The Critical Link: Empowering Utilities for The Energy Transition – Modelling annex

This annex describes the modelling in Section 3 of the *The Critical Link* paper. The modelling involves forward-looking analyses for a vertically integrated utility over the 2025-2060 horizon to illustrate the challenges and opportunities the energy transition poses onto electric utilities. These forward-looking analyses complement the analysis of historical data shown in Section 2 in paper.

The forward-looking analyses involved three parts:

1. Part 1 (Section A1): Determine the evolution of the electricity demand, utility technology mix and associated utility economic and financial results for the scenarios without and with the energy transition.

2. Part 2 (Section A2): Simulate different shocks to assess selected challenges and opportunities for the utility, for the cases without and with the energy transition.

3. Part 3 (Section A3): Analyze the need for concessional finance to reduce the incremental costs of decarbonization.

A1. Forward-looking analyses without shocks

This first step allows understanding how the broad goals of the energy transition impact the technical and economic-financial makeup of the utility.

Assumptions

The scenarios without and with the energy transition only differ in terms of electricity demand (and resulting electricity consumption served by the utility) and the utility technology mix:

- Electricity demand
    - Without transition: organic growth of 2.5% per year only
    - With transition: on top of organic growth as in the without transition scenario, the with transition scenario considers additional demand from end-use electrification (e.g., cars, heating, industry, etc.) and increasing access.
- Utility technology mix – generation and storage[1]
    - Without transition: least cost optimization expansion of the system without emission constraints for the 2025-2060 period
    - With transition: least cost optimization expansion of the system **with** emission constraints for the 2025-2060 period. The emission constraint in each year decreases linearly to near zero by 2050. Impacts of adaptation of the power system to climate risks have not been considered.

[1] Capital costs, operating costs, and expected reductions in capital costs for the different technologies are in line with IEA World Energy Outlook (2022) and the NREL Annual Technology Baseline (2022). The least-cost expansion plans are based on the power system of a hypothetical representative utility in Africa.

Beyond 2050, we have assumed that the share of each technology remains unchanged and that demand patterns, including load factors and hourly profiles, do not change. The evolution of the transmission and distribution systems in both scenarios was obtained by post-processing the results of the optimal generation and storage expansion plan using engineering considerations and reasonable assumptions. The key assumptions resulting in different network expansion plans for the without and with transition scenario include:

(i) location-constrained wind and solar generation are more distant of load centers and the existing transmission grid than thermal power plants running on fossil fuels
(ii) increased electricity access in the with transition scenario comes at lower demand per consumer and higher distances from the existing grid than demand resulting from organic growth in the without transition scenario
(iii) higher load factors and higher demand per unit of network length from the additional demand due to electrification in the with transition scenario, as these new loads will mainly be in urban areas and/or close to the existing grid.

The same set of regulatory and financial assumptions are applied to both scenarios:

(i) A vertically integrated utility subjected to rate-of-return regulation with a price control period of 5 years (2025-2029; 2030-2034; 2035-2039; ...). As a result, regulatory parameters such as the cost of debt, the cost of equity, and the weighted average cost of capital (WACC) are fixed for each 5-year price control period. The utility is remunerated for a return on capital (WACC x regulatory asset base), depreciation, and operating costs (opex).

(ii) A rate-of-return regulation primarily focused on incentivizing efficient utility behavior. As a result, we have assumed that working capital is not remunerated. The utility is assumed to be reasonably efficient, and its performance (in terms of operations, costs for the different generation and storage plants, cost of transmission and distribution) is close to typical (efficient) regulatory benchmarks.

(iii) All (new) debt is assumed to be commercial, and the utility does not utilize other classes of debt priced below market rates. Debt is assumed to be split 80/20 between long term (10-year repayment period at 11.7% interest rate) and short term (2-year repayment period at 8.4% interest rate). The maximum allowable debt service coverage ratio (EBIT divided by debt service costs) is 1.2. The maximum allowable share of debt in the capital structure is 60%.

(iv) The cost of equity is calculated using the capital asset pricing model using a typical country risk premium for emerging markets. The assumed cost of equity is 17.0%.

Results – Physical features

Figure A1 shows the electricity demand forecast (including losses) for the scenarios without and with the energy transition. The least-cost capacity plan to meet demand in the two scenarios is shown in Figure A2. In the case with the transition, the utility needs to: (i) cope with much higher demand growth rates, especially in the 2035-2045 period, (ii) integrate much higher amounts of (variable) generation capacity into its network; and (iii) move away from unabated fossil-fueled plants towards more capital intensive (a higher share of capital costs as part of total costs in the cost structure) technologies, notably wind and solar photovoltaic (PV) plants but also fossil-fueled generation with carbon capture and storage (CCS)[2]. The expected 1.5 times increase in demand by 2050 in the with transition scenario vs. the without transition scenario is based on the 2050 (the final year in the IEA scenarios) ratio of total electricity demand in the IEA Net Zero Emission (NZE) scenario and the IEA Stated Policies (STEPS) scenario[3]. The IEA STEPS scenario gives an outlook based on stated policies with minimal additional climate actions and increase in access, in line with our scenario without the transition. The IEA NZE provides an ambitious pathway towards net zero emissions in the energy sector by 2050 and with universal access by 2030 and the highest growth rates in electricity demand after 2030, in line with our with transition scenario. The NZE Scenario is consistent with limiting global temperature rise to 1.5°C (with at least a 50% probability).

