GREENHOUSE GAS EMISSIONS ACCOUNTING FOR ADB ENERGY PROJECT ECONOMIC ANALYSIS

GUIDANCE NOTE

DECEMBER 2019

ASIAN DEVELOPMENT BANK

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ISBN 978-92-9261-766-0 (print), 978-92-9261-767-7 (electronic)
Publication Stock No. TIM190476-2
DOI: http://dx.doi.org/10.22617/TIM190476-2

Notes:
In this publication, "$" refers to United States dollars.

Printed on recycled paper

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ACKNOWLEDGMENTS

This guidance note was written by David Anthony Raitzer, Manisha Pradhananga, and Lotis Quiao under the direction of Rana Hasan, Director of the Economic Analysis and Operational Support Division, and Edimon Ginting, Deputy Director General, Economic Research and Regional Cooperation Department. Gee Ann Carol D. Burac proof-read the note. Jindra Nuella and Roslyn Perez provided administrative support. Tuesday Soriano copyedited the note, while Joe Mark Ganaban did the layout and typesetting.

We are grateful to the Climate Change and Disaster Risk Management Division of the Sustainable Development and Climate Change Department, especially Preety Bhandari, Christian Ellermann, and Virender K. Duggal for engaging with the study-team and providing valuable feedback and suggestions. Kee-Yung Nam, Sustainable Development and Climate Change Department Energy Sector Group also provided valuable comments that improved the quality of the document.

ABBREVIATIONS

ADB	—	Asian Development Bank
CO_2	—	carbon dioxide
EA	—	economic analysis
EE	—	energy emissions
EIRR	—	economic internal rate of return
GHG	—	greenhouse gas
GWh	—	gigawatt hour
kWh	—	kilowatt hour
MWh	—	megawatt hour
OPEX	—	operating expense
tCO_2	—	tons of carbon dioxide
TJ	—	terajoule

ABSTRACT

This guidance note reviews and compares how current approaches for project economic analysis and for calculating greenhouse gas emissions effects of energy projects define "without project" or "baseline" scenarios. Economic analysis generally treats the comparison "without project" scenario as the absence of any new projects or investment, whereas greenhouse gas calculations treat the comparison baseline scenario as expansion of the current power generation mix. This leads to differing estimates of mitigation and project economic benefits between the two comparison scenarios, which this note illustrates. Recommendations are offered for future practice to keep the basis of greenhouse gas emissions effect valuation and mitigation reporting clearer.

INTRODUCTION

1

The Asian Development Bank (ADB) introduced shadow pricing of greenhouse gas emissions in its 2017 Guidelines for the Economic Analysis of Projects (which define accepted practices for "economic analysis" [EA]).[1] These guidelines require that projects in the energy and transport sectors and those with a primary objective of greenhouse gas emissions mitigation should quantify and value those emissions as part of calculating the project's economic internal rate of return (EIRR). They also stipulate the use of a global marginal damage cost of $36.3 per ton of carbon dioxide (tCO_2) equivalent in 2016 prices, which is to be increased at 2% per annum in real terms, as well as adjusted for inflation. The source of the damage estimates is an average of a summary of estimates presented in the Intergovernmental Panel on Climate Change's Fifth Assessment Report for 1% and 3% pure rates of time preference.[2] Only projects that hurdle ADB EIRR requirements (9% for most projects, 6% for poverty or environmentally oriented projects), inclusive of carbon valuation, are to be approved. Although the guidelines are clear on the carbon value to be applied in economic analysis, they specify little about how emissions are to be accounted.

ADB has also developed Guidelines for Estimating Greenhouse Gas Emissions of Energy Projects (which define the "energy emissions" [EE] approach) to facilitate consistent reporting on climate change achievements.[3] The EE approach was developed without reference to economic analysis and for different audiences.[4] As a result, there is a substantial difference in the conceptual basis applied for the EE and EA approaches. The difference must be recognized and addressed for carbon valuation to be conducted in a manner that is internally consistent with current economic analysis procedures. As most ADB energy investment is for electricity supply/access, this document is framed toward power supply/access investment.

1 ADB. 2017. *Guidelines for the Economic Analysis of Projects*. Manila. https://www.adb.org/documents/guidelines-economic-analysis-projects.

2 Arent, D.J., R.S.J. Tol, E. Faust, J.P. Hella, S. Kumar, K.M. Strzepek, F.L. Tóth, and D. Yan. 2014. Key economic sectors and services. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 659-708.

3 ADB. 2017. *Guidelines for Estimating Greenhouse Gas Emissions of Asian Development Bank Energy Projects: Additional Guidance for Clean Energy Projects*. https://www.adb.org/documents/guidelines-estimating-ghg-energy-projects.

4 The ADB Safeguard Policy Statement requires that greenhouse gas (GHG) emissions from projects emitting 100,000 tCO_2 or more to be monitored. GHG reduction is monitored and reported as one of the Level 2 results framework indicators.

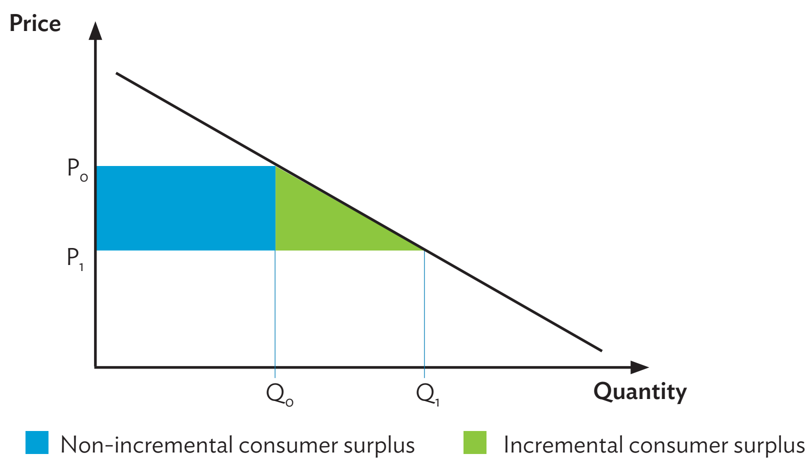
1.1 Economic Analysis Approach to "Without Project" Scenario

Calculations of project-level EIRRs are premised on the difference between a "with project scenario" and a "without project scenario" over a 20- to 40-year time frame. The with project scenario reflects the cost and benefit flows with the project facility in place, while the without project scenario usually reflects absence of any new facility providing the same service.[5] Different ways of providing the service are compared before EIRR calculations, during least-cost analysis, in which the lowest present-cost option to provide the service is selected. In most cases, the without project scenario thus reflects no expansion of the service from the present level. For example, in a power generation project, on-grid generation capacity for the beneficiary area is often held constant in the without project scenario, whereas capacity expands in the with project scenario.

The costs and benefits derived from establishing or expanding a project facility are usually conceptualized as consumer surplus for those sectors for which carbon valuation is required (energy and transport). Consumer surplus is the difference between willingness-to-pay for the service, as reflected in a downward sloping demand curve relating price to quantity, and the actual price paid. Projects in the energy sector are usually considered as providing lower-cost service (such as electricity cost per kilowatt hour [kWh]) to end users than would exist without the project.

Effects on consumer surplus from that cost reduction can be considered as consisting of two elements: non-incremental and incremental benefits. Non-incremental benefits are derived from a substitution effect, in which the lower-cost project service replaces consumption of a higher-cost non-project service. For example, expanded lower-cost grid electricity can replace the use of more costly diesel generators, candles, or kerosene. Incremental benefits are derived from increased consumption of the project service when the price is lower. These are the benefits, for example, from expanded energy use after electrification or other improved energy service.

