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A business plan to achieve full electrification in Rwanda under the Integrated Distribution Framework (IDF)

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1. THE GENERAL CONTEXT

The Government of Rwanda (GoR) has established an ambitious and comprehensive National Energy Sector Strategic Plan (ESSP)[2], which includes a 100% electrification target by 2024, meant to contributing to economic growth and poverty alleviation. With the support of multiple development partners, Rwanda has successfully accelerated the rate of access to electricity during the last decade, which has increased from 10% in 2010 to 43% in 2018[3], almost exclusively by grid extension. But the pace of grid extension is insufficient to achieve the established access target, and there are less expensive off-grid solutions to meet the estimated demand of many of the still non-electrified customers.

The MIT/Comillas Universal Access Laboratory, using its electrification planning software REM and with funding from the World Bank, has contributed to the electrification effort by developing a Master Electrification Plan for the entire country.[4] This plan is the least cost option to meet the GoR target, subject to some constraints that were necessary to ensure technical viability and consistency with the priorities set up by the ESSP. In addition to a sound estimation of the investment and operation costs, the results obtained make possible to inform prospective off-grid investors about what areas are not contemplated for grid extension for the temporal scope of the plan (now to 2024). The detailed results of this study will also inform the implementation of the National Electrification Strategy (NES) and the preparation of the National Electrification Plan (NEP).

Preliminary conversations with key stakeholders in Rwanda about potential adoption of the Integrated Distribution Framework (IDF)[5] were initiated by members of the GCEEP Research Team, taking advantage of the partial overlap in time of the present Rockefeller Foundation project that is promoting the IDF approach and the end of the elaboration of the Master Electrification Plan. These conversations have continued afterwards, in Rwanda and elsewhere, including also some GCEEP members. All those contacted have encouraged the Research Team to continue the effort, to examine the potential of IDF for Rwanda in more detail and to bring some

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[2] National Energy Sector Strategic Plan (ESSP), September 2018. http://mininfra.gov.rw/fileadmin/user_upload/new_tender/Energy_Sector_Strategic_Plan.pdf

[3] Sources: MININFRA and ESMAP et al. report "Rwanda: Beyond connections. Energy access diagnostic report based on the multi-tier framework", June 2018.

[4] MIT&IIT-Comillas UEA Lab 2019. TASK 2 Report. Design of the National Electrification Plan in Rwanda. https://www.reg.rw/fileadmin/user_upload/Report_of_the_Design_of_the_National_Electrification_Plan_in_Rwanda.pdf

[5] I. Pérez-Arriaga, R. Stoner, D. Nagpal and G. Jacquot. "Global Commission to End Energy Poverty: Inception Report", September 2019. https://www.endenergypoverty.org/reports

quantification into the proposed approach. This is the objective of the present Working Paper.

The results of the MIT/Comillas least cost electrification plan can be the basis for the development of a business plan to check the financial viability of a potential distribution concession in Rwanda. Different versions of the business plan can be useful to explore other business models with different levels of private sector participation. From an objective viewpoint, Rwanda appears to be a very adequate country for a potential implementation of the IDF, as suitable conditions exist for each of the four IDF pillars and progress has been made in every one of them[6]. Rwanda is also in a good situation – from the perspective of the criteria of the international development banking community – to embark in a significant infrastructure project like the full electrification plan.

The GCEEP Research Team has prepared a detailed template – in excel spreadsheet format – of a business plan *that accounts only for the electrification component of the plan (i.e. all that presently is not electrified yet), but that could be expanded to include the complete electrification segment of REG*[7]. For the time being this template is just meant to be an instrument for discussion and clarification of the potential of the IDF, in Rwanda and elsewhere. The present Working Paper, after providing some background to the electrification situation in Rwanda, focuses on the description of the template and its application in Rwanda.

The GCEEP Research Team is ready to continue conversations with all interested stakeholders, investigate the open issues, and perform its role as convener to achieve a potential consensus on the implementation of the IDF in Rwanda.

2. BACKGROUND ON THE RWANDAN POWER SECTOR

The Gross Domestic Product per capita in Rwanda was $826 in 2018, which is equivalent to just 7% of the world's average. This low level of economic development can be partly attributed to infrastructure shortcomings, linked to high electricity costs that hinder socio-economic development and to lack of access that limits the transformation from an economy based on subsistence agriculture to a knowledge

[6] I. Pérez-Arriaga, D. Nagpal, G. Jacquot and R. Stoner. "Integrated Distribution Framework: Guiding principles for universal electricity access". GCEEP Working Paper. May 2020. https://www.endenergypoverty.org/reports

[7] The detailed cost estimates provided by the MIT/Comillas electrification plan refer only to what remains to be electrified, but not to what has to be done in the existing distribution network. The business plan can only be completed once this information is included in the financial analysis of the distribution concession business model, which must comprise the entire Rwandan distribution system.

economy. Developing the energy sector is key to develop other sectors, such as manufacturing, agro-processing, housing, mining, tourism and IT services.

The electrification rate in Rwanda primarily reflects grid-connected users in urban areas and remains largely concentrated in the two top quintiles, with almost negligible coverage in the bottom 40 percent of the population. Electrification is primarily a rural challenge: 77 percent of the urban population is electrified, and their access is concentrated in the higher levels of service. By contrast, 84 percent of the rural population has no access to electricity and only very few are in the top levels. Off-grid solutions are more common in rural areas and they typically provide low levels of access.

Rwanda is a small, densely populated country that will ultimately be fully electrified through the national grid. However, grid extension to reach clusters with very low total demand is too expensive. Off-grid solutions, which provide lower-tier service but are more affordable, can provide an important interim solution for these households. The affordability challenge and the steep cost reductions in off-grid solar solutions have made the Government reconsider its strategy for access expansion and put more emphasis on off-grid solar for households that have basic electricity needs and would have difficulties affording even a subsidized grid connection fee. To implement the new targets, the Government has launched least cost electrification planning efforts – of which the MIT/Comillas study is the last example – and has put in place new procedures for simplified procurement of small mini-grids.[8]

At present, tariff revenues collected by the Rwanda Energy Group (REG, the national energy company) are insufficient to recover the operating costs of service provision to its customers. Rwanda's electricity supply is expensive due to limited domestic energy resources and noncompetitively procured generation capacity. Tariffs are among the highest in the region, but they are below cost recovery because the low incomes limit the consumers' ability to pay for electricity services. The gap is covered by budget transfers to REG. Even at a subsidized rate, firms pay a higher price of electricity compared to neighboring countries, making access to electricity among the main constraints to scaling up private investment flows.

Absent a vigorous increment of demand as a result of an acceleration of the electrification plan, the estimated surplus of generation capacity after 2020 will create pressure on the tariff and – if the tariff remains below costs – on the need for Governmental subsidies. To increase the affordability of electricity for low-income households, a new tariff regime was put in place from January 2017. A number of important changes were made. First, the price of electricity was reduced by 51 percent

[8] IRENA (2019). Policies and regulations for renewable energy mini-grids.

for households with monthly consumption up to 15 kWh (the average monthly consumption of households in Rwanda was an estimated 35 kWh per month in 2016/17). Second, a new connection policy aims to make connections affordable for all consumer categories and introduces new payment options for the connection fee, including one with zero down payment targeted at low-income households. Tariffs for selected non-household consumers that are not exposed to international competition—commercial customers, broadcasters, telecom towers and health facilities—have been brought closer to cost recovery.

The governance of Rwanda's power sector has historically been highly concentrated in the Government, with relatively little independent decision making, for example, in the utility. This favors reform coordination and can speed up program implementation. However, with limited separation of commercial, regulatory, and political objectives in decision making, it carries risks of inefficiencies and nonadherence to business plans or regulatory mandates. To mitigate such risks, in 2013, with the support of the World Bank and other development partners, the Government restructured the key energy sector institutions, aiming at achieving regulatory independence, financial sustainability, and increased private sector engagement. REG was created to take over the electricity utility functions as well as carry out power sector planning and development. While the Government retains ownership of REG, its affiliated companies are governed under company law as opposed to public service law. RURA is the sector regulator with a track record of independent tariffs decisions and utility performance reviews.

Rwanda has been a leading reformer among African economies in Doing Business indicators[9], ranking second in Africa only after Mauritius in the business enabling environment. According to recent reports by the World Bank, overall, while risks remain, Rwanda's macroeconomic policy framework is considered adequate by World Bank reviews and rating institutions. Rwanda's prudent macroeconomic policy has enabled the country to achieve high economic growth and macroeconomic stability in the past decade. Both monetary and fiscal policies have been implemented in a prudent manner. The World Bank/International Monetary Fund assessment of Rwanda's DSA indicates continuation of low risk of debt distress. Rwanda's public sector debt has increased with an investment push in recent years but remains comfortable in absolute terms. Rwanda's domestic public debt has also increased to develop a broader domestic market in recent years but also remains low in absolute terms.

[9] http://www.doingbusiness.org/data/exploreeconomies/rwanda#getting-electricity

Support from development financial institutions (DFIs) will be necessary to make the electrification plan financially viable. The core elements of the proposed electrification planning strategy rest upon not just putting in place an adequate plan and a decision-making framework but mostly on finding consensus among stakeholders, including the Government, development partners and private sector, on how to address fiscal risks and payment guarantees.

3. THE ELECTRIFICATION PLAN

Based in the report developed by the MIT-IIT Universal Energy Access Laboratory in 2019 for the National Electrification Plan of Rwanda 2020-2024 (NEP 202-2024)[10], the Rwandan Energy Group and the Government of Rwanda have established the roadmap to rapidly achieve universal electrification in 2024, with a least-cost mix of grid and off-grid technologies. This First Roll-out Wave will supply 100% of the expected residential, community and industrial loads in 2024 assuming a demand trend projected from the, still very small, values in 2019.

In this business plan we assume that this initial electrification push will lead out to a more stable period until 2030, where the large investments developed from 2020 to 2024 will require limited network reinforcements. Additional connections to the backbones designed for 2024 and any necessary upgrades in the off-grid and on-grid generation will continue to accommodate later demand growth.

During the period 2031-2040 we expect that increased development rates, accompanied by larger demand growth, as well as lower generation costs will drive the network connectivity further, reducing the weight of stand-alone systems from 40% in 2030 to 20% in 2040.

This Second Roll-out Wave will require significant investments to accommodate this new demand, and to allow the transition of the present infrastructure to a future smarter network capable of meeting the expectations of quality of service, sustainability, integration of renewable energies with distributed characteristics and management of flexible energy demand.