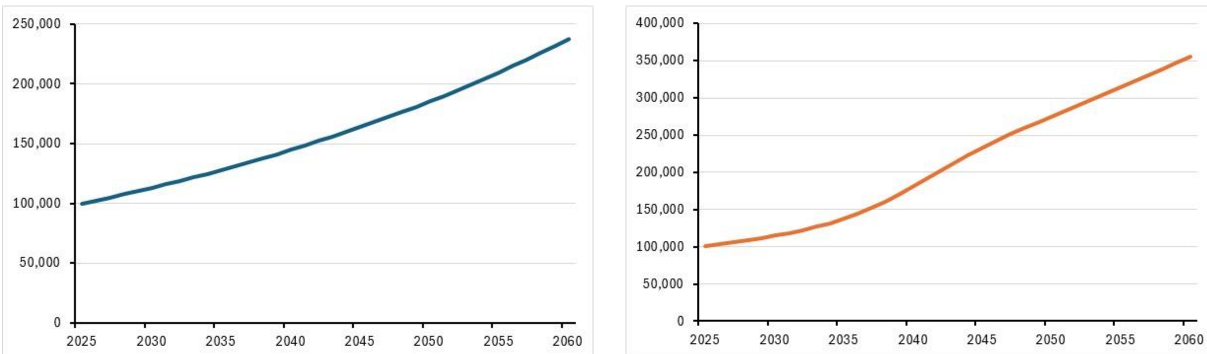

Figure A1: Electricity demand including losses (in GWh) – without (left) and with (right) the energy transition.

The generation capacity (GW) grows at even higher rates than electricity production (in GWh) in the with transition scenario since wind and solar PV produce less energy per unit of capacity than most fossil-fueled plants. The large growth in capacity for the with transition scenario (especially solar PV and wind) contributes to the higher intensity of capital expenditures (capex) for the with transition scenario.

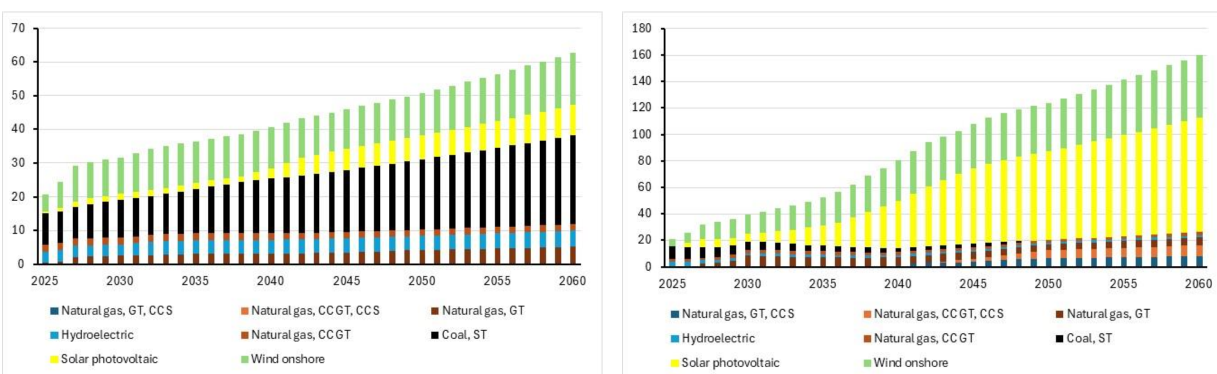

Figure A2: Installed capacity (in GW) – without (left) and with (right) the energy transition.

[2] The capital intensity of CCS for the generator depends on technology options and commercial arrangements. The technical options to capture carbon from the power plant flue gas are generally capital-intensive. Transportation and storage of captured carbon may be a service provided by third parties and perceived as opex by the generator or may be achieved via infrastructure developed by the utility itself. We assume that the utility has built the necessary capital-intensive infrastructure for carbon capture, transportation, and storage.

[3] Based on IEA World Energy Outlook (2023). Both scenarios cover the horizon 2024 - 2050.

In the transition scenario, solar and wind contribute to more than 80% of generation by 2050 (Figure A3). Consequently, the percentage of VRE generation increases from 17.5% in 2025 to 83% in 2050 in the with transition scenario.

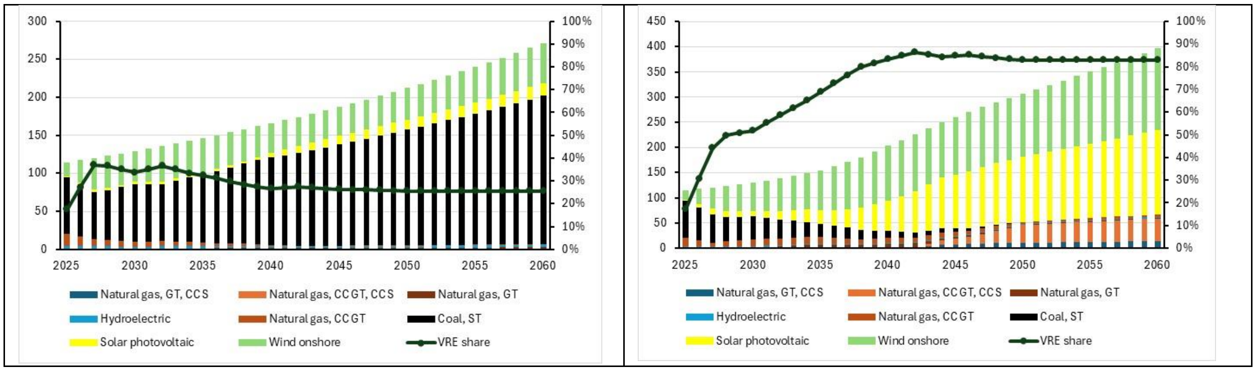

Figure A3: Generation (in GWh; primary axis) and VRE share of generation mix (secondary axis) – without (left) and with (right) the energy transition.

