# The Gambia Electricity Sector Roadmap – High Level Update

August 2017

*PRELIMINARY DRAFT – NOT FOR CIRCULATION*

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**Abbreviations and Acronyms**

| | |
|---|---|
| AfDB | African Development Bank |
| BADEA | Arab Bank for Economic Development in Africa |
| DNI | Direct Normal Irradiation |
| ECOWAS BANK for Investment and Development | EBID |
| European Investment Bank | EIB |
| EU | European Union |
| FIT | Feed-in-Tariffs |
| GESP | Gambia Electricity Support Program |
| GPPA, | Gambia Public Procurement Act |
| GgCO2e | Gigagrams of Carbon dioxide emissions |
| GoTG | Government of The Gambia |
| GBA | Greater Banjul Agrea |
| HFO | heavy fuel oil |
| IPPs | Independent Power Producers |
| INDCs | Intentionally Nationally Determined Contributions |
| IDA | International Development Association |
| IsDB | Islamic Development Bank |
| LCDP | least cost development plan |
| MIP | Management Improvement Plan |
| MoFEA | Ministry of Finance and Economic Affairs |
| MoPE | Ministry of Petroleum and Energy |
| MoU | Memorandum of Understanding |
| NDO | National Development Plan |
| NEPCO | National Electric Power Company of Jordan |
| NPPPP | National Policy on PPPs |
| NAWEC | National Water and Electricity Corporation |
| OMVG | *Organisation pour la Mise en Valeur du fleuve Gambie*/Gambia River Basin Development Organization |
| PURA | Public Utilities Regulatory Authority |
| REA | Renewable Energy Act |
| SENELEC | Société National d'Éléctricité du Sénégal |
| COP | the Conference of Parties 21 |
| AFD | the French Development Agency |
| GIEPA | The Gambia Import and Export Promotion Act |
| NEP-II | The National Energy Policy II |
| T&D | Transmission and Distribution |
| ToU tariffs | time of Use |
| WBG | World Bank Group |

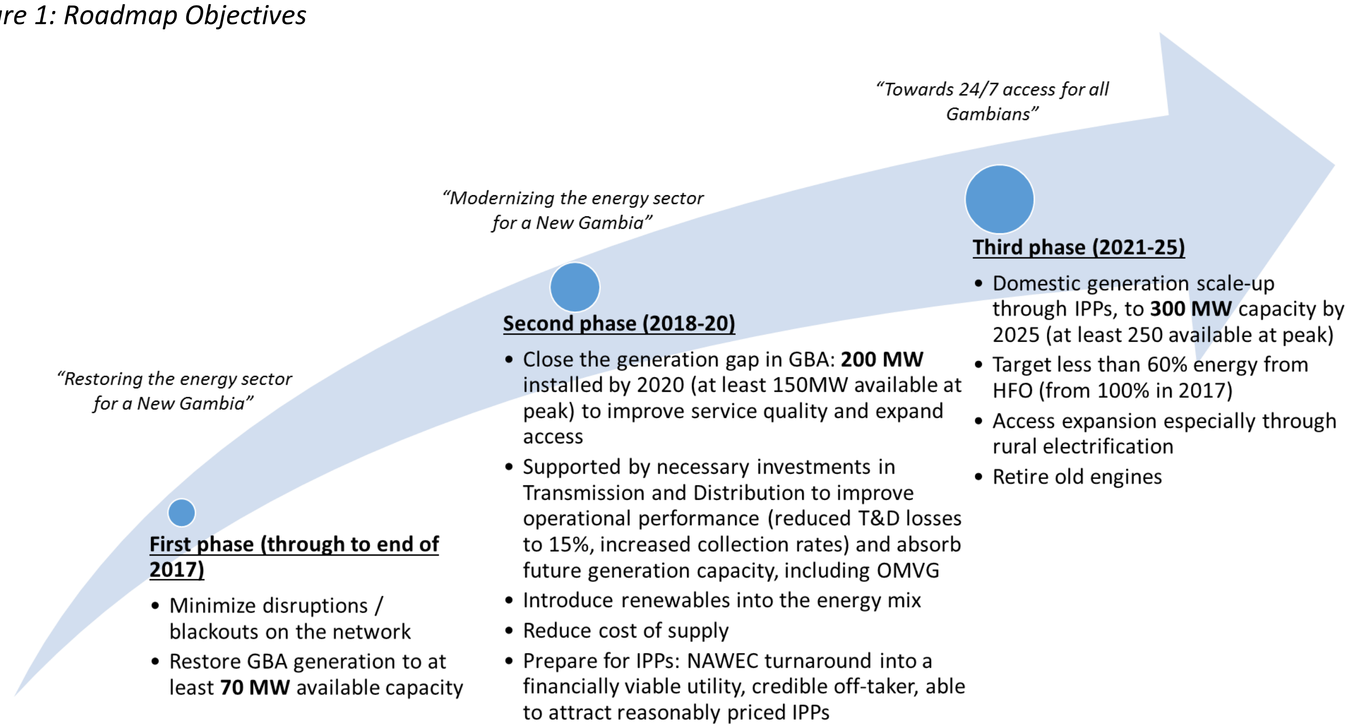
# Executive summary

The Gambia's power sector is in a precarious situation. Only 45MW of generation capacity is available in the Greater Banjul Area (GBA) compared to at least 70 MW demand, meaning blackouts are pervasive. Moreover, the national electricity and water utility (NAWEC) is not financially viable and thus it's debt has mushroomed to 9 billion Dalasi (approximately US$200 million). However, there is real reason for hope. There are potentially game changing developments on the horizon such as the ability to import low-cost power via a regional interconnection. The new political chapter in The Gambia provides a fresh start to the sector, with fresh leadership. This provides an opportune moment to reassess the country's power sector and update the electricity sector roadmap originally prepared in 2015.

The primary focus of the update is on the Least Cost Power Development Plan (LCPDP). In addition, it reviews investments required in Transmission and Distribution (T&D), as well as institutional changes required to attract reasonably priced IPPs to the sector. The update also helped prepare an Emergency Plan for 2017.

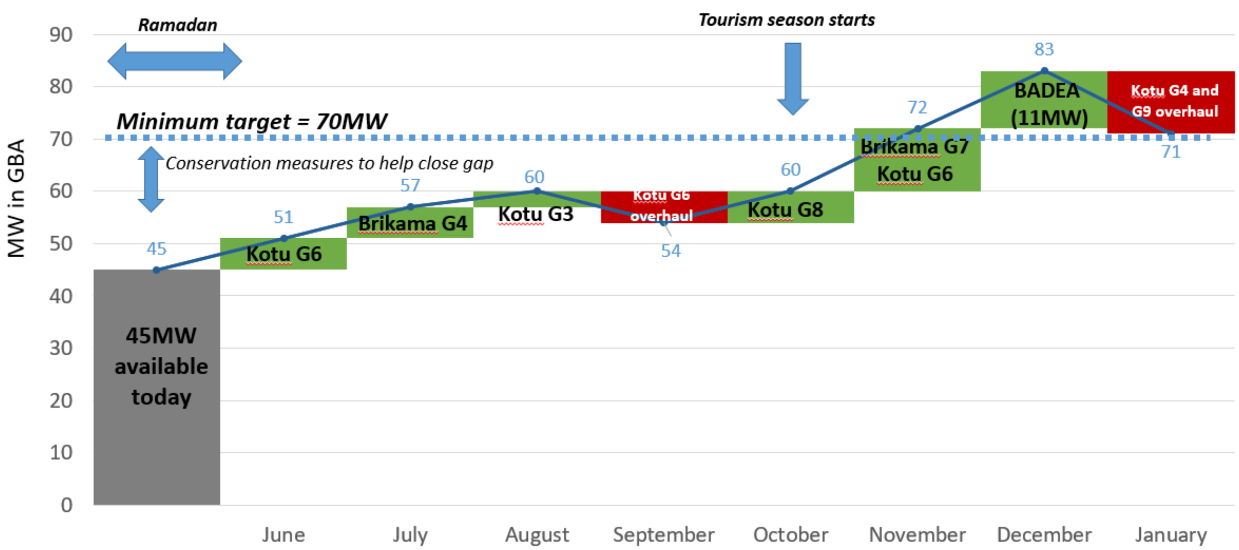
The roadmap objectives are presented in three phases. The first phase aims to minimize disruptions and blackouts on the network and restore the GBA generation to at least 70MW of available capacity by the end of 2017, and kick off preparation for the first IPP. The second phase (2018-20) includes closing the generation gap and investments T&D, as well as commissioning the first IPPs. The third phase aims to scale generation to 300MW of available capacity by 2025 and expand access. These are summarized in the Figure 1.

*Figure 1: Roadmap Objectives*



In the short-term, an emergency plan has been developed for 2017. The main features of the plan in the GBA are fast-tracking of capacity expansion through rehab and new engines to reach the minimum 70 MW by the end of the calendar year. This should help to phase out black outs. The path to 70 MW in outlined in Figure 2. Other measures in the GBA include the replacement of all street lights with LED bulbs to reduce demand, and an emergency communications plan to communicate with customers and the media on what is happening in the sector. In the provinces, cross border lines with Senegal are to be fast tracked to purchase up to 10MW of power from the national electricity utility in Senegal, Société National d'Éléctricité du Sénégal (SENELEC).

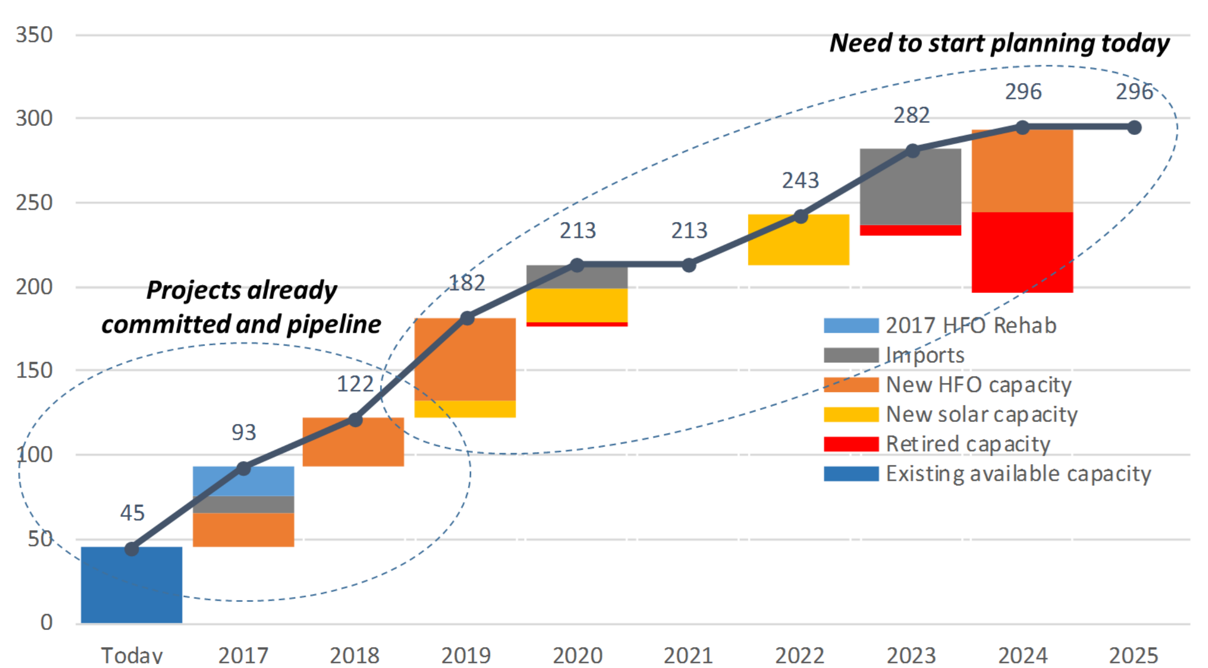
*Figure 2: Power generation capacity through to the end of 2017 in GBA*[1]




In the medium term, steps must be taken to scale-up generation capacity to 300MW by 2025. A basic update of the LCPDP has been prepared. The primary sources of new generation considered were HFO and imports for baseload, and solar for providing lowest cost electricity during the day. Gas-to-Power is also explored as a potential source of base load energy, but more work needs to be done to confirm the viability and timing of potential opportunities. The Government of The Gambia (GoTG) has expressed a preference for up to 50 percent of energy to be delivered through low cost imports from neighboring countries including Guinea and Senegal. A key factor for imports will be the import price. At current global oil prices, the cut off for imports to be financially competitive with HFO is approximately $0.14-15 / kWh. The potential path to 300MW can be found in Figure 3, validated during roadmap consultations.

[1] GBA only i.e. does not include 10MW of cross-border imports expected from SENELEC for the provinces

*Figure 3: Potential power generation expansion through to 2025 in The Gambia*




The update provides the basis for assessing the size and timeline of the investments that are required to realize the model's projections. Based on this exercise, total investment in new generation projects is estimated at US$236 million (excluding US$53 million in investments from committed and pipeline public projects). Most of this investment is expected to come from the private sector, with IPPs and imports being the governments preferred choice for future generation expansion. Table 1 provides a potential generation expansion plan with suggested preliminary design for the required generation assets.

*Table 1: potential generation expansion plan*

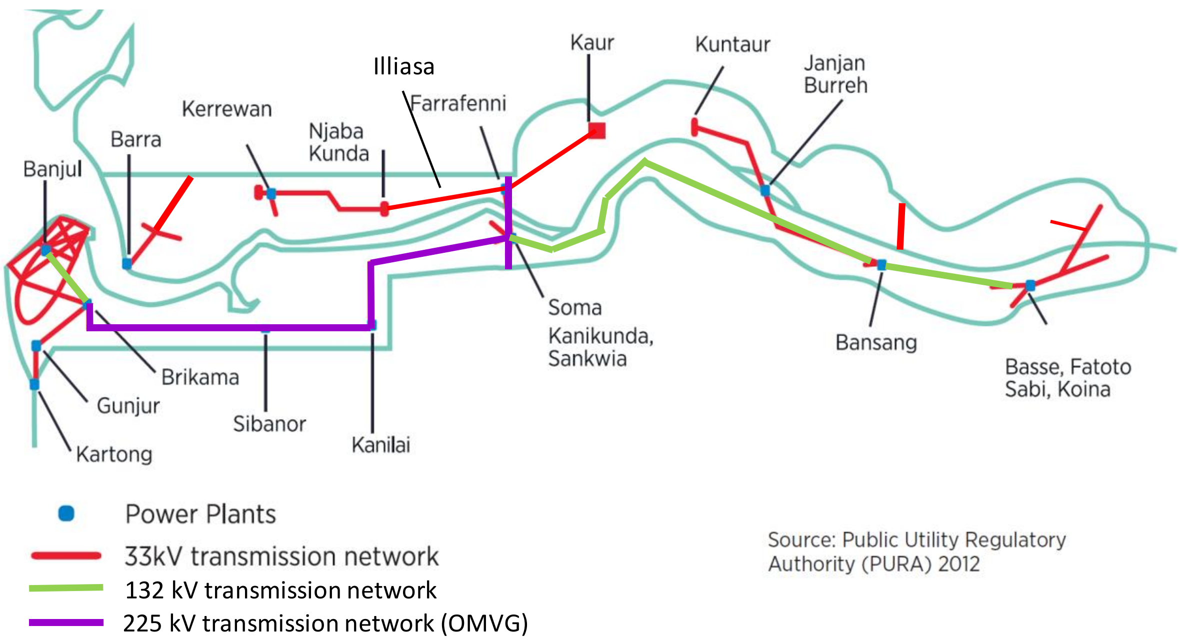
| ***Power Plant*** | ***Nominal Power*** | ***Business model*** | ***Estimated budget*** | ***Kick off project preparation*** | ***Bidding timing*** | ***Construction period*** | ***Commission*** |
|---|---|---|---|---|---|---|---|
| ***Solar 1*** | 1 x 10 MW | EPC | $12 million | Feb 2017 | Apr 18-Sep 18 | Jan 19-Sep 19 | Oct-2019 |
| ***HFO Dual Fuel 1*** | 3 x 17 MW engines | IPP | $82 million | Aug 2017 | Jun 18-Dec 18 | Jan 19-Sep 19 | Dec-2019 |
| ***Solar 2*** | 1 x 20 MW | IPP | $24 million | Aug 2018 | Apr 19-Sep 19 | Oct 19-May 20 | Mid-2020 |
| ***Solar 3*** | 1 x 30 MW | IPP | $48 million | Aug 2020 | Apr 21-Sep 21 | Oct 21-May 22 | Mid-2022 |
| ***HFO Dual Fuel 2*** | 3 x 17 MW engines | IPP | $282 million | Aug 2021 | Apr 22-Sep 22 | Jan 23-Sep 23 | Dec-2024 |
| ***Total Investment*** | | | **$236 million** | | | | |

Substantial investments in T&D infrastructure will be necessary to absorb new generation capacity especially renewables and imports, reduce T&D losses, and expand access. Scaling T&D infrastructure to meet growth projections is estimated to require US$133 million by 2025, which will come through public finance. Figure 4 illustrates the network proposed for 2025. Several transmission projects are currently underway, which will improve the performance of the grid. Projects are expected to be completed in the period 2017-2020 include[2]:

- OMVG: a 225 kV western backbone line. Completion expected in 2020
- World Bank GESP investments. Completion is expected in 2018.
- An India Exim Bank distribution project in GBA. Completion date is to be confirmed.

Further investments in T&D are required to further reinforce and expand the existing network in order to cope with the expansion in generation identified as part of the Roadmap. There is currently a financing gap of US$58 million for T&D investments.

*Figure 4: proposed T&D network in The Gambia, 2025 (illustrative)*




While a substantial number of studies are available, additional analysis is required in several key areas, notably in the area of access. The government has not yet established a target date of universal access. GIS-based electrification studies are urgently needed to determine the investment cost for expanding access. Preliminary estimates suggest the cost of electrification could be approximately of $132 million.

Total investment in the sector is estimated at almost $600 million through to 2025. Of this, $224 million is expected to come from the private sector through IPPs, and $350 million from the public sector. Of

[2] A draft description of committed and pipeline projects can be found in Annex 3

the public-sector investments, $185 million are already committed or in the pipeline, leaving a gap of $165 million in T&D and access. Table 2 summarizes the investment needs.

*Table 2: overview of electricity sector investment needs (US$ million)*

| | Total investment needed by 2025 | Of which private | Of which public | Public – already committed or pipeline | **Public financing gap** |
|---|---|---|---|---|---|
| *Generation* | $289 | $224 | $65 | $65 | $0 |
| *Transmission & distribution (down to 1kV)* | $133 | $0 | $133 | $75 | $58 |
| *Access (1kV and below) ** | $132 | $0 | $132 | $30 | $102 |
| *Technical Assistance* | $20 | $0 | $20 | $15 | $5 |
| ***Total*** | **$574** | **$224** | **$350** | **$185** | **$165** |

** Indicative estimate – needs to be validated through electrification study. Estimate based on access rate of 47%, population of 2 million, average household size of 8 people, average cost of connection of approximately $1000 (including LV, meter and internal wiring)*

Implemetation of the roadmap is the responsibility of the Ministry of Petroleum and Energy (MoPE). Successful implementation of the roadmap will require the creation of a small multi-agency task force that meets regulalry to track progress against the roadmap. As action plan has been drafted for 2017 and should be expanded by the task force for the remainder of the roadmap period. Finally, the roadmap is intended to be a living document, and should be updated regulalry as new information becomes available. There are several important analytical gaps to be filled including (i) completion of an electrification study to define access goals, confirm the demand forecast used in the LCPDP, and investments needed to reach universal access; (ii) exploration of the opportunities for The Gambia to benefit from gas-to-power, potentially via imports with Senegal; and (iii) solar mapping study to determine the true potential of Solar based generation in The Gambia. Once information from these studies is available, the roadmap should be updated, no later than 2019.

**Roadmap outline**

The roadmap aims to provide clarity to stakeholders in the electricity sector on the pathway and tasks required to realize its objectives. The roadmap outline in Figure 5, the associated Action Plan (Annex 4), and summary of electricity sector investment needs are tools that provide direction to stakeholders on what actions should be prioritized.

*Figure 5: Roadmap outline*

| | *"Restoring the energy sector for a New Gambia"*<br>2017 | *"Modernizing the energy sector for a New Gambia"*<br>2018-20 | *"Towards 24/7 access for all Gambians"*<br>2021-25 |
|---|---|---|---|
| Generation | ○ Rehab (15MW)<br>○ New engines (23 MW)<br>○ Cross border trade with Senegal (10MW)<br>○ Kick-off IPP preparation<br>○ Kick off solar feasibility study | ○ First utility scale solar (10-20 MW)<br>○ First IPP (50 MW HFO in 2019)<br>○ Second IPP (20 MW solar in 2020)<br>○ Sign OMVG PPAs and TSAs<br>○ Imports from Kaleta (via OMVG from 2020) | ○ Imports from Souapiti (via OMVG from 2023)<br>○ Additional imports (from Senegal?)<br>○ 1 solar IPP (30MW in 2022)<br>○ 1 HFO IPP (50 MW in 2024)<br>○ Retire old engines |
| T&D | ○ Power Transformer Upgrade and Installation of Switch gear (GESP)<br>○ Kick off feasibility studies for Kotu-Brikama line and access studies<br>○ Efficiency: LEDs for street lights<br>○ Reduce non-technical losses (13,000 prepaid meters and smart meters) | ○ Western backbone (OMVG)<br>○ Upgrade of Brikama-Kotu from 33kV single circuit to132 kV double circuit<br>○ Dispatch center with Scada<br>○ Access densification within GBA | ○ Eastern transmission backbone<br>○ Scale up of rural electrification |
| Institutional | ○ **NAWEC:**<br>  ○ Debt restructure<br>  ○ Competitive tender for fuel<br>  ○ Communications campaign<br>  ○ Management Improvement Plan<br>  ○ Service Contractor<br>○ **Sector:**<br>  ○ MoPE re-org<br>  ○ Vehicle levy for street lights | ○ **NAWEC**: Service Contractor; Separation of accounts; new IT system<br>○ **Sector**:<br>  ○ Performance Contract between MoFEA and NAWEC Board<br>  ○ prepare for IPPs<br>  ○ Tariff review<br>  ○ Review tariff structure | ○ **NAWEC**: build capacity to pursue and develop additional import deals via the OMVG interconnection |

# 1. Purpose of this document

An electricity sector roadmap was originally developed in 2015. The update to the roadmap provides an opportunity for the new government to express its vision for the sector and for all stakeholders, including national and international players (old and new) to re-affirm their commitment to the vision for the sector.

