) the reduction of the share of hydro power as a percentage of the total energy supply; and (iv) the dependence on more fossil fuel generation, given demand growth. Considering the past 10 years the average PLD price is 230 R$/MWh in constant prices (71 US$/MWh). This lower price, in turn, reflects the more stable energy supply in the last years of the past decade, given a lower electricity demand with a larger share of hydropower in the energy mix.
  2. In the scenario without the Program, considering the current mix of power generation, the growth of electricity demand, and current difficulties in obtaining licenses for hydro power generation, it is be expected that PLD prices in the future will resemble those of the 2-5 years average, with similar conditions in the electricity system. Hence, the 5 year average PLD price is used as a proxy for the generation marginal cost in the base scenario (336.77 R$/MWh, or 104 $US/MWh). Conversely, the 10 year average PLD price was selected as an alternative scenario for the sensitivity analysis to reflect a lower marginal cost (230.10 R$/MWh, 71.33 US$/MWh) in a system without the mentioned stresses, assuming an optimistic view for the development of the power system, particularly without shortfall in hydro power generation (Scenario 1).
  3. Table 2 shows the % of months that the PLD prices are higher than a defined threshold of R$200/MWh, R$250/MWh and R$300/MWh. Last years shows PLD prices lower than R$/MWh 75% of the time, this is due to the reduction of demand in 2015, due to the economic crisis. Nonetheless, in the last 2 years to 5 years, PLD prices were higher than 200 R$/MWh more than 58% of the time, and higher than 300 R$/MWh, at least 42% of the time. In the last 10 years, PLD prices were higher than 200 R$/MWh 40% of the time. For the scenario without the Program (base case), considering demand growth, and the current electricity mix in the matrix, it can be expected that the probability of PLD prices being higher than 200 R$/MWh will be 60% or higher (taking the last 5 years into consideration).

Table 2. PLD prices higher than a threshold (Constant R$/MWh)

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **PLD (R$/MWh)** | **Last year** | **Last 2 years** | **Last 3 years** | **Last 5 years** | **Last 10 years** |
| >200 R$/MWh | 25.0% | 58.3% | 72.2% | 63.3% | 40.0% |
| >250 R$/MWh | 0.0% | 41.7% | 61.1% | 50.0% | 30.8% |
| >300 R$/MWh | 0.0% | 41.7% | 61.1% | 46.7% | 27.5% |
| Average ( constant R$/MWh) | 138.12 | 323.80 | 415.20 | 336.77 | 230.10 |

1. **Long-term marginal cost of generation**
   1. The long-term marginal cost of the system is calculated by EPE (Empresa de Pesquisas Energeticas), as a weighted average of the long-term prices of the contracts of energy provision in the regulated market. The calculation of the long term expansion cost considers: (i) the generation cost for each technology expected to be deployed in the future, as shown in Figure 2; and (ii) the expected distribution of each technology in the planned expansion, shown in Figure 3. The resulting weighted average for the last long term expansion cost release by EPE in 2016 for the period 2021-2025 is R$ 193/MWh (60 US$/MWh).



Figure 2. Generation costs considered for the long term expansion cost of the system (source EPE)

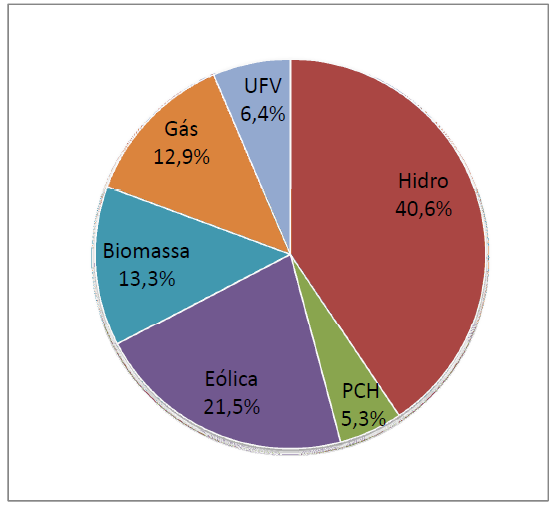
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Figure 3. Distribution of technologies in the planned expansion