Figure 1: Consumer Surplus Effects of ADB Projects



P_0 = price without project, P_1 = price with project , Q_0 = quantity without project , Q_1 = quantity with project
Source: Authors.

5 The without project scenario reflects the consequences of the absence of public sector investment to provide the same service, under the assumption that market failures prevent the investment from being financially attractive to the private sector.

When the demand curve is approximated linearly, simple shapes and algebra can be used to reflect these two effects on consumer surplus (Figure 1). Non-incremental benefits can be considered as a rectangle with the height of the difference in energy unit costs without (P_0) and with (P_1) the project, multiplied by the quantity of the service without the project (Q_0). Incremental benefits consist of a triangle defined as half of the difference in average energy unit costs without (P_0) and with (P_1) the project, multiplied by the difference in number of units consumed with (Q_1) and without (Q_0) the project.

1.2 Energy Emissions Approach to "Without Project" Scenario

To date, guidelines for estimating ADB greenhouse gas emissions cover the (clean) energy and transport sectors. For the transport sector, greenhouse gas emissions guidelines follow a clear division between incremental (generated traffic) and non-incremental (existing and diverted traffic) effects.[6] Transport infrastructure development is assumed not to occur in the without project scenario. In addition, economic analysis tools, such as the Highway Development Model 4, also perform emissions calculations, so that approaches are harmonized with those of EA.[7] However, EE calculations takes a very different approach to both EA and the transport sector guidelines.

The EE approach is derived from the methodologies used more broadly in climate change mitigation modeling, policies, and projects. The perspective is regarding potential future emissions trajectories in the context of expected peak levels of radiative forcing and global warming, which occur in 2100 or later in many climate scenarios and models without mitigation action. Mitigation is considered as reduction of future emissions relative to these "baseline" or "reference" scenarios in which infrastructure development continues according to economic growth. This approach has underpinned both international climate negotiations and national targets, as well as the methodologies for mitigation calculations under the Clean Development Mechanism. It has been further developed in methodologies agreed among international financial institutions for climate reporting, but the approach has not been intended for economic analysis.[8]

This means that in the energy sector, the EE approach treats all project effects as non-incremental. In other words, it considers that the level of service consumed with and without the project would be the same. For example, the amount of electricity consumed over the project duration is the same in the with and without project scenarios. ADB project outputs are thereby only substituting for other types of projects that provide the same quantity of service.

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6 ADB. 2016. *Guidelines for Estimating Greenhouse Gas Emissions of Asian Development Bank Projects: Additional Guidance for Transport Projects*. https://www.adb.org/sites/default/files/institutional-document/219791/guidelines-estimating-ghg-emissions-transport.pdf.

7 Bennett, C.R. and I.D. Greenwood. 2003. Volume 7: Modeling Road User and Environmental Effects in HDM-4. Version 3.0. International Study of Highway Development and Management Tools (ISOHDM), World Road Association (PIARC), Cedex, France.

8 World Bank. 2015. IFI Approach to GHG Accounting for Renewable Energy Projects. http://documents.worldbank.org/curated/en/758831468197412195/pdf/101532-WP-P143154-PUBLICBox394816B-Joint-IFI-RE-GHG-Accounting-Approach-clean-final-11-30.pdf.

More specifically, the EE approach assumes that the baseline without project scenario either consists of an existing facility to be replaced or reflects some sort of expansion of business-as-usual approaches to provide the service at the same quantity as with the project. With levels of service held constant, changes in emissions only result from the differences in emissions intensity between the baseline and the with project scenario for providing the service.

In concrete terms, the EE approach consists of first quantifying baseline emissions on the basis of emissions factors that relate to either unit fuel consumption or unit energy output to carbon dioxide (CO_2) equivalent emissions. The baseline emissions can be considered to come from two principal elements:

(1) the facility to be replaced (if a specific facility, such as an existing power plant will be replaced by the project before the end of its economic life); and

(2) additional facilities that would need to be constructed to provide the same level of service as the project.

For element no. 2, the assumed practices and corresponding emissions factors are the current and projected power grid of the country, or for "the most prevalent technology in the country or region where the project will be implemented."[9] When based on the power grid, a "grid emissions factor" is used to reflect the average emissions per unit of electricity generated nationally. This is based on the emissions factors of the operating and planned powerplants in the grid, often averaged at assumed 50–50 weighting between operating and planned plants.[10]

This has substantial differences from the EA without project scenario. As discussed previously, in the EE approach all effects are non-incremental and occur at the level of service (energy) suppliers by changing supply technologies. Conversely, in the EA approach, both incremental and non-incremental effects are possible, and most non-incremental effects are for consumers, via user substitution effects, such as grid electricity replacing energy from generators, candles, and gas lighting.

1.3 Economic Principles and "Without Project" Scenario

According to economic principles, the quantity of a service consumed usually has a negative price elasticity. This means that, for the quantity consumed to remain unchanged, everything else held constant, the price should also remain unchanged. Following this principle, the fact that the EE approach holds the quantity of the project service consumed constant relative to the without project scenario means that the price of the service for consumers is unaffected. As a result, any changes in the cost of service provision are implicitly assumed to accrue to the utility in the EE approach, whereas consumers are the main beneficiaries under the EA approach.

9 ADB. 2017. *Guidelines for Estimating Greenhouse Gas Emissions of Asian Development Bank Energy Projects: Additional Guidance for Clean Energy Projects*. https://www.adb.org/documents/guidelines-estimating-ghgenergy-projects.

10 ADB database. The IFI (Interim) Dataset of Harmonized Grid Factors—July 2016.

If utilities are assumed to act as rational economic agents, the EE approach implies that, absent of carbon valuation, the economic benefits of many ADB projects are negative. Under the EE approach, benefits all accrue to the power producers. As rational economic agents, the power producers should be seeking to minimize supply costs, so that the without project scenario should be the lowest-cost option. If costs are minimized by default practices, the effects of changes to supply practices can only be to increase costs relative to the without project scenario. If the with project scenario has lower costs than the practices that the utility would otherwise follow, the utility is not behaving rationally or consistently with basic economic principles.

The implication is that, for ADB to offer non-carbon economic benefits via public energy services, those services cannot be assumed only as non-incremental substitutes at the utility level. There should be effects on prices and quantities at the level of consumers. In turn, this will mean that there will be both incremental and non-incremental effects, which only the EA approach captures.

At the same time, recognizing the presence of both incremental and non-incremental effects can have profound implications for accounting of effects on greenhouse gas emissions. First, all incremental benefits represent additional service consumption that does not occur in the without project scenario. Thus, there can be no mitigation on incremental consumption, and there can well be an increase in emissions, even if the project is relatively "clean." This means that, absent other considerations, for a clean energy project, mitigation will fall by at least the proportion of energy output that is considered incremental.

In terms of non-incremental effects, the EA approach implies much more consideration of substitution on the part of consumers. In cases where the carbon intensity of the consumer energy replaced is higher than that of the grid, this substitution may increase the mitigation quantified on the non-incremental share of supply. For example, diesel generators used by households have a higher carbon intensity than most sources of grid electricity, so that the emissions reduction per kWh from replacing diesel generators is higher than from replacing most grid sources.