The objective of this document is to provide all stakeholders in the electricity sector, including the GoTG, national stakeholders, and the international community with a reference point to guide decision-making in the electricity sector. The document assesses the main challenges facing the sector and provides information and analysis on: i) the current situation of the sector; ii) a least cost development plan and an assessment of required investments in generation; iii) the current T&D infrastructure and required investments; iv) financial and institutional reforms required for the sector; and (v) policy choices available to the Government to improve electricity service delivery and sector efficiency, and achieve and maintain financial viability. This note also intends to serve as an input to the National Development Plan (NDP).

The update to the roadmap was led by the Ministry of Petroleum and Energy, with inputs from NAWEC, MoFEA, PURA, and other national stakeholders. Technical Assistance to develop the roadmap was provided by the World Bank. Consultation workshops were held in Banjul on June 14$^{th}$ 2017 and July 18-19$^{th}$ 2017. The roadmap also leveraged recent reports on Gambia's Energy sector (annex 1 provides a list of the most relevant documents).

## 1.1. Scope of the update

The update addresses the essential components of an energy sector roadmap. The main objectives of the updated are to:

- Provide a high-level least cost generation plan through to 2025;
- Project associated T&D investments that will be required to increase absorption capacity and reduce T&D losses;
- Detail institutional actions needed to transform NAWEC into an efficient, financially viable off-taker able to attract IPPs

However, there are pertinent issues to the Gambian energy sector that have not been included in the update. These issues include NAWAC corporate issues, such as a complete assessment of their financial situation, governance structure, and tariff review process. Specifically, the update does not update sections 8-12 of the Fichtner roadmap, a task expected to be performed by the NAWEC Service Contractor. The World Bank is supporting Technical Assistance to NAWEC as part of the Gambia Electricity Support Program (GESP) to bring in a Service Contractor for NAWEC that will help address these issues. The contract runs for approximately four years and will assist NAWEC to improve its technical, financial, and managerial capacity, as well as providing strategic advice. Work with a debt management consultant is also part of this Technical Assistance.

# 2. Background

The Gambia's installed generation capacity is currently 99 MW, which is entirely heavy fuel oil (HFO) thermal power plants. A lack of resources for maintenance has led to a deterioration in available capacity in the Greater Banjul Agra (GBA) to about 45 MW available today. This is not sufficient to meet peak demand, which between June and September is expected to exceed 70 MW. The situation has worsened with the scarcity of cash available to purchase fuel. Urgent measures have been taken to ensure short term HFO purchases, but these are nevertheless estimated to only cover consumption for just four months.

New generation capacity in the pipeline is expected to relieve these shortages in the medium term. Over the next 12-18 months around 50 MW of baseload capacity are coming on line. At the end of 2018 projects from the World Bank/GESP (18-20 MW); the Islamic Development Bank (IsDB), 11MW; and 20 MW from the Arab Bank for Economic Development in Africa (BADEA), will add new generation capacity, all of which will be HFO. In the long term, the regional WAPP interconnection transmission project, *Organisation pour la Mise en Valeur du fleuve Gambie*/Gambia River Basin Development Organization (OMVG), will provide 14 MW from Kaleta in 2020, and 45 MW from Souapiti in 2023, all at affordable prices.

Despite these planned increases in generation, additional investment is required; recent forecasts suggest that electricity demand will grow to 150 MW in 2020 and 200 MW in 2025. There is therefore a critical need to develop sustainable, low-cost generation.

From a sector perspective, NAWEC is in dire financial situation. It is currently unable to cover its operational expenses. Institutional actions are needed that will transform NAWEC into an efficient, financially viable off-taker that can attract IPPs. It is therefore necessary to find strategies that balance the needs of short-term supply while also reducing generation costs to help make the sector more financially sustainable.

With these substantial needs and a new political chapter beginning in The Gambia, the electricity sector is being inundated with unsolicited proposals. These include proposals from both emergency power as well as long-term Independent Power Producers (IPPs). The high volume of unsolicited proposals is distracting senior management from core functions. NAWEC reports over 20 proposals received alone since the new government came into place and over 50 proposals in the last seven years, none of which have reached financial closure. In parallel, many donors are seeking to engage or re-engage in the sector including, but not limited to, the European Union (EU), the EIB (European Investment Bank), the French Development Agency (AFD), and the African Development Bank (AfDB). Stakeholders have noted the urgent need to shift from a mode of chaos to a mode of control in the electricity sector.

# 3. The Gambia's COP commitments

The energy sector roadmap update also serves as an opportunity to review the electricity sectors contribution to realizing the Intentionally Nationally Determined Contributions (INDCs) that The Gambia submitted as part of the Paris Agreement at the Conference of Parties 21 (COP) in December 2015. As summarized in Table 3, The Gambia`s INDC plan identifies five areas for emission reductions in the energy sector (reduced transmission losses, efficient lighting, solar water heating, renewable energy & energy efficiency, and efficient cook-stoves). Combined emissions reductions are 425.7 Gigagrams of Carbon dioxide emissions (GgCO2e) in 2020, 541.1 GgCO2e in 2025 and 629.6 GgCO2e in 2030.

*Table 3: Emission Reductions per Mitigation Option in the Energy Sector*

| Mitigation options | Projection (GgCO2e) | | |
|---|---|---|---|
| | 2020 | 2025 | 2030 |
| Reduced transmission losses | 46 | 69.6 | 98.7 |
| Efficient lighting | 23.1 | 42.9 | 41.7 |
| Solar water heating | 3 | 19.3 | 36.4 |
| Renewable energy + energy efficiency | 56.4 | 121.7 | 174.4 |
| Efficient cook-stoves | 297.2 | 287.6 | 278.4 |

Source: Intended Nationally Determined Contribution of The Gambia

# 4. Sector organization

## 4.1. Institutional Setting

The key stakeholders of the Gambian electricity sector are National Water and Electricity Utility (NAWEC), the Public Utilities Regulatory Authority (PURA), the Ministry of Petroleum and Energy (MoPE), and the Ministry of Finance and Economic Affairs (MoFEA). Electricity, water, and sewerage services in The Gambia are provided by NAWEC, a vertically integrated public utility that handles generation, transmission, and distribution of electricity, as well as water production and distribution, and sewerage. The MoPE is responsible for the implementation of Government policy in relation to electricity supply and distribution and renewable energy. PURA was established in 2001 and conducts tariff reviews and recommends tariff adjustments to the MoFEA, which evaluates the financial implications and provides advice to the president for final decisions.

## 4.2. Snapshot of electricity sector performance

*Table 4: Snapshot of electricity sector performance*

| Parameter | Value |
|---|---|
| **Electricity Access rate** | 47% (2014, SE4ALL GTF) |
| **Number of electricity customers** | 155,000 (2016) |
| **Installed capacity** | Country: 99MW of which 54MW is available (May 2017)<br>Banjul: 88MW of which 45MW available (May 2017) |
| **Peak Demand** | Approx. 70MW, but generation requirement for up to 150MW given suppressed demand (2017) |
| **Energy mix** | 100% HFO (2017) |
| **Share of private sector in generation** | 0% (2017) |
| **Average cost of service** | \$0.44 / kWh (2014) |
| **Average tariff** | \$0.22 / kWh (2014) \$0.26 / kWh (2016) |
| **Average T&D losses** | 23% (2016) |
| **Electricity bill collection rate** | 88% (2016) |
| **Utility debt (electricity water and sewerage)** | Stock of debt is ~D9billion (~\$220m), or 4x annual turnover |

Table 4 highlights some of the key characteristics of the Gambia`s electricity sector. These include:

**Low access to electricity:** electricity access in The Gambia is estimated at 35 percent of the population. While 60 percent of the population in the GBA is served, only six percent of the population in the outlying provinces has access.

**Inadequate supply means blackouts are frequent**: NAWEC has an installed capacity of 99 MW of which only 54 MW are currently available. 88MW is installed in the GBA, of which 45 MW is available against an estimated peak demand of 70 MW. Installed capacity is 100 percent liquid fuels, with NAWEC consuming on average 6,000 metric tons of HFO per month.

**High transmission and distribution losses**: Transmission and Distribution network losses were approximately 23 percent in 2016, increasing the cost of supply on a per kWh basis.

**Commercial**: NAWEC had 155,000 electricity customers in 2016, over 90 percent of which are in the GBA. Bill collection rates have steadily improved to 88 percent thanks to the widespread introduction of prepaid meters (almost universal coverage for residential customers).

**Highly indebted utility**: Collected revenues have not covered accrued costs forcing the utility to expand its debt to cover short term operating costs in addition to investment needs. Despite a 12 percent tariff in January 2015 and a government backed debt restructure in 2015, NAWECs debt has mushroomed to 9 billion Dalasi (approximately $200 million), equivalent to four times the annual utility revenue, or 25 percent of GDP.

**Earlier reform efforts:** In terms of reform, the sector successfully established a regulator. NAWEC remains a small and traditional vertically integrated state owned utility. The government tried to bring the private sector into generation in 2006 through a HFO IPP (Global Electric Group). However, following irregular payments and cash flow issues, NAWEC purchased the assets from the IPP in 2013.

A more detailed breakdown of the operational performance of NAWEC is included in Table 5 below.

*Table 5: NAWEC Operational Performance Data 2012-16*

| **Generation (MWH)** | | | | | |
|---|---|---|---|---|---|
| **Station** | **2012** | **2013** | **2014** | **2015** | **2016** |
| KOTU | 102,009 | 101,192 | 96,028 | 91,628 | |
| BRIKAMA 1 | 84,533 | 103,536 | 140,166 | 144,807 | |
| WARTSILA / Brikama II | 50,391 | 39,415 | 22,288 | 49,513 | |
| *Total GBA* | *236,933* | *244,143* | *258,482* | *285,948* | *298,535* |
| Provinces | 8,584 | 7,063 | 7,910 | 9,396 | 15,174 |
| **TOTAL** | **245,517** | **251,206** | **266,392** | **295,344** | **313,709** |

| **Sales (MWH)** | **2012** | **2013** | **2014** | **2015** | **2016** |
|---|---|---|---|---|---|
| **Prepaid** | **n/a** | **114,609** | **127,219** | **148,770** | **168,276** |
| - GBA | n/a | 114,609 | 122,576 | 142,578 | 159,228 |
| - Provinces | n/a | | 4,643 | 6,192 | 9,048 |
| **Credit** | **n/a** | **67,765** | **71,162** | **64,215** | **72,176** |
| - GBA | n/a | 64887.523 | 68,285 | 61,942 | 69,673 |
| - Provinces | n/a | 2877.198 | 2,877 | 2,273 | 2,503 |
| Total | **175,000** | **182,374** | **198,382** | **212,986** | **240,452** |
| Growth | | **4%** | **9%** | **7%** | **13%** |

| **T&D losses** | **2012** | **2013** | **2014** | **2015** | **2016** |
|---|---|---|---|---|---|
| T&D losses (MWH) | 70,517 | 68,832 | 68,010 | 82,358 | 73,257 |
| **T&D Losses (%)** | **28.7%** | **27.4%** | **25.5%** | **27.9%** | **23.4%** |

Source: NAWEC Generation and Commercial Departments

## 4.3. Key obstacles in The Gambia's electricity sector

Some of the key obstacles that pose challenges to progress include NAWEC`s unsustainable debt levels, inadequate spending on maintenance of HFO engines, and tariffs that are set at rates that are too low and leaves NAWEC exposed to external shocks beyond its control. These obstacles are explained in more detail in Table 6.

*Table 6: Key obstacles in The Gambia's electricity sector*

| ***Obstacle*** | ***Description*** |
|---|---|
| *Unsustainable debt* | NAWEC is highly indebted and essentially bankrupt. For years, collected revenues have not covered accrued costs forcing the utility to expand its debt to cover short term operating costs in addition to investment needs. Despite a 12 percent tariff in January 2015 and a government backed debt restructure in 2015 in March 2015 in the form of a consolidated bond, total debt taken out by or on behalf of NAWEC has mushroomed to around 9.5 billion Dalasi (approximately $215 million), equivalent to four times the annual utility revenue, or around 20 percent of GDP. The debt is so large that loan default threatens the stability of the nation's banking system, often forcing the government to bail out NAWEC. A snapshot of NAWEC debt is provided in Annex 3. |
| *Inadequate spending on maintenance* | Due to a constrained financial position, NAWEC has been unable to carry out all of its routine maintenance activities. As a result, less than 50 percent of installed generation capacity is available and T&D losses have increased. |
| *Tariff levels are too low* | Even if NAWEC collected 100 percent of its billed revenue, cash collected would not be sufficient to cover costs. While the cost of supply should reduce in the medium to long term (as the energy mix improves through OMVG (expected to be operational by 2020) and T&D losses are reduced), current tariff levels are inadequate to cover accrued costs. |
| *Tariff structure leaves NAWEC exposed to external shocks beyond its control* | With the cost structure outlined above, external shocks have a major impact on NAWEC. For example, between 2000 and 2016, the Gambian Dalasi depreciated 200 percent against the US dollar. There is no automatic pass through mechanism in the tariff structure to respond to these shocks, and no minimum period within which tariff reviews need to happen (NAWEC need to initiate a tariff review process which it is often hesitant to do). The utility therefore remains exposed to global oil price shocks and exchange rate fluctuations which are beyond its control. |

## 4.4. Opportunities

The Energy Roadmap and Action Plan for The Gambia identified basic, short-term, and medium-term investments needed to restore the sector's performance. The basic needs include the rehabilitation of existing HFO plants, targeted investments in T&D to reduce losses, and the installation of meters. The short-term investment needs include new thermal power plants to run on HFO and further T&D network improvement investments. Medium-term investments are comprised of regional interconnections that provide access to clean and low-cost electricity imports.

A. Financial Viability: The urgent short term need is to achieve financial equilibrium in the sector and "stop the bleeding". A November 2016 workshop convened key stakeholders in the energy sector to agree short and medium term measures to address NAWECs financial viability challenges. Key workshop agreements included:
    1. NAWEC to renegotiate its fuel supply contract with GNPC, or explore sourcing from the market directly (per the practice of other utilities in the region)
    2. NAWEC to develop a debt restructure and debt sustainability plan. In the short term, the government may be forced to bail the utility out, but given that it faces its own debt sustainability issues, NAWEC will need to restructure its debt, develop a debt sustainability plan, and put in place a strong financial management and control system to avoid the situation repeating itself. A capital injection may be necessary.
    3. NAWEC is to apply for a tariff review
    4. GoTG is to initiate a Performance Contract between the State and NAWEC
    5. GoTG is to explore the possibility of an automatic pass through mechanism for fuel prices and exchange rate changes.
    6. GoTG is to ensure that Public Service Obligations are funded.

B. Operational Competence: in parallel, it is critical to improve the management of NAWEC, a major focus of the current World Bank project (GESP). The project will finance a service contractor to provide advisory support to the key management functions (finance, commercial, technical etc.). The service contractor will also implement a revenue protection plan, design a new IT system for finance (commercial and HR), and support the separation of accounts for the various service lines (Electricity, water, sewerage). Unbundling the utility into separate companies according to service line could be considered as a next step, however it remains unclear if this would lead to efficiency gains. As mentioned above, a Performance Contract may also be introduced between the State and NAWEC to enhance the operational performance of NAWEC. More information can be found in section 11.

C. Security of Supply: In the medium to long term, the OMVG regional interconnection project is a potential game changer for The Gambia, enabling the import of reliable low cost clean energy (hydro) from Guinea at a cost of around $0.12/kWh compared to current generation costs in excess of $0.30/KWh. Hydro plants in Guinea include Kaleta (240MW of which 14MW is reserved for The Gambia, commissioned in 2015) and Souapiti (500MW of which 50MW is reserved for The Gambia, construction started in 2016 with completion expected by 2023). OMVG have agreed term sheets for the agreed shares of electricity. Power Purchase Agreements (PPAs) will not be signed until construction of OMVG line is complete and final construction costs are known. Construction of the OMVG line is expected to start 2017 and should be completed in 2020. The project involves four countries (Senegal, The Gambia, Guinea, and Guinea Bissau) and eight donors to construct a 1600km 220kV transmission loop.

D. Energy Access: OMVG will also provide substantial opportunities for rural electrification by providing a transmission backbone throughout the country and several 220kV / 30 kV substations which can be used for grid extension. In addition, there are several opportunities for rural electrification through pipeline projects (see section 9.3 for more detail). However, a national electrification plan is still needed.

# 5. Electricity Sector Roadmap key principles and objectives

## 5.1. Key principles

The key principles that are foundational to the roadmap are that:

- The GoTG and NAWEC agree on the aim to reach a position where new generation capacity is achieved mainly through imports and competitively tendered IPPs, with public investment in Transmission and Distribution.
- Due to National Security concerns, target available domestic capacity able to deliver at least 50 percent of demand, but willing to import more than 50 percent if lower cost imports are available
- Strictly enforce that anyone – public or private – who wants to act in the sector needs to be aligned within the roadmap.
- Roadmap remains a living document, updated to changing circumstances and new information.

## 5.2. Objectives

As illustrated in Figure 1, the roadmap is presented in three phases:

**The first phase (through to end of 2017):** the first phase addresses the immediate actions that must be taken to restore GBA generation to at least 70MW of available capacity to minimize disruptions and blackouts. A communications strategy has been prepared to inform the population about the restrictions in the power supply and the actions that are being taken to restore generation in the short term. The sector will kick off preparations for the first IPPs by starting the process of transforming NAWEC into a financially viable utility and credible off-taker that can attract reasonably priced IPPs.

**The second phase (2018-20)**: a series of steps to close the generation gap will begin in 2018. Finalizing investments in early 2018 should increase generation to 100MW. Further increasing generation to 120MW will help to improve service quality and expand access in the GBA. Investments in T&D will support this generation expansion and improve operational performance (through reduced T&D losses and higher collection rates) and absorb future generation capacity. This includes OMVG, whose PPAs will be signed.

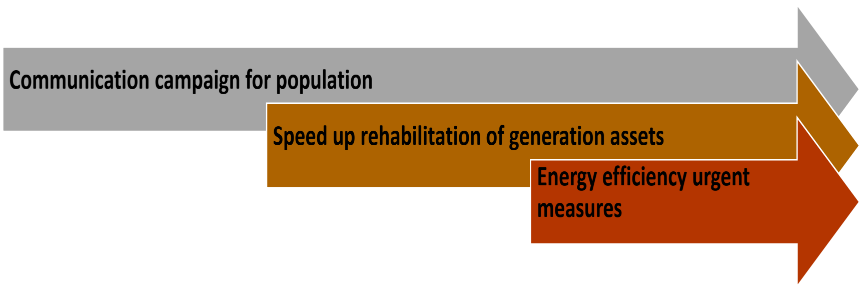
**The third phase (2021-25):** in the third phase, domestic generation will scale up through additional IPPs, and the OMVG interconnection is expected to provide additional hydro imports from Guinea. This will permit the majority of the existing aging fleet to be retired. Finally, progress towards universal access will be targeted through rural electrification programs.

# 6. Emergency plan for 2017

*Activities in 2017 will be focused on the currently situation of the power sector and will be organized into three main blocks. into three main blocks. Activities will support each other and will target the increase of electricity availability for the population availability for the population (increasing generation and reducing consumption in public buildings). The communications communications campaign will address the population directly with updates on steps being taken to improve the situation. improve the situation.*

Figure 6 illustrates the three branches of activities that will be undertaken in 2017.