The electricity demand and generation patterns impact network activities as follows:

- *Transmission*: The higher shares of wind and solar PV in the generation mix for the with transition scenario lead to higher values for the average transmission network length per unit of demand, measured in kilometers per MWh (Figure A4), due to: (i) a higher parcel of location-constrained generation sited further away from load centers, as high-quality solar and wind resources are assumed to be further away from load centers than other generation resources and requiring additional network redundancy leading to an average increase in network length per unit of demand ~~by 15% for every increase in~~ ; and (ii) the lower average use of the transmission grid, due to the lower average capacity factors (average yearly production per MW installed) of wind and solar plants and their variability, resulting in increased investments to accommodate variable power flows through additional structural redundancy[4].

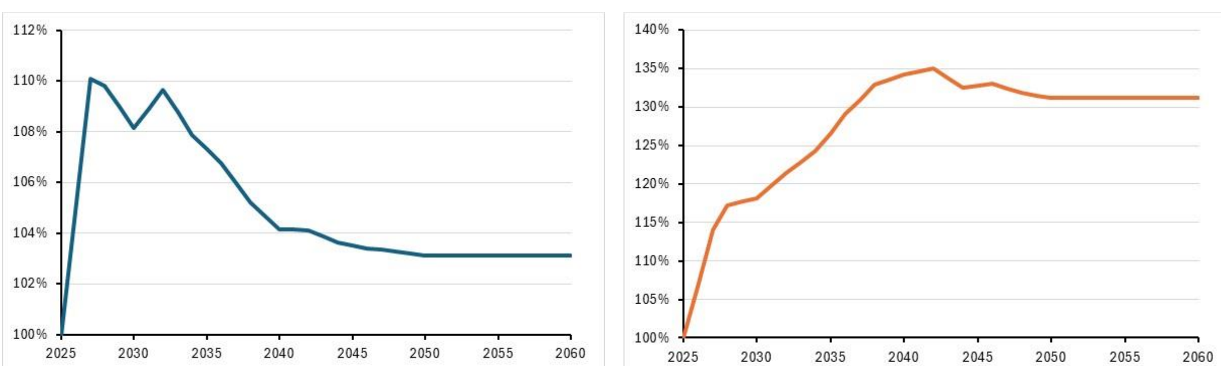

Figure A4: Transmission grid length per unit of demand (2025 = 100%) – without (left) and with (right) the energy transition.

- *Distribution*: ~~n.~~ Distribution costs per unit of demand in the without transition scenario decrease as a result of the assumed (small) increase in load factor. Initially the increase in electricity access, with the incorporation of consumers located further away from the existing grid and in areas with lower

[4] Even after technologies to improve the observability and control of the transmission system have been deployed.

load density result in higher costs per unit of demand in the with transition scenario vs. the without transition scenario. After 2035, the electrification of final energy uses outweighs the effect of increased access resulting in a decrease in distribution costs per unit of demand over time in the with transition scenario. End-use electrification, including industry and transport, incorporates consumers with a higher load density per consumer typically within urbanized areas with higher network density.

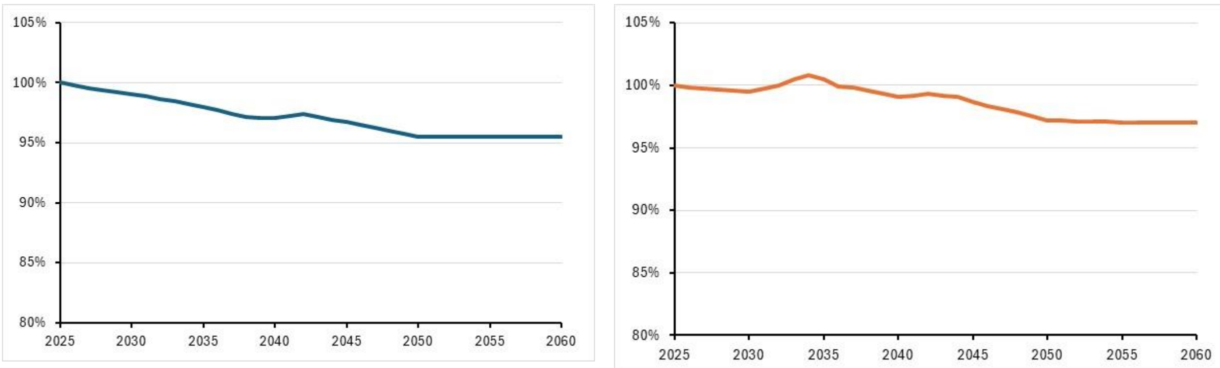

Figure A5: Distribution cost per unit of demand served by the grid (100% = 2025) – without (left) and with (right) the energy transition.

Results – Cost structure and asset base

Figure A6 shows the comparatively higher capital-intensity of the utility's cost structure for the scenario with the energy transition. The share of capital costs (capital recovery and remuneration) in the cost structure is consistently higher in the with transition scenario. This results from: (i) the higher share of capital-intensive renewables, storage, and gas with carbon capture in the installed capacity; and (ii) the increase share of the transmission segment in the total costs, which is usually more capital-intensive than generation and distribution.