3.1. NEP 2020-2024. First Roll-out Wave

The National Electrification Plan of Rwanda 2024 details at village level the least-cost areas where the national grid needs to be extended at the end of this period, the

[10] MIT&IIT-Comillas UEA Lab 2019. TASK 2 Report. Design of the National Electrification Plan in Rwanda. https://www.reg.rw/fileadmin/user_upload/Report_of_the_Design_of_the_National_Electrification_Plan_in_Rwanda.pdf

location of least-cost mini-grid villages, and the areas where DC solar kits and other AC standalone systems should be supplied as a first, temporary, solution.

NEP 2024 included the detailed design of the power systems required to supply each one of the 2.5 million new customers of the Rwandan power sector in 2024. NEP also detailed the 931 individual grid extension and 1,973 mini-grid projects, scheduled for their implementation from 2020 to 2024 according to the priorities for electrification of community and industrial loads, and the budget and operative constraints specified by EDCL.

Our detailed computer-based analysis with the REM model has been limited to the electrification of those customers which required to be supplied by grid extension that needed new MV distribution lines, with any necessary MV/LV transformers and LV lines to reach the end residential and C&I customers and to the off-grid solutions for customers located beyond the already electrified areas in service by the current MV central network. Customers to be connected by just densification, i.e. wired to existing nearby LV lines in already electrified villages and customers close to the existing MV lines, did not need of the REM analysis to determine their least cost electrification mode as grid extension. NEP 2024 has provided an initial rough estimation of the cost of the densification effort based on EDCL estimations. However, an additional densification plan – still to be done – is required to analogously provide detail down to customer level of the implementation of these new connections and of the associated upstream reinforcements required in the existing distribution grid, and their potential impact at transmission and generation levels.

In agreement with EDCL indications, the demand profiles and quality of service requirements for all grid-standard customers (either connected to the central network or to decentralized generation in mini-grids) are equivalent, targeting a reliability as close to 100% as possible, which will allow the development of productive and commercial activities, as well as the provision of appropriate public services, mainly education and health.

The National Electrification Plan aims at the end of 2024 for a share of grid extension of 56.1% for all of Rwanda, bearing the larger investment effort in this period. Around 750 thousand connections will be required for 4,700 villages within the reach of the existing grid, requiring an estimated investment cost of $448 millions[11] (average of $600 per fill-in connection). Additionally, the extension of the MV and LV grid to 2,400 new villages, designed in detail by the Reference Electrification Model REM for over

[11] MIT&IIT-Comillas UEA Lab 2020. TASK 3b Report. Institutional and Regulatory Recommendations for the National Electrification Plan in Rwanda.

430 thousand new customers, will require an overnight investment cost of $316 million (average of $735 per connection).

A very significant, and innovative, effort will also be devoted to developing mini-grids for around 320 thousand customers in 2000 villages, with a total investment of $200 million (average of $625 per connection). Grid and off-grid high-quality standard solutions by 2024 will have reached 2.5 million (64.2%) of the customer base.

The remaining 5100 villages in this First Roll-out wave, almost 1 million customers, will be electrified with a DC solar kit, while a few thousand of community and productive loads will also remain isolated and supplied by standalone AC systems, adding $59 million in overnight investment ($59 per solar kit).

Considering together fill-in, new extensions, mini-grids and standalone systems, the total investment effort for the First Roll-out wave reaches $1,023 billion.

NEP also establishes for this period the corresponding total annual O&M costs for densification ($30.7 million/year, $41.1/year per customer), grid extension ($20.7 million/year, $48.0/year per customer), mini-grids ($6 million/year, $18.7/year per customer) and standalone systems ($0.7 million/year, $0.7/year per customer) at the end of 2024. The densification investment and O&M costs have been roughly estimated from known per-household connection costs[12] and estimated new connection needs. It is also important to highlight here again that the CAPEX and OPEX associated to the growth of demand of customers already connected to the already existing network are not included within the scope of NEP 2024.

3.2. 2031-2040. Second Roll-out Wave

Reducing the share of customers supplied with a standalone system from 40% to 20% between 2031 and 2040 will require an investment close to $1.3 billion throughout this period. Almost $900 million will be devoted to reaching most of the 5,100 isolated villages in non-risk areas with grid extensions adequate to their demand in those years. $290 million will still be required for further densification in areas with connection to the main grid, also considering that most of the mini-grids created by 2024 will probably be embedded into the central grid at the end of this Second Roll-out wave. Finally, the cost of new solar kits and replacements within these 10 years will still account for another $100 million. This is a rough estimation, representing the capex deployed to deal with population and consumption growth and the replacement of the kits that have been amortized during the 2031-2040 period.

[12] These average connection costs encompass many different situations, ranging from cases where only a drop line to the closest LV line is needed, to cases where a new MV/LV transformer is also necessary, plus the meter and protections in all cases.

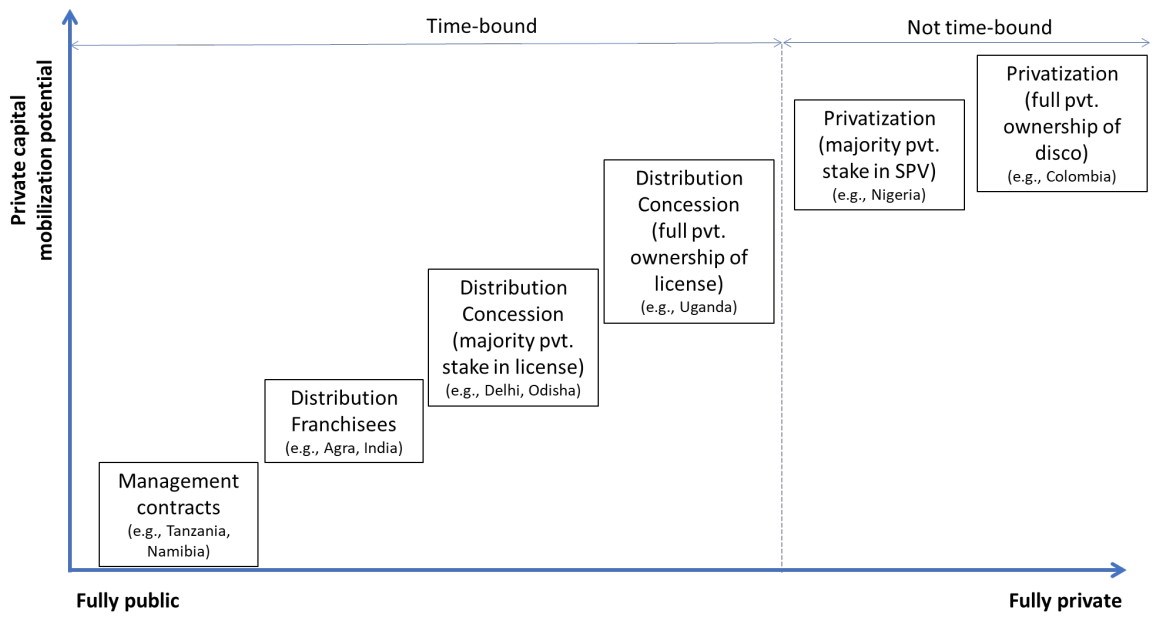
4. MODELS OF PRIVATE SECTOR PARTICIPATION IN THE DISTRIBUTION SECTOR[13]

Distribution companies in most low-access countries are faced with a deteriorating financing situation as a result of a combination of factors: limited cost-recovery due to tariff structures and high cost of wholesale power supply, along with large technical and commercial losses. This has resulted in under-investments in the distribution segment, including infrastructure and network expansion, affecting accessibility, quality and reliability of supply. In turn, commercial and industrial consumers that traditionally have been the important sources of revenue for discos are increasingly investing in captive generation based on diesel and renewable energy.

Addressing the structural challenges and long-term financial-sustainability concerns of discos will be crucial for mobilising investments towards the urgently needed infrastructure in distribution, as well as meeting the universal electricity access objectives. With a heavy involvement of the state in the ownership and management of discos, greater private sector participation in distribution is seen as an important catalyst for improving internal management and operation with a view to improve operational viability. Importantly, it is also a means to attract the substantial levels of investments needed for the development and strengthening of infrastructure to improve quality and reliability of service and add new connections.

Graph 1 illustrates different models of private sector participation in the distribution sector. The models are assessed from the perspective of meeting the two pre-requisites for strengthening the distribution sector in low-access countries: nature and extent of private sector involvement and the potential for mobilising substantial private capital.

[13] D. Nagpal, I.J. Pérez-Arriaga. “How is the distribution sector in low-access countries attracting private sector participation and capital?”. GCEEP Working Paper. May 2020. https://www.endenergypoverty.org/reports



Graph 1. Different modes of privatization of distribution sector in developing countries.

Private sector involvement in the distribution sector can be designed to be time-bound or indefinite. Time-bound measures for participation of the private sector are for a specific period of time, after which the operational and economic rights of distribution reverts back to the government/public sector control. Examples of such measures include:

- *Management contracts* wherein private sector involvement is short-term (5-10 years) and largely limited to improving internal management and reducing aggregate technical and commercial (AT&C) losses through higher collections and tariff reforms. The large-scale mobilisation of private capital is often not the focus of such measures.
- *Distribution franchisees* are usually short- and medium-term (5-15 year) agreements between existing distribution licensees and private entities to carry out activities related to supply, billing and collection, customer engagement, reduce technical losses and undertake capital expenditures needed to meet prescribed performance objectives.
- *Distribution concessions* wherein an entity, which is majority or completely privately-owned, is provided a long-term (20-25 years) distribution license to service a certain territory. In such cases, the entity has full operational and investment rights over the duration of the concession while the extent of economic rights vary, depending on whether the government retains total (this is the case in a pure concession contract) or partial ownership in the entity. Here, the objective is usually to mobilise private capital for investments into the infrastructure and operations.

Indefinite privatization measures essentially involve transfer of operational and economic rights of distribution to the private sector with the intention that at no time does the control revert back to the government/public sector. The entity taking over the distribution licensee under such a privatization model may either be entirely owned by the private sector (*e.g.,* as is the case in Colombia) or majority-owned (as is the case in Nigeria).

4.1. The distribution concession model

A Distribution Concession (DC) engages the private sector to mobilise investments in the distribution sector and is usually long-term (20-25 years). Compared to management contracts, the level of private sector engagement increases under such concessions as they assume a greater risk in anticipation of a return. Strict concessions require the private lessor to operate, maintain, and expand the asset, and, at the end of the concession period, return the asset, with all improvements, to the owner, and receive a payment for the residual value of the investments made[14].

