Impact of Discount Rates on Renewable Energy Investment Timing and Cost-Optimal Energy Transition Pathways in the Philippine Power Sector

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Abstract

Energy plays a vital role in enabling social and economic development through its generation, conversion, distribution, and use. In the Philippines, ongoing efforts to boost economic growth and global competitiveness are driving a continuous rise in energy demand. However, the country's continued dependence on fossil fuel-based power generation poses serious environmental risks, particularly in terms of greenhouse gas emissions and climate change. This study investigates the impact of varying discount rates on energy transition plans under the following scenarios using the TIMES model: RE_PH with 35% renewable energy (RE) penetration by 2030 and 50% by 2040; RE_PH1 with 40% by 2030 and 55% by 2040; and RE_PH2 with 45% by 2030 and 60% by 2040. Results show that lower discount rates promote earlier investment in renewable energy technologies to meet the 2030 and 2040 policy targets across all modeled scenarios. Specifically, at a 3% discount rate, it indicates that deployment of capital-intensive renewable energy technologies, such as pumped hydro storage and onshore wind becomes a more economically viable option and is deployed in period 2024 for PP-PUMP-HYD and 2030 and onwards for PP-ONS, respectively. These early investments can lead to significant operation cost savings compared to baseline 10% discount rate. Furthermore, the 3% discount rate enhances the economic attractiveness of early RE deployment across all scenarios, resulting in lower cumulative investment, lower operating costs, and lower electricity prices over time. These findings highlight the critical role of discount rates in promoting sustainable energy transitions and informing long-term climate planning.

Keywords: climate change, discount rates, energy transition, renewable energy

1. Introduction

Anthropogenic global warming and climate change are currently causing significant and observable shifts in Earth's natural systems. According to Dixon *et al*. (2025), limiting global warming to below 2 degrees Celsius and mitigating the most severe impacts of climate change require a substantial reduction in emissions from the energy sector, which accounts for over 75% of global greenhouse gas emissions. To mitigate these effects, several climate actions were made by the United Nations (UN) through its Framework Convention on Climate Change (UNFCCC) in accordance with the Paris Agreement (2015) and also with the Kyoto Protocol (1997). These actions set binding emissions reduction targets for developed countries and limit global warming to well below 2 degrees Celsius and pursue efforts to limit the increase to 1.5 degrees Celsius.

In this context, the Philippines—a developing country in Southeast Asia—continues to advance its economic development through the growth of its service sector and gross domestic product (GDP). As a result of this economic momentum, a significant increase in energy demand is expected, presenting both challenges and opportunities for the country's energy transition efforts.

In the Philippine power sector, fossil fuels remain dominant due to their established infrastructure and lower costs compared to renewables. Coal-fired power plants remain the primary source of electricity for Filipino households (Manych & Jakob, 2021; Moey *et al*., 2020; Brahim, 2014). To address this issue, the government has committed to reducing greenhouse gas emissions under the Paris Agreement, aiming to decrease reliance on coal and increase the use of renewable energy sources like wind and solar (Canlas & Jandoc, 2024).

The Philippines is committed to its Nationally Determined Contribution (NDC) aiming for a reduction in greenhouse gas (GHG) emissions by 2030, with 72.29% of this target contingent upon international support and 2.71% representing unconditional emissions reductions (Republic of the Philippines, 2021). Additionally, the Philippines also established targets to enhance the adoption of renewable energy in the electricity generation mix of 35% share in 2030 and 50% in 2040 according to the Department of Energy [DOE] (2023).

Notably, to support the energy transition, several studies have been conducted, incorporating various scenarios, policies, and targets within the Philippine power sector. Jacobson *et al*. (2018) conducted a global study modeling pathways to 100% renewable energy by 2050, which includes the Philippines. Additionally, Mondal *et al*., (2018) performed an assessment of low-carbon energy scenarios in the Philippines for the period 2014–2040, while Gulagi *et al*., (2021) and Alexander *et al*., (2023) conducted analyses of the country's transition to 100% renewable energy (2015–2050) and clean energy transition scenarios (2015–2070), respectively. Moreover, Dixon *et al*. (2025) evaluated the potential of offshore wind (both floating and fixed), floating solar PV, in-stream tidal, and nuclear power to contribute to a net-zero energy plan for the Philippines.

Above all, few studies have examined the sensitivity of Philippine energy transition pathways to varying discount rates (Dixon *et al*., 2025). The transition to renewable energy is shaped by various interrelated factors, including global energy prices, investment dynamics, and climate change imperatives. These economic and institutional drivers significantly influence the cost competitiveness of renewable technologies and the development of supporting infrastructure, both of which remain key challenges in achieving large-scale renewable deployment (Canlas & Jandoc, 2024; Mondal *et al*., 2018; La Viña *et al*., 2011).

Beyond these challenges, renewable energy projects in the Philippines often face high upfront investment costs, limited access to financing, and challenges in infrastructure development, such as transmission lines connecting renewable-rich regions to load centers (Agaton & Karl, 2018; Banerjee *et al*., 2016). Policy uncertainties, grid integration issues, and technological limitations further hinder large-scale adoption of renewables (Reyes & Calderon, 2025).

Discount rates play a vital role in project planning, especially in financial and economic evaluations. They are also key in energy sector expansion and climate policy planning. Economic viability refers to the extent to which an investment is considered cost-effective over its lifetime, considering both upfront capital costs and future operating costs and benefits. In energy system planning, discount rates influence this economic viability by determining how future costs and savings are valued in present terms. In energy, discount rates differ by technology and development stage, while in climate policy, lower rates are generally preferred because they place greater value on future benefits and support long-term sustainability (Philibert, 2023; Saługa *et al.*, 2020).

This study aims to assess how varying discount rate assumptions influence the feasibility of achieving renewable energy target scenarios in the Philippines' power sector. Specifically, it seeks to evaluate the impact of different discount rate values on the cost-effectiveness of various renewable energy technologies under different scenarios. By analyzing how financial assumptions affect technology choices and investment timing, the study provides insights into the critical role of discount rates in shaping the country's energy transition pathway and climate policies.