EA rarely reflects premature replacement of a functional facility, such as a power plant. Were such cases considered, they should have little difference between EE and EA approaches. However, in the context of developing Asian countries, where services often have difficulties coping with demand, those cases are likely to be rare.

To summarize, in comparison with current EE approaches, the use of an EA without project scenario will mean

(1) a lower emissions reduction (or higher emissions increase) effect for projects with a substantial share of energy supply that is incremental;

(2) in many cases, a higher emission reduction effect for projects with a substantial share of energy supply that is non-incremental; and

(3) little effect on emissions for project elements that involve premature facility replacement.

2 ILLUSTRATION OF DIFFERENCES IN APPROACHES

This section provides simplified examples to illustrate the differences in the EA and EE approaches. In particular, the examples illuminate the difference in (i) net CO_2 emissions, and (ii) EIRRs. It should be stressed that the examples are intended for illustrative purposes only. The EE approach is not designed for economic analysis and is not expected to be used for EIRR calculations. The examples below illustrate the following cases:

(1) non-incremental energy generation on the supply side;

(2) non-incremental energy generation on the demand-side;

(3) incremental energy generation; and

(4) a mix of non-incremental and incremental energy generation.

All examples are for electricity, which is the energy subsector that dominates ADB's investments.

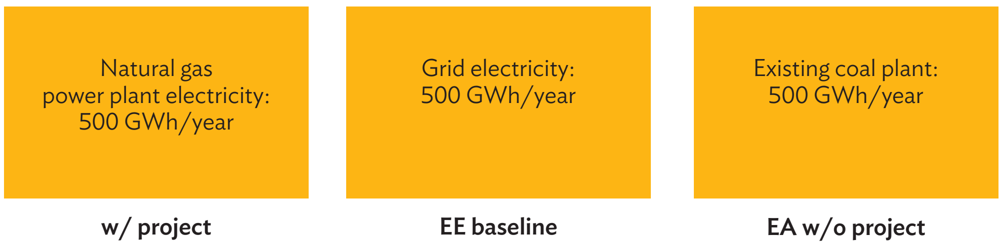
2.1 Example 1: Non-Incremental (Supply Side) Power Generation

This example aims to show emissions calculations and EIRRs under the EE and EA approaches in a case where the power generation investment substitutes for or replaces an existing facility. In such cases, emissions and EIRR calculations are most harmonized between the approaches.

It can be noted that for cases in which a power plant is being replaced before the end of its economic life, the calculations for emissions and the EIRR will be identical under the two approaches. In both cases, the without project scenario is represented by the existing plant and the with project scenario reflects the project. However, in practice, few ADB projects fall under this category. In the context of developing Asia's rapidly expanding demand for electricity, few countries can afford to take capacity prematurely offline. The more common situation is replacing a facility at or after the end of its economic life, as illustrated in this example. In this situation, the EE and EA approaches differ, as the EA without project scenario reflects continued operation of the plant, whereas the EE approach reflects expansion of the current generation mix.

In this example, a natural gas power plant will replace 500 gigawatt-hours (GWh) annually of electricity currently being supplied from a grid-connected coal power plant (Figure 2). The coal plant is being replaced at the end of its economic life. The capital expenditure required for the project is $300 million, spent equally over 5 years. The project life of the natural gas power plant is 25 years after the construction period. Operating expense (OPEX) is $6 million annually. Transmission and distribution losses are assumed to be 10%. The cost of coal is $110/ton, natural gas is $3/million British thermal units, and diesel is $0.77/liter. The social cost of carbon is $36.30/t$CO_2$ in 2016, increasing at 2% annually in real terms.[11]

Figure 2: Comparison of Electricity Outputs in Non-Incremental (Supply Side) Power Generation Example



EA = economic analysis (approach), EE = energy emissions (approach), GWh = gigawatt-hour, w/ = with, w/o = without.
Source: Authors.

Assumptions:

Grid emissions factor = 0.714 tCO_2/megawatt hour (MWh)
Coal power plant emissions factor = 0.935 tCO_2/MWh[12]
Natural gas power plant emissions factor = 0.337 tCO_2/MWh[13]
Diesel emissions factor = 0.889 tCO_2/MWh[14]
The power mix of the grid is 40% coal, 35% natural gas, and 25% diesel.

Project emissions: based on natural gas power plant emissions factor
Amount of electricity generated = 500 GWh/year
Project emissions = 500,000 MWh/year * 0.337 tCO_2/MWh = 168,500 tCO_2/year

EE baseline: based on grid emissions factor
Amount of electricity generated = 500 GWh/year
Baseline emissions = 500,000 MWh/year * 0.714 tCO_2/MWh = 357,000 tCO_2/year

EA w/o project scenario: based on emissions factor of the coal power plant
Amount of electricity generated = 500 GWh/year
Without project emissions = 500,000 MWh/year * 0.935 tCO_2/MWh = 467,500 tCO_2/year

11 For simplification, the examples will assume that these costs represent economic costs and present all analysis in 2016 real prices.
12 Assuming subcritical coal efficiency factor of 37% and sub-bituminous coal with an emission factor of 96.1 tCO_2/terajoule (TJ).
13 Assuming a combined cycle power plant with efficiency factor of 60% and natural gas emissions factor of 56.1 tCO_2/TJ.
14 Assuming open cycle oil with efficiency factor of 30% and diesel emissions factor of 74.1 tCO_2/TJ.

Effect on greenhouse gas emissions:

Project emissions are calculated on the basis of the power plant emissions factor and the quantity of power generated by the plant. The EE baseline for comparison is based on the grid emissions factor and the quantity of power generation, as the existing coal plant is beyond its economic life. However, the EA approach uses the coal power plant emissions factor instead of the grid emissions factor for the without project scenario, leading to higher comparison emissions and more mitigation (Table 1).

Table 1: Comparison of Emission Reductions in Non-Incremental (Supply Side) Power Generation Example

(tons of carbon dioxide per year)

	EE Approach	EA Approach
w/o project emissions	357,000	467,500
w/ project emissions	168,500	168,500
Emission reductions	188,500	299,000

EA = economic analysis, EE = energy emissions, w/ = with, w/o = without.
Source: Authors.

Effect on economic internal rate of return:

Benefits of the project are all non-incremental (replacing an existing energy source, not expanding supply), which is valued at resource cost savings. In the EA approach, resource cost savings include fuel savings from the coal power plant that will be replaced by the natural gas power plant; while in the EE approach resource cost savings include fuel savings from the grid that will be replaced by the natural gas power plant. In this case, as the coal power plant has lower operating costs than the grid, the EE approach has a higher EIRR (Table 2).

Implications:

In terms of emissions, the EA approach leads to more mitigation in this case, as the coal power plant to be replaced is more emissions intensive than the overall grid generation mix. However, the average power generation cost of the grid is higher than that of the coal power plant, so the generation cost savings is lower. To the degree that a project substitutes for carbon-intensive energy sources on the supply side, and grid power generation is more diversified, similar patterns are likely to hold for a range of projects.