*Figure 6: Measures in 2017*



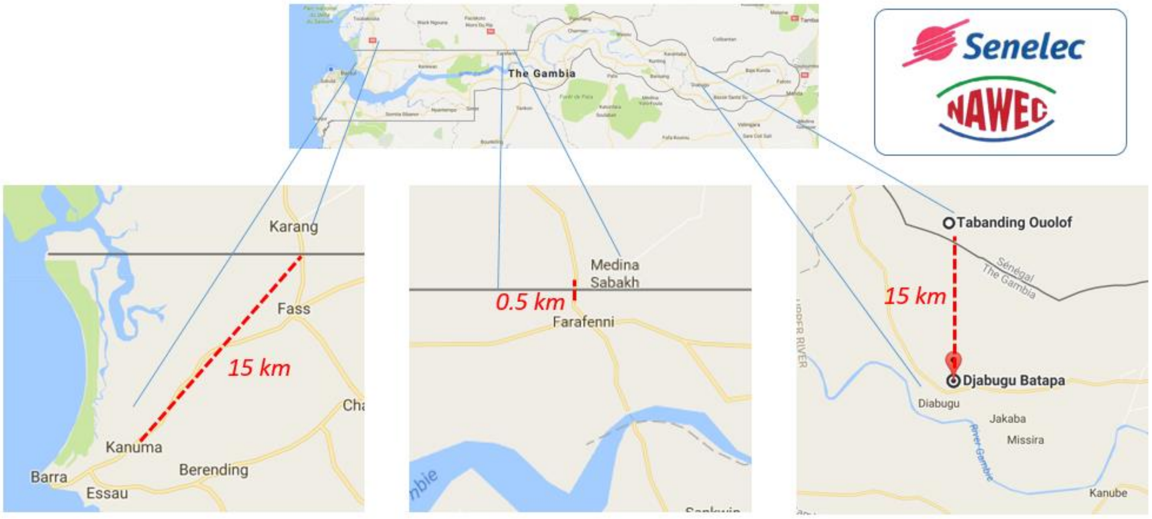

## 6.1. Generation in 2017

There is an urgent need to increase short-term generation capacity. In the GBA, these actions will be focused on the priority rehabilitation and generation expansion of up to 25 MW in the existing power plants of Kotu and Brikama. By the end of 2017, available capacity is expected to reach over 70MW (see Figure 2).

Beyond 2017 in the GBA, additional generation capacity committed for 2018 include 29MW from committed projects including 9 MW from World Bank financing for Brikama II, and 20MW from IsDB Brikama III (20 MW). The new World Bank / EIB / WU renewable energy project could add an additional 10-20 MW by the end of 2018 if project preparation and implementation stays on track.

In the provinces, actions to boost generation capacity will be focused on cross-border electrification to reduce cost of supply in provinces, with the provision of up to 10MW from SENELEC. Three medium-voltage 33kV lines, totaling approximately 30km, have been proposed that will be financed through the World Bank GESP project for the Gambia side of the border. SENELEC has agreed in principle to finance the lines on the Senegal side of the border. The PPA for these imports, including the tariff, is expected to be negotiated in July 2017. Construction of these lines could be completed as soon as Q3 2017.

*Figure 7: cross border transmission lines (KM represent Gambian side only)*




## 6.2. Emergency communications campaign

Since there will be a generation gap and continued blackouts until at least November 2017, there is a need to implement a communications campaign to reassure customers and decision makers that although the situation is grave, there are credible plans in place to improve supply. A communication strategy has been developed through Technical Assistance from the World Bank. It has identified high-impact actions that need to be prioritized in the short-term, with the goal of informing the population of the nature of the problem and action being taken to address it, as well as to mobilize consumers to reduce consumption during peak hours. The target audience for the communication campaign is households, major consumers, the government, and policy makers.

The communications strategy is partly based on results from focus groups that have been run with NAWEC customers representing the residential sector, the hotel industry, and the agricultural sector. Common complaints expressed during the focus group sessions will be addressed as part of the communications campaign as well as provide valuable customer service advice for NAWEC going forward. Complaints were expressed over the lack of reliability and quality of electricity. The lack of information provided by NAWEC about where, when, and for how long the blackouts were to occur, and what NAWEC what was doing to address them. There was also frustration expressed that the government doesn't have to pay its electricity bill, but they still receive service. Businesses are especially concerned about the impact electricity shortages have in attracting investors and the difficulty it creates in planning for the future. In the hotel industry, there are concerns about the upcoming tourism season and the potential negative impact blackouts might have on business. All businesses noted that backup generation is expensive. This feedback will be complemented by a survey of 200 residential consumers asking them about their views of NAWEC and their electricity consumption habits.

The communications strategy will build on this data by taking a number of steps that will help alleviate the electricity shortage. It will begin to implement a power alert system (like in South Africa) to alert viewer of upcoming blackouts. TV spots with an animated infographic communicating what actions are being taken to address the issue and another advertisement with a message on saving energy will be implemented. Social media will be used to better engage and communicate with NAWEC's customers. This will include Facebook and twitter and there will be a consultant hired to manage the accounts. Weekly briefs and updates will be provided to the press. These initiatives will be rolled out by the NAWEC PR team from June – August and will all feed into a long-term communications strategy that will help NAWEC better interact with its customers and build stakeholder support.

## 6.3. Energy efficiency measures

NAWEC and other relevant stakeholders will implement energy efficiency measures in public buildings and areas. Emergency measures include replacing 5,000 street lamps and government offices with LED bulbs. The current lamps are 250W (less than 1000 are 400W) incandescent and run approximately from 7pm to 7am. The LED bulbs are approximately 100W and could reduce electricity demand by 1-2 MW during the night.  An estimate for the number of bulbs in government offices is pending. These emergency measures are supported by the communications campaign. Consideration must be given to the who implements the LED street map replacement – NAWEC or the local councils.

Medium term measures (4-6 months) include reducing commercial losses by improving metering. Smart meters will be distributed for 300 large customers as part of GESP. In addition, 13,000 additional prepayment meters will be deployed to residential customers. Currently, about 85 percent of GBA consumers are provided with prepayment meters.

Ideas that were considered but are not being moved forward include limiting the A/C temperature in government buildings to 25C, which was deemed to be too difficult, and implementing time of Use (ToU) tariffs, which only have limited potential to shave peak demand.

# 7. Least Cost Power Development Plan

The LCPDP provides guidance to the government on how to expand the electricity sector to meet the needs of customers while minimizing total system costs. It also helps diversify the energy mix to reduce NAWEC's exposure to oil prices and transition towards cleaner energy sources in line with The Gambia's COP21 commitments. The LCPDP has been carried out considering three scenarios, with sensitivity analysis for fuel prices and transmission losses on the preferred scenario.

## 7.1. Least cost plan methodology

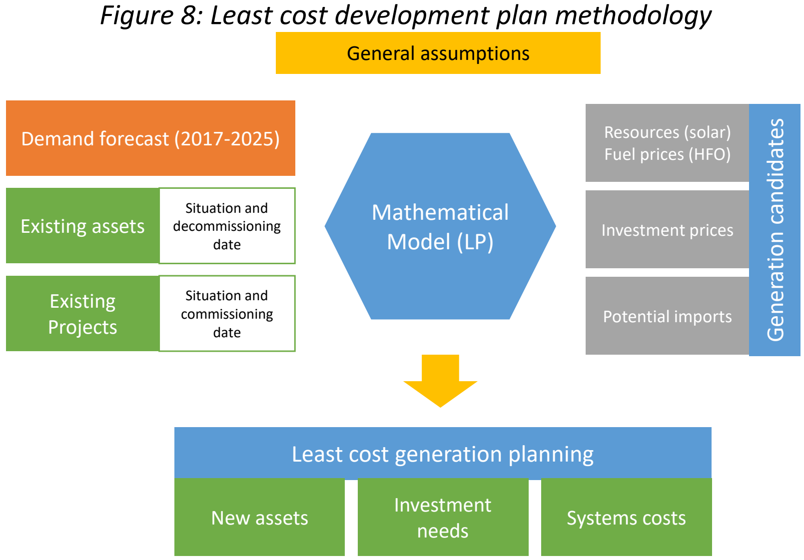
The planning methodology follows a linear programming (LP) capacity and dispatch optimization model to assess the least-cost generation mix using the assumptions discussed below. Data included in the exercise comes from NAWEC, previous studies from Fichtner and the National Electric Power Company of Jordan (NEPCO), and general benchmarks in the region.

The LP model:

1. Minimizes total discounted system cost comprising fuel and variable O&M, fixed O&M and annualized capital costs (for new plants) and cost of unserved energy
2. Considers all existing power stations and proposed/planned/anticipated projects
3. Considers annual load duration curve to represent demand
4. Considers penetration of generation from renewable energies, in particular solar power and the daily solar profile
5. Use of additional fuels that may become available in the future, such as natural gas.

Figure 8 shows the typical data and flows in this type of model.

*Figure 8: Least cost development plan methodology*



The LCPCP model requires various input data, including generation energy mix options, daily demand profiles, leak demand forecast, existing and committed generation plants, and detailed assumptions; all of which are described below.

### 7.1.1. Generation energy mix

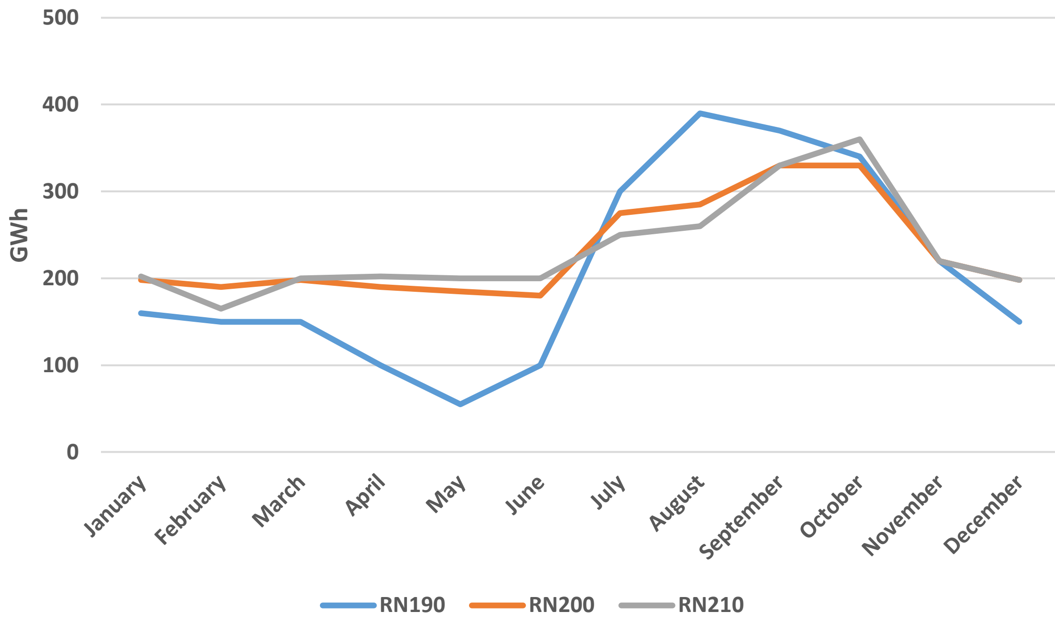
The technologies considered in the exercise are HFO, gas and hydro (imported via the OMVG interconnection) for baseload, and Solar PV during the day. Figure 11 summarizes the assessment of nationally suitable and realistic sources. The network today is 100 percent dependent on HFO the only viable option for base load until the OMVG interconnection is completed. Gas, hydro and solar all represent good opportunities for The Gambia but more work needs to be done to understand the precise opportunity and timing of each. The roadmap is a living document should be updated with new information as it becomes available e.g. what is the true potential of solar, what are the economically viable options for gas, what is the real timeline for availability of hydro etc.

**Regarding imported Hydro**, the OMVG interconnection will potentially be a game changer for The Gambia giving the country access to lower cost electricity from the sub-region, but timing and seasonality are key factors. Power Purchase Agreements (PPAs) have not yet been signed but the four countries party to the OMVG (The Gambia, Guinea, Guinea-Bissau, and Senegal) have agreed an allocation of power for the first three power projects (Kaleta, Souapiti and Sambangalou). The OMVG interconnection line is expected to be commissioned in 2020. However, the Souapiti hydro plant, which is the large 550MW hydro plant under construction in Guinea, is not expected to be available until 2023. The Memorandum of Understanding (MoU) with OMVG therefore includes an allocation on energy in two phases. In 2020 The Gambia will have access to 14 MW of peak power coming from Kaleta. In 2023, the allocation will be increased up to 60 MW when Souapiti comes online. Sambangalou is expected beyond 2025.

Seasonality of hydro is key factor. Neither Kaleta nor Souapiti are expected to provide firm power. Indeed, in the OMVG MoU, power supply is limited to 270 GWh per year in 2025 (equivalent to an average of 30MW through the year), with high generation in the wet season (July-October) and lower generation the rest of the year.

Figure 9 shows the seasonal variability considered in the model, specifically the Normal Reservoir Level (RN) RN210.

*Figure 9: Forecasted generation for Kaleta+Souapiti hydropower plants*




**Additional imports**: the volume of electricity imports will ultimately depend on their availability and the Government's strategy on energy security and interdependence. Due to National Security concerns, target available domestic capacity able to deliver at least 50 percent of demand, but the Government of The Gambia have expressed a willingness to import more than 50% of energy if there are lower cost import options available, but always having the installed capacity available domestically to generate at least 50% of energy domestically. For example, there is potential for Gambia to import power from Senegal in the future. This import preference is therefore considered in the design of the scenarios. The upper limit to the cost of imports is around US$0.14-0.15/kWh. It is also noted that with a regional project such as OMVG there can be less dependence on one bilateral partner and therefore it is a more secure arrangement for imports.

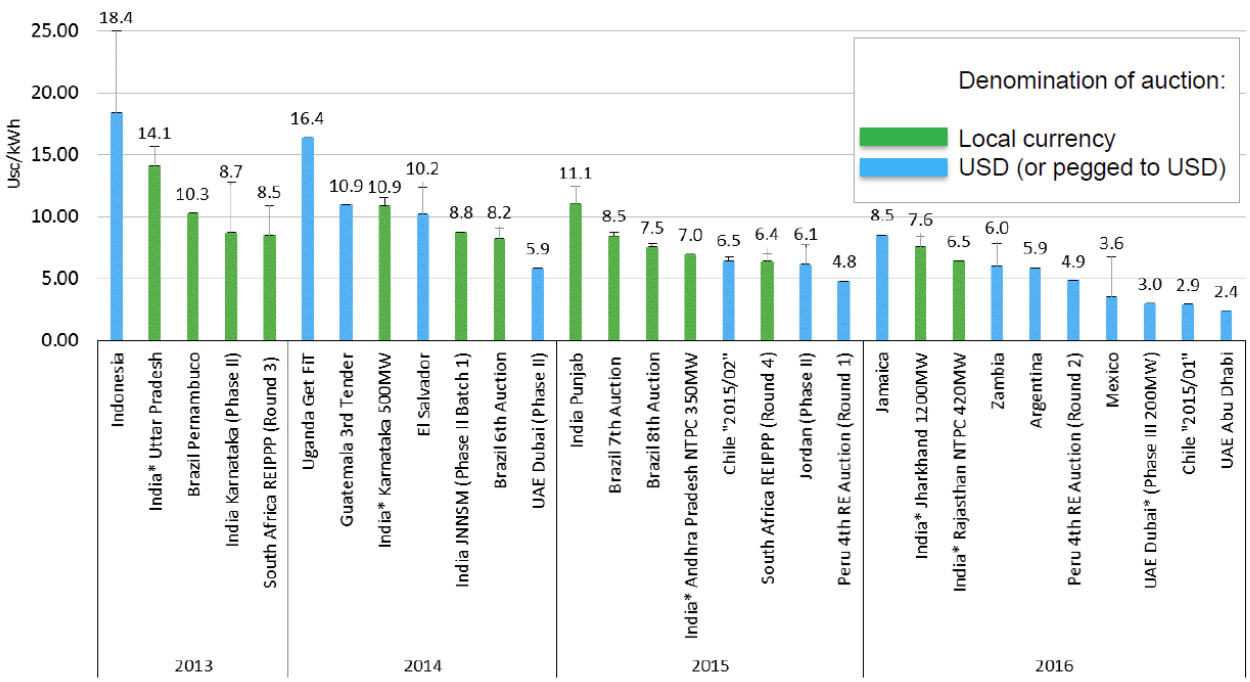
Indeed, as discussed above as part of the emergency plans for 2017, NAWEC is negotiating a PPA with SENELEC to import power at three MV lines. However, imports in MV need to be carefully analyzed because of technical losses that occur along line transmission lines. The cost of imports is typically measured at the customer delivery level, not at the substation intake. Given that some of the proposed import lines with Senegal are 30kV lines that run as long as 40km, losses on these lines will be high. This will have a significant impact on the MWhs actually delivered to the customer and this should be taken into account in price considerations.

**Regarding Gas**, this represents an opportunity for providing base-load power in The Gambia, and a good complement to the seasonality of hydropower imports. However, at the time of this roadmap update there is limited information available on the nature of the opportunity. There are several possibilities including (i) a discovery of domestic resource (exploration activities underway); (ii) importing gas from Senegal when it becomes available (indeed there is a pipeline envisaged as part of the WAPP masterplan); or (iii) importing power from a gas-to-power plant located within Senegal (potentially co-owned). Importing LNG is not seen as an option in the short-term because the CAPEX investments are too substantial for a small country like The Gambia.

One of the recommended next steps for the roadmap is for The Gambia to commission a study to assess the opportunities above and determine what are the most economically viable options, and on what timeline. As a starting point to get this work going, the option of gas has been considered in the LCPDP scenarios to show what kind of price would be required in order for gas to be economically viable. In any case, none of the options would be available before 2022-23 at the soonest, but The Gambia cannot wait that long for gas baseload so in the meantime HFO is the only short-term option available.

**Regarding Solar** is also recognized as a substantial opportunity for The Gambia. As illustrated in Figure 10, the cost of solar-PV has dropped dramatically in recent years. Competitive procurement consistently delivers prices below USc10/kWh over the last 2 years with a clear declining trend. The generation potential for solar power in The Gambia is also quite good. The average annual solar Direct Normal Irradiation (DNI) is approximately 1,525 kWh/m2. This compares to areas such as southern France, where there is 6.5 GWp installed solar PV capacity in 2015.

*Figure 10: Global prices of PV electricity*




Note: The lowest winning bid (nominal price) in each auction is shown. Local currency prices were recalculated to USD with exchange rates at the time of announcement of each plant Bars above the lowest winning bid represent ranges of all winning bids in every auction in cases when there were several winners. *For India only the auctions with the highest and the lowest winning bid per year are shown (due to too many auctions being organized in India).
Source: World Bank

However, the constraints of solar are the typical constraints, including:

**Intermittancy of solar:** utility scale battery storage is now available, but the cost structures remain high. It would therefore be cost-prohibitive for solar to provide baseload in The Gambia in the short-term.

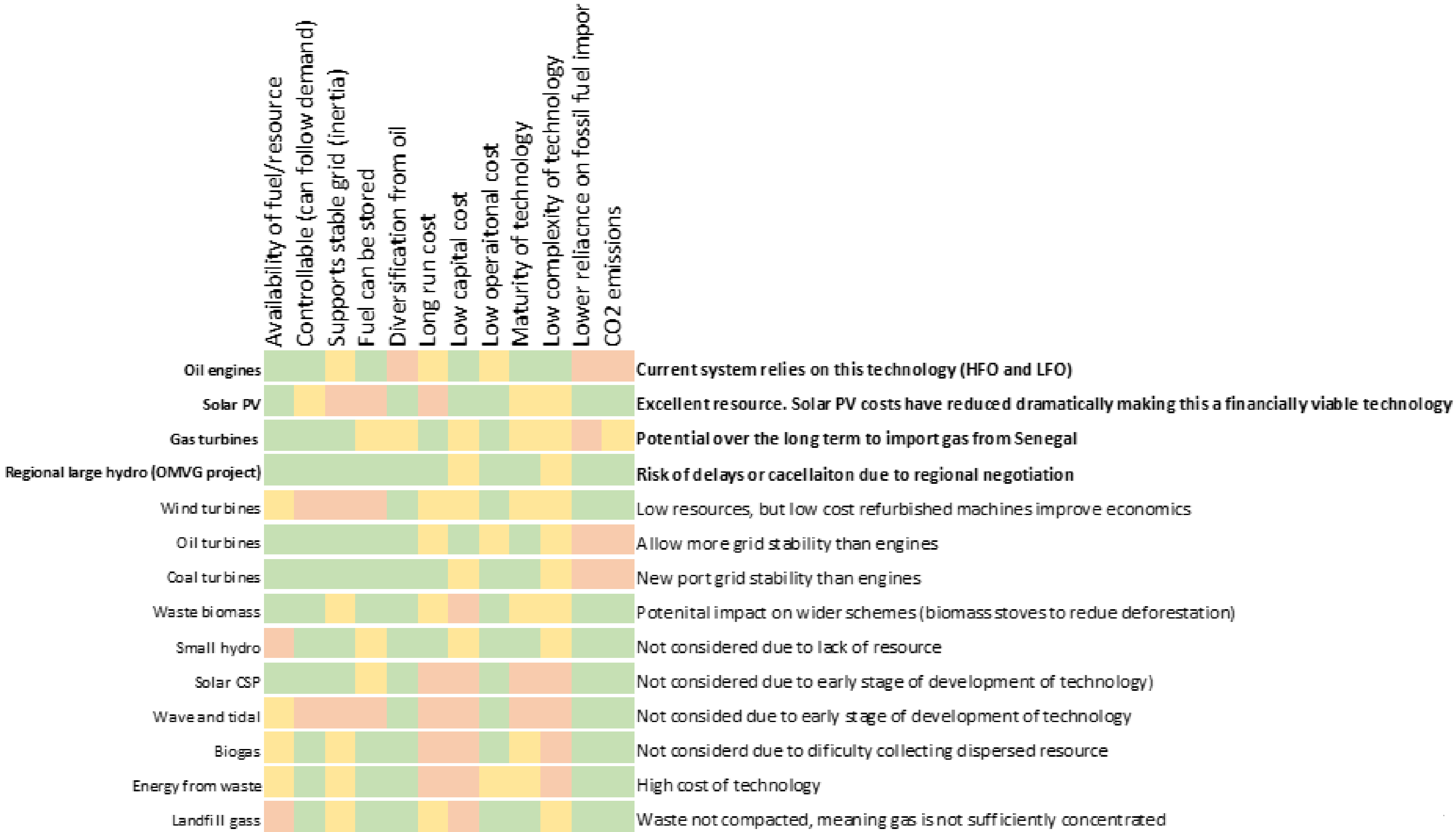
**Grid stability on solar**: solar plants require a combination with a stable generation and reliable transmission grid. In the current situation in The Gambia, neither condition is met. While there are several upgrades to the T&D network underway, the amount of solar that the country system can absorb is limited to around 30 MW in the period 2018-2020 and additional 30 MW in the period 2020-2025. The limits will be validated through planned solar feasibility studies planned. Scenarios 2 and 3 take into consideration this constraint while scenario 1 is just illustrative of an unconstrained scenario where solar is not limited.