2. Methodology

2.1 TIMES Model

The Integrated MARKAL-EFOM System or commonly TIMES model, is a bottom-up, dynamic, cost-optimization modelling framework that determines the system-wide cost-optimal evolution of the energy system. TIMES provides a robust and validated framework made by the International Energy Agency's Energy Technology Systems Analysis Program (IEA-ETSAP). It is a model generator for conducting energy and environmental analyses, policy planning, combining technical engineering and economic approaches to project future energy scenarios. In addition, TIMES is also suitable for modelling in detail individual sub sectors of the energy system, such as the power sector (Kannan & Turton, 2013).

Compared to other widely used tools such as LEAP, which is primarily scenario-based and accounting-oriented, TIMES from the cost effectiveness perspective provides endogenous optimization of investment decisions. In contrast to its predecessor MARKAL, TIMES offers enhanced flexibility in temporal resolution, technology representation, and policy constraint modeling, making it more suitable for detailed long-term transition analysis (Liu *et al.*, 2018).

Investment timing is determined endogenously based on the least-cost optimization across the study horizon 2024–2050. The model selects the period in which new capacity additions occur depending on the assumed discount rate, technology costs, and policy constraints. Thus, changes in the discount rate influence not only the total level of investment but also the optimal timing of technology deployment.

The objective function minimizes the discounted costs of the entire system in the planning period to meet the energy demand of the whole sector and is shown as Equation 1:

$$minTDSC_{t_m} = \sum_{t\in(t_0,t_e)} DISC_{t,t_m} \times INVCOST_t + FIXCOST_t + VARCOST_t + INVTAXSUB_t + IMPCOST_t - EXPREV_t + EMCOST_t) - SALVAGE_{t_m} \quad (1)$$

Where

$$DISC_{t,t_m} = \frac{1}{(1+r)^{t,t_m}} \quad (2)$$

$TDSC_{t_m}$ is the total discounted system cost, discounted to the beginning of year t_m; t_0, t_e are the initial year and the last year in the model run; $DISC_{t,t_m}$is the discounted factor of currency at year t to year t_m and r is the social discount rate applied as shown in Equation 2; $INVCOST_t$ is the technology investment cost at year t; $FIXCOST_t$ is the fixed annual costs when each unit of capacity operates; $VARCOST_t$ is the variable operational costs of technology at year t; $INVTAXSUB_t$ is the taxes/subsidies on investments at year t; $IMPCOST_t$ is the costs of energy import; $EXPREV_t$ is the export revenue earned from export of energy; $EMCOST_t$is the emissions fees when the user specifies a cost per ton of emissions; and $SALVAGE_{t_m}$ is the residual monetary value of all the investments remaining at the end of the modeling horizon (Liu *et al.*, 2018).

Whereas, constraints are a number of equations that must be satisfied by the model when minimizing the total discounted costs like in this case: demand satisfaction, commodity balance, capacity utilization and emissions constraints (Liu *et al.*, 2018).

For demand satisfaction, it is given as Equation 3:

$$\sum_i CAP_{i,j,tp} \geq DEM_{j,tp} \quad (3)$$

Where $CAP_{i,j,tp}$ is the capacity of end-use technology i for any demand j at the end of period tp, and $DEM_{j,tp}$ is the demand j at period tp, which is exogenous based on the Philippine Power Development Plan 2023-2050 to satisfy.

Moreover, commodity balance is expressed as Equation 4:

$$\sum_i out_{i,k} ACT_{i,tp} + IMP_{k,tp} - \sum_i in_{i,k} ACT_{i,tp} + EXP_{k,tp} \geq 0 \quad (4)$$

Where subscript *i* is the energy technology in the model, $ACT_{i,tp}$ is the activity produced from technology *i* at period *tp*. $IMP_{k,tp}$ and $EXP_{k,tp}$ are the amount of energy imported and exported in form *k* at period *tp*, respectively. While both $in_{i,k}$ and $out_{i,k}$ are the energy amount produced and consumed in form *k* by one unit of activity of technology *I*, respectively.

Capacity transfer (Equation 5), on the other hand, is equivalent to:

$$CAP_{i,tp} - \sum_{tp} INV_{i,tp'} \leq resid_{i,tp} \quad (5)$$

Where $INV_{i,tp'}$ is the investment *i* in technology *i* over all the previous period *tp'* such that *tp*-*tp'* does not exceed the lifetime of the technology *i*. whereas, $CAP_{i,tp}$ is the total capacity of technology *i* at period *tp*. $resid_{i,tp}$ is the residual capacity of technology *i* at period *tp*.

Correspondingly, Capacity utilization (Equation 6) is equal to:

$$ACT_{i,tp} - util_i CAP_{i,tp} \leq 0 \quad (6)$$

Where $util_i$ is the annual utilization or capacity factor of technology *i*, multiplied by the total capacity of technology *i* at period *tp* $CAP_{i,tp}$.

In addition, limiting flow shares is expressed as Equation 7:

$$out_k ACT_{tp,RE} \leq share * \sum_i out_{i,k} ACT_{i,tp,RE} \quad (7)$$

Where $ACT_{tp,RE}$ is the total activity produced from renewable energy technology at period *tp*, $ACT_{i,tp,RE}$ is the activity produced from each renewable energy technology *i* at period *tp* and $share$ is the percentage share target output at period *tp*.

And lastly, Emission constraint is expressed as Equation 8 and 9:

$$ENV_{l.tp} = \sum_i (EMFuel_{f,tp} ACT_{f,tp}) \tag{8}$$

and,

$$ENV_{l.tp} \leq ENV\_LIMT_{l.tp} \tag{9}$$

Where $ENV_{l.tp}$ is the emission of pollutant *l* at period *tp*, and $EMFuel_{f,tp}ACT_{f,tp}$ is the fuel emission factor of fuel and the activity of fuel consumed at period *tp*, whereas, $ENV\_LIMT_{l.tp}$ upper limit of the pollutant *l* at time period *tp*.

2.2 Reference Energy Systems

In this section are the details provided for the base model, temporal scope, current social discount rate, and energy demand and energy resource potentials for the Philippines.