The DC is a more complex regulatory and legal construct than the distribution franchise (DF). The major difference with the DF is the need for substantial investments, therefore requiring additional regulations regarding the remuneration in order to reduce the risk of the concessionaire (of not having its investment and operation costs properly remunerated) and the risk of the consumer paying too much for the service (or too little, rendering the distribution activity insolvent). As in the case of the DF, regardless whether the incumbent power company is vertically integrated or not, the concession only refers to the activities and assets corresponding to the distribution segment.

The concessionaire is a company, which in general would be established as a special purpose vehicle (SPV), i.e. with several participating entities, just for the purpose of managing the concession, possibly with non-recourse. The ownership of the SPV may be structured in different ways. In the case of Uganda, for instance, the SPV is owned entirely by the private sector. Meanwhile, in Delhi or Odisha (India), the private sector owns a majority controlling stake in the SPV, while the remainder of the equity stake is held by the government. At the end of the concession all the assets are returned to the incumbent utility.

As with the DF, the SPV will take over the entire management of the distribution company. However, in this case all investments will be made entirely by the SPV, in

[14] Hoseir et al. (2017) and Jacquot (2019) provide a comprehensive overview of the different types of concessions supported by country examples.

line with an agreed capital expenditure plan and following approvals by the regulator and/or the ministry for any major investments.

The distribution assets will be split into two categories for regulatory and business model purposes: i) the new investments "A" made by the SPV during the duration of the concession, and ii) the assets "B" that existed at the moment of awarding the concession.

In the case of a DC, the concession contract is signed between the SPV and some governmental entity, acting on behalf of the customers, and it will be supervised by the regulator or some ministerial department or public agency. It follows a description of the general characteristics of this kind of contract, illustrated by some examples.

Treatment of assets A.

The regulator computes the revenue requirement RRA to be paid to the SPV for the cost of service associated with the new investments. The RRA comprises capital costs CAPEXA and administrative, operation and management costs OPEXA.

Regarding CAPEXA, the regulator must follow the usual procedure to determine the regulatory asset base of the new investments (RABA), and the corresponding cost of capital to be paid every year to the SPV on this concept. The usual separate remuneration of debt and equity resulting in the WACC to be applied to the entire RABA would be followed. The return on equity might be established from the outset for the entire period (this is the case of the 20% of Umeme, or the 16% of Tata Power Delhi. Alternatively, it could be adapted to the capital market conditions. The cost of amortization of the assets will be computed on the basis of the economic lives of each one.[15]

Guaranteed return on equity incentivizes much-needed investment in distribution. In the decade between 2002 and 2013, Tata Power Delhi incurred capital expenditures of over INR 3000 crores (or USD 418 million at current rates) [16]. Meanwhile, Umeme in Uganda has invested over USD 600 million since 2005 in the distribution system (Umeme, 2019)[17]. Where other investment risks may be prevalent, de-risking measures have been introduced such as the setting up of an escrow fund to ensure

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[15] The actual composition of the capital of the company will consist of a mix of debt and equity, where debt may have return periods much shorter than the economic lives of the power systems assets. The business plan of the SPV must provide a solution to this mismatch, by making use of a suitable financial strategy.

[16] Tata Power – DDL (), https://www.tatapower-ddl.com/Editor_UploadedDocuments/Content/FAQ's.pdf

[17] Umeme (2019),

https://www.umeme.co.ug/umeme_api/wp-content/uploads/2019/07/UMEME_Power_Book_web.pdf

payments from the government to the concessionaire and political risk insurance from MIGA as has been the case in Uganda (World Bank, 2015)[18].

One important issue is what assets the regulator considers that can be included in the RAB. For instance, in the concession contract of Tata Power in Odisha, investments in generation or storage, either on- or off-grid, that might be used to reinforce the end of long feeders where reliability and quality of service may be poor, will not be included in the RAB.[19]

The concession contract of Tata Power in Odisha establishes that the CAPEXA annuity will be updated every year to account for the new investments, while the annual value of OPEX is reviewed every three years. This incentivizes Tata Power to improve the efficiency of O&M, as well as gold plating (regulator permitting) its new investments.[20]

At the end of the concession period (20 or 25 years are typical values), if the concession is not renewed the residual value of the A assets must be paid to the owners of the SPV, which is terminated. The Government retains the full ownership of the distribution company.

Treatment of assets B.

Assets B, that existed at the time of awarding the concession, require administration and operation and maintenance. Therefore, CAPEXB must be included in the revenue requirement, as it is done with CAPEXA.

The issue to be addressed now is what to do with the capital cost associated with Assets B. First, it is to be expected that a rigorous accounting of the value of the existing distribution assets has not taken place, and therefore the value of CAPEXB is not known precisely. Second, in most developing countries with access deficit, governments do not want to apply cost reflective tariffs because of a diversity of

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[18] World Bank (2015), http://documents.worldbank.org/curated/en/354661498163378835/pdf/116661-WP-P150241-PUBLIC-53p-Detailed-Case-Study-Uganda.pdf

[19] This creates an interesting dilemma. If the SPV is not mandated to improve reliability and quality of service in these areas, or it does not have the economic incentives to do it, then a potential market opportunity opens in using off-grid solutions – either mini-grids or standalone systems – to offer an alternative reliable and high-quality supply to those customers that might be interested in paying extra for it – typically commercial, industrial and well-off residential customers. Since Tata Power is also in the off-grid business, this may create some conflict of interest. There might be some better approach to incentivize the adoption of societal least cost solution in each case.

[20] This is the classical regulatory dilemma concerning the incentives created by any specific regulation on the relationship between CAPEX and OPEX for any Disco. In fact, often the same goal in reliability or quality of service can be achieved by capital investment or by increasing O&M activities. The specific regulation determines in which direction the distribution company will be incentivized to perform.

reasons, including that a large fraction of the population cannot afford the costs, that customers may not want to pay for a service of poor quality, and that is popular to maintain the tariffs low, even if this means that the government has to spend money in bailing out the Discos instead of using it for other purposes, while condemning the discos to permanent underperformance.

In a concession agreement, the Government can fix a value of RABB for the B assets well below what should be in reality. This has the effect of creating a low value for the corresponding CAPEXB annuity, resulting in a low tariff, as desired, but one that is cost-reflective, if the "tuned" value of RABB is accepted as the true value of the assets. Although the tariff in this case is cost-reflective, the ad-hoc declaration of a low value for the RABB is actually a tariff subsidy for the end customers.

In the concessions of Delhi and Odisha it has been agreed that the concessionaire will own 51% of the company during the duration of the concession, while the Government of Delhi or the Government of Odisha, respectively, will own the remaining 49%. This seems to imply (to be verified) that the amount paid by the concessionaire in the auction will entitle it to an initial 51% of the rights to the revenues of the company as well as to the control of the board. The amount paid also determines the value of the initial RAB (which is RABB, since RABA is zero at the outset).

The economic terms of the concession.

The concession is awarded by means of an auction, where several concepts are evaluated. First, the key economic component of the auction is the bid on the amount to pay to the Government to get the concession. The regulator announces a minimum value for this amount, and the bidders will equal or better the minimum value, or they will quit the auction.[21] This minimum value set by the regulator can be interpreted as the value RABB of the existing distribution assets that the concessionaire will be able to use while their physical lives last and only until the end of the concession[22]. Note, however, that the concessionaire will just manage but not own the assets B, for which no compensation will be given at the end of the concession. On the other hand, at the termination of the concession, if it is not renewed, the concessionaire will receive the residual value of all the assets A that have been included in the RABA (and of any investment associated to the assets B and allowed to be included in the RAB). This completely ends the relationship between the concessionaire and the Government.

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[21] In the case of Uganda, the concessionaire Umeme pays an annual fee for the use of the existing distribution network (assets B).

[22] Therefore, this value is NOT exactly the RABB, but the economic value of leasing these assets for all purposes of economic and managerial control of the company for the duration of the concession. Subtle point.

The second economic component of the auction may be a detailed business plan, whose soundness will be evaluated in addition to the other two components. This has been the case in the auction for the concession in Odisha that was awarded to Tata Power.

And the third and final component are commitments to meet performance targets, such as loss reduction, reliability metrics, or number of new connections, whose level of realization will be subject to penalties or credits. In the case of the Odisha only a loss reduction commitment was required. In the case of Delhi, year-on-year reduction in AT&C losses were sought for a 5-year period.

To provide certainty to the private investors, in Delhi's case the government issued policy directions to provide clarity on bidding criteria, availability of assured returns and tariff fixation criteria, among other parameters. For instance, prior to the bidding, the bulk supply tariff order was issued by the regulator from 2002 until the end of 2006-07 to provide clarity on revenue/expense outlook[23].

Revenue requirement, tariffs and subsidies.

The regulator will compute the tariffs that will allow to recover the established total revenue requirement, including now the A and B assets. The initial tariffs must take into account the present value of total losses, either technical or commercial, so that the estimated revenues to be collected allow the recovery of this revenue requirement. The tariffs in the following years will be computed on the basis of the prescribed trajectory of losses. Therefore, the SPV has the incentive of reducing the total losses as much as possible, while it is cost effective, taking also any incentive regulation into account.

Note the conceptual difference between the revenue requirement, which needs to be cost reflective, since otherwise no private investor would be willing to participate in a concession agreement, and the estimated revenue collected from the tariffs that are determined by the regulator. If the tariffs are designed to be cost-reflective, both quantities will be equal. If the amount to be collected by the tariffs is below the cost of supply, then a subsidy is needed to make the distribution activity whole. This subsidy can be deployed in different ways: for instance, a direct individual subsidy to some categories of customers; an annual lump sum to the concessionaire to make it whole; or a reduction in the wholesale price of the electricity that is purchased by the SPV to meet the demand of its customers.

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[23] Tata Power – DDL (2012), https://www.tatapower-ddl.com/Editor_UploadedDocuments/Content/TPDDL%20Case%20Study_COMPLETION%20OF%2010%20YRS.pdf

If the concession covers a rural territory that has not been electrified yet, or that has been electrified for a minimum demand level that could grow substantially under a more robust supply of electricity, or where there is connection, but of poor reliability and quality, then the necessary investment to achieve a satisfactory electricity supply can be substantial. If the physical condition of the B assets is poor, significant investment may be needed to achieve the levels of performance required in the concession contract. Proper metering and customer attention may require additional investment and O&M costs. Even if the tariffs prior to the concession contract were cost reflective, they will be probably insufficient to cover these new high costs, and therefore an additional subsidy might be needed to make the concessionaire whole. As a hypothetical example, this would be the case of Umeme, the only distribution company in sub-Saharan Africa (with Seychelles) where tariffs are cost reflective, in case a new concession – for a new term starting 2025 – is negotiated that includes the obligation of universal electrification in some territory (perhaps the entire country), which mostly consists of rural electrification. Then, a distribution activity that was initially financially viable without subsidies will now need to be subsidized.