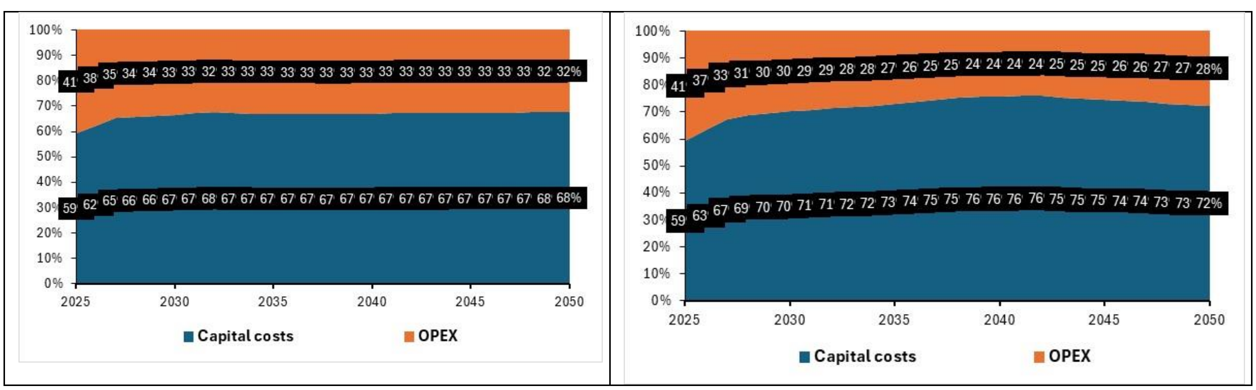

Figure A6: Cost structure of utility (%) – *without* (left) and *with* (right) energy transition.

Figure A7 shows the increase in regulatory asset base (RAB) for the without and with transition scenarios. The RAB in the with transition scenario is consistently higher since a) the utility needs to meet a higher demand and b) the utility needs to invest in more capital-intensive assets. A consistently higher RAB in the with transition scenario also implies that the cumulative required capital outlays in the transition scenario are much higher: 62% more capital expenditure is required by 2050 in the with transition scenario.

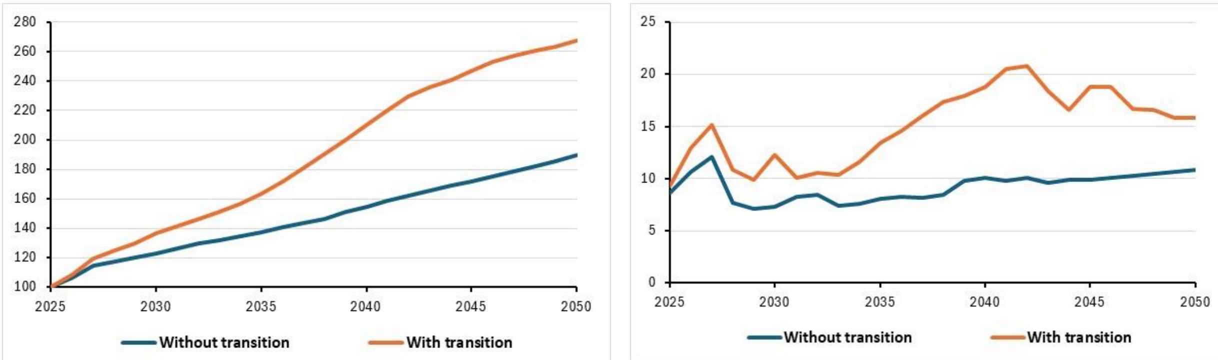

Figure A7: Regulatory asset base (in billion USD; left) and capital expenditure (in million USD; right).

A2. Forward-looking analyses with shocks

Context – Shocks illustrating challenges related to a shift towards increased capital-intensity

The following sections describe the impact for both the without and with transition scenario of a) an interest rate shock; b) a fuel prices shock; c) an asset impairment shock and d) a demand shock. The selected metric to compare across scenarios without and with the transition is the economic cost recovery, defined as the ratio of revenue to economic costs (operational expenses, depreciation, taxes, interest on debt, and target equity remuneration at the actual opportunity cost for equity shareholders).

A. Interest rate shock – Higher exposure to oscillations in interest rates due to higher capex-intensity in the with transition scenario.

For the interest rate shock, we have assumed that the country-specific risk-free interest rate[5] changes in line with the oscillations in Figure A8. The pattern and magnitude of these oscillations were obtained from historic data on real rates for 10-year treasury bonds in an emerging market (Brazil). In the baseline scenario without the shock, the value remains constant (Figure A8).

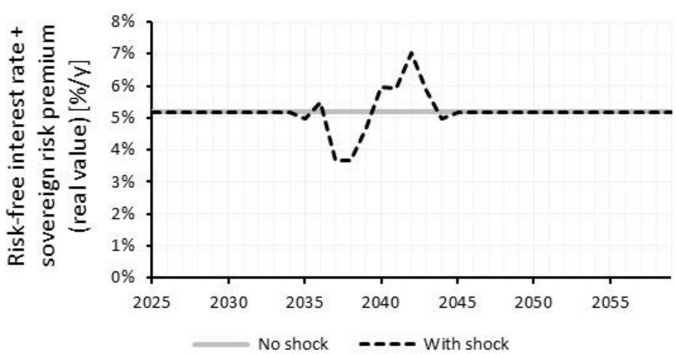

Figure A8: Simulated shock – country-specific risk-free interest rate.