Table 2: Comparison of Economic Internal Rate of Return Calculations in Non-Incremental (Supply Side) Power Generation Example

(in thousands, 2016 $)

Year	Costs		Benefits: EA Approach			Benefits: EE Approach		
	CAPEX	OPEX	Non-Incremental	GHG	Net Benefits	Non-Incremental	GHG	Net Benefits
2018	60,000				(60,000)			(60,000)
2019	60,000				(60,000)			(60,000)
2020	60,000				(60,000)			(60,000)
2021	60,000				(60,000)			(60,000)
2022	60,000				(60,000)			(60,000)
2023		6,000	25,483	12,467	31,950	39,975	7,860	41,835
2024		6,000	25,483	12,717	32,199	39,975	8,017	41,992
2025		6,000	25,483	12,971	32,454	39,975	8,177	42,153
2026		6,000	25,483	13,231	32,713	39,975	8,341	42,316
2027		6,000	25,483	13,495	32,978	39,975	8,508	42,483
2028		6,000	25,483	13,765	33,248	39,975	8,678	42,653
2029		6,000	25,483	14,040	33,523	39,975	8,852	42,827
2030		6,000	25,483	14,321	33,804	39,975	9,029	43,004
2031		6,000	25,483	14,608	34,090	39,975	9,209	43,184
2032		6,000	25,483	14,900	34,382	39,975	9,393	43,369
2033		6,000	25,483	15,198	34,680	39,975	9,581	43,556
2034		6,000	25,483	15,502	34,984	39,975	9,773	43,748
2035		6,000	25,483	15,812	35,294	39,975	9,968	43,943
2036		6,000	25,483	16,128	35,611	39,975	10,168	44,143
2037		6,000	25,483	16,451	35,933	39,975	10,371	44,346
2038		6,000	25,483	16,780	36,262	39,975	10,578	44,554
2039		6,000	25,483	17,115	36,598	39,975	10,790	44,765
2040		6,000	25,483	17,457	36,940	39,975	11,006	44,981
2041		6,000	25,483	17,807	37,289	39,975	11,226	45,201
2042		6,000	25,483	18,163	37,645	39,975	11,450	45,426
2043		6,000	25,483	18,526	38,009	39,975	11,679	45,655
2044		6,000	25,483	18,897	38,379	39,975	11,913	45,888
2045		6,000	25,483	19,274	38,757	39,975	12,151	46,126
2046		6,000	25,483	19,660	39,143	39,975	12,394	46,370
2047		6,000	25,483	20,053	39,536	39,975	12,642	46,617
				EIRR	8.4%			10.7%

( ) = negative, CAPEX = capital expense, EA = economic analysis, EE = energy emissions, EIRR = economic internal rate of return, GHG = greenhouse gas, OPEX = operating expense.

Source: Authors.

2.2 Example 2: Non-Incremental (Demand-Side) Power Generation

The intent of this example is to illustrate the differences in emissions calculations and EIRRs between the EE and EA approaches when an energy project leads to substitution of energy sources among energy consumers, rather than producers. This consumer substitution effect is considered under the EA approach, but the EE approach treats the substitution as on the supply/generation side. Due to differences between what is identified as replaced, the emissions and EIRR calculations come out differently under the two approaches.

In this example, a new grid-connected natural gas power plant will transmit power to an area that was previously unconnected to the grid. The total demand for electricity is 450 GWh annually, which is currently being met by small diesel generators (Figure 3). Assuming transmission and distribution losses of 10%, a generation capacity of 500 GWh/year is required to replace the 450GWh/year currently provided by diesel generators. The capital investment (transmission, distribution, and natural gas generation) required for the project is $600 million, spent equally over 5 years. The project life of the infrastructure is 25 years after the construction period. OPEX is $12 million annually. Other costs follow those of Example 1.[15]

Figure 3: Comparison of Electricity Outputs in Non-Incremental (Demand-Side) Power Generation Example

EA = economic analysis (approach), EE = energy emissions (approach), GWh = gigawatt-hour, w/ = with, w/o = without.
Source: Authors.

[15] For simplification, this assumes that these costs represent economic costs and present all analysis in 2016 real prices.

Assumptions:

Grid emissions factor: 0.714 tCO_2/MWh
Emissions factor of diesel generator: 0.953 tCO_2/MWh[16]
Natural gas emissions factor = 0.337 tCO_2/MWh[17]
Power mix of the grid: 40% coal, 35% natural gas, and 25% diesel

Project emissions: based on natural gas power plant emissions factor
Amount of electricity generated per year = 500 GWh/year
Project emissions = 500,000 MWh/year * 0.337 tCO_2/MWh = 168,500 tCO_2/year

EE baseline: based on grid emissions factor
Amount of electricity generated per year = 500 GWh/year
Baseline emissions = 500,000 MWh/year * 0.714 tCO_2/MWh = 357,000 tCO_2/year

EA without project scenario: based on diesel generators
Amount of electricity generated per year = 450 GWh/year
Without project emissions = 450,000 MWh/year * 0.953 tCO_2/MWh = 428,850 tCO_2/year

Effect on greenhouse gas emissions:

Project emissions are calculated on the basis of the power plant emissions factor and the quantity of power generated by the plant. The EE baseline for comparison is based on the grid emissions factor and the quantity of power generation. However, the EA approach uses the diesel generator emissions factor instead of the grid emissions factor for the without project scenario, leading to higher without project emissions and more mitigation (Table 3).

Table 3: Comparison of Emission Reductions in Non-Incremental (Demand-Side) Power Generation Example
(tons of carbon dioxide per year)

	EE Approach	EA Approach
w/o project emissions	357,000	428,850
w/ project emissions	168,500	168,500
Emission reductions	188,500	260,350

EA = economic analysis, EE = energy emissions, w/ = with, w/o = without.
Source: Authors.

16 Assuming reciprocating engine system efficiency factor of 28% and gas/diesel oil with emissions factor of 74.1 tCO_2/TJ.
17 Assuming combined cycle power plant with efficiency factor of 60% and natural gas emissions factor of 56.1 tCO_2/TJ.

Effect on economic internal rate of return:

Benefits of the project are all non-incremental and valued at resource cost savings. In the EA approach, resource cost savings include fuel savings from the diesel generators that will be replaced by the natural gas power plant. In the EE approach, resource cost savings include fuel savings from the grid that will be replaced by the natural gas power plant. As generators have much higher operating costs than the grid, the EA approach has a higher EIRR (Table 4).

Table 4: Comparison of Economic Internal Rate of Return Calculations in Non-Incremental (Demand-Side) Power Generation Example

(in thousands, 2016 $)

	Costs		Benefits: EA Approach			Benefits: EE Approach		
Year	CAPEX	OPEX	Non-Incremental	GHG	Net Benefits	Non-Incremental	GHG	Net Benefits
2018	120,000				(120,000)			(120,000)
2019	120,000				(120,000)			(120,000)
2020	120,000				(120,000)			(120,000)
2021	120,000				(120,000)			(120,000)
2022	120,000				(120,000)			(120,000)
2023		12,000	115,415	10,826	114,240	39,975	7,838	35,813
2024		12,000	115,415	11,043	114,457	39,975	7,995	35,970
2025		12,000	115,415	11,263	114,678	39,975	8,155	36,130
2026		12,000	115,415	11,489	114,903	39,975	8,318	36,293
2027		12,000	115,415	11,718	115,133	39,975	8,484	36,460
2028		12,000	115,415	11,953	115,367	39,975	8,654	36,629
2029		12,000	115,415	12,192	115,606	39,975	8,827	36,802
2030		12,000	115,415	12,436	115,850	39,975	9,004	36,979
2031		12,000	115,415	12,684	116,099	39,975	9,184	37,159
2032		12,000	115,415	12,938	116,353	39,975	9,367	37,343
2033		12,000	115,415	13,197	116,611	39,975	9,555	37,530
2034		12,000	115,415	13,461	116,875	39,975	9,746	37,721
2035		12,000	115,415	13,730	117,144	39,975	9,941	37,916
2036		12,000	115,415	14,005	117,419	39,975	10,140	38,115
2037		12,000	115,415	14,285	117,699	39,975	10,342	38,318
2038		12,000	115,415	14,570	117,985	39,975	10,549	38,524
2039		12,000	115,415	14,862	118,276	39,975	10,760	38,735
2040		12,000	115,415	15,159	118,573	39,975	10,975	38,951
2041		12,000	115,415	15,462	118,877	39,975	11,195	39,170
2042		12,000	115,415	15,771	119,186	39,975	11,419	39,394
2043		12,000	115,415	16,087	119,501	39,975	11,647	39,622
2044		12,000	115,415	16,409	119,823	39,975	11,880	39,855
2045		12,000	115,415	16,737	120,151	39,975	12,118	40,093
2046		12,000	115,415	17,071	120,486	39,975	12,360	40,335
2047		12,000	115,415	17,413	120,827	39,975	12,607	40,583
				EIRR	14.0%		EIRR	3.2%