**Land constraints on solar**. Solar plans also require the acquisition of physical space for their installation. The more solar installed, the more finding adequate land to install plants and dealing with land rights are likely to become issues. In scenario 2 and 3 the required space for 60 MW is very reasonable. In Brikama and the outskirts of GBA there is enough space for this level of installation. Scenario 1, however, requires 208MW of solar installation, a significantly higher level. Finding physical spare for this amount of solar installation might not be realistic in the Gambia when practical realities of land acquisition are taken into account.

A solar mapping study is necessary to understand what are the potential sites for a solar plant given these constraints, network location etc. In the short term, there is consensus on the potential for at least 50-60 MW, so in practical terms the short-term priority is to get started with this level of capacity, and in parallel commission a study to understand the true potential and update the roadmap accordingly.

Other technologies including Coal, Diesel, Wind, Biomass, and Biogas are not considered as viable options, as in the current situation it does not seem very likely that the country can have access to those technologies in the medium term (2020-2025). Gas (via imports from Senegal) may be considered in future but currently there is insufficient quantity and price data to include it as a scenario, but the opportunity for gas-to-power is noted as an area for additional research.

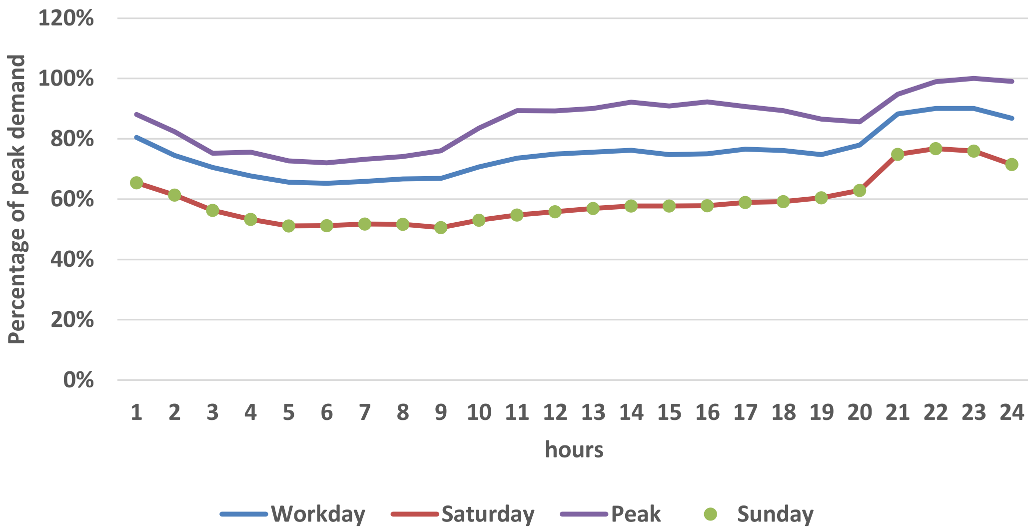
*Figure 11: Generation decision variables overview*



### 7.1.2. Demand profile

The daily demand profile for a typical day has been estimated following data from similar countries and verified with the limited data provided by NAWEC from one primary substation, presented in Figure 12.

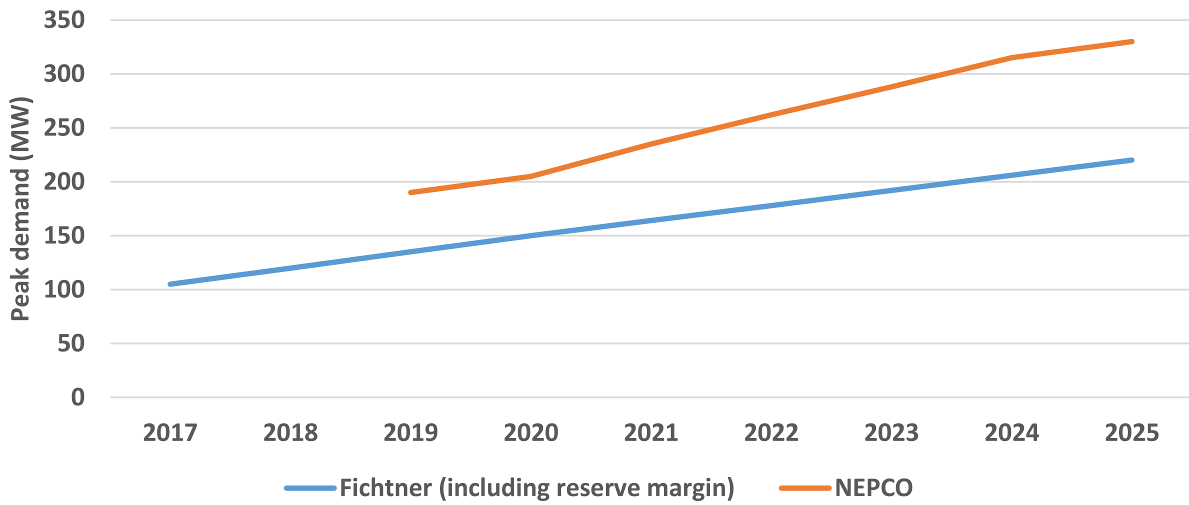
*Figure 12: Demand profile for different week days*




### 7.1.3. Peak demand forecast

A critical foundation of the LCPDP exercise is the demand forecast. Various studies on the Gambian electricity sector have been conducted in recent years. The NEPCO study in 2008 and Fichtner study in 2013 are especially important as they developed different demand forecasts based in existing demand and expected population and economic growth (Figure 13 charts their forecasts). The NEPCO study develops a demand forecast starting with a projected 200 MW peak demand in 2019 reaching more than 320 MW in 2025. On the other hand, the Fichtner study projected a peak demand forecast that only reaches 200 MW by 2025. Considering the evolution of the power sector in the country in the last decade, the Fichtner study demand forecast has been considered more realistic and is therefore used as the reference for this LCPDP.

*Figure 13: Demand forecast from two reference studies*


Peak demand (MW)
350
300
250
200
150
100
50
0
2017
2018
2019
2020
2021
2022
2023
2024
2025
Fichtner (including reserve margin)
NEPCO

### 7.1.4. Existing and committed generation plans

The planning exercise includes all existing plants, including decommissioning schedules, and new committed plants with specific commissioning dates. "Existing HFO" includes all existing plant including decommissioning schedules, and new committed plants (20 MW from GESP, 11 MW from BADEA, 20 MW from ISDB). These are summarized in Table 7.

*Table 7: Schedule for existing and committed HFO plants*

| **Power plant** | **Group** | **Fuel** | **Funder** | **Status** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Kotu | G1 | LFO | | Decommissioned in 2020 | 0 | 3 | 3 | 3 | 0 | 0 | 0 | 0 | 0 |
| Kotu | G2 | LFO | | Not running | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Kotu | G3 | HFO | | Decommissioned in 2025 | 0 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Kotu | G4 | HFO | | Decommissioned in 2023 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 | 0 |
| Kotu | G5 | HFO | BADEA / OFID | Commissioned in 2018 | 0 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Kotu | G6 | HFO | | Decommissioned in 2025 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Kotu | G7 | HFO | | Decommissioned in 2024 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 |
| Kotu | G8 | HFO | WB | Rehabilitated in 2018 | 0 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Kotu | G9 | HFO | | Decommissioned in 2023 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 | 0 |
| Brikama | I-G1 | HFO | | Decommissioned in 2024 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 |
| Brikama | I-G2 | HFO | | Decommissioned in 2024 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 |
| Brikama | I-G3 | HFO | | Decommissioned in 2024 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 |
| Brikama | I-G4 | HFO | | Decommissioned in 2024 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 |
| Brikama | I-G5 | HFO | | Decommissioned in 2024 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 |
| Brikama | I-G6 | HFO | | Decommissioned in 2024 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 |
| Brikama | I-G7 | HFO | WB | Commissioned in 2018 | 0 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Brikama | II-G1 | HFO | WB | Commissioned in 2018 | 0 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Brikama | III-G1 | HFO | IsDB | Commissioned in 2019 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Brikama | III-G2 | HFO | IsDB | Commissioned in 2019 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 |
| | | | | **Total installed** | **66** | **94** | **104** | **114** | **114** | **114** | **114** | **102** | **60** |

### 7.1.5. Model assumptions

To execute the different scenarios, the model needs specific assumptions. Table 8 describes general assumptions included in the model, and Table 9 details the technical assumptions.

*Table 8: General model assumptions*

| Factor | Assumption |
|---|---|
| **Scope of model** | Cost minimization of total generation costs over the targeted year, accounting for existing generation capacity. |
| **Decision variables** | The amount of power dispatched by each power unit in the system in each hour is adjusted by the model in the least cost option. The results show only installed capacity of HFO, solar PV and imports. |
| **Fuel** | The model considers two types of scenarios: scenarios A where only HFO is available and conventional plants should run with this fuel, and scenarios B where in addition to HFO, the country will have access to natural gas from 2022 (see discussion above on the opportunity of gas). |
| **Imports** | Imports, at the price range expected for OMVG are, for the time being, the cheapest source of electricity for The Gambia. For that reason, the plan does not include a scenario with unlimited access to imports. In addition to the unrealistic character of this assumption, it would not have real added value to the exercise, because the model would produce a recommendation of 100% imports. Thus, from a least cost perspective The Gambia may absorb all the imports available, being only limited by national energy security limits that Government may impose (currently 50 percent limit).<br><br>The Gambia is currently building a 10 MW connection with Senegal in MV to supply electricity to isolated areas of the country. This connection has not been included in the modeling as it is not grid connected, so the flow cannot be used to supply other areas of the country. |

*Table 9: Model Technical assumptions*

| Variable | Value | Unit | Comment |
|---|---|---|---|
| **T&D Network losses** | 15 | Percent | The model only considers technical losses and assumes 15% technical losses in the baseline. This is an ideal level of T&D losses, and compares to the current level of approx. 23% network losses (technical and some non-technical). Commercial losses are not counted in the exercise because least cost planning is focused on producing advice on cost efficient generation and transmission planning and commercial losses (i.e. an optimally planned system might still have high non-technical losses, but this does not mean that the generation and transmission system should be planned differently). It is important to note, |

| | | | |
|---|---|---|---|
| | | | however, that reducing non-technical losses are an important part of a cost-efficient electricity sector. |
| **Reserve margin** | 15 | Percent | |
| **Availability**<br>**- Existing engines**<br>**- New engines** | <br>55%<br>90% | <br>Percent<br>Percent | <br>Aging fleet requires regular maintenance |
| **WACC for capex investments** | 10 | Percent | |
| **Capex**<br>**- Solar**<br>**- HFO Dual Fuel** | <br>1.2<br>1.6 | $m / MW | Based on recent contracts for these technologies in West Africa. |
| **Starting HFO price** | 400 | $ / ton | |
| **Natural Gas Price** | 10 | $/mmBTU | Available only from 2022 |
| **Annual fuel price increase** | 3 | Percent | |
| **Solar radiation** | 18 | Percent | Good but not excellent in The Gambia |
| **Battery storage** | 10 | MWH | Just for ancillary services. No capacity for peak shifting has been included. |
| **Import prices** | $0.13 | $ / kWh | Tariff assumptions are considered conservative. PPAs to be signed. Assumptions based on feasibility studies. LCPCP excludes Sambangalou (after 2025) and any additional imports from Senegal. |

## 7.2. LDPDP scenarios and results

### 7.2.1. Planning variables for scenario definition

This section presents the scenarios that have been studied as part of the LCPDP and the rationale for selecting them. In selecting the scenarios consideration was given to issues that have an important role in generation planning including key factors discussed above including solar constraints, the Government's preference for imports, and the possibility of gas.

Three scenarios have been modelled:

**Scenario 1**: "unconstrained solar"

- Assumes all demand (per Fichtner study) can be met by 2025 with no constraints on solar
- Imports are limited to around 50% of national needs but are considered as firm baseload power (14 MW from 2020 and 60 MW from 2023).

**Scenarios 2**: "firm power imports"

- Given grid, land and capital constraints, solar PV is constrained to a maximum of 30 MW by 2020 and 60 MW by 2025

- Imports are limited to around 50% of national needs but are considered as firm baseload power (14 MW from 2020 and 60 MW from 2023)
- This scenario is analyzed in two cases:
    - **Scenario 2A:** only available fuel during the study period is HFO.
    - **Scenario 2B:** Natural gas become available in 2022.

Sensitivity analysis has also been done on scenario 2A. It has been tested for:

- 10 and 20% T&D network losses (as opposed to 15% in the base case)
- 5% annual increase in HFO prices (as opposed to 3% in the base case)

**Scenarios 3**: “seasonal power imports”

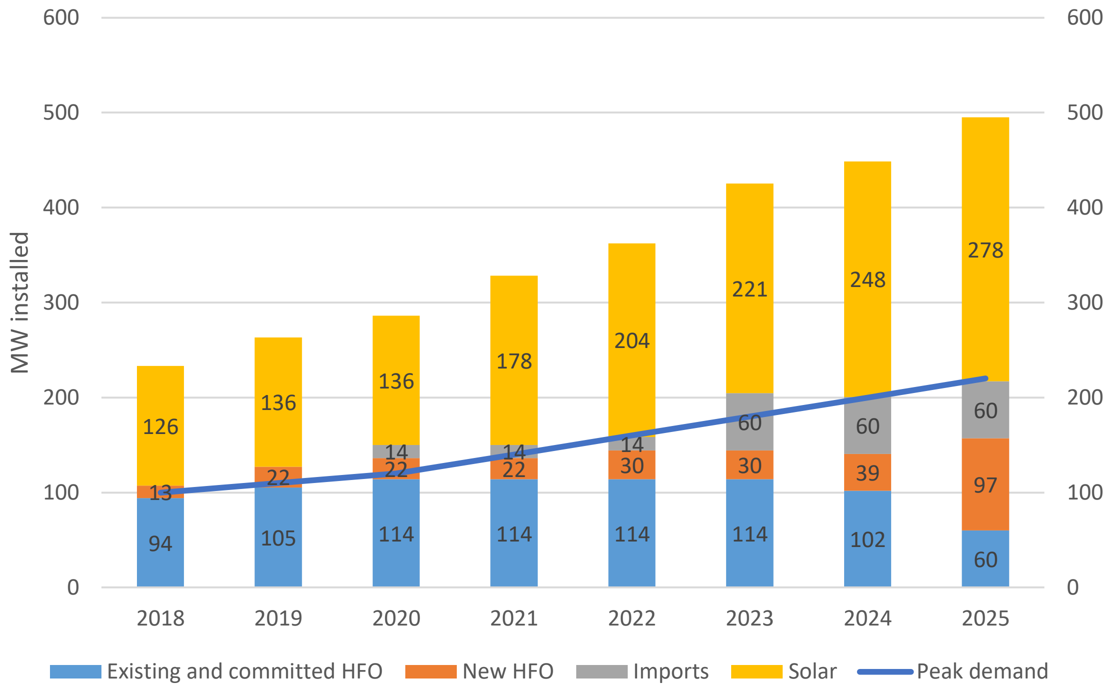
- Solar PV is constrained to a maximum of 30 MW by 2020 and 60 MW by 2025
- Imports are scheduled with the actual amount that is included in the MoUs with the OMVG. This agreement includes a cap on the annual imports, a cap on the peak power, and a seasonality supply, depending on the hydropower capacity in the regional pool.
- This scenario is analyzed in two cases:
    - **Scenario 3A:** only available fuel during the study period is HFO.
    - **Scenario 3B:** Natural gas become available in 2022.

### 7.2.2. Scenario 1 “unconstrained solar” results

Scenario 1, the ‘unconstrained solar’ scenario, assumes all demand (per the Fichtner study) can be met from 2018 onwards without any constraints on solar. The scenario indicates limited development of HFO plants in the short-term and a significant deployment of solar (

Figure 14). The rapid growth of solar plants in this scenario is driven by their ability to reduce the cost of electricity during daylight.

*Figure 14: Results from scenario 1, installed capacity in MW*




Note: it is import to note on this chart and subsequent charts showing installed capacity that when comparing to the peak demand, capacity factor of the installed capacity needs to be considered. For example, the capacity factor of solar is only 18% meaning the 278 MW of solar capacity in 2025 is equivalent to 278*18% i.e. approximately 50MW equivalent.

**Solar:** with no constraints on solar, installed capacity would increase to 126 MW by 2018, 136 MW by 2020, and reach 278 MW by 2025. These are very high amounts of solar and raise important considerations regarding its feasibility. Some of these considerations include the availability of physical space to accommodate the required number of solar plants. Additionally, grid capacity constraints would need to be assessed given the significant amount of solar generation that will be supplied to the grid during the day (a grid stability and integration analysis is include as part of the action plan). Additional battery support would also be needed for grid stability.

**New HFO:** Just 13 MW of new HFO are required in 2018, with increases throughout the period up to 30 in 2022, and 97 in 2025 because of the retirement of an important amount of capacity from older plants that year.

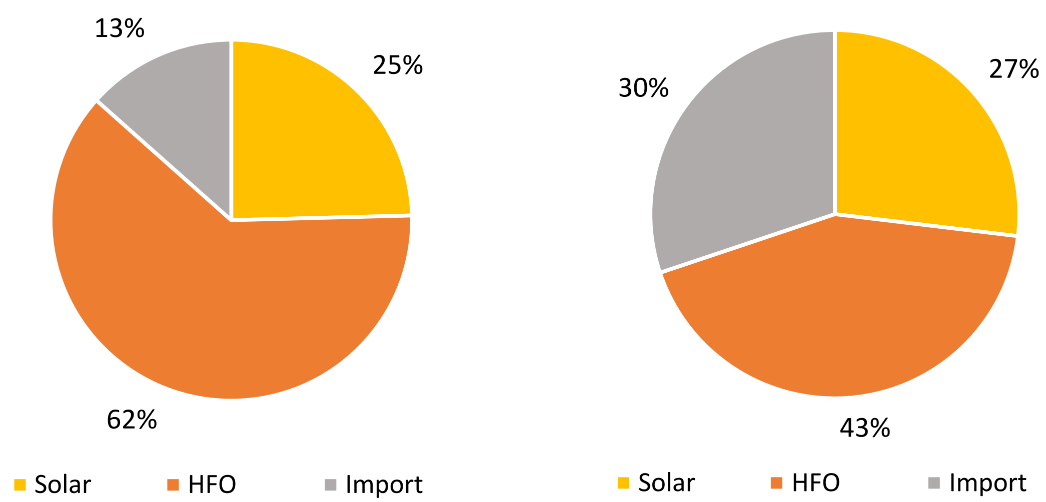
**The total system cost:** (including fix and variable cost) for the period 2018-2025 is US$ 1,022 million. Following US$78 million in costs in 2018, it then increases annually, reaching US$200 million in 2025.

**The average cost of electricity** (just variable cost) increases form US$0.113/kWh in 2018 to US$0.132/kWh in 2025. The cost is stabilized between 2022 and 2024 caused by the increase in imports from OMVG in 2023.

**Total capex investments:** are USD $488m. A significant portion of this ($173m) is needed in the short term (2018). The large investment is mainly due to the need of building solar plants. Additional investment is needed at the end of period (US$129 million) for HFO plants.

**Generation mix**: As a share of the overall energy generation portfolio, HFO is projected to decline from being 100% of the energy mix (2017) to 62% by 2020 and then 43% in 2025. Solar will expand to 25% in 2020 and stay around the same level as imports are the fastest growing share of the energy mix between 2020 – 2025 (see Figure 15).

*Figure 15: scenario 1 energy mix (MWh) for 2020 (left) and 2025 (right)*




**Economic dispatch:** sample daily energy dispatch graphs (see

Figure 16 and Figure 17) show the effects of having large amounts of solar dispatched to the grid. In 2020, solar is a cheaper generation option than HFO so it is dispatched over HFO when it is available. Solar is almost able to generate enough electricity to meet demand during its peak generation hours (around mid-day). But HFO is still required to meet full demand. In 2025, imports can cover a larger share of the baseload dispatch. Solar is now able to meet demand for a more extended period, between approximately 9am and 5pm. But HFO is still required to cover a significant portion of demand outside of these hours. The variability this builds into the grid means that battery storage capacity or minimum HFO capacity must be deployed to balance the variability.