2.2.1 Base Model and Temporal Scope

The base model from this study is based on the Philippine Power Development Plan 2023-2050 and Philippine Energy Plan 2023-2050, reference scenario targets. This aligns with the National Renewable Energy (RE) power generation mix target of 35% by 2030 and 50% by 2040 up to 2050 (DOE, 2025b; 2023).

For temporal Scope, the study considers 8 time slices, representing four distinct seasons (December–February, March–May, June–August, September–November), further subdivided into day and night periods (Dixon *et al*., 2025).

2.2.2 Current Social Discount Rate

The National Economic and Development Authority (NEDA) Board, during its September 14, 2016 meeting, confirmed the Investment Coordination Committee's (ICC) approval of updating the Social Discount Rate (SDR) for the Philippines. The SDR was updated from the current rate of 15% to a lower rate of 10%. The SDR reflects the hurdle rate which the economic internal rate of return (EIRR) of a proposed project must equal or exceed to be considered economically viable (National Economic and Development Authority, 2016).

2.2.3 Electricity Demand

The electricity demand in this model was exogenously based on the electricity sales forecast in the Power Development Plan 2023-2050, reference scenario. The projection considers several future factors, such as the impact of distributed photovoltaics (PV), the adoption of electric vehicles (EV), the implementation of demand-side management programs, and improvements in energy efficiency (DOE, 2025). This Exogenous demand is inputted into the TIMES model as the demand data.

2.2.4 Primary Energy Resource Potentials

In this study the Coal and oil used in the power sector were assumed to be imported, while natural gas was domestically supplied by Malampaya Gas Field with proven reserves of about 2.7 trillion cubic feet (TCF) of natural gas reserves and 85 million barrels of condensate (DOE, n.d). However, aside from domestically availability for natural gas, this study also considers importation of natural gas.

Correspondingly, Geothermal power has a primary energy resource potential of around 4.407 GW based on a report stated by Halcon (2015). Hydropower has an estimated primary energy resource potential of approximately 653.9 GW, while solar and wind resources are estimated at 57 GW and 93.9 GW, respectively, across all provinces, according to data presented in the "*Ready for Renewables: Grid Planning and Competitive Renewable Energy Zones (CREZ) in the Philippine*" by conducted by Lee *et al.* (2020). The renewable energy potentials used in this study are based on national technical assessments and represent the total possible instantaneous capacity or the upper limit that could be achieved if all suitable land areas were fully developed

2.3 Techno-economic Parameters

Table 1 presents the techno-economic parameters of the technologies used in the power sector conversion process. The investment costs for fossil fuel-based technologies, such as coal-fired power plants and natural gas plants, were based on the Global Energy and Climate Model key input data 2024 (International Energy Agency, 2024), while the investment cost for Bunker/Diesel Internal Combustion Engines was based on the study by Limmeechokchai *et al.* (2022).

For geothermal, biomass, and hydro technologies—specifically single flash, binary type, and run-of-river—the investment costs were based on the *Renewable Power Generation Cost in 2023* (International Renewable Energy Agency, 2023). Meanwhile, for other types of hydropower plants and renewable energy technologies such as dam-type hydroelectric, solar, and wind power plants, investment cost data were requested and obtained from the Energy Regulatory Commission (ERC) of the Philippines through access in the freedom of information with tracking no #ERC-452655919866, and data were based the ERC Resolution No. 02, Series of 2022; ERC Resolution No. 06, Series of 2023; and ERC Resolution No. 19, Series of 2024.

Similarly, fixed and variable operating and maintenance cost secondary data were obtained from the same request in #ERC-452655919866 for each power plant installed in the Philippines, and a weighted average was computed for each type of power plant.

Lastly, the capacity factor was calculated from historical data using Equation 10, yielding a weighted average.

$$Capacity\ Factor = \frac{Actual\ Energy\ Output\ in\ a\ Given\ Period}{Maximum\ Possible\ Energy\ Output\ in\ the\ Same\ Period}\ x\ 100\% \quad (10)$$

Table 1. Techno economic parameters

Technology	Investment Cost (USD/MW)	Fixed O&M cost (USD/MW)	Variable O&M cost (USD/MWh)	Capacity Factor
Circulating Fluidized Bed (CFB) Coal	1,800,000.00	74,285.16	4.61	0.70
Pulverized Sub Critical Coal	1,800,000.00	56,178.52	2.29	0.70
Super Critical Coal	2,100,000.00	65,860.14	0.70	0.70
Bunker/Diesel Internal Combustion Engine	687,000.00	30,360.63	5.94	0.05
Combined Cycle Gas Turbine (CCGT)- oil based	1,000,000.00	47,844.11	2.45	0.05
Open Cycle Gas Turbine (OCGT)- oil based	500,000.00	38,155.47	13.45	0.05
Combined Cycle Gas Turbine (CCGT)- Natural Gas	1,000,000.00	47,844.11	2.45	0.58
Open Cycle Gas Turbine (OCGT)- Natural Gas	500,000.00	38,155.47	13.45	0.58
Single Flash Geothermal	4,589,440.88	32,828.98	1.61	0.66
Binary Geothermal	3,014,449.26	112,889.15	2.39	0.66

Dam-type HEPP-Impounding	4,098,990.24	41,825.60	8.13	0.25
Dam-type HEPP- Pumped Hydro	3,024,932.14	30,985.06	12.70	0.25
Run-of-River Type HEPP	1,870,883.02	82,950.64	16.68	0.25
Biomass Power Plant	3,566,292.48	49,572.43	25.54	0.29
Ground Mounted Solar PVs	890,000.00	30,558.22	8.31	0.17
Rooftop Installed Solar PVs + Battery	2,620,570.22	57,201.29	0.00	0.17
On-shore Wind Turbine	1,307,390.00	36,197.32	4.29	0.35

**Dollar to Peso conversion is based in the 2024 average value= Php 57.29 (Bangko Sentral ng Pilipinas)*

2.4 Learning Rates

Learning rates are essential parameters in energy system models and integrated assessment models, as they facilitate the projection of future technology costs and the optimization of overall energy system cost. It represents the percentage reduction in cost associated with each doubling of cumulative production or installed capacity (Rubin *et al.*, 2015) as shown in Equation 11.

$$Y = ax^b \tag{11}$$

Where Y denotes the unit cost of a technology, while x represents cumulative experience—typically measured as cumulative installed capacity (MW) or, in some cases, cumulative energy produced (MWh) for power generation technologies. The constants a and b in Equation 11 correspond to the initial unit cost and the rate of cost reduction, respectively. The learning rate (LR) refers to the fractional decrease in cost resulting from each doubling of cumulative experience as shown in Equation 12:

$$LR = 1 - 2^b \tag{12}$$

where the factor 2^b in the above equation is known as the “progress ratio”. In this study, learning rate values for each technology were taken from Rubin *et al*. (2015) and cost is modeled exogenously before inputted to TIMES model.