The interest rate shock affects both the actual cost of capital (equity and debt) of the utility and the regulatory benchmark for the weighted average cost of capital (WACC) used for revenue setting. Impacts on the actual WACC are felt immediately[6], whereas impacts on the regulatory benchmark are delayed since this parameter is determined only at the beginning of each 5-year tariff review cycle. The regulatory benchmark WACC is recalculated in the beginning of each 5-year cycle. The interest shock is assumed to only affect the utility's capital costs, not its operating costs. The shock begins in the first year of the 2035-2039 tariff cycle, and the valley of the oscillations precedes the peak. Therefore, the utility first experiences actual costs below the regulatory benchmark, improving the economic cost recovery. In the following tariff cycle (2040-2044) the actual costs exceed the regulatory WACC, and the economic cost recovery deteriorates with respect to the no shock baseline. Figure A9 shows the resulting change

[5] This can be understood as the global risk-free interest rate plus a sovereign (country) risk premium.

[6] Impacts on the cost of equity will generally immediately materialize. The impacts on the cost of debt will depend on the share of debt contracted at fixed and at floating rates. Many utilities, especially in developing countries, have a significant portion of floating rate debt in their debt stock. Our modelling assumes that all debt is priced at floating rates.

in cost recovery. The change in cost recovery from top to trough is 21.5 percentage points (pp) for the without transition scenario whereas the impact in the without transition scenario is 19.5 pp. The higher share of capital-related costs in the economic cost structure in the with transition scenario results in oscillations with higher magnitude, amplifying peaks (when the utility perceives an upside) and valleys (downsides) with respect to the without transition scenario. This sensitivity thus shows the comparatively higher financial risks resulting from interest rate changes for the utility undergoing the transition.

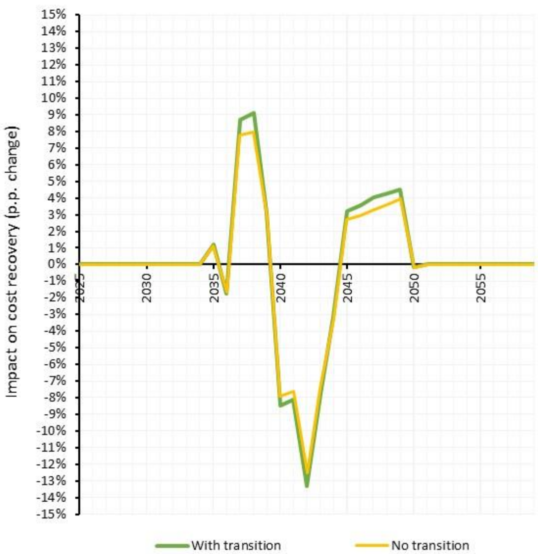

Figure A9: Impact of interest rate shock on economic cost recovery for scenarios *without* (yellow) and *with* (green) transition.

B. *Fuel prices shock – Lower exposure to oscillations in fuel prices due to higher capex-intensity in the with transition scenario.*

Capital intensive utilities (as in the with transition scenario) are less exposed to fluctuations in prices of operational inputs such as fuel prices. In this sensitivity international prices of coal and gas are subject to a sharp increase after 2040 as illustrated in Figure A10. The year-on-year variations in percentage terms for the four years starting in 2040 match actual oscillations in prices of international fuel prices benchmarks (Henry Hub, South African coal) over the 2022 - mid 2023 period.

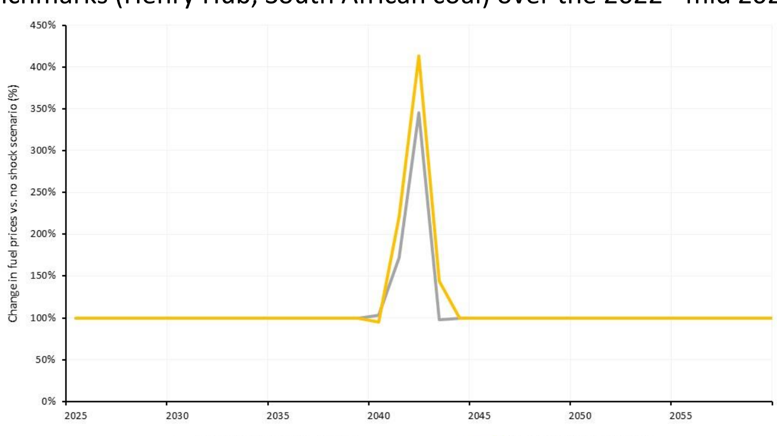

Figure A10: Simulated shock – international fuel prices (coal and gas)

The modelling assumes the utility purchases all fossil fuels in short-term markets, either in the spot market or via very short-term contracts. The shock therefore affects the actual fuel prices immediately. The impact on regulatory benchmarks is however delayed by one year, since we assume that the regulator prepares operational cost forecasts (and thus fuel price forecasts) based on the previous year's fuel prices~~. In addition, the regulator is assumed to not adopt inter-annual revenue equalization accounting for differences between actual and forecasted fuel prices, nor intra-yearly updates of regulatory fuel price benchmarks~~.

The more capital-intensive utility undergoing the energy transition is less exposed to the risks of fluctuations in international fossil fuel prices, as evidenced by the lower decreases (increases) in cost recovery upon an increase (decrease) in fuel prices (Figure A11). The magnitude of the oscillations in cost recovery is lower in the case with the transition, signaling a lower exposure to financial risks resulting from fuel prices changes.