5. THE BUSINESS PLAN

As indicated in the introduction section, the business plan to be presented here *accounts only for the electrification plan (i.e. all that presently is not electrified yet), but not the existing distribution network – i.e. the assets A but not the assets B, as in the discussion in the previous section 4.*[24] Should information on assets B be made available, the business model could be extended to include both the existing and future distribution system, including off-grid solutions. For the time being this template is just meant to be an instrument for discussion and clarification of the potential of the IDF, in Rwanda and elsewhere.

5.1. Scope of Work

The purpose of this preliminary business plan is to facilitate a consensus among the main stakeholders that could be involved in making possible a concession agreement to achieve full electrification in Rwanda. Each one of these main stakeholders has different business, financial and social objectives:

- The GoR wants a plan where everyone gets electricity within a reasonable but short-term timeframe, with an entity with the financial and technical resources to

[24] The detailed cost estimates provided by the MIT/Comillas electrification plan refer only to what remains to be electrified, but not to what has to be done in the existing distribution network. The business plan can only be completed once this information is included in the financial analysis of the distribution concession business model, which must comprise the entire Rwandan distribution system.

deliver reliable supply, and with the cost of periodic bailouts to the disco being replaced by a financially manageable amount of subsidies. We have assumed these subsidies would include both yearly amounts to complement the tariff income and some financing/equity-like support (whether acting as principal or most likely facilitating some DFI funding, "GoR Subsidized Financing") to complement initial equity and debt financing.

- The incumbent distribution company seeks the improvement of the existing network and its extension to connect new customers, plus the development of off-grid solutions, with a satisfactory level of reliability and quality of service, and in an integrated way – although separate accounting might be needed for each one. This can be accomplished by turning the management of the company to the concessionaire for a period of time.
- The regulator will oversee both current and new developments to ensure the regulatory framework is fully respected by all industry players and to provide the required stability and confidence to the industrial partner and the financing providers.
- The different financing providers are all assumed to seek some level of balance between achieving their respective financial targets and contributing to the economic and social development of Rwanda.
- Finally, the new industrial partner will play a critical role as equity provider and, most importantly, new business operator to contribute their industrial expertise and to assume ultimate responsibility on the execution of the business plan.

The business plan has been prepared and this document has been written from the Government standpoint, i.e. with the main purpose of aligning the interests of the other key stakeholders around the DC implementation.

As discussed above we have assumed that, in a first approximation, the Government is indifferent to, from a pure financial perspective, whether the grid extension, the development of mini-grids and the provision of services with standalone systems are done by a single entity or by separate ones. Therefore, and for simplicity purposes, the financial model:

- Limits itself to provide an indicative quantification of the total required investment, the operational management and potential financing plan for the non-electrified customers during the 2021-2040 period.
- Assumes that a single entity will be responsible for investing, operating and managing these future distribution assets, while being compatible and adaptable to other structure scenarios.

- Provides a useful platform to, upon completing appropriate diligence, eventually incorporate the existing distribution business so the full system and its key business drivers could be further analyzed.
- Incorporates the key business and financial assumptions required to evaluate and articulate the implementation of the DC model explained above (assuming that is the finally selected alternative).

5.2. Financial Model Structure

The economic and financial model is built around four modules: the new distribution network roll-out plan, the expected/required operating income to support the network investment, the working plan associated with such business development and the overall financing plan to make it all possible:

- As stated in the description of the electrification plan in section 3, the new network investments will be rolled-out in two stages: (i) during the period 2021-2025, where there will be an optimal mix between grid extension, fill-in consumers, mini-grids and stand-alone systems in order to achieve full population coverage by the end of period ("First Roll-out Wave" – as described in section 3 and corresponding to the Master Electrification Plan), and (ii) during the period 2031-2040, where the objective will be to improve the population connectivity to the grid by reducing the weight of stand-alone systems from 40% in 2030 to 20% by 2040 ("Second Roll-out Wave" – with its basic parameters defined in this section), together the "Roll-out Waves". During the Roll-out Waves, some amount of capex is also deployed to deal with population and consumption growth. In addition, we have obviously assumed and modelled that all capital expenditure incurred will be replaced once amortized considering the different network components, employed technologies and respective life expectancy periods.

- Therefore, our revenue stream will be mostly generated by the revenues coming from the different types of customers paying for their consumption at the corresponding tariff for each customer class as detailed in section 5.3. Additionally, we have assumed the following revenues:
    i. connections and other non-energy sales (including revenue from works and other expenses initially incurred by the company but ultimately born by and invoiced to clients),
    ii. grants linked to the GoR Subsidized Financing and recognized in the P&L account as the proportionate capital expenditure is being rolled-out, and
    iii. subsidies from the Government (representing amounts not received under the tariff setting methodology and declining over time as they become non-essential to support initial business development).

The operating cost structure includes the cost of energy upstream (cost of sales), operation and maintenance costs (including all operating/yearly expenditure) and administrative expenses (split between direct customer billing/service and other overheads), in addition to the provisioning of some expected bad debt from customers.

- Working capital has been modelled including the ordinary trade receivables, inventory and trade payables required to launch and operate the business. The tax schedule has also been modelled, anticipating a 4 years tax holidays period which, together with the expected significant tax shield the business would generate, would avoid any tax payments during the First Roll-out Wave.
- Financing has been structured considering three main sources to fund the initial network roll-out as well as the expected initial operating losses:
    i. commercial/corporate debt, estimating the structure, amount, tenor and terms at or close to market conditions (potentially structuring a syndicated bank loan in which, for instance, some DFI related institution could participate),
    ii. GoR Subsidized Financing (again, some subsidized/concessional debt to be eventually provided by the Government, most likely utilizing totally or partially some DFI/World Bank facility) to be raised as required by the business plan funding (see section 5.3.) and recognized as “grants” on a yearly basis (as the funded capex is being invested),
    iii. and the required equity injection to be provided by the critical industrial partner mentioned above (although the model would allow some dividend pay-out, no distribution to shareholders has been assumed in the forecasted period to reduce financial leverage/risk and to avoid the need for any subsequent equity contribution).

Financing has also been structured taking into consideration both Roll-out Waves, which require new funding and linked debt refinancing to support the network roll-out strategy explained above.

5.3. Financial Model Main Assumptions

The table below in column 3 presents the key assumptions used in building the economic and financial model. Consequences of these assumptions can be found in columns 4 and 5.

Key Category	Key Metric	Key Assumption	Compound Annual Growth Rate ("CAGR") 2021/2030	CAGR 2031/2040
Macro	GDP (real growth)	9%		
	Inflation USD	2%		
	Inflation RWF	5%		
Capex	The network roll-out, the associated investment costs incurred in any given year and the connection of all consumers are assumed to take place proportionally throughout the year, so a mid-year convention is assumed for every year additional capex and new customers (same assumption is considered for the Upstream Energy Cost, O&M and Administrative Expenses). - Period 2021/2025.- Network deployment to connect the remaining additional customers so that Universal Access can be achieved by the end of 2025 - Period 2026/2030.- Capex to cope with population and consumption growth and replacement capex as required by specific D&A schedule - Period 2030/2040.- Capex focused to connect Stand Alone Systems to the grid (reducing SAS from 40% in 2031 to 20% by 2040) and cover population growth			
	Period 2021/2025	USD 1,023 million		
	Period 2026/2030	USD 245 million		
	Period 2031/2040	USD 1,277 million		
	Total Capex (2021/2040) of which:	USD 2,545 million		
	- Extension	49%		
	- Fill-in	26%		
	- Mini-grids	16%		

	- Standalone Systems	9%		
Depreciation and Amortization	Extension	100% capex: 25 years		
	Fill-in	100% capex: 25 years		
	Mini-grids	82% capex: 25 years		
		15% capex: 5 years		
		3% capex: 10 years		
	Standalone Systems	100% capex: 5 years		
	Population increase	2021/2025: The electrification plan is being implemented under the assumption of the expected population in 2025.		
		2031/2040: progressive reduction from 3% to 2% per year.		
	Demand increase per customer	2021/2025: The electrification plan is being implemented under the assumption of the expected demand per customer in 2025.		
		2026/2040: 6% per year		
Revenues	Tariffs (pass-through of wholesale energy costs)	In addition to inflation, tariffs are subject to a pass-through scheme of the cost of energy reduction for all end customers tariffs for the 2031/2040 period (the pass-through reduction linearly evolves from 5% in 2031 to 50% of the total energy cost reduction in 2040)		
	Number of C&I Consumers	Airport Cell office	3.4%	2.4%

		Coffee washing station Irrigation pumping Markets Milk collection center Mining Sector Office Tea Factory Telecom Tower Water Pumping Stations		
	C&I Tariff	2021 - initial 25% increase on current regulated tariff (to be compensated by the 2031/2040 pass-through evolution)	1.1%	-0.6%
	Number of non-C&I Customers	Health center Health post IDP Model Village (avg.) Preprimary school Primary school Secondary school Technical Schools VTC Residential 10W Residential 50W	13.2%	2.4%
	Non-C&I Tariff	2021 - no increase on current regulated tariff	1%	-0.2%
	Connections/Other income	2021/2040 period: 5% of tariff income	11.9%	8.1%
	Grants	Grant revenues (for a total of USD 400 million, equal to the GoR Subsidized Financing) recognized in the P&L proportionally to the percentage of annual capex over total capex		
	Subsidies from Government	2021/2030 period: 10% of tariff income	10.6%	-100%

		2031/2040 period: progressive/linear decrease from 10% (2031) down to 0 (2040)		
Operating Costs	Cost of Sales (Upstream Energy Cost)	Upstream energy cost equivalent rate ($/kWh) per energy consumed/year	2.4%	5.8%
		Period 2021/2024: decrease from $20 (cents/kWh) in 2021 to $12 (cents/kWh) in 2024 in line with the NEP energy cost forecast.		
		Period 2025/2040: linear decrease until it reaches $7 (cents/kWh) by 2040.		
	Other Distribution Cost (O&M)	Estimated as a percentage of capex incurred: - Extension: 5,30% capex until 2030, being reduced from 2031 to 3% by 2040 due to efficiencies and economies of scale - Fill in – 5,30% capex - Mini-grids: 0,87% capex - SAS – 0% capex	16.5%	4.4%
	Bad Debt Provision	3% from tariff income	11.9%	8.1%
	Administrative Expenses (Customers/Billing)	9 USD/year/client to increase with inflation	18.1%	3.8%
	Other Administrative Expenses (Overheads)	2020/2039 period: 5% from tariff income	11.9%	8.1%
	Concession Agreement	Not applicable (at this stage)		