( ) = negative, CAPEX = capital expense, EA = economic analysis, EE = energy emissions, EIRR = economic internal rate of return, GHG = greenhouse gas, OPEX = operating expense.
Source: Authors.

Implications:

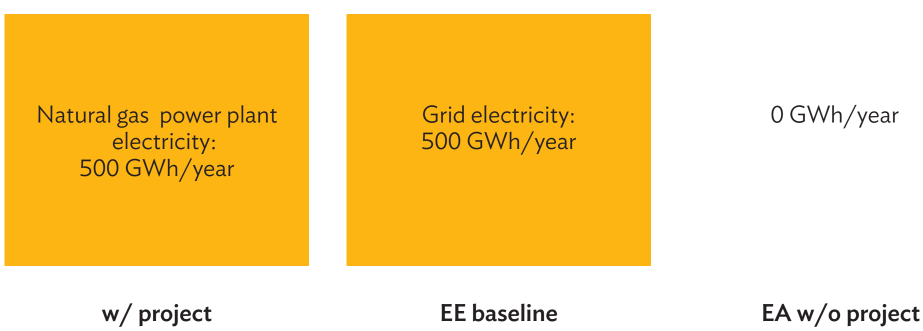
In terms of emissions, the EA approach leads to more mitigation in this case, as the energy sources to be replaced by consumers are more emissions intensive than the overall grid generation mix, which includes modern and clean energy. In addition, the cost of energy replaced is higher than the overall grid, so that non-incremental benefits are also higher than under the EE approach. To the degree that a project substitutes for dirty and costly energy sources on the demand-side, similar patterns are likely to hold for a range of projects.

2.3 Example 3: Incremental Power Generation

This example shows the difference in emissions and EIRR calculations in cases where energy supply is considered incremental, or additional to without project levels of consumption, under the EA approach. As the EE approach does not consider any energy supply intervention as incremental, the emissions and EIRR results differ strongly.

In this example, the project will construct a natural gas power plant that will generate 500 GWh of electricity annually. The powerplant will increase the supply of electricity to an area that is already connected to the grid (Figure 4). The capital investment required for the project is $300 million, spent equally over 5 years. The project life of the infrastructure is 25 years after the construction period. OPEX is $12 million annually.[18] Transmission and distribution losses are assumed to be 10%. Other unit costs follow the assumptions described for Example 1.[19] The average willingness-to-pay for incremental supply is $0.17/kWh of electricity.

Figure 4: Comparison of Electricity Outputs in Incremental Power Generation Example



EA = economic analysis (approach), EE = energy emissions (approach), GWh = gigawatt-hour, w/ = with, w/o = without.
Source: Authors.

18 The operating expense includes cost of transmission and distribution.
19 For simplification, we will assume that these costs represent economic costs and present all analysis in 2016 real prices.

Assumptions:

Grid emissions factor: 0.714 tCO_2/MWh
Natural gas power plant emissions factor: 0.337 tCO_2/MWh[20]
The power mix of the grid is 40% coal, 35% natural gas, and 25% diesel.

Project emissions: based on the natural gas power plant emissions factor
Amount of electricity generated = 500 GWh/year
Project emissions = 500,000 MWh/year * 0.337 tCO_2/MWh = 168,500 tCO_2/year

EE baseline: based on the grid emissions factor
Amount of electricity generated = 500 GWh/year
Baseline emissions = 500,000 MWh * 0.714 tCO_2/MWh = 357,000 tCO_2/year

EA without project scenario: no power is transmitted/generated
Amount of electricity generated = 0 GWh/year
Without project emissions = 0 tCO_2/year

Effect on greenhouse gas emissions:

Project emissions are calculated on the basis of the power plant emissions factor and the quantity of power generated by the plant. The EE baseline for comparison is based on the grid emissions factor and the quantity of power generation, under the assumption that the current generation mix expands to provide the same amount generated by the project. However, the EA approach reflects no generation in the without project scenario, so that the project increases emissions (Table 5).

Table 5: Comparison of Emission Reductions in Incremental Power Generation Example

(tons of carbon dioxide per year)

	EE Approach	EA Approach
w/o project emissions	357,000	0
w/ project emissions	168,500	168,500
Emission reductions	188,500	(168,500)

( ) = negative, EA = economic analysis, EE = energy emissions, w/ = with, w/o = without.
Source: Authors.

[20] Assuming a combined cycle power plant with efficiency factor of 60% and natural gas emissions factor of 56.1 tCO_2/TJ.

Effect on economic internal rate of return:

In the EA approach, benefits of the project are all incremental and valued at average willingness-to-pay for the expanded power supply. In the EE approach, benefits are considered non-incremental and valued based on fuel savings from the grid (and its power mix) that will be replaced by the natural gas power plant. As the ability to save generation costs relative to the grid is limited, the EA approach shows higher EIRRs (Table 6).

Table 6: Comparison of Economic Internal Rate of Return Calculations in Incremental Power Generation Example

(in thousands, 2016 $)

Year	Costs		Benefits: EA Approach			Benefits: EE Approach		
	CAPEX	OPEX	Incremental	GHG	Net Benefits	Non-Incremental	GHG	Net Benefits
2018	60,000				(60,000)			(60,000)
2019	60,000				(60,000)			(60,000)
2020	60,000				(60,000)			(60,000)
2021	60,000				(60,000)			(60,000)
2022	60,000				(60,000)			(60,000)
2023		12,000	76,500	(7,007)	57,493	39,975	7,838	35,813
2024		12,000	76,500	(7,147)	57,353	39,975	7,995	35,970
2025		12,000	76,500	(7,290)	57,210	39,975	8,155	36,130
2026		12,000	76,500	(7,436)	57,064	39,975	8,318	36,293
2027		12,000	76,500	(7,584)	56,916	39,975	8,484	36,460
2028		12,000	76,500	(7,736)	56,764	39,975	8,654	36,629
2029		12,000	76,500	(7,891)	56,609	39,975	8,827	36,802
2030		12,000	76,500	(8,048)	56,452	39,975	9,004	36,979
2031		12,000	76,500	(8,209)	56,291	39,975	9,184	37,159
2032		12,000	76,500	(8,374)	56,126	39,975	9,367	37,343
2033		12,000	76,500	(8,541)	55,959	39,975	9,555	37,530
2034		12,000	76,500	(8,712)	55,788	39,975	9,746	37,721
2035		12,000	76,500	(8,886)	55,614	39,975	9,941	37,916
2036		12,000	76,500	(9,064)	55,436	39,975	10,140	38,115
2037		12,000	76,500	(9,245)	55,255	39,975	10,342	38,318
2038		12,000	76,500	(9,430)	55,070	39,975	10,549	38,524
2039		12,000	76,500	(9,619)	54,881	39,975	10,760	38,735
2040		12,000	76,500	(9,811)	54,689	39,975	10,975	38,951
2041		12,000	76,500	(10,007)	54,493	39,975	11,195	39,170
2042		12,000	76,500	(10,207)	54,293	39,975	11,419	39,394
2043		12,000	76,500	(10,411)	54,089	39,975	11,647	39,622
2044		12,000	76,500	(10,620)	53,880	39,975	11,880	39,855
2045		12,000	76,500	(10,832)	53,668	39,975	12,118	40,093
2046		12,000	76,500	(11,049)	53,451	39,975	12,360	40,335
2047		12,000	76,500	(11,270)	53,230	39,975	12,607	40,583
				EIRR	13.7%		EIRR	9.2%