2.5 Model Validation

The model is validated using 2024 generation data and greenhouse gas (GHG) emissions based on the Department of Energy (DOE) 2024 Key Energy Statistics (DOE, 2025). Table 2 presents the generation mix validation results. Table 3 shows the GHG emission validation, confirming that the model outputs fall within the acceptable error threshold of 10% absolute percentage error before extending the model to 2050.

Table 2. Generation mix validation

Technology	Actual (2024) TWh	TIMES Model (2024) TWh	Error (%)
Oil	1.34	1.36	1.49%
Natural Gas	18.05	18.95	4.99%
Coal	79.35	79.75	0.50%
Renewable Energy	28.2	29.47	4.50%
Geothermal	10.79	11.28	4.54%
Hydro	10.91	11.32	3.76%
Wind	1.24	1.31	5.65%
Solar	3.81	4.04	6.04%
Biomass	1.45	1.52	4.83%

Table 3. GHG emission validation

Emission	Actual (2024) Million Tons	TIMES Model (2024) Million Tons	Error (%)
2024	97.46	90.63	7.01%

2.6 Scenarios

Table 4 presents the scenarios employed in this study, where variations in discount rates—specifically 3%, 5%, 8%, and 10%—were applied for the period 2024–2050. These values were selected based on the range of discount rates used in the study conducted by Limmeechokchai *et al.*, (2022). The RE_PH scenario represents baseline renewable energy scenario (RE_PH), which reflects the targets under the Philippine Energy Plan (PEP) and National Renewable Energy Program (NREP). In addition, two additional scenarios—RE_PH1 and RE_PH2—are introduced as sensitivity cases representing higher renewable energy ambition levels. These increments are designed to systematically explore the response of the power system to progressively stricter renewable energy targets, and to assess the implications for installed capacity, generation mix and system costs aligned with global decarbonization trends (Akpan & Olanrewaju, 2024). The 10% discount rate was used as the baseline, as it is the social discount rate set by the National Economic and Development Authority (NEDA) in the Philippines.

Table 4. Descriptions of scenarios used in the study

Scenario	Description
RE_PH	RE share in generation mix: at least 35 percent by 2030 and 50.0 percent by 2040 onwards. Capacity targets under the National Renewable Energy Program (NREP). This Scenario is Based on the Philippine Energy Plan 2023-2050 and Philippine Power development Plan 2023-2050 Business as Usual (BAU) scenario.
RE_PH1	An enhanced renewable energy scenario assuming an RE share of at least 40% by 2030 and 55% by 2040 onwards.
RE_PH2	A high renewable energy scenario assuming an RE share of at least 45% by 2030 and 60% by 2040 onwards.

3. Results and Discussion

3.1 Impact on RE Targets

This study investigates the impact of discount rates on the generation mix, installed capacity, fuel consumption, and emissions under specified renewable energy (RE) target scenarios for Philippines. Discount rates were applied across three scenarios, each representing different RE targets as outlined in Section 2.6.

In line with this shift towards clean energy, the Department of Energy (DOE) announced a moratorium on approvals for new coal-fired power plant projects last December 22, 2020. The moratorium is in line with the DOE's initiatives to enhance the sustainability of the Philippine Electric Power Industry and aid in achieving the renewable energy capacity goals set forth in the National Renewable Energy Program (NREP). The advisory states that the DOE will no longer process applications for endorsement of new coal fired power plant projects, except for those: projects already considered "committed coal-fired power projects" that have made significant progress (a), existing coal-fired power plants with firm expansion plans and pre-existing land site provisions (b), and indicative power projects that have also made substantial progress (c), including signed and notarized land acquisition or lease agreements, and approved permits or resolutions from local government units (DOE, 2025).

In this study the capacity of coal will approximately be maximum in 2030 at 14.7 GW based on Department of Energy's approved projects in the future until 2030 and will become constant until 2050. This data will be inputted into the model, and no additional units will be added further from 2030 up to 2050.

These assumptions were all applied across all scenarios in this study and solved through an optimization model called TIMES model. Figure 1 and 2 shows the generation mix and installed capacity expansion across all scenarios.

For RE_PH, a 3% discount rate shows a shift in early deployment of additional renewable energy technology from Run-of-River (PP-ROR) technology to Pump Hydro storage (PP-Pump-HYD) technology as shown in Figure 2a, with additional installed capacity of 1.1 GW supposed to be added in the period 2024 compared to other discount rates. This additional capacity produces an additional 2.9 TWh of electricity in the mix in the same year and the next succeeding years.

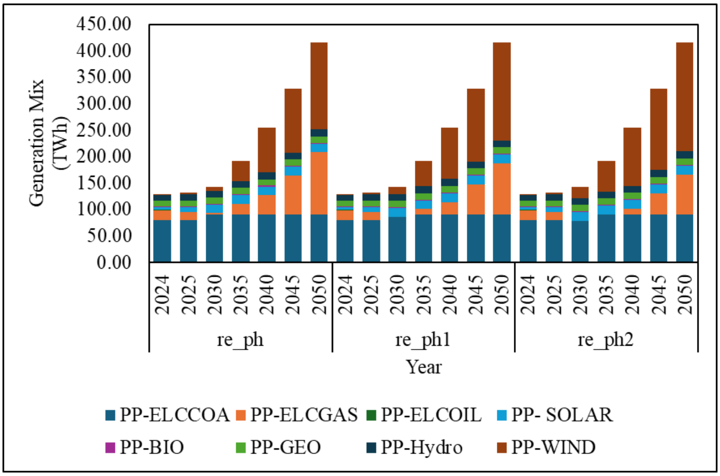

Figure 1. Generation mix: re_ph (a), re_ph1 (b), re_ph2 (c)