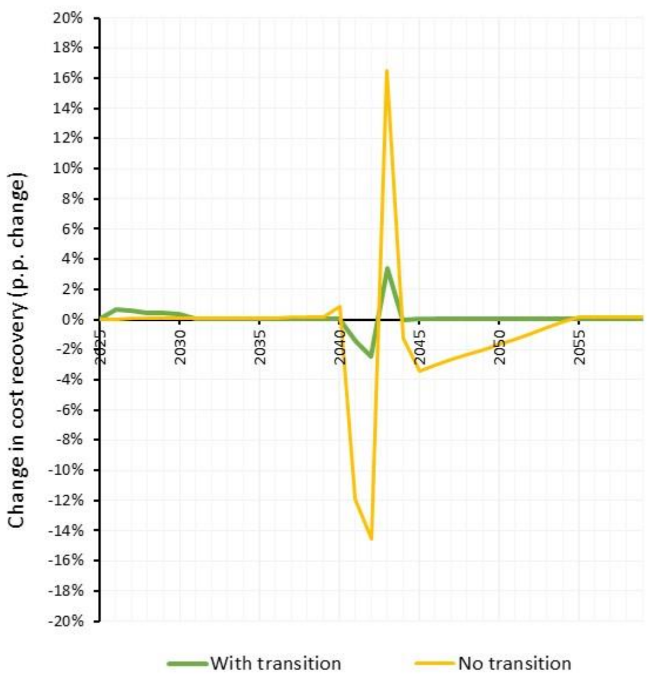

Figure A11: Impact of fuel prices shock on economic cost recovery for scenarios without (yellow) and with (green) the transition.

C. Asset impairment shock – Higher exposure to assets not included in the regulatory asset base in the transition scenario.

Assets owned by the utility but excluded from the regulatory asset base represent a financial risk for utilities operating under a rate-of-return regulation[7]. For modelling purposes, we have assumed that investments in all new *transmission and distribution* assets between 2035 and 2039 are partially

[7] There are several reasons why assets may not be included into the regulatory asset base. As an example, a fossil-fueled power plant decommissioned before the end of its regulatory lifetime may be removed from the regulatory asset base, if the regulator explicitly choses to allocate losses to the utility.

impaired, and only 75% of their value is included in the regulatory asset base. Figure A12 displays the simulated asset impairment shock.

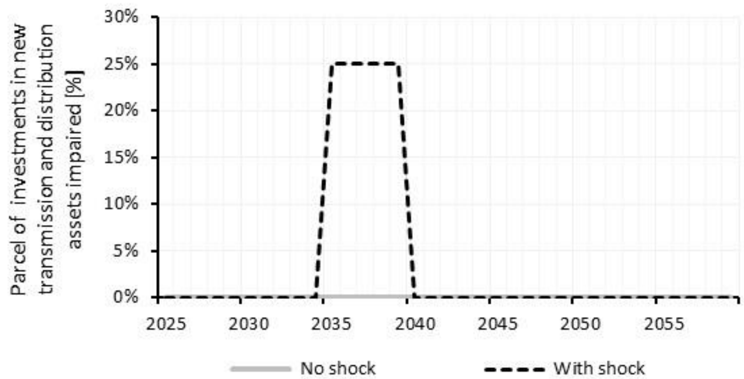

Figure A12: Asset impairment shock – partial impairment of new investments in transmission and distribution.

For all years between 2035 and 2039, the ratio of investments in new assets to the existing regulatory asset base is much higher in the scenario with the transition, due to higher demand growth and higher capital intensity. Therefore, the impact of asset impairment is more severe in the scenario with the transition. Figure A13 shows the impact of the asset impairment shock on economic cost recovery, evidencing the larger impact on cost recovery for the scenario with the transition. The impairment risks are thus clearly higher for the scenario with the transition.

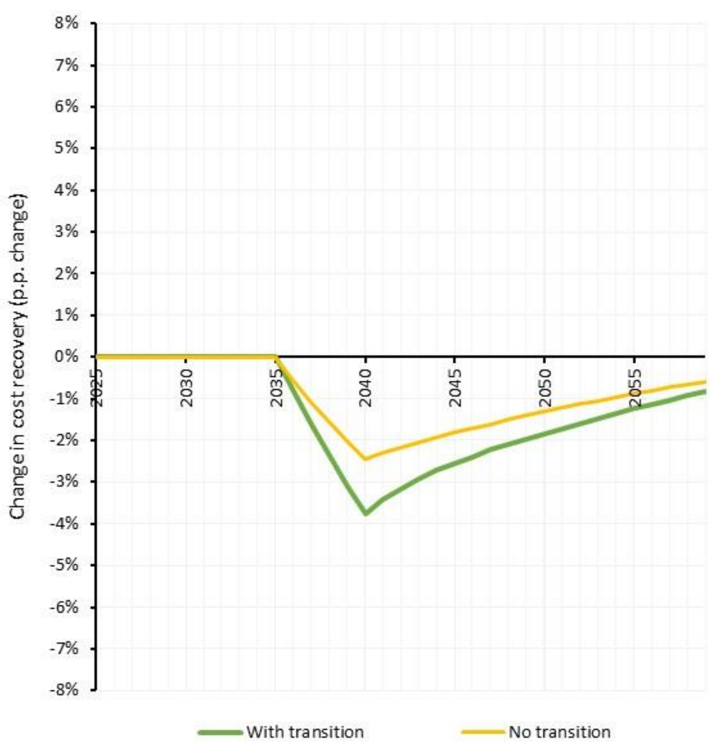

Figure A13: Impact of impairment shock on cost recovery: *without* (yellow) and *with* (green) the transition.