Working Capital	Trade receivables (as #days of Revenues)	45 days		
	Inventories (as #days of COGS/Distribution costs)	30 days		
	Trade payables (as #days of COGS/Distribution costs)	60 days		
Financing – Equity	Amount	2021: 150 USD million		
		2022: 150 USD million		
	Total	300 USD million		
	% Total financing (First Roll-out Wave)	30%		
	Dividend (Pay-Out Policy)	0% (no pay-out indicatively assumed)		
Financing - GoR Subsidized Financing	Amount	2021: 150 USD million		
		2022: 150 USD million		
		2031: 100 USD million		
	Total	400 USD million		
	% Total financing (First Roll-out Wave)	30%		
	Drawdown/Repayment schedule	Drawdown as above, P&L recognition as per Grants schedule, no repayment assumed		
	Cost	Interest Rate: 0%		
Financing - Commercial Debt (linked to First Roll-out Wave)	Amount	2024: 200 USD million		
		2025: 200 USD million		
		2026: 100 USD million		
	Total	500 USD million		
	% Total financing (First Roll-out Wave)	40%		
	Drawdown period	3 years		
	Principal grace period	2 years		
	Repayment schedule	2026: 10 USD million		
		2027: 20 USD million		
		2028: 20 USD million		
		2029: 20 USD million		
		2030: 20 USD million		
		2031: 410 USD million		
	Cost	Interest Rate: 7%		

Financing - Commercial Debt (linked to Second Roll-out Wave)	Amount	2031: 500 USD million		
	Drawdown period	1 year		
	Principal grace period	2 years		
	Repayment schedule	2033: 10 USD million		
		2034: 10 USD million		
		2035: 10 USD million		
		2036: 10 USD million		
		2037: 10 USD million		
		2038: 450 USD million		
	Cost	Interest Rate: 7%		
	Refinancing/Amount	2038: 500 USD million		

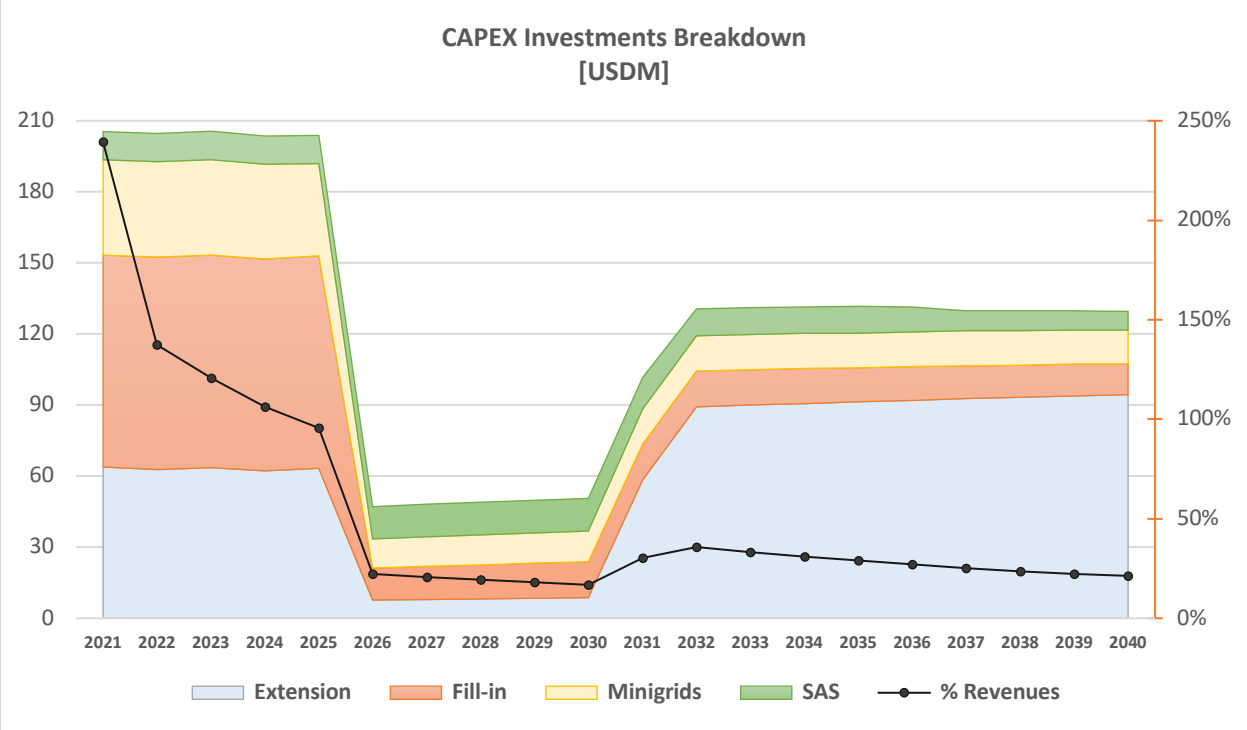
5.4. Financial Model Main Results

Key results deriving from the financial model are analyzed following the same structure as in the tables of the previous sections.

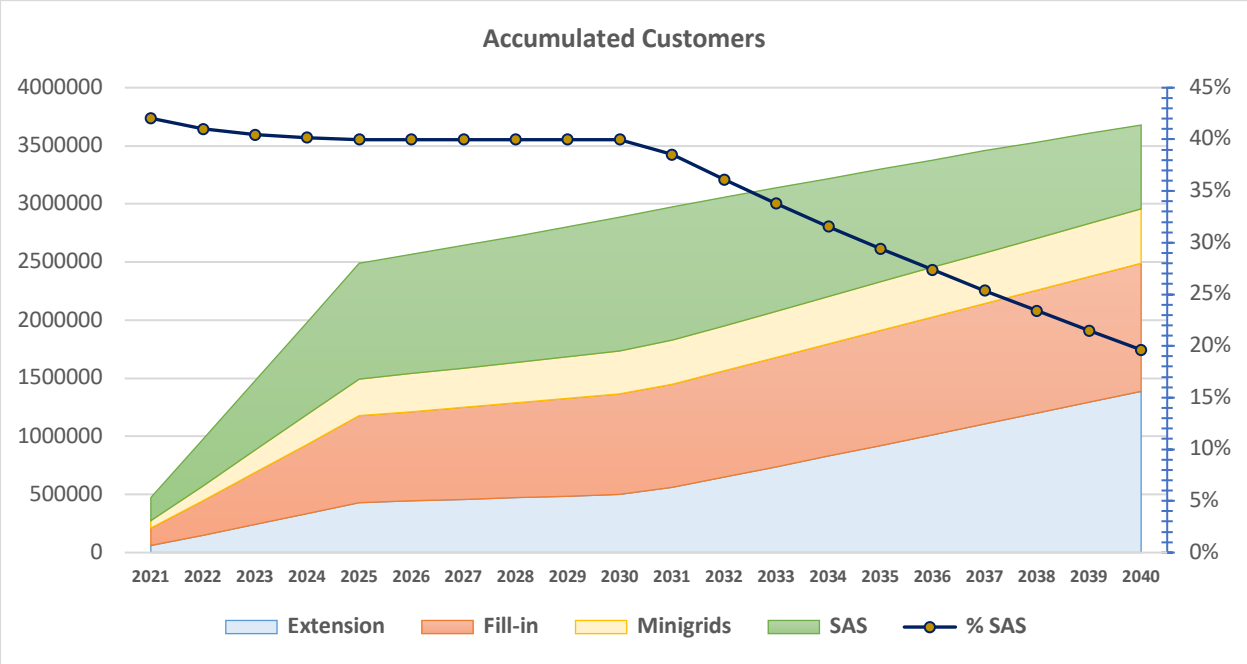
Capital Expenditure Plan

The capex plan has been elaborated aiming at reaching full population coverage with acceptable reliability by the end of 2025 (First Roll-out Wave) while maximizing population connectivity to the grid by reducing the weight of stand-alone systems from 40% in 2030 to 20% by 2040 (Second Roll-out Wave). To satisfy this goal and as per the assumptions detailed in 5.3 above, all required investments shall be completed in two distinctive stages allowing the business growing operations to address a significant – albeit non-unusual – execution and financing challenge.

As shown in Graph 2, First Roll-out Wave capex for the mix of technologies is deployed in parallel for all of them throughout the 2021-2025 period as directed by the prior Master Electrification Plan. Between 2026 and 2030 both the replacement capex and the additional investments to address expected population growth (maintaining same quality of service) require annual capex in the region of 20% of total revenues. In 2031 the Second Roll-out Wave capex starts to be deployed, requiring a decreasing percentage of revenues (from 30% in 2031 down to 20% in 2040) while delivering a significant reduction of stand-alone systems (only 20% of total expected population by 2040).