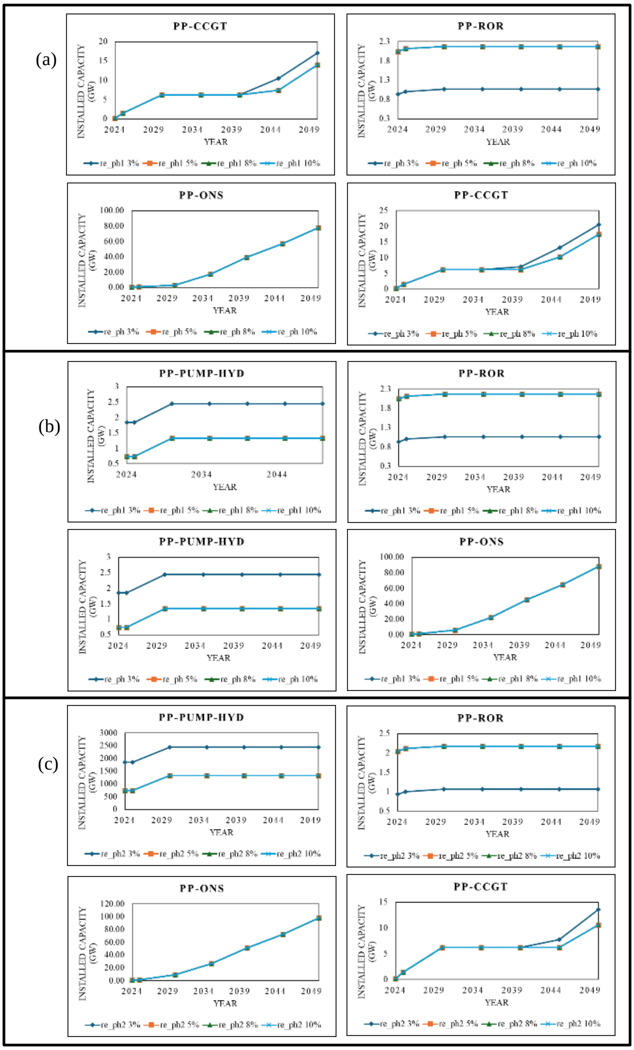

Figure 2. Capacity expansions during the period: re_ph (a), re_ph1 (b), re_ph2 (c)

Subsequently, to meet RE target share in 2030 approximately 1.6 GW of onshore wind power (PP-ONS) is projected to be added across all discount rate scenarios, resulting in a cumulative capacity of 2.6 GW and an annual generation of 8.2 TWh. By 2050, the cumulative capacity of PP-ONS increases to 78.1 GW, producing approximately 165 TWh of electricity in contribution to the target RE generation share.

In contrast, for combined-cycle gas turbines (PP-CCGT), additional units were exogenously specified in the model, as the Department of Energy (DOE) has already approved several projects expected to be commissioned around 2030. However, the model finds it optimal under the 3% discount rate to install an additional 0.9 GW in 2040, compared to higher discount rate scenarios, to achieve the desired generation mix in conjunction with renewable energy technologies. This results in a cumulative capacity of 7.1 GW and generation of 37 TWh in 2040. By 2050, the cumulative capacity of PP-CCGT further increases to 20.5 GW under the 3% discount rate, compared to 17.5 GW under the 5%, 8%, and 10% discount rate scenarios, generating about the same amount 118 TWh of electricity, supplying the remaining share beyond the RE generation mix.

Also to achieve the increasing demand in the preceding years, majority of the simulations across discount rates except for 3% in RE_PH scenario's pump hydro storage, run-of-river plant, onshore wind and combine cycle gas turbine technology, shows a uniform total installed capacity for both fossil fuel (coal and oil) and renewable energy sources until 2050. No additional capacities endogenously added by the model except for capacities already approved by the DOE in their capacity expansion until 2030 and is exogenously inputted in the model.

Similarly, in both RE_PH1 and RE_PH2 scenarios, a similar effect was observed at the 3% discount rate compared to the higher rates as shown in Figure 2b and 2c. In these scenarios, the 3% discount rate also led to shift in early deployment of additional renewable energy technology from Run-of-River (PP-ROR) technology to Pump Hydro storage (PP-Pump-HYD) technology with same installed capacity of 1.1 GW in the same year. However, Since RE deployment targets were increased in these scenarios a notable increase in wind power capacity was invested and installed in the period 2030 up to 2050 to meet demand.

For the RE_PH1 scenario, 4.5 GW of onshore wind power (PP-ONS) capacity is added in 2030 across all discount rates resulting in a cumulative capacity of 5.5 GW and generating approximately 14.2 TWh to meet demand and meet the targeted generation mix during the period. Furthermore, by 2050, the cumulative installed capacity increases to 88 GW, producing about 185 TWh of electricity to meet demand and sustain the RE share in the overall mix.

Despite the increase in renewable energy (RE) investments, the capacity of combined-cycle gas turbines (PP-CCGT) also expands beyond the units exogenously specified in the model up to 2030. The model finds it cost-optimal under the 3% discount rate to endogenously build an additional 4.3 GW of PP-CCGT capacity, resulting in a cumulative capacity of 10.5 GW by 2045 and generating 41 TWh electricity. This value is higher than the cumulative capacities under 5%, 8%, and 10% discount rate scenarios, which is only 7.4 GW supplying the same amount of electricity produced in 3% discount rate after achieving the RE generation mix targets. Furthermore, by 2050, the cumulative capacity under the 3% discount rate increases to 17 GW, compared to 14 GW under the 5%, 8%, and 10% discount rate and produces 97 TWh of electricity.

In the same way, for the RE_PH2 scenario across all discount rates, wind power (PP-ONS) capacity increases by an additional 8.1GW by 2030 to supplement renewable generation and achieve the 2030 RE target. The Cumulative capacity in 2030 reaches 9 GW and generating 21.3 TWh of electricity in the mix. Furthermore, by 2050, the cumulative capacity further increases to up to 98.2 GW complementing other RE generators to meet target share for the period and contributing about 207 TWh to the total generation mix.