D. Demand shock – Cost structure less flexible to sudden demand decrements and higher impacts for the transition scenario

This sensitivity considers a sudden and short-duration decrement in demand (e.g., as a result from an economic crisis). Costs varying proportionally to the amount of energy delivered by the utility in the short term will decrease during such demand shocks. Utilities more intensive in fixed costs – including capital recovery and remuneration and fixed operational expenses – will perceive lower decreases in costs[8] for the same drop in demand.

The simulated demand shock involves a sudden and short-term decrease in demand for a duration of one year. The shock is assumed to affect demand levels only in the same way across all customers. Three independent shocks are simulated, in 2035, 2040, and 2045, as shown in

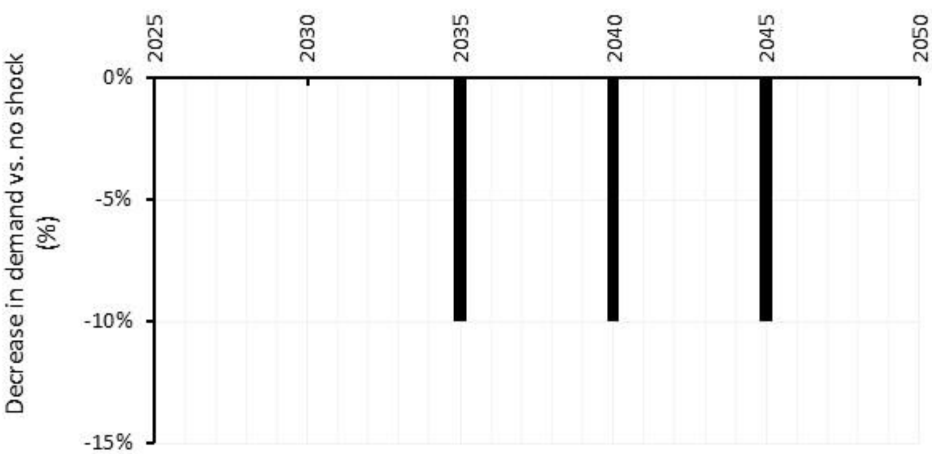

Figure A14.

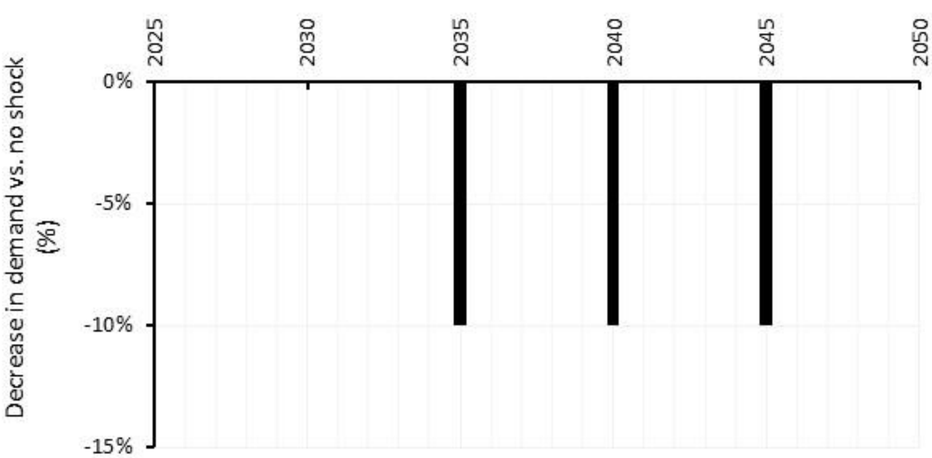

Figure A14: Demand shock: decrease in consumption

[8] ~~The actual reduction in costs for the utility will depend on several factors, including commercial and contractual arrangements with providers. This is also true for vertically integrated utilities, which could have, negotiated fuel purchases agreements or contracts for provision of operation and maintenance services~~.

Assuming the same proportional decrease in revenue for the scenario without and with the transition, the impact on cost recovery will be the largest for the utility which is most capital intensive. The utility in the with transition scenario will see a lower decrease in total costs given the higher share of capital costs in its cost structure. As a result, this utility will see a larger decrease in cost recovery in the years with a decrease in demand, as evidenced in Figure A15.

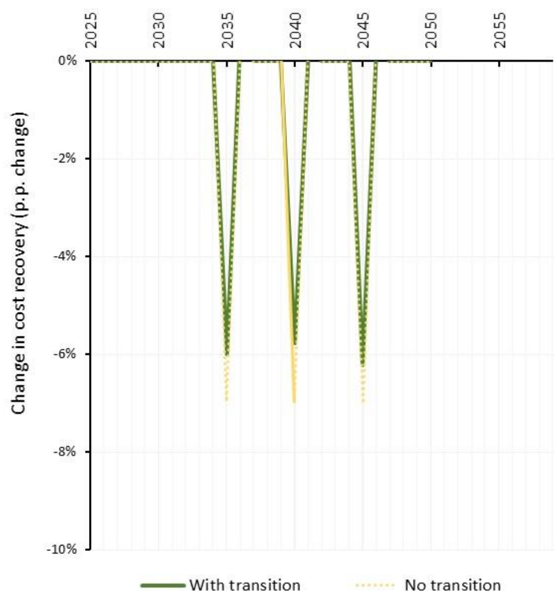

Figure A15: Impact of demand shock on cost recovery: *without* (yellow) and *with* (green) the transition.