*Figure 16: daily energy profile, scenario 1, 2020*

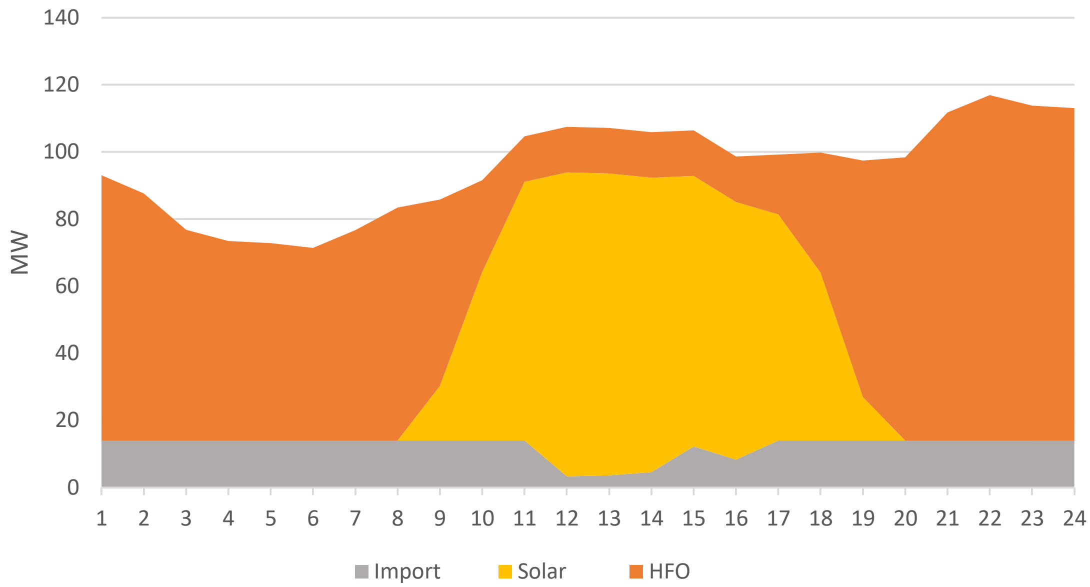
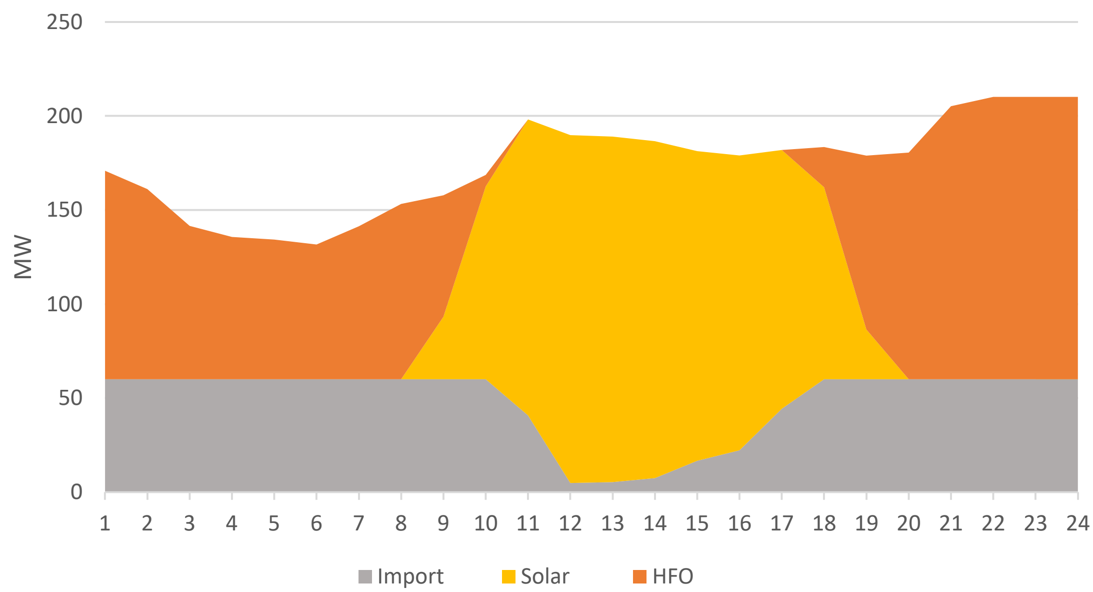



*Figure 17: daily energy profile, scenario 1, 2025*



### 7.2.3. Scenarios 2 “stable power imports”

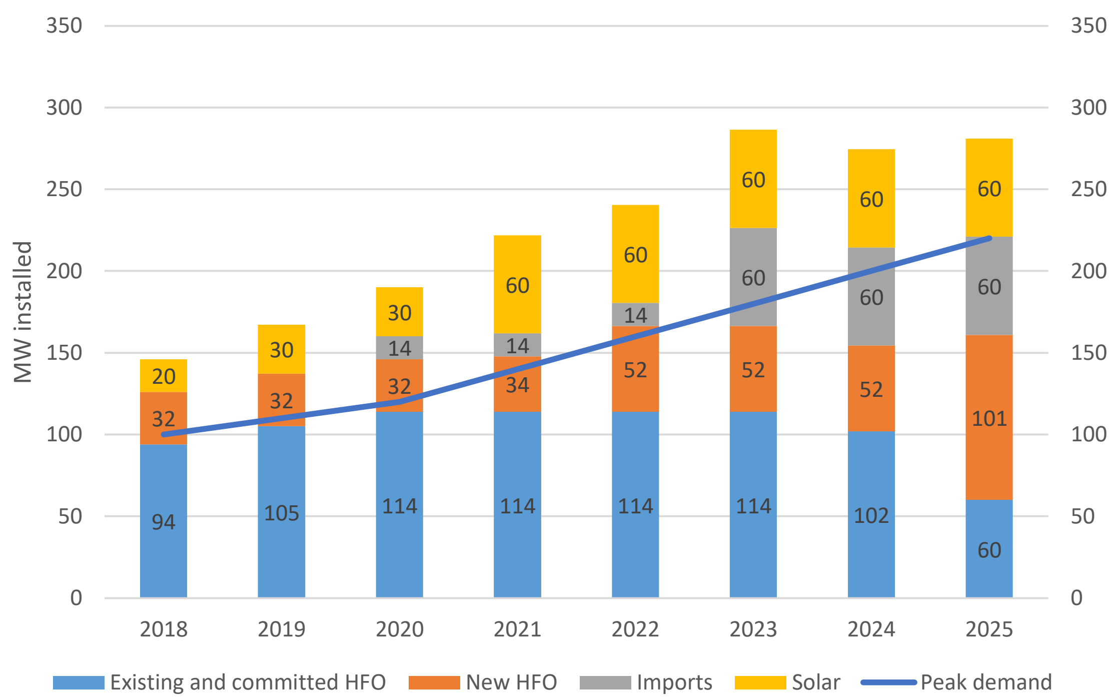
Scenarios 2 assume The Gambia signs the OMVG PPAs for Kaleta and Souapiti, plus additional import PPAs to complement the seasonality of hydro from these plants (seasonality outlined in section 7.1.1). For example, imported power from Senegal using gas-to-power could be a good complement to such seasonal effects. In effect, this would mean that The Gambia could consider the 60MW of power from 2023 as firm power (i.e. 24/7 power supply at that capacity).

### 7.2.4. Scenario 2A “stable power imports” only HFO

Scenarios 2A considers the availability of only HFO for the whole study period i.e. it does not consider gas being an option. As outlined in Figure 18, the key takeaways of this scenario in terms of installed capacity are:

> **Solar**: solar is restricted by the scenario definition and hence is set at 30 MW until 2020 and then 60MW until 2025.
>
> **New HFO:** 100MW of new HFO are need by 2025. This includes an initial amount of 32 MW of new HFO in 2018. Additional new HFO installations are required in 2022 with 20 MW more and an additional 49MW in 2025 as many existing HFO need to be decommissioned.

*Figure 18: Results from scenario 2A, installed capacity in MW*



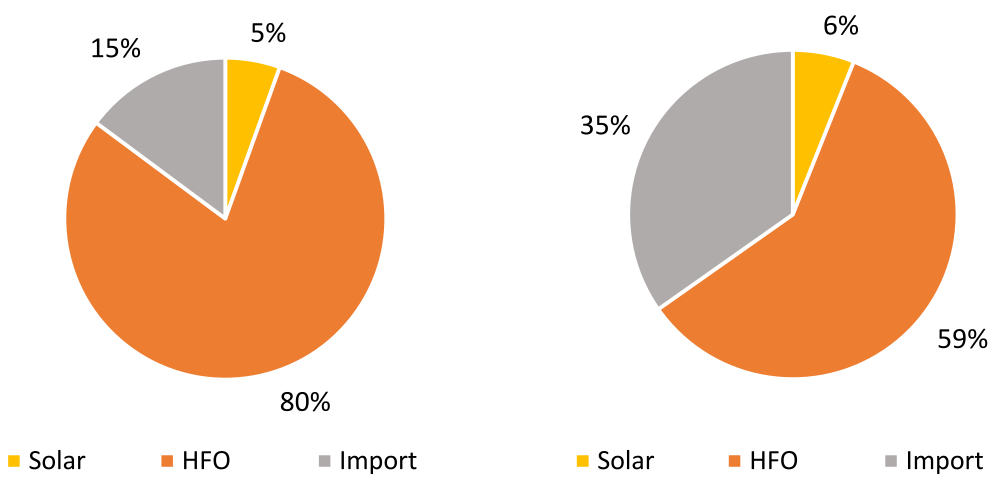
**Total system cost:** this installed capacity will result in a total system cost of approximately US$ 1,065 million for the period 2018-2025. The annual costs follow a continuous increase from US$81 million in 2018 to US$207 million in 2025.

**The average cost of electricity** (just variable cost) increases form US$0.118/kWh in 2018 to US$0.137/kWh in 2025. The cost is stabilized between 2022 and 2024 caused by the increase in imports from OMVG in 2023.

**The total capex investment:** is US$ 233 million, with a significant portion of this (US$75 million) needed in the medium-term (2018) and another big share at the end of period (US$78 million).

**Generation mix:** as outlined in Figure 19**,** by 2020 HFO is 80% of the overall energy portfolio, solar is only 5% and imports 15%. By 2025, HFO's share of the energy mix is projected to have decreased to 59% due to the increase of imports up to 35%. Solar remains at a modest 6%.

*Figure 19: scenario 2A energy mix (MWh) for 2020 (left) and 2025 (right)*




**Economic dispatch:** with less solar being dispatched to the grid, scenario 2A's sample daily dispatches in 2020 and 2025 are much steadier than scenario 1's.

Figure 20 shows that in 2020, the dispatch is predominately HFO with small amounts of imports as baseload and a bit of solar being dispatched when it is available. Figure 25 shows that in 2025, imports will cover a much larger portion of daily dispatch, reaching 60MW. More solar will be dispatched when it is available but it is not enough to cover demand at its peak point. The remaining dispatch is covered by HFO.

*Figure 20: daily energy profile, scenario 2A, 2020*

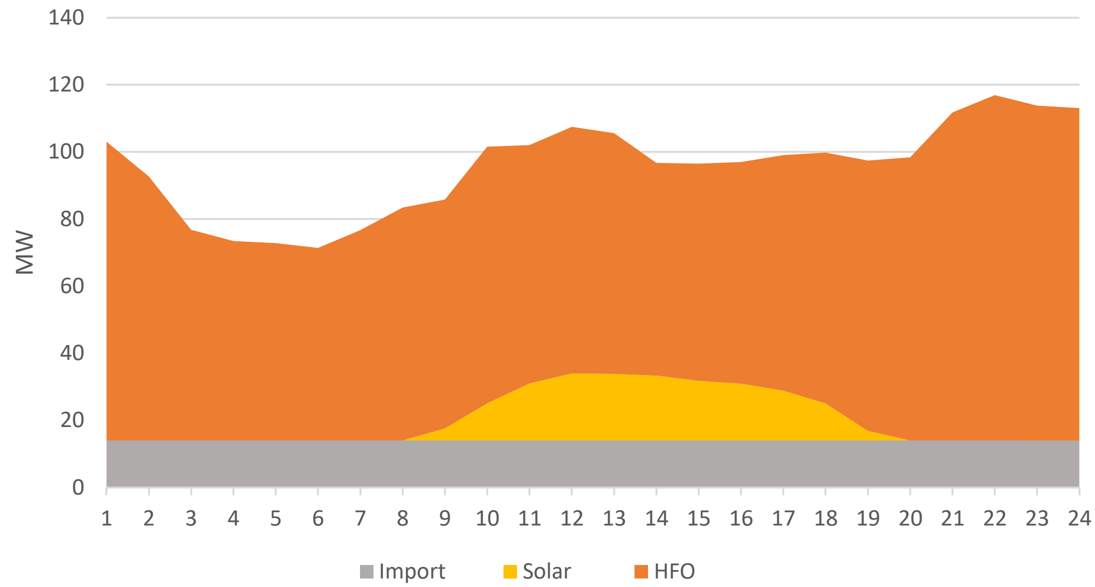
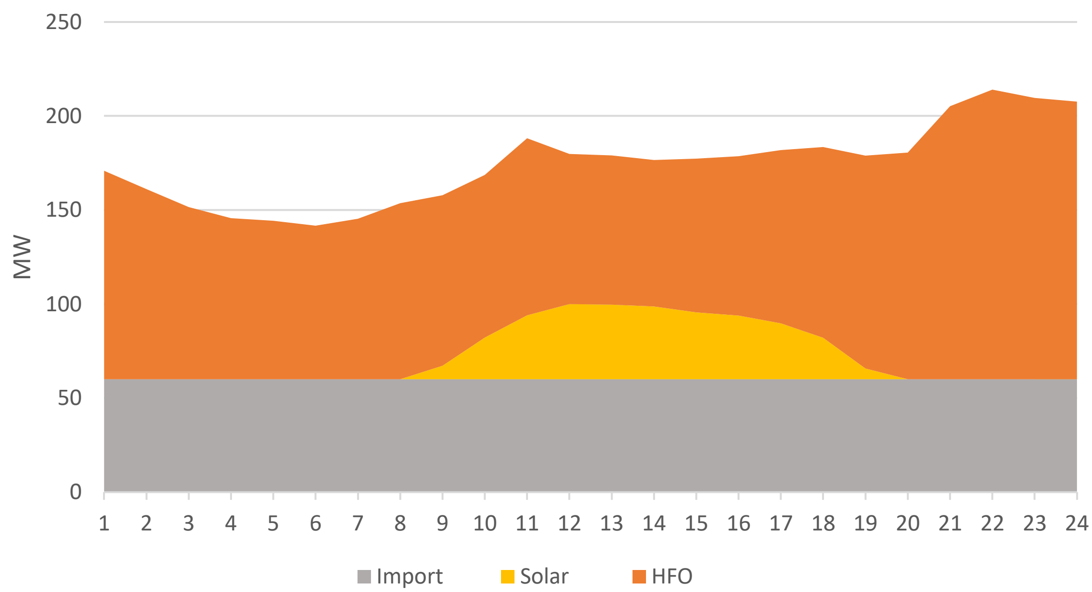



*Figure 21: daily energy profile, scenario 2A, 2025*



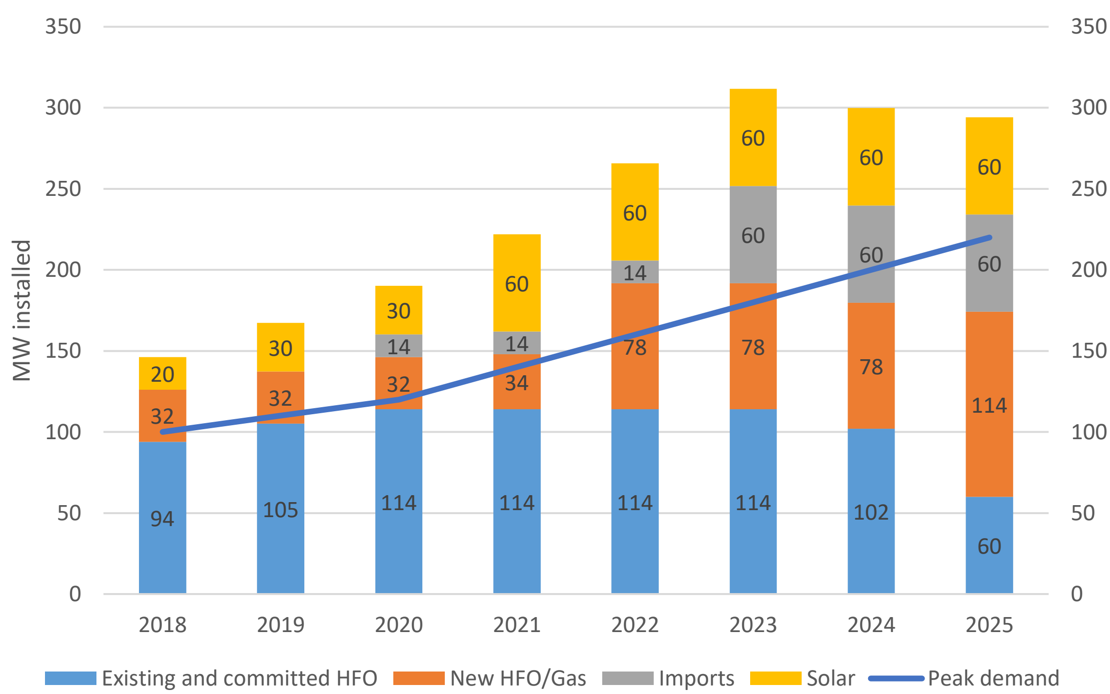
### 7.2.5. Scenario 2B “stable power imports” HFO and natural gas available

Scenario 2B considers the availability of both HFO and natural gas, but the latter only from 2022. Per Figure 22, the key takeaways of this scenario in terms of installed capacity are:

**Solar**: solar is restricted by the scenario definition and hence is set at 30 MW until 2020 and then 60MW until 2025.

**New HFO:** identically to scenario 2A just 32 MW of new HFO are required in 2018. However, this scenario shows a larger increase in HFO/Gas plants in 2022, with an additional 44 MW and in 2025 another 36 MW to cover the retirement of existing plants. This additional capacity in comparison to Scenario 2A is due to the lower cost of electricity from gas (available in 2022) which recommends the installation of additional plants instead of using the existing capacity.

*Figure 22: Results from scenario 2B, installed capacity in MW*



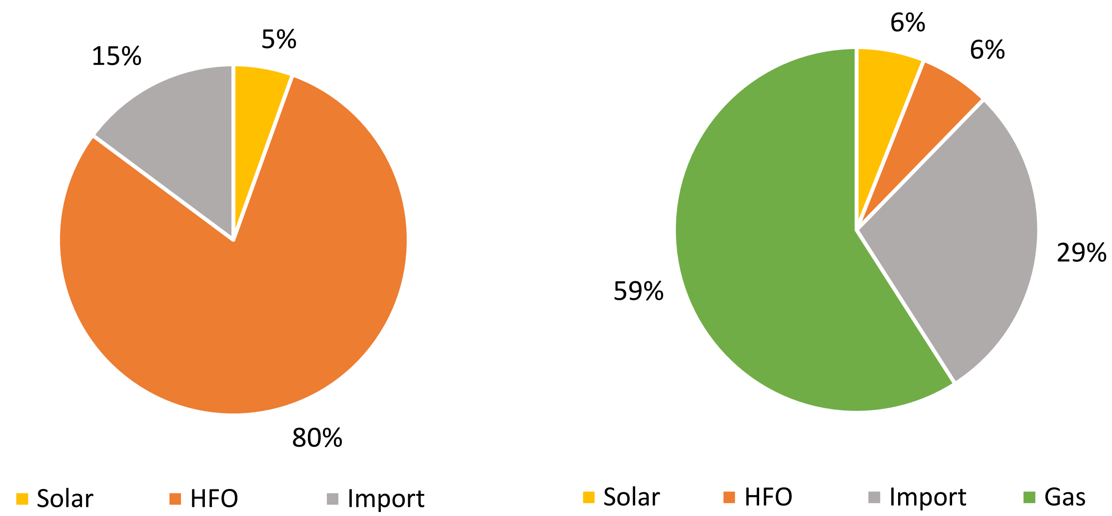

**Total system cost:** this installed capacity will result in a total system cost of approximately US$ 1,018 million for the period 2018-2025. The system costs increase steadily from US$80 million in 2018 up to US$188 million in 2025.

**Average cost of electricity**: increases from US$0.118/kWh in 2018 to US$0.124/kWh in 2021 and the decreases US$0.121/kWh to remain increasing again until 2025. This stabilization is caused by the introduction of natural gas in 2022.

**The total capex investment** is US$ 254 million, with the disbursement spread out throughout the period: US$75 million in 2018, US$70 million in 2022, and US$58 million in 2025. Required investment would be slightly higher than in scenario 2A.

**Generation mix:** by 2020 HFO is 80% of the overall energy portfolio (Figure 23). Solar is only 5% and imports 15%. By 2025, natural gas has reached a big share of 59%, while HFO is reduced to just 6% from the existing plants. The increase of solar is very modest to 8% of the mix, and imports expand to 29%.

*Figure 23: scenario 2B energy mix (MWh) for 2020 (left) and 2025 (right)*




**Economic dispatch:** In 2020, the dispatch is predominately HFO with small amounts of imports as baseload and a bit of solar being dispatched when it is available (

Figure 24). In 2025, natural gas and imports will cover a much larger portion of daily dispatch (Figure 25). It is significant in this year that imports are not always dispatched because gas generation is more convenient from cost perspective. In 2025, HFO is just reduced to a marginal use for isolated peaks.