In addition, combined-cycle gas turbines (PP-CCGT) also expand beyond the units exogenously specified in the model up to 2030. Similarly, the model also finds it cost-optimal under the 3% discount rate to endogenously build additional units 1.6 GW of PP-CCGT capacity, resulting in a cumulative capacity of 7.8 GW by 2045 and generating 57.4 TWh electricity. This capacity is higher compared to the cumulative capacities under the 5%, 8%, and 10% discount rate, which is 6.2 GW only. Furthermore, by 2050, the cumulative capacity under the 3% discount rate increases to 13.6 GW, compared to 10.6 GW under the 5%, 8%, and 10% discount rate producing the same amount 76.34 TWh electricity in the period.

The projected long-term expansion of wind power across all scenarios and discount rates is largely driven by the Philippines' significant wind resource potential, as identified in *Ready for Renewables: Grid Planning and Competitive Renewable Energy Zones (CREZ) in the Philippine*s (Lee *et al*., 2020). As a techno-economic optimization framework, the TIMES model allocates technologies based on cost-optimal utilization of available resources. However, the model is not spatially explicit and therefore cannot represent the exact geographical distribution of resource deployment or the specific locations of future wind capacity installations.

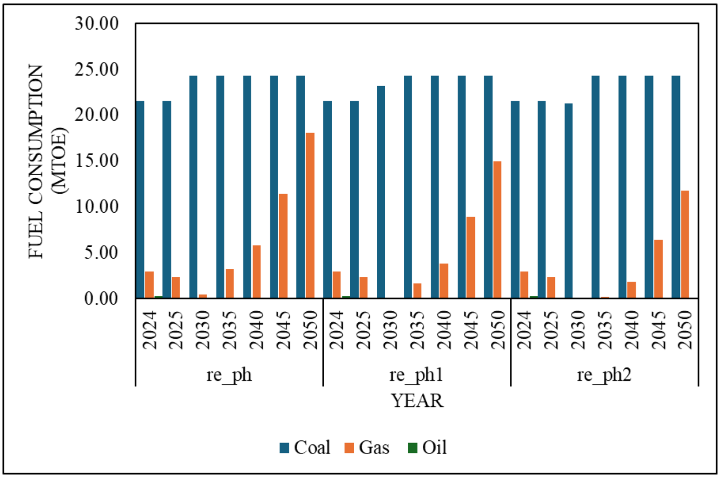

Figure 3. Fuel consumption

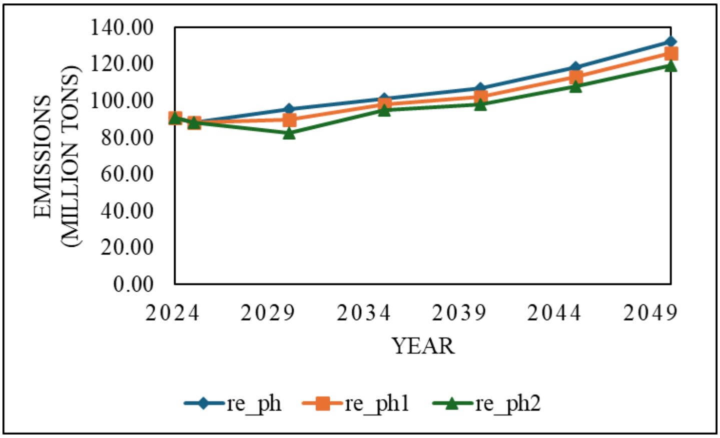

Figure 4. Emissions

For fuel consumption and emissions, as shown in Figure 3 and 4, there is no significant variation across all discount rate scenarios (3%, 5%, 8%, and 10%). In the RE_PH scenario, cumulative fuel consumption for coal, natural gas, and oil across 2024-2050 is equivalent to 652 MTOE, 200 MTOE and 0.27 MTOE, respectively, while cumulative emissions over the period is 2,951 million metric tons as computed based on Equation 8. In comparison, the RE_PH1 scenario results in cumulative fuel consumption in coal, natural gas, and oil to 646 MTOE, 152 MTOE and 0.27 MTOE, respectively, and emissions equivalent to 2,828 million metric tons. Meanwhile, the RE_PH2 scenario records cumulative fuel consumption of 636 MTOE, 107 MTOE, and 0.27 MTOE for coal, natural gas, and oil, respectively, with total emissions totaling 2,694 million metric tons.

Total emissions remain nearly constant across all discount rates, suggesting that the discount rate primarily affects investment timing and technology selection rather than the overall emissions level. This stability results from the consistent consumption of fossil fuels, as coal-, oil-, and gas-fired technologies continue to operate at maximum load, constrained by their installed capacities and capacity factors to meet renewable energy share targets. Consequently, variations in the discount rate have a negligible impact on total emissions. A substantial reduction in emissions can only be achieved through a significant increase in the share of renewable energy in the generation mix as illustrated in Figure 4, thereby displacing fossil fuel consumption.

3.2 Cost-Effectiveness of RE Technologies

Figure 5 presents the results of the sensitivity analysis of total discounted costs and discounted savings across all scenarios. In RE_PH scenario, the total discounted cost at the baseline discount rate of 10%, established by the National Economic and Development Authority (NEDA), is approximately 103 billion USD. For rates 8%, 5%, and 3%, the total discounted cost escalates to 125, 175, and 227 billion USD, respectively. Meanwhile, sum of period-averaged discounted savings generated by 8%, 5%, and 3% are equivalent to 0.5, 2.3 and 4.6 billion USD, respectively, relative to baseline 10%.

A comparable trend is also evident in the RE_PH1 and RE_PH2 scenarios. In RE_PH1 scenario, the baseline 10% discount rate total discounted cost is approximately 101 billion USD, which increases to 122, 169, and 218 billion USD for 8%, 5%, and 3% discount rates, respectively. Sum of period-averaged discounted savings generated are equivalent to 0.6, 2.6, and 5.2 billion USD, respectively.