( ) = negative, CAPEX = capital expense, EA = economic analysis, EE = energy emissions, EIRR = economic internal rate of return, GHG = greenhouse gas, OPEX = operating expense.
Source: Authors.

Implications:

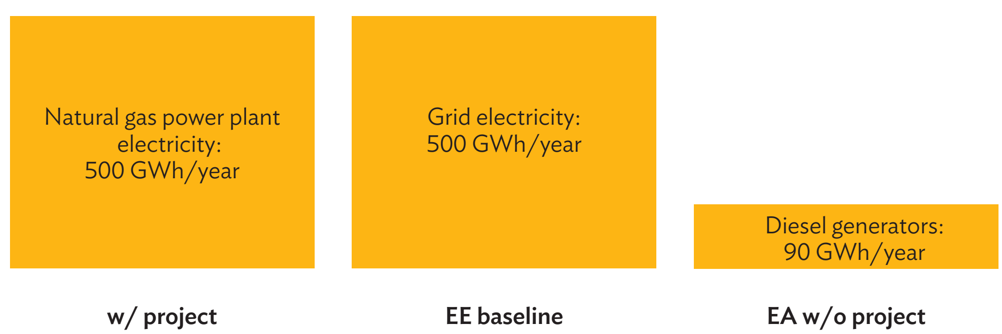
The EA approach leads to negative emissions mitigation in this case, as the without project scenario is to have zero emissions, rather than assume expansion of the current generation mix. However, the economic benefits are much higher, as the additional electricity has much more value than the generation cost savings from the project plant type relative to the overall grid. In most cases, the average value of incremental electricity is likely to be higher than the cost savings possible from a particular plant type relative to the grid, and similar patterns will hold.

2.4 Example 4: Mix of Incremental and Non-Incremental (Demand-Side) Power Generation

Previous examples are simplified cases that are rarely encountered in actual energy supply projects. Most real-world energy supply projects have a mix of incremental and non-incremental effects. This example illustrates the differences between the approaches in a more realistic case where a project leads to such a combination of effects.

In this example, the project will construct a natural gas power plant and supply 500 GWh annually of electricity to an area that is currently unconnected to the grid. Currently, some households in the area use diesel generators to generate 90 GWh annually of electricity, which will be replaced by electricity from the natural gas power plant (Figure 5). Assuming transmission and distribution losses of 10%, a generation capacity of 100 GWh/year is required to replace the 90GWh/year currently provided by diesel generators. The capital investment required for the project is $600 million, spent equally over 5 years. The project life of the infrastructure is 25 years after the construction period. OPEX is $12 million annually.[21] Other unit cost assumptions and the average willingness-to-pay for incremental supply follow the previous examples.

Figure 5: Comparison of Electricity Outputs in a Mix of Incremental and Non-Incremental (Demand-Side) Power Generation Example



EA = economic analysis (approach), EE = energy emissions (approach), GWh = gigawatt-hour, w/ = with, w/o = without.
Source: Authors.

[21] The operating expense includes cost of transmission and distribution.

Assumptions:

Grid emissions factor: 0.714 tCO_2/MWh
Natural gas power plant emissions factor: 0.337tCO_2/MWh[22]
Emissions factor of diesel generator: 0.953 tCO_2/MWh[23]
The power mix of the grid is 40% coal, 35% natural gas, and 25% diesel.

Project emissions: based on the natural gas power plant emissions factor
Amount of electricity generated = 500 GWh/year
Project emissions = 500,000 MWh/year * 0.337 tCO_2/MWh = 168,500 tCO_2/year

EE baseline: based on the grid emissions factor
Amount of electricity generated = 500 GWh/year
Baseline emissions = 500,000 MWh* 0.714 tCO_2/MWh = 357,000 tCO_2/year

EA without project scenario: based on replaced use of diesel generators and their emissions factor
Amount of electricity generated = 90 GWh/year
Without project emissions = 90,000 MWh/year * 0.953 tCO_2/MWh = 85,770 tCO_2/year

Effect on greenhouse gas emissions:

Project emissions are calculated on the basis of the power plant emissions factor and the quantity of power generated by the plant. The EE baseline for comparison is based on the grid emissions factor and the quantity of power generated, under the assumption that the generation mix expands to provide the same generation as the project. However, the EA without project scenario reflects only the existing diesel generation to be replaced. As a result of primarily incremental generation, the EA approach finds an emissions increase (Table 7).

Table 7: Comparison of Emission Reductions in a Mix of Incremental and Non-Incremental (Demand-Side) Power Generation Example
(tons of carbon dioxide per year)

	EE Approach	EA Approach
w/o project emissions	357,000	85,770
w/ project emissions	168,500	168,500
Emission reductions	188,500	(82,730)

( ) = negative, EA = economic analysis, EE = energy emissions, w/ = with, w/o = without.
Source: Authors.

[22] Assuming a combined cycle power plant with efficiency factor of 60% and natural gas emissions factor of 56.1 tCO_2/TJ.
[23] Assuming reciprocating engine system with efficiency factor of 28% and gas/diesel oil with emissions factor of 74.1 tCO_2/TJ.

Effect on economic internal rate of return:

In the EA approach, 400 GWh of power is considered incremental supply of the project, which is valued at average willingness-to-pay for expanded power, while 100 GWh is non-incremental supply valued at resource cost savings from replacing diesel generation. In the EE approach, all benefits are non-incremental and valued at fuel savings from the grid that will be replaced by the natural gas power plant. As the incremental value of power is higher than the cost savings possible relative to the grid, the EA approach has a higher EIRR (Table 8).

Implications:

The EA approach leads to negative emissions mitigation in this case, as the without project scenario is to have zero emissions for incremental supply, rather than assume expansion of the current generation mix. Despite this, the EA economic benefits are much higher, as the additional electricity from the incremental portion of supply has a higher value than the generation cost savings from the project plant type relative to the overall grid. In addition, the non-incremental supply (from demand-side substitution) has more unit cost savings and unit emissions reduction than the supply-side substitution assumed in the EE approach. To the degree that energy supply is mostly incremental, the EA approach will have lower mitigation and higher EIRRs, and to the degree that it is mostly non-incremental on the demand-side, the EA approach will also have higher mitigation.