*Figure 24: daily energy profile, scenario 2B, 2020*

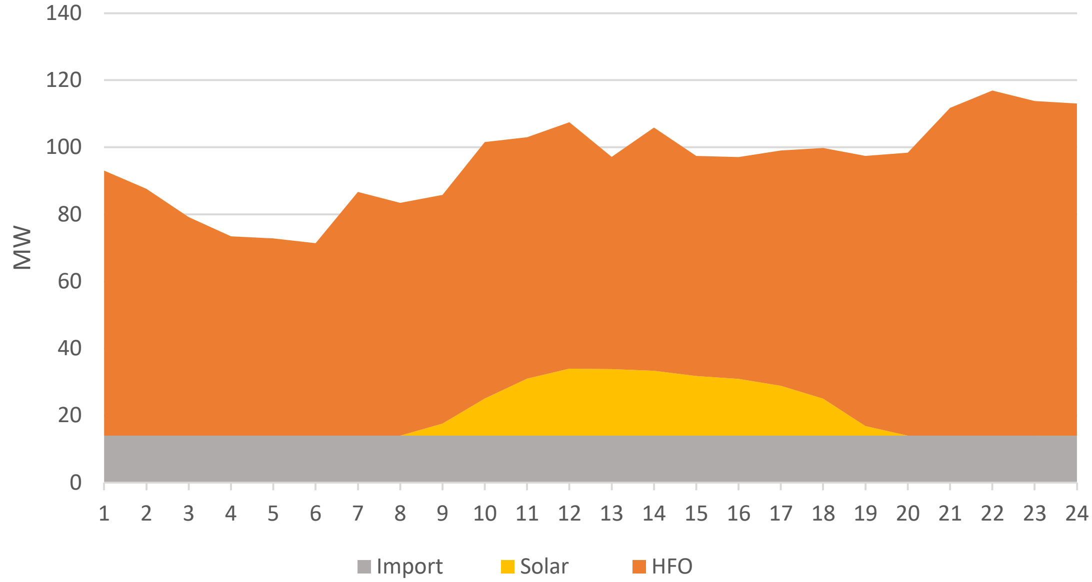
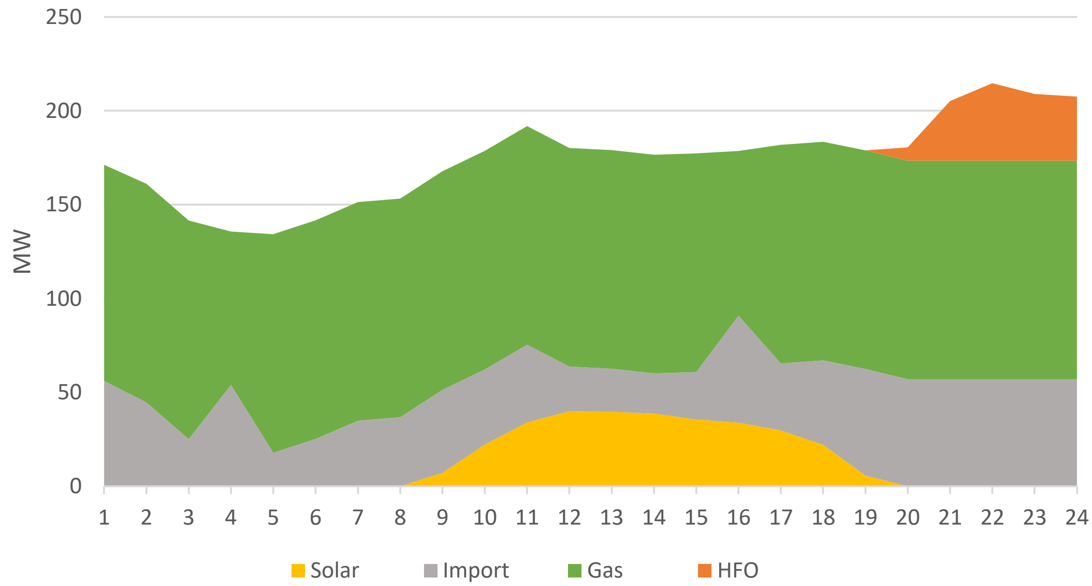



*Figure 25: daily energy profile, scenario 2B, 2025*



### 7.2.6. Scenarios 3 "seasonal power imports"

In scenarios 3, the imports are scheduled per the current OMG MoU of 270 GWh/year, with the seasonality described in section 7.1.1, and assumes no additional import PPAs are signed.

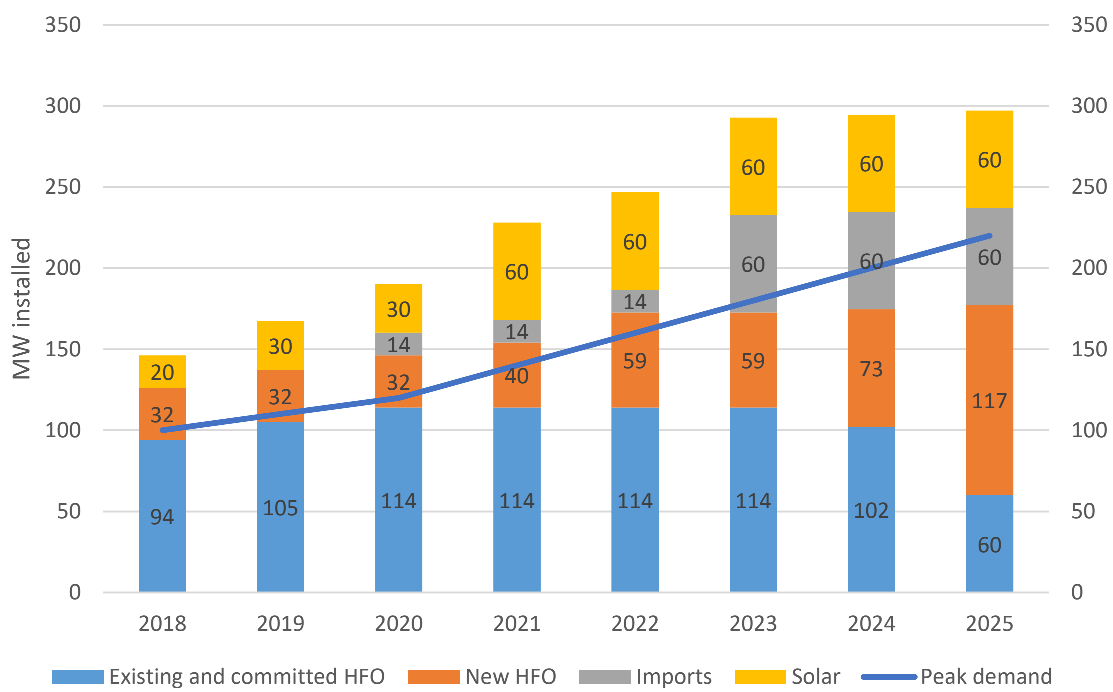
### 7.2.7. Scenario 3A "seasonal power imports" only HFO

Scenario 3A considers the availability of only HFO for the whole study period. Per Figure 26, the key takeaways of this scenario in terms of installed capacity are:

**Solar**: solar is restricted by the scenario definition and hence is set at 30 MW until 2020 and then 60MW until 2025.

**New HFO:** again just 32 MW of new HFO are required in 2018. Additional new HFO installations are required in 2021 (8 MW), 2022 (19 MW), 2024 (14 MW) and a significant amount in 2025 (44 MW).

*Figure 26: Results from scenario 3A, installed capacity in MW*



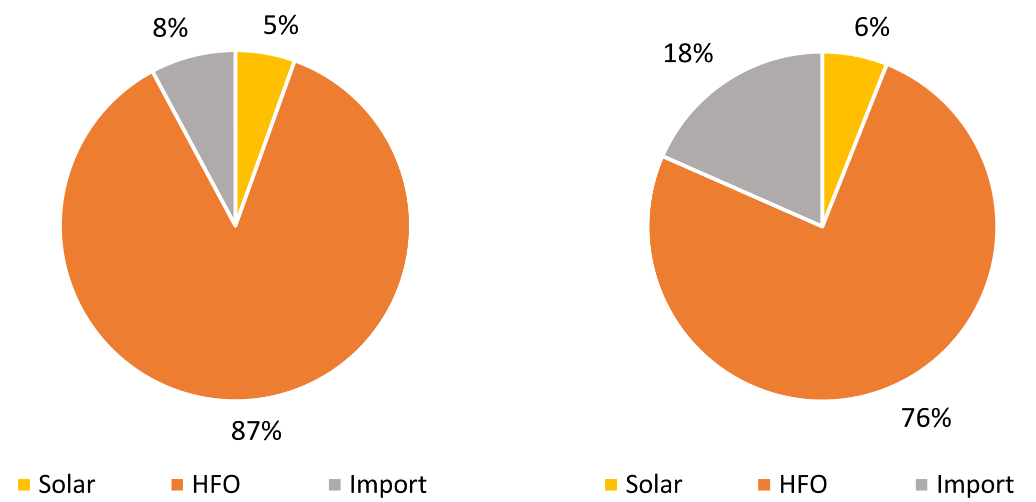

**Total system cost:** this installed capacity will result in a total system cost of approximately US$ 1,082 million for the period 2018-2025. The annual costs follow a continuous increase from US$80 million in 2018 to US$211 in 2025.

**Average cost of electricity**: increases continuously from US$0.118/kWh in 2018 to US$0.141/kWh in 2025. The cost is not stabilized due to the variability of imports that needs to be covered with HFO.

**The total capex investment** is US$ 259 million, with the disbursement spread out throughout the period: US$75 million in 2018, US$12 million in 2019, US$50 million in 2021, US$30 million in 2022, US$22 million in 2024 and US$71 million in 2025.

**Generation mix:** by 2020 HFO is 87% of the overall energy portfolio. Solar is only 5% and imports 8% (Figure 27. By 2025, HFO's share of the energy mix is projected to have decreased to 77%. Solar will have only increased to 6% of the mix, while imports will expand modestly to 18% due to the variability of the supply.

*Figure 27: scenario 3A energy mix (MWh) for 2020 (left) and 2025 (right)*




**Economic dispatch:** with variable power imports in the grid, the sample dispatch in 2020 and 2025 need to rely in HFO (

Figure 28 and
Figure 29). In 2020, the dispatch is predominately HFO with small amounts of imports, when available, and a bit of solar during daylight. In 2025, situation is quite similar, although the amount of imports increases. More solar will be dispatched when it is available but it is not enough to cover demand at its peak point. The remaining dispatch is covered by HFO.

*Figure 28: daily energy profile, scenario 3A, 2020*

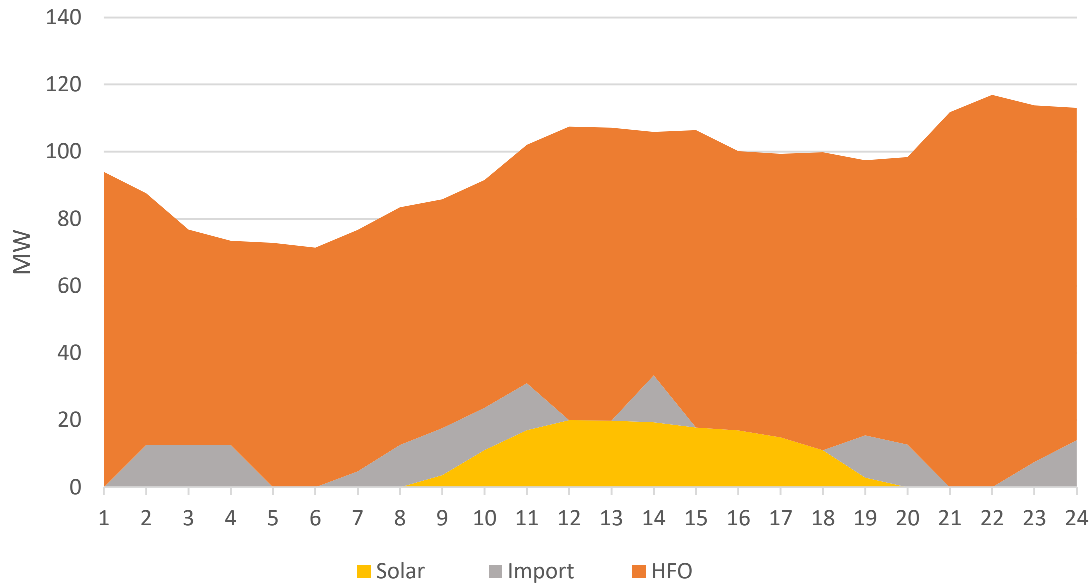
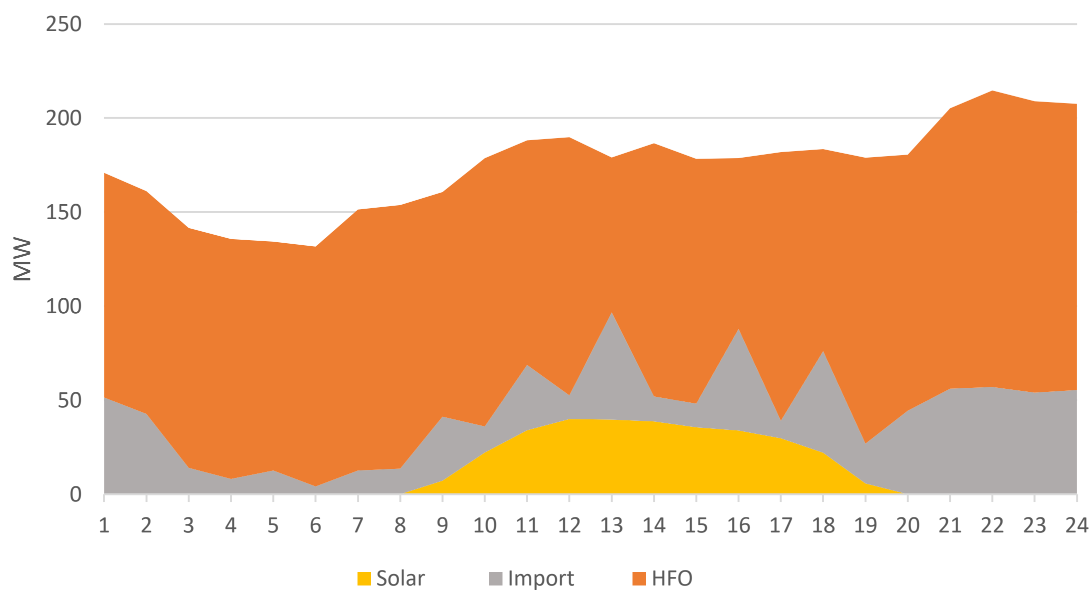



*Figure 29: daily energy profile, scenario 3A, 2025*



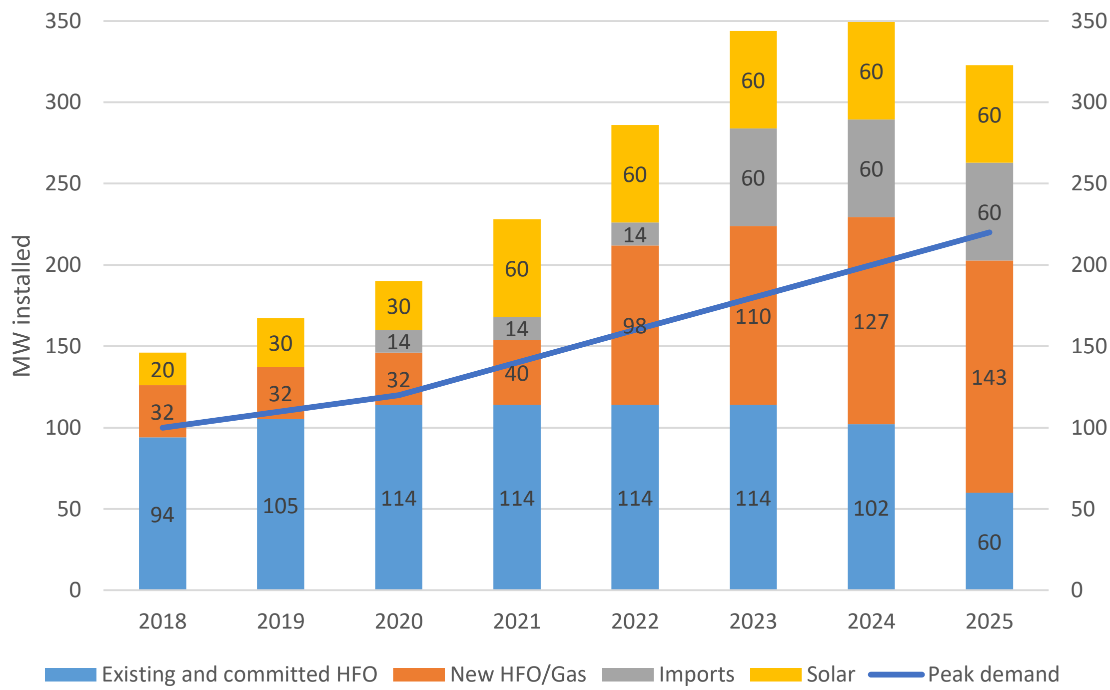
### 7.2.8. Scenario 3B "seasonal power imports" HFO and natural gas available

Scenario 3B considers the availability of both HFO and natural gas, but the latter only from 2022. Per Figure 30, the key takeaways of this scenario in terms of installed capacity are:

**Solar**: solar is restricted by the scenario definition and hence is set at 30 MW until 2020 and then 60MW until 2025. These are considered to be very much realistic and feasible levels of solar installation.

**New HFO:** as in all scenarios just 32 MW of new HFO are required in 2018. Similar to scenario 2B, this scenario shows a significant increase in HFO/Gas plants in 2022, with additional 58 MW and steadily increase of installed capacity throughout the consecutive years: 21 MW in 2023, 17 MW in 2024 and 16 MW in 2025. This progressive additional capacity 2A is due to the lower cost of electricity from gas (available in 2022), which compensate the installation of additional plants instead of using the existing capacity and the instability of imports.

*Figure 30: Results from scenario 3B, installed capacity in MW*



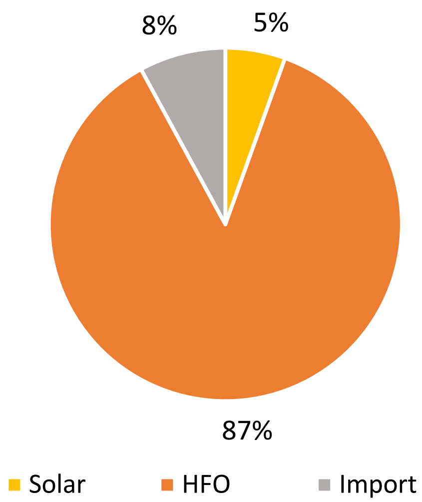

**Total system cost:** this installed capacity will result in a total system cost of approximately US$ 1,024 million for the period 2018-2025. The system costs increase steadily from US$81 million in 2018 up to US$190 million in 2025.

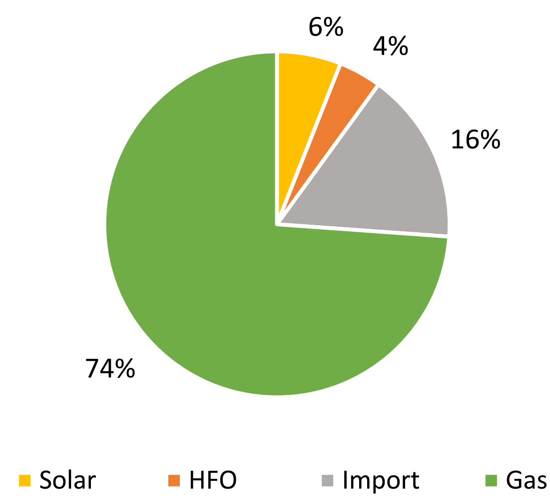
**Average cost of electricity**: increases from US$0.119/kWh in 2018 to US$0.125/kWh in 2021 and the decreases US$0.121/kWh to remain increasing again until 2025. This stabilization is caused by the introduction of natural gas in 2022.

**The total capex investment** is US$ 300 million, with the disbursement spread out throughout the period: mainly US$75 million in 2018, US$93 million in 2022, and US$53 million in 2024-2025. Required investment would be slightly higher than in other scenarios 2 and 3 because of the bigger amount of install capacity to compensate instable imports and take advantage of lower generation cost from gas.

**Generation mix:** by 2020 HFO is 87% of the overall energy portfolio (Figure 31). Solar is only 5% and imports 8%. By 2025, natural gas has reached a major share of 74%, while HFO is very minimal 4% due to the availability of gas. The increase of solar is negligible to 6% of the mix, while imports expand to just 16% because of variability.

*Figure 31: scenario 3B energy mix (MWh) for 2020 (left) and 2025 (right)*




**Economic dispatch:** In 2020, the dispatch is predominately HFO with small amounts of imports and a bit of solar being dispatched when it is available (

Figure 32). In 2025, natural gas will cover a much larger portion of daily dispatch (Figure 33). More solar will be dispatched during daylight and imports when economically convenient. HFO is reduced to a minimal use for isolated peaks.