In the RE_PH2 scenario, the baseline total discounted cost is approximately 100 billion USD and rises to 120, 165 and 211 billion USD at 8%, 5%, and 3% discount rates, respectively. Moreover, sum of period-averaged discounted savings generated are 0.7, 3 and 6 billion USD, respectively relative to baseline

Furthermore, Figure 6 shows the cumulative undiscounted cost of each scenario with varying discount rates up to the year 2050. For RE_PH the cumulative undiscounted cost amounts to approximately 201, 189, 171, and 161 billion USD across discount rates 10%, 8%, 5% and 3%, respectively. Meanwhile, for RE_PH1, approximately 215, 201, 181 and 170 billion USD for 10%, 8%, 5% and 3%, respectively. As well as, for RE_PH2 cost estimates are up to 229, 214, 192 and 179 billion USD for 10%, 8%, 5% and 3% discount rates. These figures can serve as estimate for informing future government energy planning and budgeting efforts for infrastructure needs.

In addition, the price of electricity across all scenarios decreases as the discount rate declines. The average electricity prices for the 10%, 8%, 5%, and 3% discount rate scenarios are presented in Table 5.

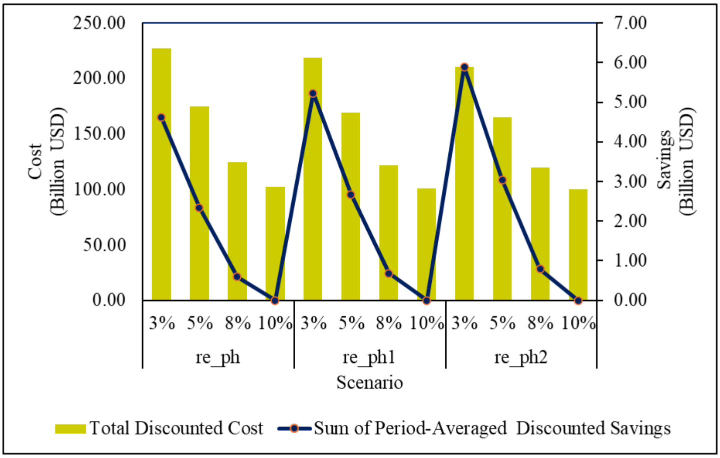

Figure 5. Comparison of total discounted system cost and discounted savings under different discount rate assumptions

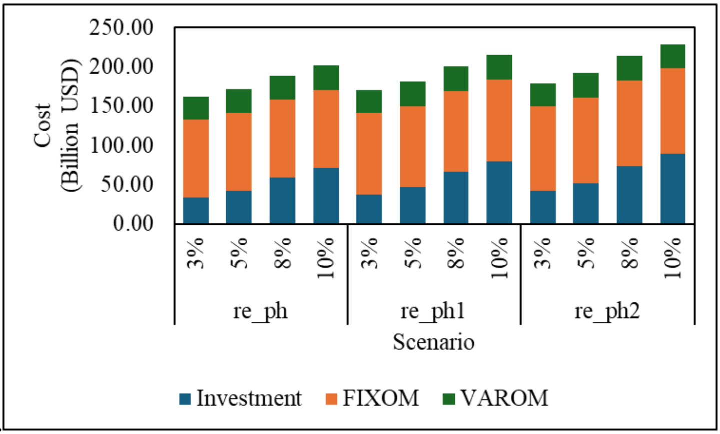

Figure 6. Cumulative undiscounted cost up to 2050

Table 5. Average electricity price across all scenarios

Scenario	Discount Rate	Average Price of Electricity (USD/MWh)
RE_PH	3%	66.48
	5%	68.38
	8%	71.47
	10 %	73.63
RE_PH1	3%	61.67
	5%	64.05
	8%	67.98
	10 %	70.73
RE_PH2	3%	60.07
	5%	62.52
	8%	66.51
	10 %	69.29

3.3 Discussion

The results indicate that lower discount rates encourage earlier investment in renewable energy technologies within the planning horizon, particularly during the critical milestone years of 2030 and 2040, when renewable energy targets must be achieved across all modeled scenarios. In this case, across all scenarios with a 3% discount rate, the model suggests that, as early as 2024, installing a pump hydro storage power plant is more economically viable in the long run rather than run-of-river hydro power plant to meet the target on time. However, these results should not be interpreted to imply that power plants can be constructed within a short period. Rather, they demonstrate the influence of discount rates on the economic timing of investments, particularly for capital-intensive renewable energy technologies, by indicating when such investments become cost-optimal within the model.

It is also important to reckon that early investment in renewable energy technologies can reduce fuel expenditures and operation and maintenance costs when system operation is optimized, particularly under stringent greenhouse gas (GHG) emission constraints. However, in this study, the scenarios were limited to renewable energy policy targets rather than explicit emission reduction constraints; consequently, no significant changes in fuel consumption or GHG emissions were observed. These findings are consistent with previous studies conducted by Diawuo et al. (2020) and Kichonge et al. (2015), which likewise concluded that lower discount rates favor earlier investments in renewable energy technologies to achieve long-term policy targets.

Across all scenarios, total discounted costs increase as discount rates decrease because greater weight is assigned to future investment and operating costs. This reflects a greater willingness to incur higher upfront investment costs in exchange for long-term reductions in operating costs as illustrated in Figure 5. In contrast, higher discount rates generally lead to reduced investments in capital-intensive renewable energy projects because future cash flows and long-term cost savings are discounted more heavily, reducing their present value making long-term generation investments appear less attractive, particularly integrating energy and climate policies (Philibert, 2023; Nesticò & Maselli, 2020). These results will help decision makers to decide which pathway to transition they will consider by valuing future costs to benefits relative to their present value.

In addition to the total discounted cost, the significant reduction in cumulative undiscounted investment costs across all scenarios under lower discount rates is primarily driven by the early deployment of renewable energy technologies and the optimization process obtaining the least cost operation (Philibert, 2023; Guerriero & Pacelli, 2020). This effect is particularly evident under the 3% discount rate, where pumped hydro storage is introduced earlier. This technology requires high upfront capital investment but has moderate fixed operation and maintenance (O&M) costs (30,985 USD/MW) and relatively low variable O&M costs (12.7 USD/MWh), which are incurred only during operation compared to run-of-river technology. Owing to its high-capacity factor and relatively high round-trip efficiency, pumped hydro storage enters the system early to support renewable energy integration, even before intermittent renewables such as wind power expand substantially.