Table 8: Comparison of Economic Internal Rate of Return Calculations in a Mix of Incremental and Non-Incremental (Demand-Side) Power Generation Example

(in thousands, 2016 $)

	Costs		Benefits: EA Approach				Benefits: EE Approach		
Year	CAPEX	OPEX	Incremental	Non-Incremental	GHG	Net Benefits	Non-Incremental	GHG	Net Benefits
2018	120,000					(120,000)			(120,000)
2019	120,000					(120,000)			(120,000)
2020	120,000					(120,000)			(120,000)
2021	120,000					(120,000)			(120,000)
2022	120,000					(120,000)			(120,000)
2023		12,000	61,200	23,083	(3,440)	68,843	39,975	7,838	35,813
2024		12,000	61,200	23,083	(3,509)	68,774	39,975	7,995	35,970
2025		12,000	61,200	23,083	(3,579)	68,704	39,975	8,155	36,130
2026		12,000	61,200	23,083	(3,651)	68,632	39,975	8,318	36,293
2027		12,000	61,200	23,083	(3,724)	68,559	39,975	8,484	36,460
2028		12,000	61,200	23,083	(3,798)	68,485	39,975	8,654	36,629
2029		12,000	61,200	23,083	(3,874)	68,409	39,975	8,827	36,802
2030		12,000	61,200	23,083	(3,952)	68,331	39,975	9,004	36,979
2031		12,000	61,200	23,083	(4,031)	68,252	39,975	9,184	37,159
2032		12,000	61,200	23,083	(4,111)	68,172	39,975	9,367	37,343
2033		12,000	61,200	23,083	(4,193)	68,089	39,975	9,555	37,530
2034		12,000	61,200	23,083	(4,277)	68,006	39,975	9,746	37,721
2035		12,000	61,200	23,083	(4,363)	67,920	39,975	9,941	37,916
2036		12,000	61,200	23,083	(4,450)	67,833	39,975	10,140	38,115
2037		12,000	61,200	23,083	(4,539)	67,744	39,975	10,342	38,318
2038		12,000	61,200	23,083	(4,630)	67,653	39,975	10,549	38,524
2039		12,000	61,200	23,083	(4,723)	67,560	39,975	10,760	38,735
2040		12,000	61,200	23,083	(4,817)	67,466	39,975	10,975	38,951
2041		12,000	61,200	23,083	(4,913)	67,370	39,975	11,195	39,170
2042		12,000	61,200	23,083	(5,012)	67,271	39,975	11,419	39,394
2043		12,000	61,200	23,083	(5,112)	67,171	39,975	11,647	39,622
2044		12,000	61,200	23,083	(5,214)	67,069	39,975	11,880	39,855
2045		12,000	61,200	23,083	(5,318)	66,965	39,975	12,118	40,093
2046		12,000	61,200	23,083	(5,425)	66,858	39,975	12,360	40,335
2047		12,000	61,200	23,083	(5,533)	66,750	39,975	12,607	40,583
					EIRR	8.3%		EIRR	3.2%

( ) = negative, CAPEX = capital expense, EA = economic analysis, EE = energy emissions, EIRR = economic internal rate of return, GHG = greenhouse gas, OPEX = operating expense.

Source: Authors.

3 WAY FORWARD

As illustrated above, the EE approach, if applied to economic analysis, eliminates most energy benefits, resulting in an EIRR below the ADB required minimum rate of 9% for many projects. At the same time, the EA approach means that, in many, but not all cases, mitigation effects will be reduced relative to the EE methodology.

For economic analysis at the project level, the EE approach is not appropriate. It is not consistent with economic theory or the approach taken in other sectors, even in terms of estimating emissions effects. The EE approach also has the inherent limitation that the grid emissions factor is aggregate and based on arbitrary weighting between the current and expected grid emissions intensities. Even if the without project scenario is to reflect some sort of “business as usual” power development absent of climate considerations, actual emissions intensities will vary over time as new plants come online, rather than follow an arbitrary weighting pattern that does not change over time.

The basic approach recommended moving forward is for economic analysis to use the EA approach for emissions accounting. Other emissions reporting may follow the EE approach or adopt a harmonized approach based on the EA approach. Adopting an EA harmonized approach would reduce confusion from multiple sets of project emissions estimates and treat transport and energy consistently, but it would mean that reported mitigation levels are likely to fall, especially for projects that supply incremental energy.

In essence, the EA approach requires careful consideration of substitution effects on both the consumer/demand-side and among producers, from the perspective of currently available infrastructure. This means that energy supply will need to be disaggregated as supply-side replacement, demand-side replacement, and incremental (additional to the current situation) when performing emissions calculations for economic analysis.

In mathematical terms, the overall framework maintains the accounting principles outlined in Equation 1 of ADB (2017),[24] but with “baseline emissions” replaced by “without project emissions.”

ER = WE – PE
ER = Emission reduction/change
WE = Without project emissions
PE = Project emissions

[24] ADB. 2017. *Guidelines for Estimating Greenhouse Gas Emissions of Asian Development Bank Energy Projects: Additional Guidance for Clean Energy Projects*. https://www.adb.org/documents/guidelines-estimating-ghg-energy-projects.

Without project emissions are then defined as the emissions from existing levels of supply (including sources that are replaced by the new service/facility). Project emissions remain defined similarly to the EE approach.

WE = CE + SE
CE = Replaced consumer emissions (e.g., from generators)
SE = Replaced supply facility emissions (e.g., from replaced power plants)

Non-incremental source emissions can result from an array of energy types and uses. These might include candles and kerosene for lighting and fuelwood/biomass for cooking, but diesel for generators is likely to be the most important. The amount of each form of replaced electricity/energy should be quantified and multiplied by its respective emissions factor.

$$CE = \sum_{1}^{i} (EG_{\text{traditional energy type i}} \times EF_{\text{traditional energy type i}})$$

$EG_{\text{traditional energy type}}$ = annual electricity (energy) generation by the replaced energy source, MWh/year

$EF_{\text{traditional energy type}}$ = emissions factor for the type of replaced energy, tCO_2/MWh

Replaced facility emissions will be based on the electricity (energy) generated by the facility replaced multiplied by its emissions factor.

$$SE = EG_{\text{facility type}} \times EF_{\text{facility type}}$$

$EG_{\text{facility type}}$ = annual electricity (energy) generation by the replaced facility, MWh/year

$EF_{\text{facility type}}$ = emissions factor for the type of facility, tCO_2/MWh

The emissions factors presented in the Appendix may be used when applying these formulas to electricity.

4 CONCLUSION

The EE and EA approaches do not follow consistent without project scenarios for greenhouse gas emissions accounting, as they have been developed for different purposes. The EE approach holds the level of public energy service provided constant across with and without project scenarios and assumes that the financed project simply changes how the service is provided (substitutes among energy supply options). The EA approach holds the level of service provided constant between the current and without project scenarios, so that a project generates both energy and climate effects.

Use of the EE approach in project economic analysis would mean that the benefit flow of energy investments becomes principally in terms of greenhouse gases, and that many projects intended to improve energy access for poorer beneficiaries will likely no longer be economically viable. It would also create a discrepancy between the treatment of energy and other sectors, such as transport, where the without project scenario does not reflect development of the project infrastructure for either reporting of greenhouse gas emissions or economic analysis.

For these reasons, the EA approach is recommended for calculating emissions effects in project economic analysis. Using this approach is in line with current economic analysis practice and allows inclusion of both climate and other benefits.