A3. Concessional finance for decarbonization

A final step in the analysis involved the use of concessional debt (debt priced below regular market rates) to reduce the incremental costs of decarbonization. The viewpoint of this analysis is to consider the limited resources of concessional debt as a means to ensure society as a whole is not worse off by decarbonizing (i.e., the cost for utilities in emerging and developing markets for attaining the global public good of decarbonization is minimal).

We are comparing the following two scenarios:

- Scenario 1: utility without the energy transition
- Scenario 2: utility under the **same demand** (no additional electrification nor access) undergoing decarbonization with the aim of reaching net zero greenhouse gas (GHG) emissions by 2050 and therefore deploying large amounts of (variable) renewable capacity to reduce GHG emissions. For now, we have assumed that the limited concessional resources are used only (as a first

application) to minimize the incremental costs of decarbonization, and not the incremental costs of increased access or electrification.

The approach adopted here aims to equate the present value of the incremental costs (revenue requirement) for the utility under the two scenarios **by** injecting concessional debt in the capital structure of the utility that decarbonizes its power system. For simplicity, we assume a constant WACC for both scenarios over the 2025 – 2050 horizon and a societal discount rate of 6%.[9] Therefore, we need to adapt the WACC for scenario 2 such that:

$$\sum_{t=1\ (2025)}^{t=26(2050)} \frac{1}{(1+0.06)^t} * \left[WACC_2 * RAB_{2,t} + Depreciation_{2,t} + OPEX_{2,t}\right]$$

$$=$$

$$\sum_{t=1\ (2025)}^{t=26(2050)} \frac{1}{(1+0.06)^t} * \left[WACC_1 * RAB_{1,t} + Depreciation_{1,t} + OPEX_{1,t}\right]$$

We achieve this by injecting concessional debt into the capital structure of the utility that is decarbonizing its power system (scenario 2). For a constant WACC in scenario 1 (without the transition) of 16.9%, we need a 1.2 percentage point decrease in WACC to make the difference in discounted costs zero (or a constant WACC of 15.7% for scenario 2). This 1.2 percentage point reduction in WACC might seem a small change, but that is not necessarily the case. Assuming a 3-percentage points discount for concessional debt (so available at 8%) vs. commercial finance at 11%, the utility would require a share of ~80% concessional debt of total debt in the capital structure to make its incremental costs of decarbonization zero.

A larger discount in the cost of concessional debt compared to the cost of commercial debt will result in a lower required percentage of concessional finance as a share of total debt to minimize the incremental costs of decarbonization.

Figure A16 shows the relation between the required percentage of concessional debt to minimize the incremental decarbonization costs and the discount on concessional debt (vs. commercial debt). As expected, larger discounts for concessional debt result in lower required shares of concessional debt to minimize decarbonization costs. In case all concessional finance would be injected as grants only ~20% of debt will need to be granted to minimize the incremental decarbonization costs in scenario 2 vs. scenario 1.

[9] Other assumptions include: an equal proportion of equity and debt in the initial capital structure in scenario 1; commercial debt cost of 11%; equity cost of 17%; commercial debt is assumed to consist of 80% long-term debt at 11.7% and 20% short-term debt at 8.4%.

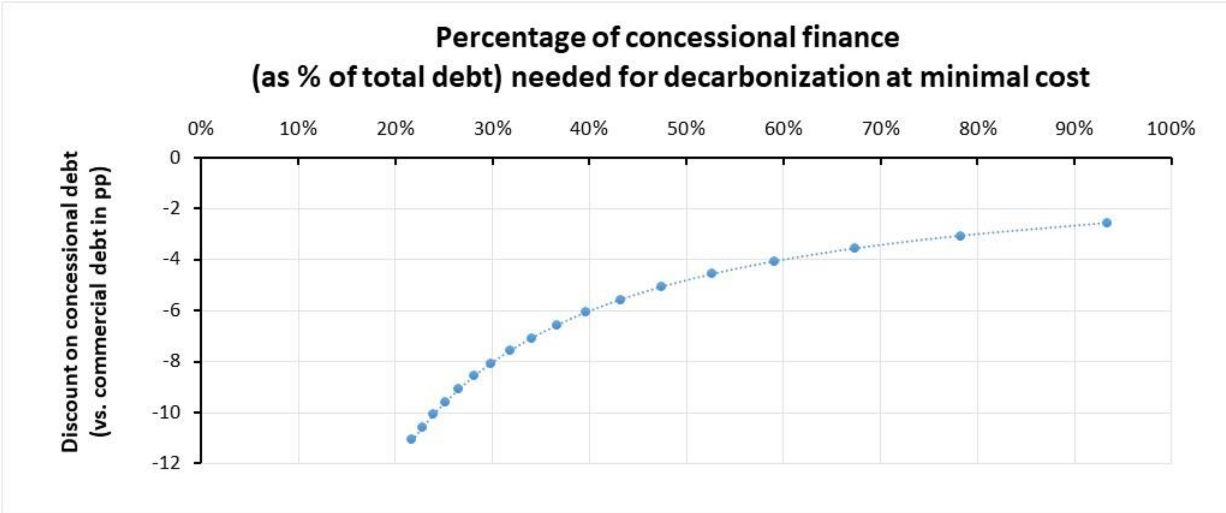

Figure A16: Required percentage of concessional debt as percentage of total debt to minimize decarbonization costs.