Graph 2. CAPEX Investments Breakdown



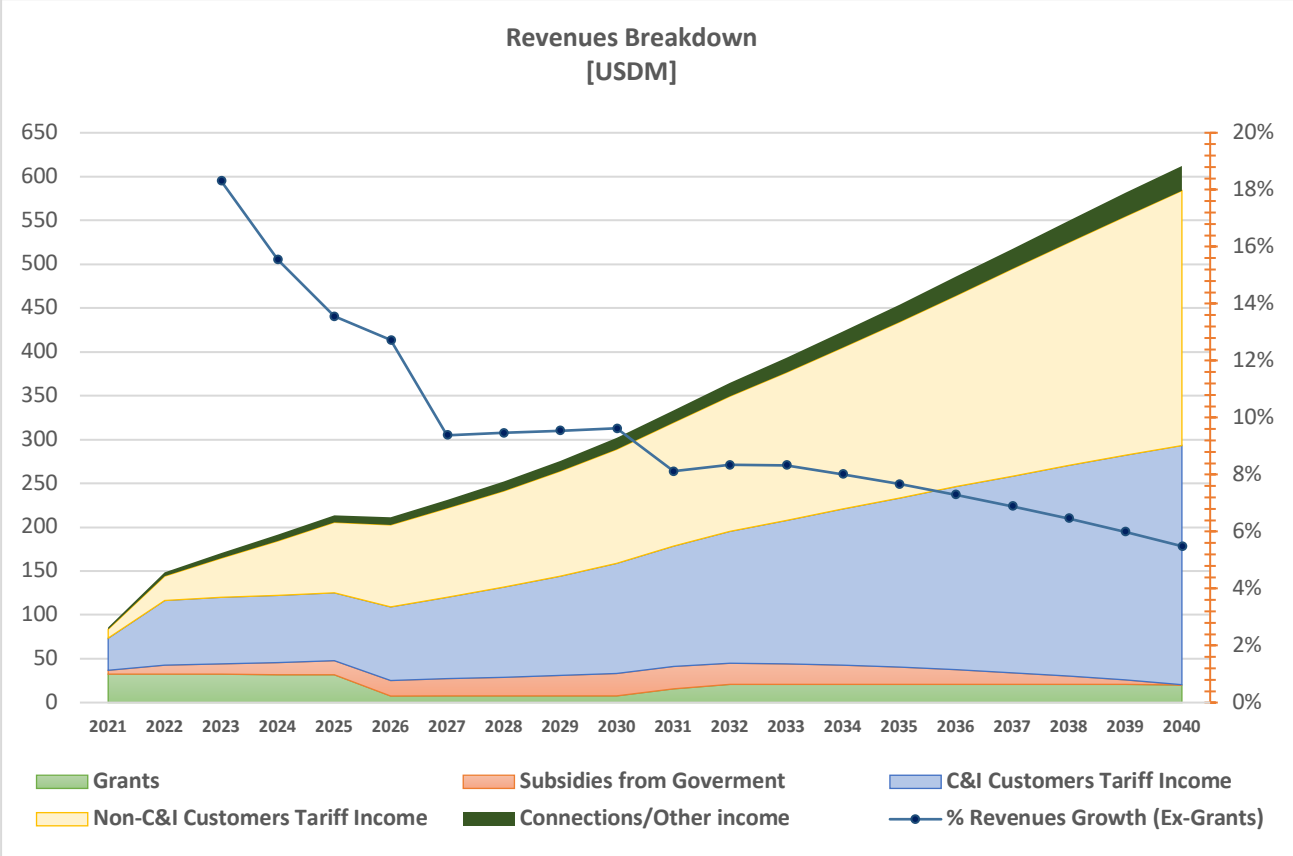
Graph 3. Accumulated number of Customers

Revenue Model

Total revenues grow at a 2021-2030 CAGR over 9% and at a 2031-2040 CAGR around 7%, from over 80 USD million the first full year of operations up to over 600 USD million by the end of the projections period. Tariff income (growing as % of total revenues from about 55% in 2021 to about 90% by 2040) and connection income follow a similar pattern, while Government subsidies (required during the network

deployment years to support business roll-out) progressively reduce their weight until they could be completely eliminated by 2040 (see Graph 4). Grants evolve in line with capex deployment further to the GoR Subsidized Financing terms, which explains some accounting (non-cash) revenues decrease in 2026 when the First Roll-out Wave is completed.

Most tariff income growth comes from non-C&I customers, increasing from just over 20% the first year of operation up to just over 50% by 2040, reflecting the significant increase in the number of non-C&I customers (over 13% 2021/30 CAGR in customers electrified for the first time), despite C&A higher estimated tariffs (25% initial increase on the Regulated Tariff) and higher expected consumption increase.



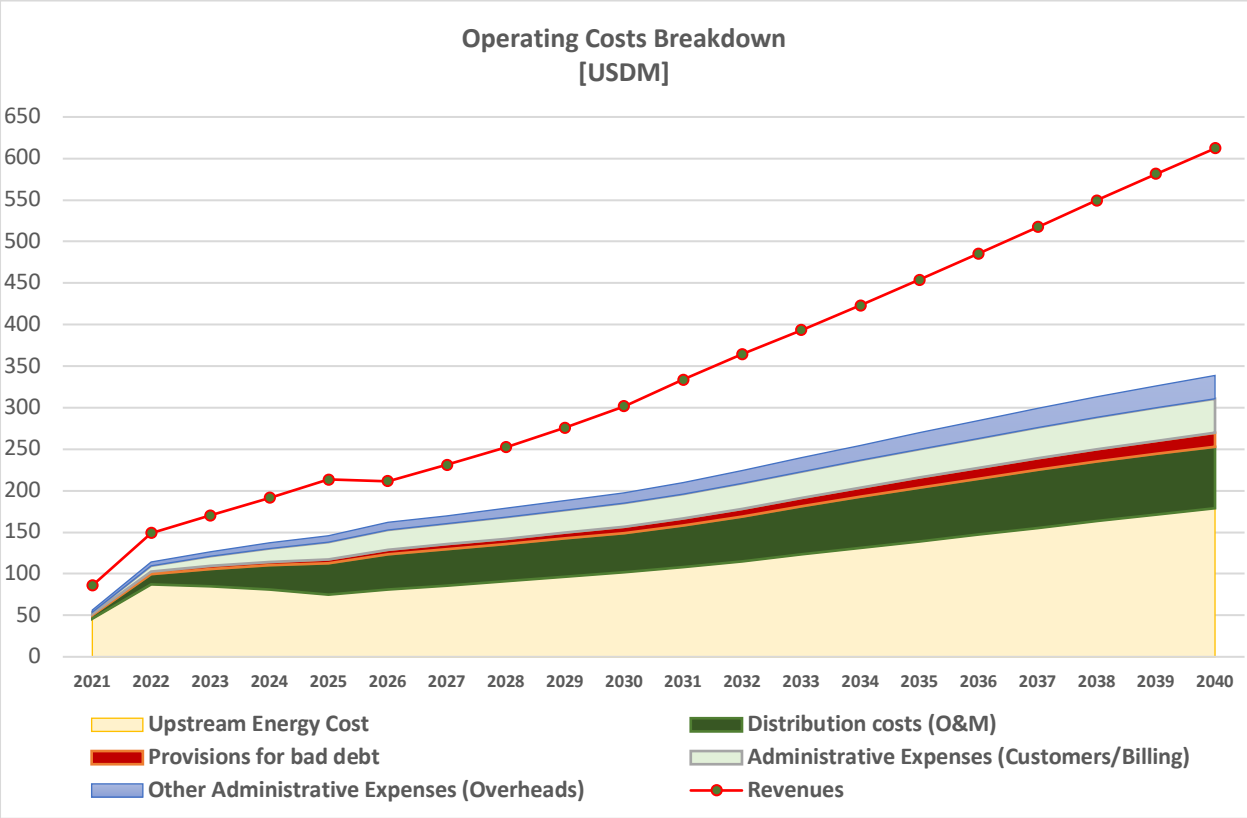
Graph 4. Revenues Breakdown

Operating Cost Model Cost Model

Total operating costs start growing at a slightly lower pace than revenues (2021-2030 CAGR about 7%) and then benefit from operating leverage (2031-2040 CAGR just over 5%), evolving from about 90% down to about 55% of ex-grants revenues by the end of the projections period, with the following cost breakdown (see Graph 5):

- As upstream energy cost moves alongside energy consumption and inflation, its relative lower growth (2021-2030 CAGR over 2% and 2031-2040 CAGR over 4%) reduce weight from over 50% down to about 30% of total revenues by 2040.

- Distribution costs, as they grow with the capital expenditure, remain between 15% and 20% of total revenues in the 2021-2030 period and between 10% and 15% of total revenues thereafter.
- Bad debt is expected to be provisioned at 3% of tariff income (no provision write-up has been assumed).
- Administrative expenses include customer/billing services (relatively stable around 7% - 10% of total revenues resulting in a 2021-2030 CAGR around 18% and a 2030-2039 CAGR of about 4% and other general overheads (estimated to be around 5% of total tariff income).



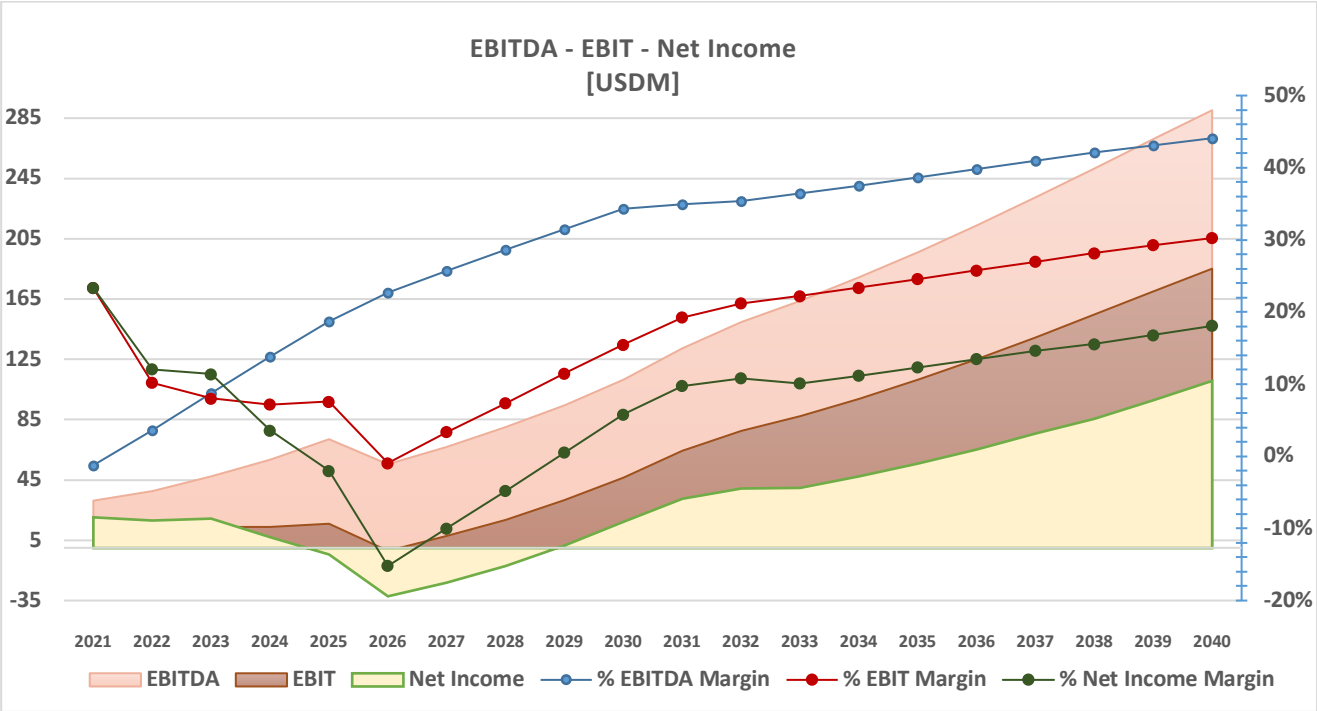
Graph 5. Operating Costs Breakdown

Operating Margins

Our estimate of revenues and cost structure produces the following operating margins (see Graph 6):