The EA approach will, in many cases, reflect far less greenhouse gas emissions mitigation than the EE approach. As the EE approach is harmonized with other international financial institutions,[25] adoption of the EA approach for public mitigation reporting may appear to place ADB at a disadvantage and disrupt harmonization efforts. Use of a baseline or business as usual forecast of further investment is also well accepted in the field of climate change mitigation and in framing of instruments, such as the Nationally Determined Contributions to the Paris Agreement. For this reason, the EE approach will need to be preserved for reporting of bank performance (outside of economic analysis) and contributions to climate change mitigation commitments.

As different mitigation estimation approaches are needed for mitigation reporting and economic analysis, there may be confusion among various audiences about what the differing mitigation numbers mean. To address this, it will be important to have a clear and concise explanation of the basis for the differing estimates both within ADB and for the general public.

[25] E.g., see World Bank. 2015. IFI Approach to GHG Accounting for Renewable Energy Projects. http://documents.worldbank.org/curated/en/758831468197412195/pdf/101532-WP-P143154-PUBLIC-Box394816B-Joint-IFI-RE-GHG-Accounting-Approach-clean-final-11-30.pdf.

APPENDIX: EMISSIONS FACTORS FOR ELECTRICITY GENERATION

Table A1: Emissions Factors of Coal-Fired Electricity Generation

(tons of carbon dioxide equivalent per megawatt-hour)

Fuel	Older (Pre-2000) Plants			Newer (2000+) Plants					Either Period
Coal	Subcritical	FBS	CFBS	Subcritical	Supercritical	Ultra-Supercritical	IGCC	CFBS	Small Steam Boilers/ Turbines
Anthracite	0.9564	0.9968	0.9695	0.9074	0.7864	0.7078	0.7078	0.8847	5.0554
Coking coal	0.9204	0.9593	0.9330	0.8732	0.7568	0.6811	0.6811	0.8514	4.8651
Sub-bituminous coal	0.9350	0.9745	0.9478	0.8871	0.7688	0.6919	0.6919	0.8649	4.9423
Other bituminous coal	0.9204	0.9593	0.9330	0.8732	0.7568	0.6811	0.6811	0.8514	4.8651
Lignite	0.9827	1.0242	0.9962	0.9323	0.8080	0.7272	0.7272	0.9090	5.1943
Brown coal briquettes	0.9486	0.9887	0.9616	0.9000	0.7800	0.7020	0.7020	0.8775	5.0143
Coke	1.0411	1.0851	1.0553	0.9877	0.8560	0.7704	0.7704	0.9630	5.5029

CFBS = circulating fluidized bed systems, FBS = fluidized bed systems, IGCC = integrated gasification combined cycle.
Source: Author's calculations from ADB. 2017. *Guidelines for Estimating Greenhouse Gas Emissions of Asian Development Bank Energy Projects: Additional Guidance for Clean Energy Projects*. https://www.adb.org/documents/guidelines-estimating-ghg-energy-projects.

Table A2: Emissions Factors of Liquid Fuel Electricity Generation
(tons of carbon dioxide per megawatt-hour)

	Older (Pre-2000) Plants			Newer (2000+) Plants			Either Period – Internal Combustion Reciprocating (capacity in kilowatts)							Either Period
Liquid Fuel	Steam Turbine	Open Cycle	Combined Cycle	Steam Turbine	Open Cycle	Combined Cycle	<10	10–50	50–100	100–200	200–400	400–1,000	>1,000	Small Steam Boilers/ Turbines
Crude oil	0.7037	0.8796	0.5737	0.6766	0.6681	0.5737	0.9424	0.7996	0.7539	0.7132	0.6766	0.6283	0.5864	3.7697
Natural gas liquids	0.6163	0.7704	0.5024	0.5926	0.5851	0.5024	0.8254	0.7004	0.6603	0.6246	0.5926	0.5503	0.5136	3.3017
Gasoline	0.6653	0.8316	0.5423	0.6397	0.6316	0.5423	0.8910	0.7560	0.7128	0.6743	0.6397	0.5940	0.5544	3.5640
Gas/Diesel oil	0.7114	0.8892	0.5799	0.6840	0.6753	0.5799	0.9527	0.8084	0.7622	0.7210	0.6840	0.6351	0.5928	3.8109
Residual fuel oil	0.7430	0.9288	0.6057	0.7145	0.7054	0.6057	0.9951	0.8444	0.7961	0.7531	0.7145	0.6634	0.6192	3.9806
Petroleum coke	0.9360	1.1700	0.7630	0.9000	0.8886	0.7630	1.2536	1.0636	1.0029	0.9486	0.9000	0.8357	0.7800	5.0143
Other petroleum products	0.7037	0.8796	0.5737	0.6766	0.6681	0.5737	0.9424	0.7996	0.7539	0.7132	0.6766	0.6283	0.5864	3.7697

Source: Author's calculations from ADB. 2017. *Guidelines for Estimating Greenhouse Gas Emissions of Asian Development Bank Energy Projects: Additional Guidance for Clean Energy Projects*. https://www.adb.org/documents/guidelines-estimating-ghg-energy-projects.

Table A3: Emissions Factors of Gas Electricity Generation
(tons of carbon dioxide per megawatt-hour)

	Older (Pre-2000) Plants			Newer (2000+) Plants			Either Period – Internal Combustion Reciprocating (capacity in kilowatts)							Either Period
Gas Fuel	Steam Turbine	Open Cycle	Combined Cycle	Steam Turbine	Open Cycle	Combined Cycle	<10	10–50	50–100	100–200	200–400	400–1,000	>1,000	Small Steam Boilers/ Turbines
Gas works gas	0.4262	0.5328	0.3475	0.4262	0.4047	0.2664	0.5709	0.4844	0.4567	0.4320	0.4098	0.3806	0.3552	2.2834
Coke oven gas	0.4262	0.5328	0.3475	0.4262	0.4047	0.2664	0.5709	0.4844	0.4567	0.4320	0.4098	0.3806	0.3552	2.2834
Blast furnace gas	2.4960	3.1200	2.0348	2.4960	2.3696	1.5600	3.3429	2.8364	2.6743	2.5297	2.4000	2.2286	2.0800	13.3714
Oxygen steel furnace gas	1.7472	2.1840	1.4243	1.7472	1.6587	1.0920	2.3400	1.9855	1.8720	1.7708	1.6800	1.5600	1.4560	9.3600
Natural gas	0.5386	0.6732	0.4390	0.5386	0.5113	0.3366	0.7213	0.6120	0.5770	0.5458	0.5178	0.4809	0.4488	2.8851
Liquefied petroleum gases	0.6058	0.7572	0.4938	0.6058	0.5751	0.3786	0.8113	0.6884	0.6490	0.6139	0.5825	0.5409	0.5048	3.2451
Refinery gas	0.5530	0.6912	0.4508	0.5530	0.5250	0.3456	0.7406	0.6284	0.5925	0.5604	0.5317	0.4937	0.4608	2.9623

Source: Author's calculations from ADB. 2017. *Guidelines for Estimating Greenhouse Gas Emissions of Asian Development Bank Energy Projects: Additional Guidance for Clean Energy Projects.* https://www.adb.org/documents/guidelines-estimating-ghg-energy-projects.

Greenhouse Gas Emissions Accounting for ADB Energy Project Economic Analysis

Guidance Note

This note is intended to help guide greenhouse gas emissions accounting for economic analysis of energy sector projects. Reporting of emissions of energy projects outside of economic analysis uses a different point of comparison (a baseline scenario) than does economic analysis (a without project scenario). As economic analysis needs to use a consistent set of scenarios across benefit streams, the note recommends and illustrates the use of a without project scenario for calculating emissions effects in project economic analysis.

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