* 1. For the purposes of the sensitivity analysis of the economic evaluation (Scenario 2), the counterfactual without project considers that a mix of small hydro (PCHs) and gas projects are implemented to cover the energy supply of ARE projects that are not implemented. Large hydro is ruled out because of times of implementation, and biomass is also not considered because of uncertainty of additional biomass production. A conservative 50/50 mix of PCHs and gas projects is assumed, to cover the electricity demand not supplied by ARE projects. The long term marginal cost of this generation mix is calculated as the average of the long term expansion costs of PCH and GAS (shown in Figure 2), and results in 212.62 R$/MWh (65.91 US$/MWh).
  2. The 50/50 mix used for scenario 2 is very conservative in the sense that normally when there is a shortage of energy supply, the technology that is primarily installed to cover demand is gas fueled power plants (which have a marginal price of 235 R$/MWh or 72.85 US$/MWh), as they have lower implementation times (6-9 months versus 3-4 years for a PCH) and, above all, lower capital costs (25% to 30% of the cost of a PCH in terms of capital investments for the same capacity). Hence, Scenario 2 can be considered as a robust test for the sensitivity analysis.

Annex II. Detailed calculations for program cash flows



1. “*Documento de Marco Sectorial de Respaldo para PyME, Acceso y Supervisión Financieros*” (IDB, GN˗2768). [↑](#footnote-ref-1)
2. The concept of ARE excludes large hydro. It is expected that ARE projects in the portfolio will use wind and solar technologies. Small hydro is not eligible for the program. [↑](#footnote-ref-2)
3. For practical purposes, the analysis uses aggregated data for the accounting of benefits over time, based on the construction of a portfolio of projects and the characteristics of a representative beneficiary firm for each type of project. [↑](#footnote-ref-3)
4. By definition, the marginal cost of the system represents the variation of the operating cost required to meet one additional MWh of demand, using existing resources. The analysis considers that without the program, the energy not supplied by ARE sources would need to be supplied by other energy sources (at a marginal cost for the system). It is worth emphasizing that the analysis is made from the point of view of the electricity system, which in the absence of ARE developments, would need to provide the same amount of energy with a marginal cost. [↑](#footnote-ref-4)
5. Without the program, the lack of financing would also affect the overall ARE investments in the medium term in the country, as the supply chain of ARE technology providers would be affected by the lack of investment, generating shortfalls in supplies of equipment, and less investors in ARE projects would be attracted to the market. As a result, in this scenario it is assumed that the proportion of ARE in the matrix does not grow. [↑](#footnote-ref-5)
6. A more pessimistic assumption would be that in the absence of the program, no energy is provided to the system, and as a result there is a need for restrictions in energy supply. The cost of energy not supplied in the Brazilian system is approximately R$3.000/MWh, which would make the program extremely viable from an economic perspective. This scenario is not considered, as currently the Brazilian electricity sector is structured and regulated in order to guarantee that all demand is covered. [↑](#footnote-ref-6)
7. The emissions rate of the current electricity mix is 115 kgCO2/MWh, while the cleanest thermal generators have emissions factor of around 300 tonCO2/MWh. [↑](#footnote-ref-7)
8. The capacity factor is based on historical production for each technology in Brasil. [↑](#footnote-ref-8)
9. The spot price in Brazil (named “PLD price”) is used as a proxy for the system’s marginal generation cost. .A five year average of the PLD price is used, as this is the best representation of the current situation of the system (see Annex I). [↑](#footnote-ref-9)
10. Technical note No. IDB-TN-623. [*Beneficios para la sociedad de la adopción de fuentes renovables de energía en América Latina y el Caribe*](http://publications.iadb.org/bitstream/handle/11319/6465/Beneficios%20sociales%20TN-623.pdf?sequence=1) [↑](#footnote-ref-10)