*Figure 32: daily energy profile, scenario 3A, 2020*

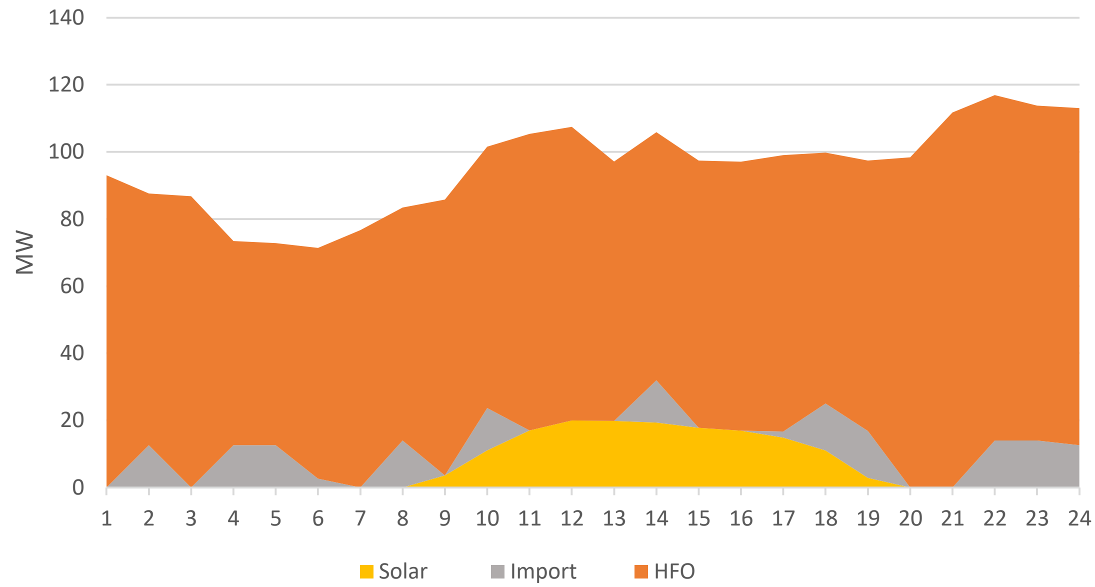
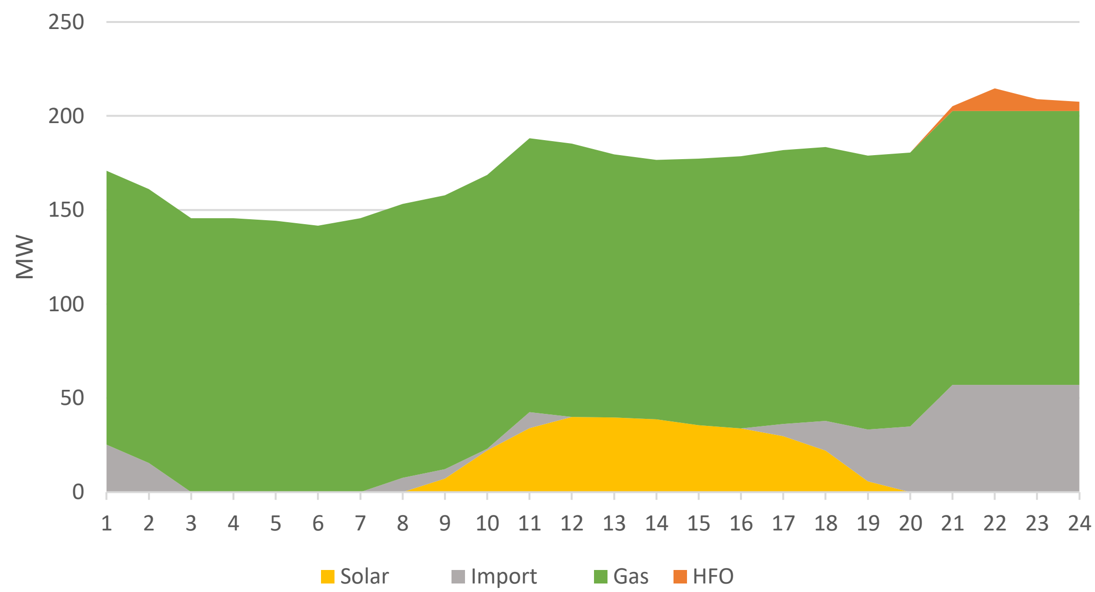



*Figure 33: daily energy profile, scenario 3B, 2025*



## 7.3. Comparison of scenarios

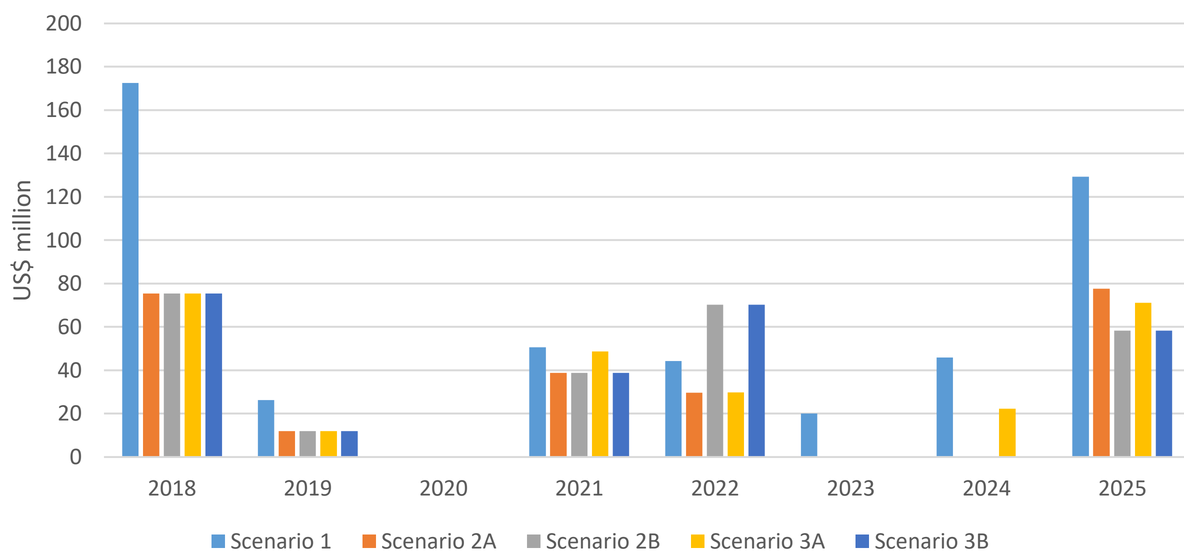
The least cost planning model yields some important conclusions for the short, medium, and long-term planning of the Gambian power sector. Table 10 compares some of the key elements of the different scenarios.

*Table 10: comparison of scenario results*

| | | Scenario | | | | |
|---|---|---|---|---|---|---|
| | | **1** | **2A** | **2B** | **3A** | **3B** |
| New HFO/Gas | MW | 97 | 101 | 114 | 117 | 143 |
| Capex investment | US$ million | 489 | 234 | 255 | 259 | 300 |
| System Cost (2018-2025) | US$ million | 1022 | 1065 | 1018 | 1082 | 1025 |
| Average electricity cost in 2025 (variable) | US$/kWh | 13.2 | 13.7 | 12.1 | 14.1 | 1213 |
| Thermal share 2025 (HFO / Gas) | % | 43 (43/0) | 59 (59/0) | 65 (6/59) | 76 (76/0) | 78 (4/74) |
| Solar share 2025 | % | 27 | 6 | 6 | 6 | 6 |

The average cost of electricity is lower in the case of scenario 1 because of solar share. While scenario 1 has lower average costs, it also has capex requirements that over twice as much as other scenarios due to its significantly amount of solar installations. Scenario 1 requires a total capex investment of US$489m, with a significant portion of this (US$173 million) needed in the short term (2018) and another important amount in 2025 (US$129 million). On the contrary, scenario 2A only requires a total capex investment of US$234 million, distributed among 2018, 2021-2022 and 2025. **Error! Reference source not found.** shows the evolution of investment requirement throughout the study period.

*Figure 34: Capex investments, scenarios*



Once the solar amount is limited, the average cost is favored by the availability of gas and the securitization of imports. Nevertheless, comparison between scenarios 3A and 3B shows that, for average electricity cost and system costs, the securitization of imports is not so important if gas is available at $10 / mmbtu because the generation with gas is more convenient from an economic point of view.

All scenarios demonstrate a clear need for investment to be undertaken in the short term, requiring speedy implementation of new capacity to face the extensive suppressed demand existing in the country.

An important finding is that the requirements for new single/dual fuel HFO/gas generation plants are very similar for all scenarios with limited solar. Only Scenario 1 calls for just 13 MW of new HFO in 2018, with large amounts of solar. All other scenarios require 32 MW in the same year. All scenarios also require a progressive implementation of conventional generation plants throughout the LCPDP period. This conclusion is very convenient for planning purposes as it provides a clear action plan for size and timing for a new HFO plant. Figure 34 and Figure 36 show the new capacities to be installed of conventional plants.

*Figure 35: New capacities to be installed in the short term (2018)*

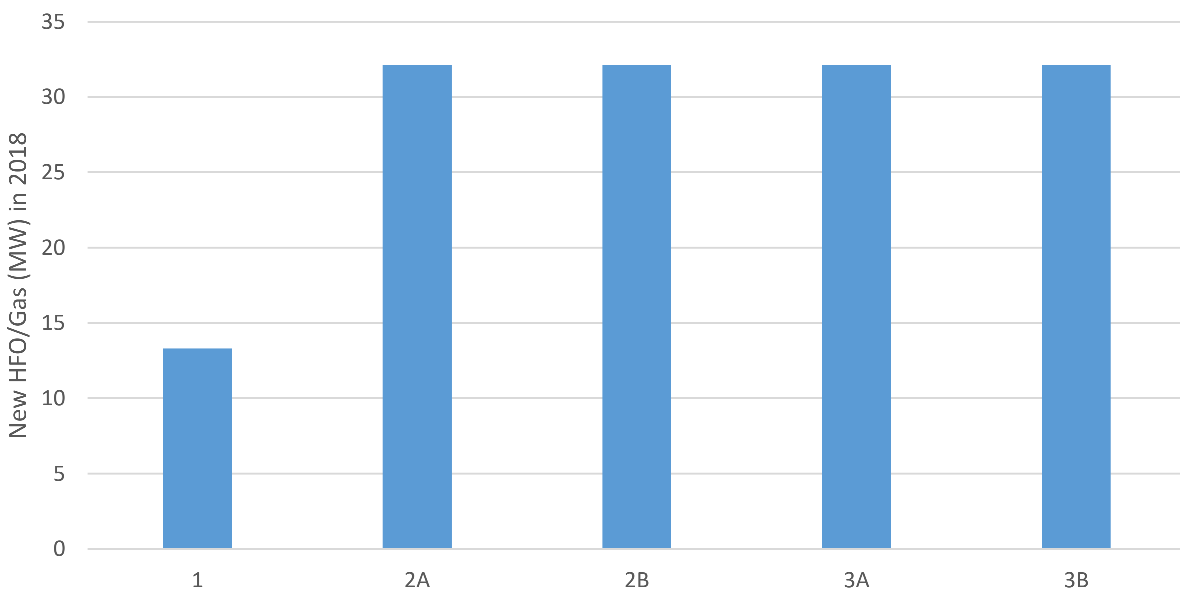
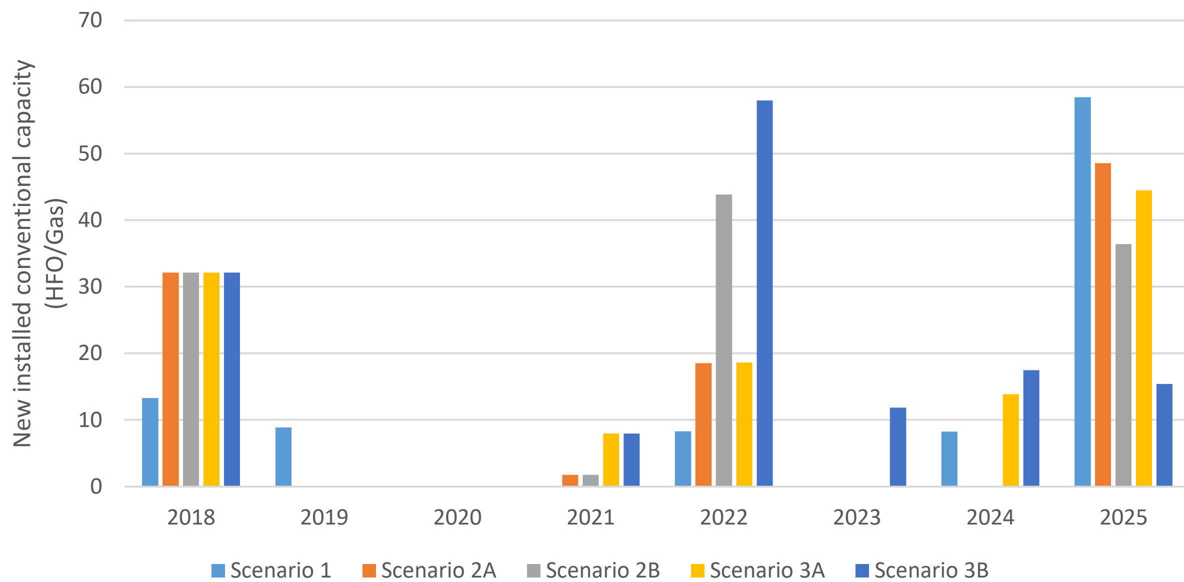



*Figure 36: Thermal capacities to be installed throughout the study period (2018-2025)*




In conclusion. Scenario 1 is not considered to be a realistic scenario given the constraints on solar discussed above, but additional work should be done to establish the true potential for solar in The Gambia. Scenario 3 does not leverage the opportunity presented by OMVG to source low cost power from the sub-region. Scenario 2 on the other hand has a realistic amount of solar, and commits the GoTG to pursue low cost import opportunities. Of the options within Scenario 2, Scenario 2b indicates that if there is a real opportunity for The Gambia to pursue gas, it would likely be the lower cost option for The Gambia if the gas is at the right price (the analysis above assumed $10 / mmbtu). Additional work is needed to determine what the realistic opportunities for gas might be. In the meantime, Scenario 2 is the preferred.

## 7.4. Sensitivity analyses

As discussed above, sensitivity analyses were conducted on fuel prices assumptions and T&D loss assumptions.

### 7.4.1. Fuel price sensitivity analysis

Scenario 2A, the preferred scenario, has been tested for a rise in fuel prices. The baseline assumes a 3% annual increase in fuel prices. The sensitivity analysis tests the scenarios under a 5% fuel price. Assuming this price increase the results of installed capacity are the same but the main impact of the higher HFO price is the increase in the average cost of generation in the period and the system costs. The results are summarized in *Table 11*. A five percent annual increase would increase the cost of electricity by an average of almost 1 cent per kWh generated.

*Table 11: Results of fuel price sensitivity*

| | | Cost of electricity | System costs |
|---|---|---|---|
| **Year** | 2020 | +US$4 /MWh | +US$4 million/year |
| | 2025 | +US$14 /MWh | +US$21 million/year |
| **Average in the period 2018-2025** | | +US$9 /MWh | +US$10 million/year |

There are additional risks that are not considered in the sensitivity analysis. These include a delay in the OMVG line, which is expected to provide 14 MW from Kaleta in 2020). Similarly, delays in commissioning of the Souapiti line (expected to provide an additional 45MW in 2023) poses a potential risk. If such delays were to be serious enough, options for additional IPPs (HFO and/or gas depending on the availability) would have to be considered.

There is also a risk posed by delays in the solar projects coming online. Land identification and acquisition is often an issue for solar projects and can lead to delays.

### 7.4.2. Transmission losses sensitivity analysis

The same scenario 2A has been tested for changes in transmission loss rates. The baseline assumes a 15% technical loss rate. The sensitivity analysis tests the scenario for a change to both 10% and 20% transmission loss rates. This exercise only considers technical losses, which in the Gambia are 14%. This compares to 25% for total losses. Commercial losses are not counted in the exercise because least cost planning is focused on producing advice on cost efficient generation and transmission planning and commercial losses (i.e. an optimally planned system might still have high non-technical losses, but this does not mean that the generation and transmission system should be planned differently). It is important to note, however, that reducing non-technical losses are an important part of a cost-efficient electricity sector.

The results from the sensitivity analysis, summarized in Table 12, show that a decrease in losses to 10% can save substantial amounts of money. Total system costs for the whole period (2018-2025) are US$53 million less than the baseline. On the contrary, an increase in losses to 20% will result in an increase in costs of US$54 million with respect to the baseline.

There is a small shift in the amount of HFO capacity required. With a decrease to 10% transmission losses, the system would require approximately 4 MW less of HFO in 2020 and 9 MW less in 2025, whereas with an increase to 20% losses the system would need approximately 4 MW more of HFO in 2020 and 11 MW more in 2025. The average cost of generational and portion of HFO as a part of the energy mix vary very little with the changes in transmission losses. This is due to the limited amount of solar and imports in the systems, that gives little options to alternatives to HFO-based generation.

*Table 12: scenario 2A results, transmission loss sensitivity analysis*

| **Total (2018-2025)** | | **10%** | **15%** | **20%** |
|---|---|---|---|---|
| **Total system costs (US$ million)** | | 1012 (-53) | 1065 | 1119 (+54) |
| **HFO capacity installed (MW)** | 2020 | 28 (-4) | 32 | 36 (+4) |
| | 2025 | 92 (-9) | 101 | 112 (+11) |
| **Average cost of generation (USD per MWh)** | 2020 | 122 | 122 | 123 (+1) |
| | 2025 | 137 (-1) | 138 | 139 (+1) |
| **HFO as % of energy mix** | 2020 | 79% | 80% | 81% |
| | 2025 | 57% | 59% | 61% |

## 7.5. Limitations of analysis

The analysis carried out in this planning has several important limitations, some of which highlight the need for additional studies.

- The exercise does not consider specific actions in access, and assumes that the increase of demand already includes the expansion of access and interconnection of provinces.
- Access activities should be addressed with other tools, that will back-feed this analysis e.g., **household level GIS analysis** to determine a more accurate demand forecast, and develop a prospectus for reaching universal access.
- Model cannot consider bankability of project agreements, government support and capacity to support IPPs.
- Grid constraints in terms of capacity and integration has only been considered in a very general way. A **proper stability and integration analysis** should be carried out for assessing precise investment needs in T&D beyond the general ones that are highlighted in this analysis. The feasibility study envisaged under the new World Bank / EIB / EU project is expected to provide a preliminary grid stability analysis.

**Additional risks not considered within the sensitivity analysis**

The roadmap, and the LCPDP within it, should be a living document to take change circumstances into account. Many assumptions about the future are built into the analysis, which may not be realized or could change over time and were not tested in the sensitivity analysis described above.

Among the most **downside risks** are:

- **Tariffs on import PPAs** end up being higher than the $0.14-15 limit. Beyond this point, it might make more financial sense to switch from imports to another baseload capacity.
- **Delays in OMVG line** (expected to provide 14 MW from Kaleta in 2020) and / or delays in commissioning of Souapiti (expected to provide an additional 45MW in 2023). In this case, MoPE and NAWEC would need to explore options for additional IPP (HFO and / or gas depending on availability)
- **Suppressed demand** ends up being substantially larger than expressed in the demand forecasts used. In this case, MoPE and NAWEC would need to accelerate the generation expansion plan.
- **Delays in solar projects** coming online e.g. due to land allocation issues.

**Upside risks**

- **Investment costs for solar, and solar storage**, may continue to fall so quickly that they could become a viable option for providing baseload capacity

# 8. Generation planning

Per the results of scenario 2A, the preferred scenario, the generation expansion plan should be launched urgently to reach the required capacity in the coming years and to match the expected plan as much as possible. The implementation of the LCPDP requires an investment plan that is coherent with the country generation needs and capacity. The generation planning exercise aims to translate the LCPDP results into an action plan considering a pragmatic lens. For example, many of the scenario results indicate substantial investments in 2018 which will not be practically feasible.

## 8.1. Decision points

Careful consideration must be given to the following decisions, which will have important implications for the expansion plan:

| Decision point | Preference of the Government of The Gambia |
|---|---|
| **Size of new units** | 15-17 MW engines likely to give the right balance of scale and system flexibility |
| **Public vs private funding** | As indicated above, the GoTG aims to transition to competitively tendered IPPs as the main source of financing new domestic generation |
| **Location of new plants** | • Brikama likely to be the long-term generation park<br>• Provinces likely to be supplied through OMVG |
| **Preference for imports** | As indicated above, the GoTG target is to have domestic generation capacity able to generate at least 50 percent of energy needs, but with a willingness to import more than 50 percent of energy if lower cost options are available |
| **Thermal technology** | Duel fuel plants slightly higher capital investment but would give flexibility for possibility of gas generation in the future |

## 8.2. Potential generation expansion plan

**Error! Reference source not found.** provides a potential generation expansion plan with suggested preliminary design for the required generation assets. The plan uses the results from the LCPDP, and take a pragmatic view over how investment should be made. For example, instead of doing a 32 MW plant in 2018 followed by a 20MW plant in 2022, The Gambia will likely benefit from economies of scale of doing one 51 MW IPP (potentially delivered in phases). Further, if planning for an IPP only starts in August 2017, it will not be feasible to deliver in 2018. Best-case scenario it could be delivered in 2019 or more likely 2020.