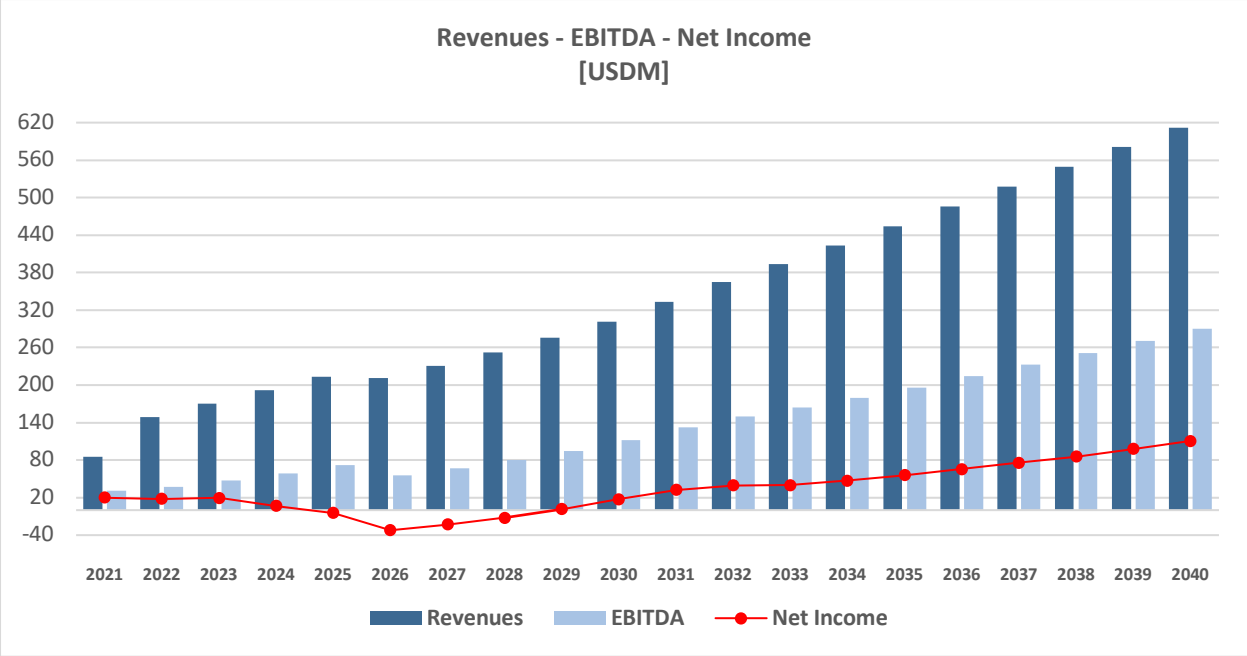
- EBITDA margin (calculated "ex-Grants" to avoid volatility brought by the GoR Subsidized Financing revenues recognition criteria) increases up to the 30/35% region by the end of the 2021-2030 period, showing some optimistic margin expansion up to the 40% area by the end of the projections period.

- As expected, EBIT margin shows a more volatile evolution linked to the network D&A schedule, starting below 10% during the first few years and growing thereafter to around 30% by the end of the projections period.



Graph 6. EBITDA - EBIT - Net Income

Graph 6 above also shows the evolution of EBITDA (2021-2030 CAGR around 15% and 2031-2040 CAGR over 9%), EBIT (2021-2030 CAGR around 17% and a 2031-2040 CAGR over 12%) and net income (very low and even negative for a few years in the 2021-2030 period but showing a healthy 2031-2040 CAGR over 15%), whereas Graph 7 below adds the evolution of revenues to provide a full overview of the business and operating model evolution.



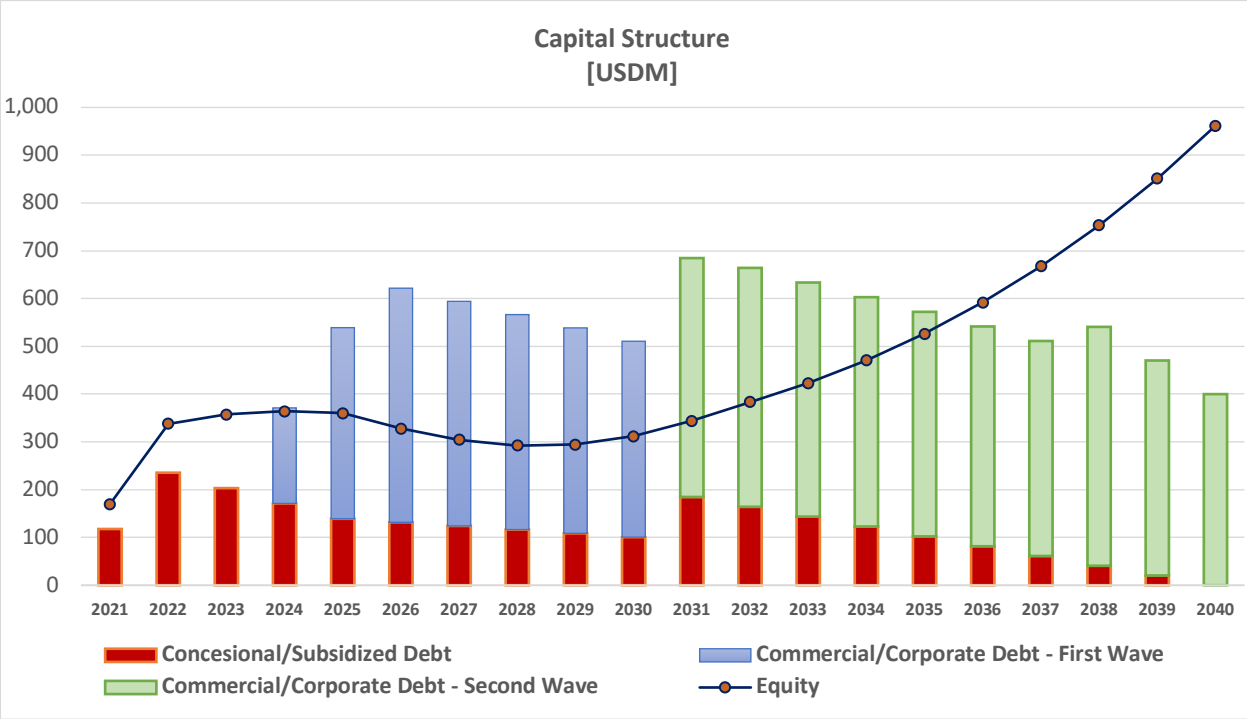
Graph 7. Revenues - EBITDA - Net Income

Financing Plan

In summary terms, to fund the **required USD 3.0 billion over the full 2021/2040 projections period** (USD 2.5 billion capex and USD 0.5 billion net financial expense), the following financing structure (see Graph 7) has been assumed:

- **Initial equity injection** of **USD 300 million in 2021/22** (around 10% of the total), anticipating the new industrial partner (either on its own or alongside other investors) will have to frontload a significant amount of the initial capex program subject to confirming funding commitments for the full program. No additional equity would be required to support the Second Roll-out Wave (as indicated above and consistent with limiting equity contributions, no dividend pay-out has been assumed during the entire projections period).
- **GoR Subsidized Financing** of (i) **USD 300 million in 2021/22** (around 10% of the total), i.e., similar amount and timing than the initial equity contribution as both financing providers would seek mutual comfort by agreeing to provide equivalent financing support and (ii) additional **USD 100 million in 2031** (around 3% of the total) to support the development of the Second Roll-out Wave (anticipating the significant social and economic benefits brought by the increase in connectivity to the grid). This subsidized debt has been assumed to be provided by the GoR linked to and conditioned to the network roll-out program at terms (cost, long tenor, covenants) below market, eventually channeling funds from DFIs (such as the World Bank or the AfDB).

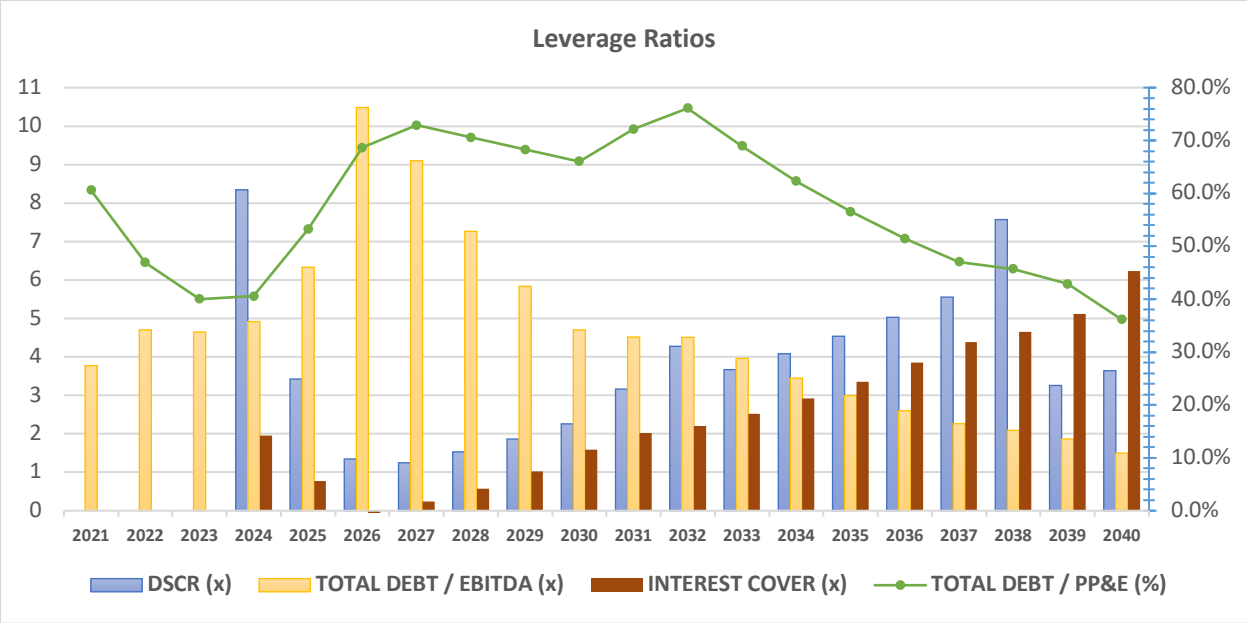
- **Commercial debt** including: (i) USD 500 million in 2024/26, contingent on the previous equity and GoR Subsidized Financing being disbursed, arranged at market terms (amount, cost – 7% coupon assumed considering some spread on the 6.625% GoR USD financing, tenor, repayment schedule and financial covenants) and thus acceptable by commercial debt financing providers (indicatively, we believe an IFC led syndicate could bring significant structuring and execution benefits but other funding sources could also be contemplated); (ii) USD 500 million commercial debt refinancing has been scheduled in 2031 (linked to the second GoR Subsidized Financing USD 100 million payment) and (iii) another USD 500 million commercial debt refinancing could be arranged in 2038 (when both business and capital structure have been stabilized so best terms could be achieved). Net debt (and so net financing inflows into the business) is estimated to be around **USD 300 million by 2040** (around 10% of the total, including USD 400 million commercial debt and USD 100 cash/equivalents).
- **Operating cash flow** of **USD 2.0 billion** generated by the business **over the 2021/2040 period** (around 67% of the total).