In contrast, other renewable energy technologies, such as ground-mounted and rooftop solar PV, are not cost-competitive in this simulation due to their inherent supply variability and relatively lower capacity factors compared to onshore wind power. Geothermal power plants, while economically viable, have already reached their maximum resource potential. Consequently, as electricity demand continues to rise, onshore wind power (PP-ONS) becomes the next least-cost renewable energy technology to expand, owing to its moderate investment requirements over time, a reasonable capacity factor of approximately 35% in this study, and its substantial resource potential as evaluated by Lee et al. (2020).

In addition, to satisfy the growing electricity demand, the model also indicates a gradual shift toward natural gas combined-cycle gas turbines (PP-CCGT) through 2050. This shift is driven by their relatively low variable operation and maintenance costs (2.45 USD/MWh) and high capacity factor (58%), allowing them to replace coal-fired capacity expansion in line with the DOE's coal moratorium.

Finally, lower discount rates also have important implications for long-term electricity prices. By improving the economic attractiveness of capital-intensive renewable energy technologies, lower discount rates encourage earlier investment of these technologies, which can reduce overall system costs, improve the long-term cost efficiency of the generation portfolio, enhance energy supply security, and mitigate economic risks associated with fuel price volatility arising from geopolitical instability, ultimately contributing to lower electricity prices over time (Chung et al., 2026). Within the TIMES framework, these effects are reflected in the shadow prices (dual values) of the electricity supply–demand balance constraints associated with Equation 4 for each region and time slice.

3.4 Policy Implications

For policy implications, the adoption of lower social discount rates may facilitate more robust decarbonization efforts within the energy sector, which is the predominant source of greenhouse gas (GHG) emissions in the

Philippines, if further explored with market-based policy instruments. This strategic shift could motivate policymakers and government officials to plan significant emission reduction targets and enhance energy strategies towards low-carbon pathways. Additionally, reduced discount rates may attract private investment, thereby increasing the competitiveness of renewable energy within the overall energy mix. Crucially, this approach aligns with the pursuit of decarbonization objectives, including the Philippines' Nationally Determined Contributions (NDC) as outlined in the Paris Agreement, by engendering interest from private investors, public institutions, and international funding agencies.

While lower discount rates are often used to promote long-term investments, it can also lead to suboptimal outcomes if not properly managed. Overvaluing future cash flows may result in overinvestment in projects with limited profitability, ultimately reducing overall economic efficiency, such as observed by Berchtold *et al*. (2021). Similarly, in the public sector, lower discount rates can influence the structure of public debt by justifying increased spending on long-term projects. Public officials may often prioritize projects with immediate benefits to gain public favor and if not strategically optimized, this can lead to higher public debt levels, inefficient allocation of public funds for subsidies, and lastly may potentially cause increase in electricity prices (Hodula & Melecký, 2020; Corotis, 2006).

The choice of discount rate involves ethical and philosophical considerations, particularly regarding how much weight to place on the welfare of future generations. Lower discount rates are often advocated to reflect the ethical stance that future generations should be treated equitably (Terzioğlu, 2021; Fleurbaey *et al*., 2019).

While a 3% discount rate shows good results in this study, real-world adoption is hindered by high financing costs, risk, market uncertainties, political priorities, and institutional constraints (Caplin & Leahy, 2023; Wolak & Hardman, 2022; Park & Matunhire, 2011). Overcoming these barriers requires coordinated policy, access to low-cost capital, and clear communication of long-term benefits. Therefore, the right choice of choosing the right discount rate needs to have a proper methodology and thorough stakeholder and expert consultation.

4. Conclusion and Recommendation

This study investigates the role of the discount rates in achieving renewable energy target goals and the cost effectiveness of renewable energy technologies in the Philippines. Using the TIMES model, a well-established, technology-rich optimization tool that enables detailed representation of energy system investment decisions under varying discount rate assumptions, this study analyzed national data and scenarios to assess the impact of different discount rates on the deployment of renewable energy technologies in the power sector.

The findings reveal that lower discount rates have a significant influence on investment timing and the cost structure of the Philippine power sector. Specifically, the 3% discount rate encourages the earlier deployment of capital-intensive renewable energy technologies, such as pumped hydro storage (PP-PUMP-HYD) and onshore wind (PP-ONS). This facilitates renewable energy integration while reducing cumulative undiscounted investment costs. While solar PVs remain less attractive due to their variability and lower capacity factors, and geothermal potential is largely saturated, natural gas combined-cycle plants complement the transition by replacing coal capacity expansion in line with the DOE's moratorium. The study further shows that lower discount rates increase total discounted system costs due to greater weight on future investments, but contributes to long-term cost savings, and reduced electricity prices.

However, results using the TIMES model are sensitive to assumptions, including discount rates, fuel prices, technology costs and renewable energy resource potentials. Changes in these assumptions can lead to substantially different investment recommendations. In addition, because TIMES focuses on cost minimization and finds least-cost solutions, it may not fully capture social, political, or institutional considerations that can affect real-world decision-making. These limitations highlight the need for careful interpretation of model outputs and complementary analyses to account for non-economic factors.

Moreover, TIMES model also is not a spatially explicit model, Therefore, it cannot capture the precise geographical locations of technology build-outs or resource deployment in the future. To ensure reliable and continuous access to electricity in the long run, incorporating spatially explicit modeling is necessary to determine the locations where large-scale renewable energy projects, such as wind power plants, can be deployed, considering factors such as resource potential, grid connectivity, environmental constraints, and social considerations.

Finally, while lower discount rates can promote long-term investments and support intergenerational equity, they must be carefully selected and managed to avoid economic inefficiencies and fiscal imbalances. A balanced, well-informed approach—grounded in robust methodology and inclusive stakeholder consultation—is essential to ensure that discount rate choices align with both economic and ethical objectives. Therefore, carefully calibrating discount rates is essential—not only to optimize the economic viability of renewable energy investments, but also to ensure a just, efficient, and sustainable energy transition in the Philippines

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