11. For the purposes of the economic evaluation, energy efficiency projects are represented by co˗generation projects, in which an additional amount of energy is produced by power generation plants, and as a result, energy consumption from the grid is reduced. The ex-post economic evaluation will be based on the actual energy efficiency projects implemented, once the program is finished. [↑](#footnote-ref-11)
12. Following IDB guidelines for economic analysis of programs financed by the IDB, it is recommended to use a discount rate of 12% for all IDB operations. [↑](#footnote-ref-12)
13. For ARE projects, the majority of projects are expected to be wind, and in less proportion solar. The average credit size for ARE projects is US$35 million and covers 60% of total investment costs. This means that roughly 24 ARE projects shall be included in the portfolio to be financed by the program, from which it is assumed that 20 will be wind and 4 will be solar. For EE projects, it was determined that the typical sub project likely to receive financing corresponds to a mid-sized cogeneration project in the industry sector (in particular, the sugar production industry). Typical loan size for these projects is US$15 million and finances 70% of total investment. [↑](#footnote-ref-13)
14. It is important to differentiate a period when a sub project is financed from that when a project begins operating. In the detailed cash flows (see Annex II) disbursements of loans and co˗financing (including investments by developers) will appear in periods preceding the accounting of benefits. Large ARE and cogeneration plants can take up to two years to finish construction. As we are considering smaller projects, timeframe for construction is reduced to one year. [↑](#footnote-ref-14)
15. Technical note No. IDB-TN-623. [*Beneficios para la sociedad de la adopción de fuentes renovables de energía en América Latina y el Caribe*](http://publications.iadb.org/bitstream/handle/11319/6465/Beneficios%20sociales%20TN-623.pdf?sequence=1)*.* [↑](#footnote-ref-15)
16. In the European Union Emissions Trading System (EU ETS), which remains the single largest international carbon pricing instrument, the average price in 2014 was €6/tCO2 (US$7/tCO2). As of August, 2015, this price stood at some US$9/tCO2. For governments, carbon pricing is an instrument to achieve emissions mitigation but also a source of revenue. (see [State and Trends of Carbon Pricing](http://www.worldbank.org/content/dam/Worldbank/document/Climate/State-and-Trend-Report-2015.pdf), World Bank and Ecofys, 2015. [↑](#footnote-ref-16)
17. United Nations Framework Convention on Climate Change, UNFCCC (2015). [Methodological Tool: Tool to Calculate the Emission Factor for an Electricity System. Version 05.0](https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v5.0.pdf). [↑](#footnote-ref-17)
18. Before implementation of the program, any existing portfolio is indicative. There is no information on specific sub projects available until it is presented by participants when applying to credits by BNDES, and in all cases this information should be treated with confidentiality. [↑](#footnote-ref-18)
19. The concept of balance of payments is related to the potential economic benefits originated from a reduction of energy imports or an increase in energy exports. [↑](#footnote-ref-19)
20. Renewable Power Generation Costs in 2014, IRENA, 2015. [↑](#footnote-ref-20)
21. Exchange rate implications are not considered a significant risk for this program. All projects financed by BNDES are required a high percentage of local content (minimum 60%) and hence the majority of project costs, both investment and operational, are not exposed to exchange rate disruptions. In any case, it could be assumed that any exchange risk involved is related to an increase in investment costs or O&M costs, already considered. [↑](#footnote-ref-21)
22. PLD is a value determined weekly for each load level based on the Marginal Cost of Operation, limited by a maximum and minimum price in effect for each calculation period and for each sub-market. [↑](#footnote-ref-22)
23. Source: [https://www.ccee.org.br/portal/faces/pages\_publico/o-que-fazemos/como\_ccee\_atua/precos/](https://www.ccee.org.br/portal/faces/pages_publico/o-que-fazemos/como_ccee_atua/precos/precos_medios?_afrLoop=1123102452682485). [↑](#footnote-ref-23)
24. Source : <http://data.worldbank.org/indicator/FP.CPI.TOTL>. [↑](#footnote-ref-24)
25. Demand growth in the period 200-2014 was 4,5% yearly. While in 2015 there was a reduction in electricity demand (due to the economic situation), for the period 2016-2024, EPE expects an annual growth of 3,8% in electricity demand. [↑](#footnote-ref-25)