Graph 8. Capital Structure

Some key leverage ratios (see Graph 9) support the capital structure sustainability, with DSCR (EBITDA/debt related payments) over 1.4x except in 2026 (1.3x) and 2027 (1.2x), Net Debt / EBITDA peaking at 9.0x in 2026 but quickly deleveraging afterwards (down to 1.2x by 2040), Total Debt / PP&E around 60%/70% until it peaks at 75% by

2032 (progressively declining afterwards) or Interest Cover (EBIT/interest expense) consistently above 2.0x during the Second Roll-out Wave.

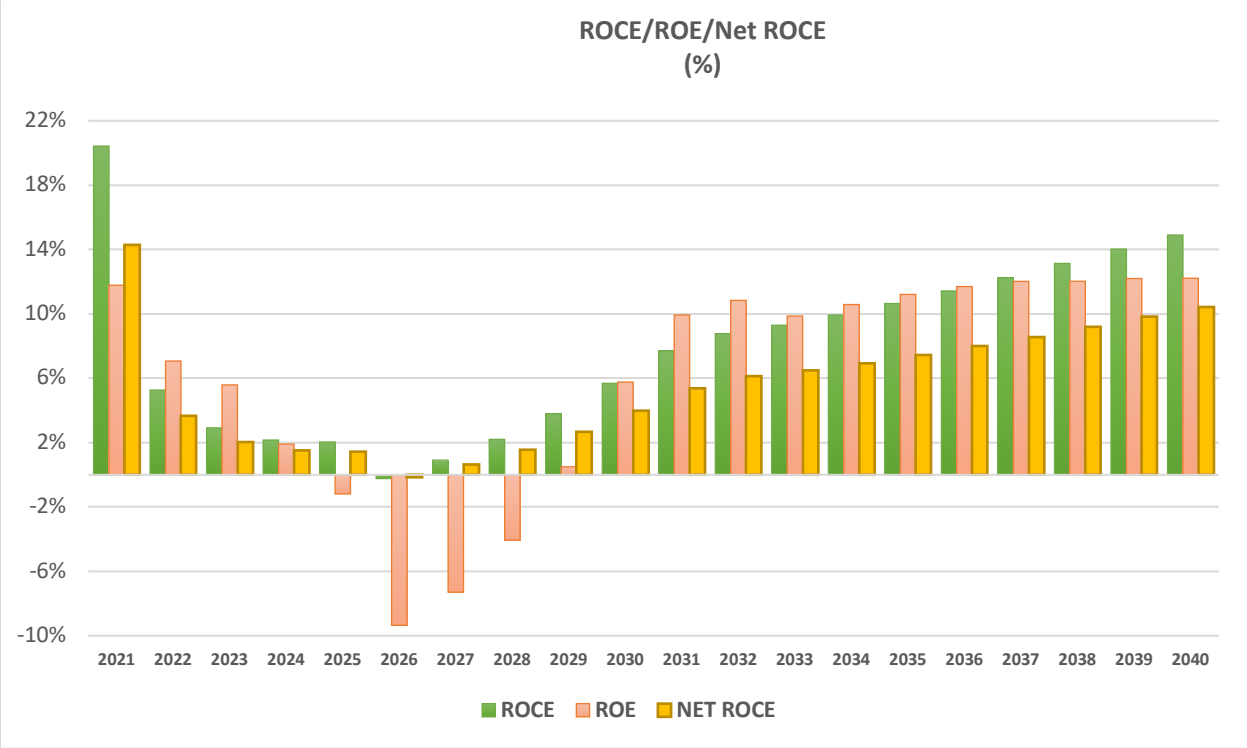


Graph 9. Leverage Ratios

Business Plan Returns

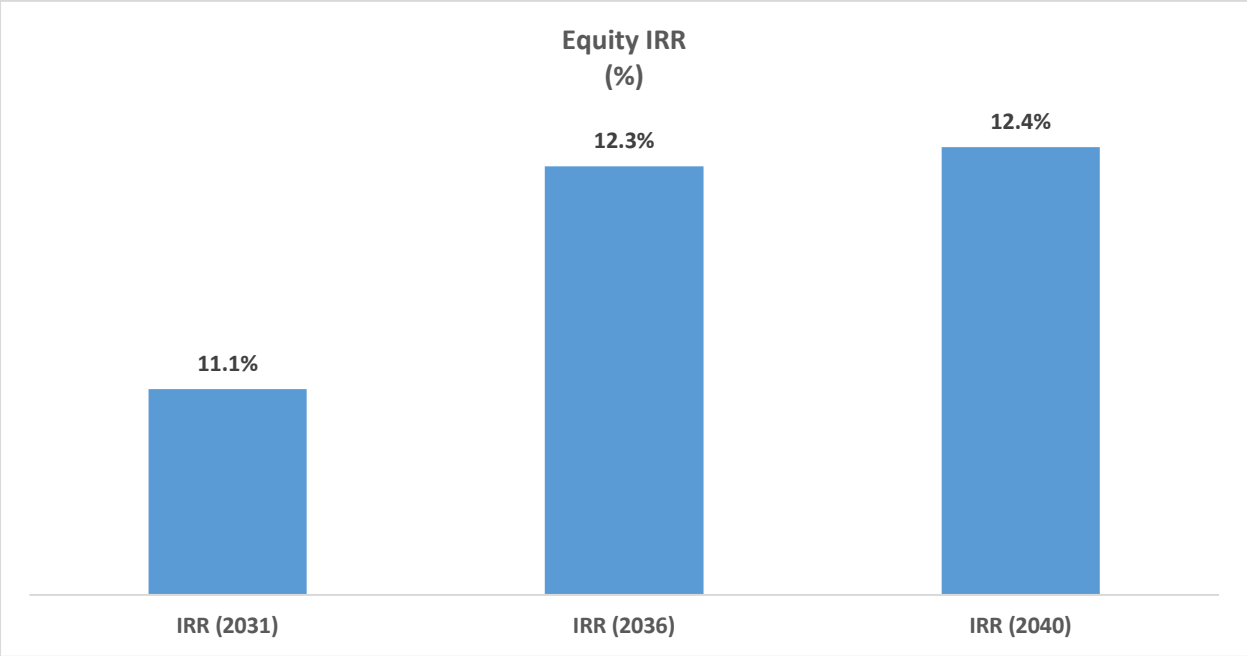
The business plan produces the following returns (see Graph 10 below):

- ROCE, calculated as EBIT/(Equity + Net Debt), below 7% during the 2021 – 2030 period, but growing from 8% in 2031 up to 15% by 2040
- Net ROCE, calculated as NOPAT/(Equity + Net Debt), below 5% during the 2021 – 2030 period, but growing from 5% in 2031 up to 10% by 2040.
- Given expected cost of debt, tax impact (estimated at 30% but, as discussed, non-applicable during the First Roll-out Wave) and lack of extraordinary cash distributions back to shareholders, return on equity (ROE, calculated as Net Income/Equity) grows from 10% to 12% in the 2031-2040 period.



Graph 10. ROCE/ROE

Finally, equity IRR (calculated under several holding/exit horizons and some estimated market value multiple of 10x EBITDA by 2031, 2036 or 2040, in line with some recent/ relevant transactions) result in 11% / 12% over 10, 15 or 20 years (see Graph 11 below).



Graph 11. Equity IRR (%)

6. CONCLUSIONS

To complement the key results explained above, some final comments are presented on the key conclusions and implementation challenges as well as the opportunities that have become apparent while building the business plan:

- The overall Integrated Distribution Framework (IDF), with the adoption of a Distribution Concession (DC) model, are the keystones of the business plan. As explained, rolling out the network (as per the explained Roll-out Waves) and hence developing the capex program are the primary drivers behind the operating model.
- The Government's role will also be critical from several standpoints: as current owner of the existing distribution business (and thus counterparty to the potential concession agreement – see comment below), as potential support to the development of the new/early business via incentivizing subsidies, as facilitator of the GoR Subsidized Financing and as ultimate guarantor of the regulatory environment (including tariffs or taxes, among other instruments). The Government participation would be key to provide the necessary comfort both to the debt and equity providers as well as to maximize, as the key stakeholder in the resulting business, the expected social and economic benefits that the execution of the electrification program would bring to the country as a whole.
- Designing the best possible capital structure (negotiating and aligning the different capital providers) is also paramount, not only to achieve a fully funded business plan but also to provide the equity partner with the appropriate financial certainty to fund the equity investment.
- The overall investment case for the new industrial partner should be further articulated on the basis of financial arguments (both in the base case and through additional scenario analysis), strategic value and, of high relevance in current corporate and financing markets, a very compelling ESG proposition: Environmental (given sector "green" status), Social (given the notorious social benefits brought by the network development program) and Governance (ensuring that the overall business plan execution and the alignment of interests among all stakeholders comply with best corporate governance standards).

Finally, it is necessary to conclude with the scope of work "not-performed" in the economic and financial model built at this stage and presented in this document. Focus has been given to the network roll-out plan for the non-electrified customers in Rwanda but, in order to provide a fully comprehensive business plan of the country entire distribution system, a complete analysis should be carried-out around the existing distribution network/business plus the new distribution network/business, as a single integrated entity within a single concession, but with separated accounting and remuneration approaches, as indicated in section 4. Completing this integrated

analysis and incorporating it into the business plan for the non-electrified customers should further confirm the overall model operating and financial feasibility as well as the social and economic benefits it would bring to all the stakeholders.