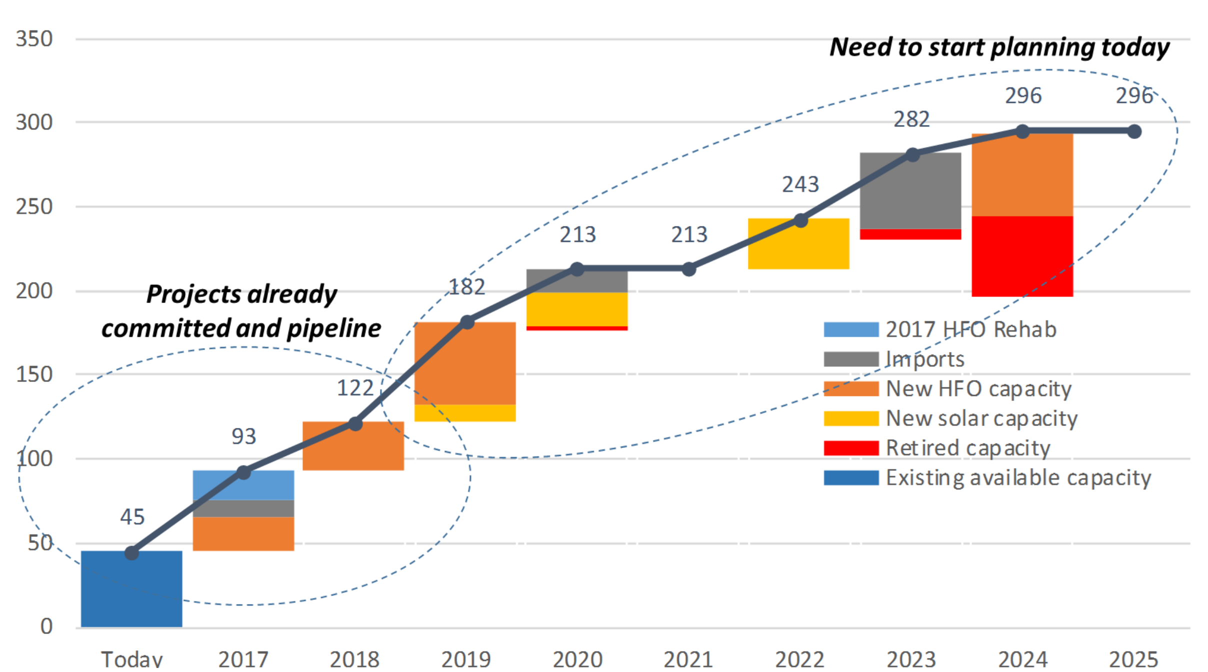
The plan indicates a total of US$236m in financing (excluding US$53 million in investments from committed projects). This plan must be discussed and contextualized within other development plans.

*Table 13: potential generation expansion plan*

| Power Plant | Nominal Power | Business model | Estimated budget | Kick off project preparation | Bidding timing | Construction period | Commission |
|---|---|---|---|---|---|---|---|
| ***Solar 1*** | 1 x 10 MW | EPC | $12 million | Feb 2017 | Apr 18-Sep 18 | Jan 19-Sep 19 | Oct-2019 |
| ***HFO Dual Fuel 1*** | 3 x 17 MW engines | IPP | $82 million | Aug 2017 | Jun 18-Dec 18 | Jan 19-Sep 19 | Dec-2019 |
| ***Solar 2*** | 1 x 20 MW | IPP | $24 million | Aug 2018 | Apr 19-Sep 19 | Oct 19-May 20 | Mid-2020 |
| ***Solar 3*** | 1 x 30 MW | IPP | $48 million | Aug 2021 | Apr 22-Sep 22 | Jun 22-Dec 22 | Mid-2023 |
| ***HFO Dual Fuel 2*** | 3 x 17 MW engines | IPP | $282 million | Aug 2021 | Apr 22-Sep 22 | Jan 23-Sep 23 | Dec-2024 |
| ***Total Investment*** | | | **$236 million** | | | | |

If this generation expansion plan were to be pursued, considering the retirement schedule for existing engines, it would result in an expansion towards 300MW of capacity by 2025 as outlined in Figure 37. An important implication of this path is that planning would need to start immediately to maximize the probability of meeting the goal to have new plants online in 2019.

*Figure 37: potential generation expansion path to 300MW*



# 9. Transmission and Distribution

Investments in T&D will be required to increase absorption capacity for the increase in generation capacity, and to reduce T&D losses. The current T&D network in The Gambia is mainly concentrated in the GBA. It is generally in good physical condition and sufficient for the currently existing load. However, the network losses are high (ca. 24%) and it is currently not possible with the available equipment (lack of meters, no SCADA, etc.) to separate technical and commercial losses and to determine the causes. The roadmap sets a target to reduce T&D losses to 15%, which is closer to the norm in Sub-Saharan Africa.

## 9.1. Existing T&D assets

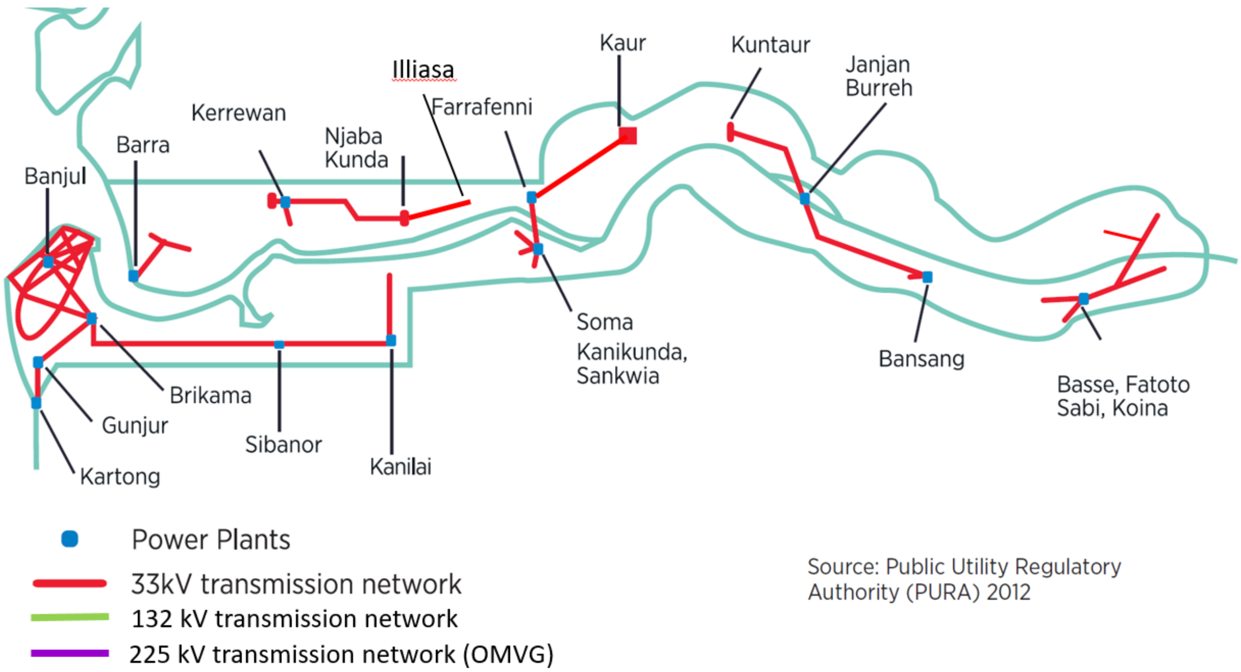
The grid in the Gambia is currently divided in two subsystems: the interconnected grid, serving the GBA, and the isolated grids in the provinces. Currently the interconnected grid system is composed of low voltage in 0.4 kV and medium voltage (MV) in 11 and 33 kV, with just 5 transformers. *Table 14* summarizes the existing infrastructure, also illustrated on Figure 38. Technical losses are estimated to be approximately 14% mainly due to overloaded substations and a weak distribution network.

*Table 14: NAWEC's existing T&D infrastructure*

| **Existing T&D installations** | | | |
|---|---|---|---|
| **Lines** | | | |
| | 33 kV | km | 260 |
| | 11 kV | km | 250 |
| | 0.4 | km | 940 |
| **Transformers** | | | |
| | 33/11 kV | piece | 5 |
| | CSS | piece | 149 |
| | PMT | piece | 90 |
| **Switchgear** | | | |
| | 33 kV | piece | 22 |

*Source: Fichtner study*

*Figure 38: Illustration of the existing T&D network*




Various projects are being undertaken on the interconnected grid and in the provinces. These will improve the performance of the grid and are expected to be completed in the period by 2020:

- GESP investments. Completion expected for 2018.
- India distribution in GBA. Completion expected for 2019.
- OMVG 225 kV, which will provide a "Western" backbone for the country. Completion expected for 2020.

Further investments are required to complement the existing network and to reinforce the grid to cope with the additional generation identified in the LCPDP.

## 9.2. Required T&D investments

This analysis is based on information available from existing studies as well as very basic indicative analysis for the roadmap. Detailed feasibility studies will be required for some investments.

The network has T&D network should expand according to the growing demand and the increasing number of new customers that are connected to the grid. Table 15 outlines the projects have been identified for growing the Gambian grid to reach near-universal access. A total of US$133 million in funding is required. US$58 million of this financing has been proposed, leaving a US$76 million funding gap. Projects that do not have a financier identified include the Soma-Bansang line, and substations and distribution in the provinces. More details on these projects can be found in the Transmission and

Distribution Investment Plan in section 9.3. For stability reasons, appropriate design principles need to be technically implemented (n-1 principle) throughout, which is currently not the case.

*Table 15: Transmission and Distribution pipeline*

| **Area** | **Investment project** | **Characteristics** | **Estimated cost (M, US$)** | **Financing status** | **Source of financing** | **Notes** |
|---|---|---|---|---|---|---|
| Backbone east | Soma - Basseh | 132 kV transmission line, approx 175km | $19.25 | Gap | | Estimates done in BADEA study - need to be reviewed |
| Backbone - west | OMVG line | Transmission line, 225 kV, 145km | $25.00 | Committed | WB/OMVG | Contract price |
| Backbone - west | Soma sub-station (OMVG) | 225/33kV substation | $8.65 | Committed | Kuwait Fund / OMVG | Contract price |
| Backbone - west | Brikama sub-station (OMVG) | 225/33kV substation | $8.65 | Committed | Kuwait Fund / OMVG | Contract price |
| Backbone - west | Brikama-Kotu | Transmission line, 132 kV double circuit, ~30 km with new substations in New Willingara | $4.88 | Proposed | WB/EIB/EU | Estimate |
| **Total backbone** | | | **$66.43** | | | |
| Dispatch center | | | $10.00 | Proposed | WB/EIB/EU | Estimate |
| GBA | Kotu | Substation upgrade | $3.00 | Proposed | WB/EIB/EU | Estimate |
| GBA | GBA distribution network | 33/11 kV lines, 33/0.4 kV pole mounted inline substation | $14.20 | Committed | India Exxim | GBA expansion, 2014 |
| **Total GBA** | | | **$27.20** | | | |
| Cross-border | 30kV cross-border | Three Transmission lines (X-border), 30 km | $1.10 | Proposed | WB/GESP | SENELEC/NAWEC 2017 |
| Provinces | Substations | Farafeni, Bansang, Bassee, Soma | $13.40 | Gap | | Estimates done in BADEA study - need to be reviewed |
| Provinces | | 33/11 kV lines, 33/0.4 kV pole mounted inline substation | $25.00 | Gap | | Estimate for connecting North bank - study required |
| **Total provinces** | | | **$39.50** | | | |
| **Total T&D** | | | **$133.13** | | | |
| Committed or proposed | | | $57.65 | | | |
| Financing Gap | | | $75.48 | | | |

Illustrative maps projecting the growth of the Gambian grid in 2020 and 2025 can be found in Figure 39 and Figure 40 below, while Figure 41 summarizes the grid forecast in the GBA by 2025.

*Figure 39: Projected network, 2020*

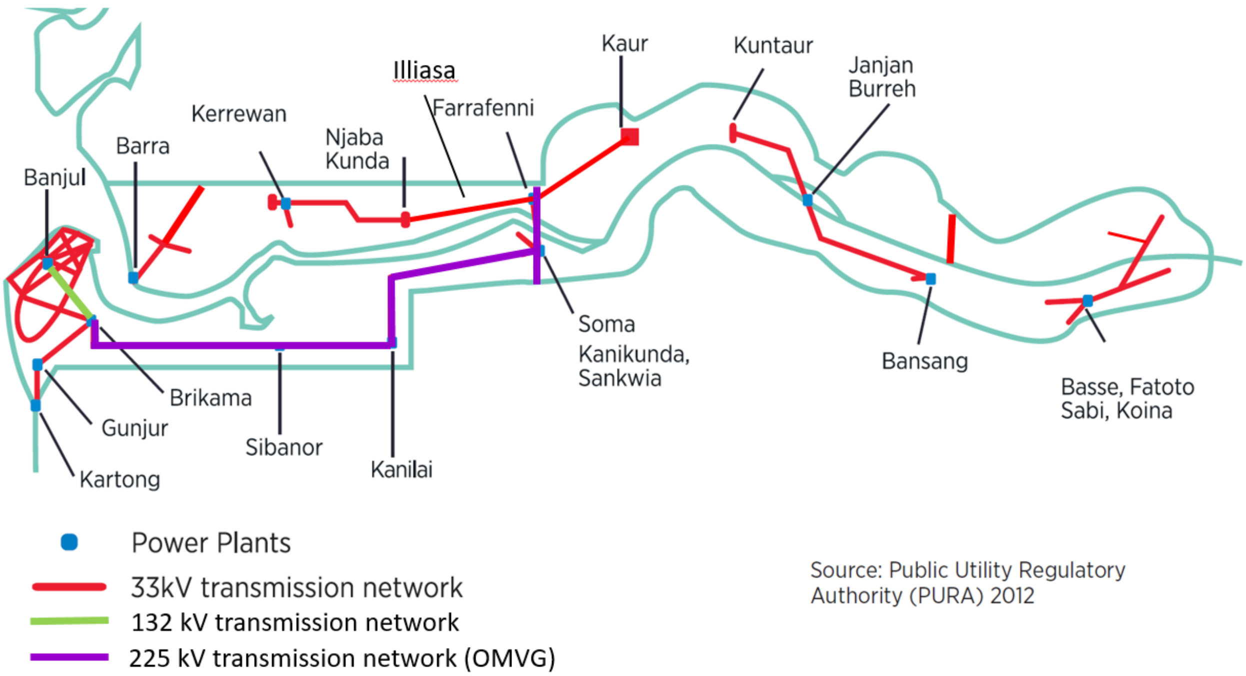



*Figure 40: Projected network, 2025*

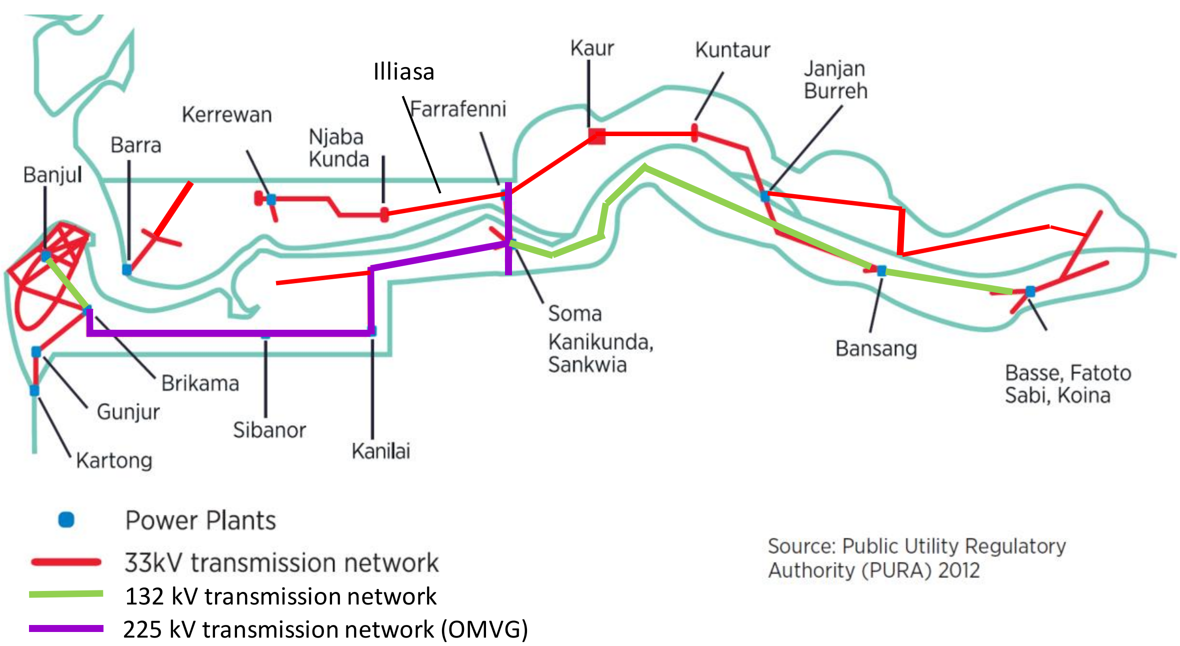
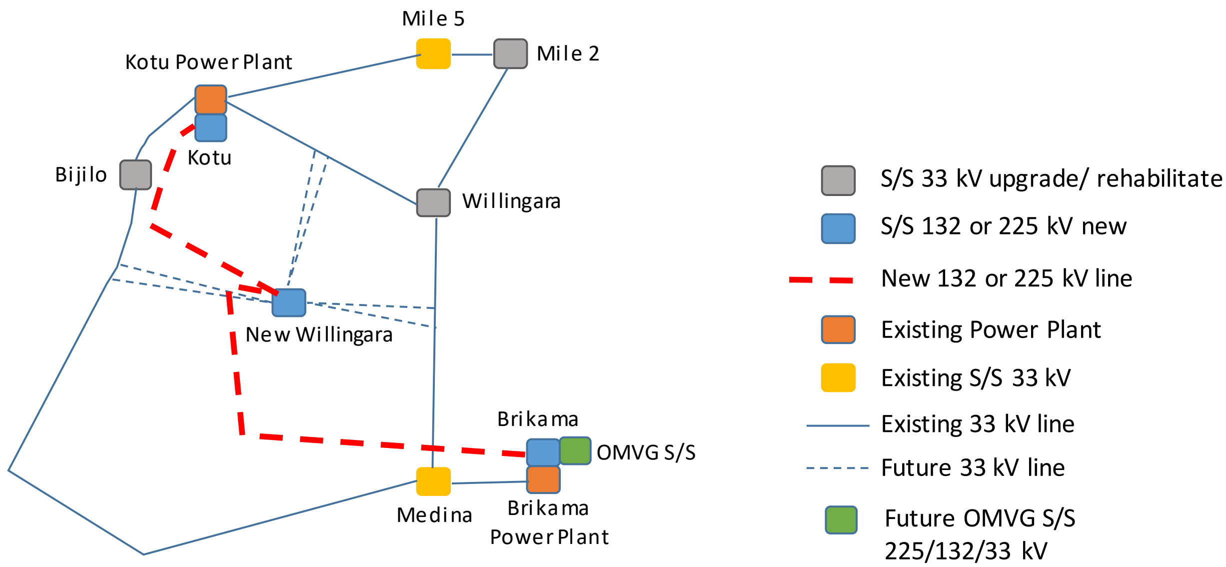


*Figure 41: Projected network to link Kotu with Brikama in the GBA, 2025*



## 9.3. Access

Access to electricity in The Gambia is estimated to be 47 percent (SE4ALL 2016). The Gambia's geographical shape also affords it to relatively low cost grid extension, once the planned transmission backbone is in place.

However, while this is relatively high for the Sub-Saharan Africa, there is no official national target to reach universal access, and no studies for electrification of the country. This remains one of the most significant analytical gaps in the electricity sector.

An indicative analysis suggests that investments required to reach universal access could be approximately $132 million. This estimate based on access rate of 47%, population of 2 million, average household size of 8 people, average cost of connection of approximately $1000 (including LV, meter and internal wiring). This preliminary estimate needs to be validated through electrification study.

The only active project active in The Gambia is the India-Exim bank project which is densifying the network within the GBA.

As for pipeline projects, a regional World Bank-implemented electricity access project could benefit The Gambia. The project will build on the substation infrastructure from regional transmission projects (OMVG, OMVS, and CLSG) to provide electricity to 500,000 households in West Africa. The project will therefore be focused on last-mile connections and have two phases.

- Phase 1: will expand medium- and low- voltage networks and bring connections and meters to households
- Phase 2: will bring in a private operator under a PPP for O&M

The Gambia is estimated to receive around US$30 million from this project. The total regional estimates are: ~US$ 500 million total; Guinea (~$100m), Guinea Bissau (~$100m), Gambia (~$30m), Mali (~$100m), Senegal (~$100m). Sierra Leone and Liberia might also be incorporated in the project.

# 10. Overview of electricity sector investment needs

Table 16 provides a summary of the financing needs identified in sections 7 and 9. A total public financing gap of US$160 million has been identified. This includes US$58 million for T&D and US$102 for access. These figures are tentative and will be refined as further work establishes funding needs on an annual basis.

*Table 16: overview of electricity sector needs (US$m)*

| | Total investment needed by 2025 | Of which private | Of which public | Public – already committed or pipeline | **Public financing gap** |
|---|---|---|---|---|---|
| *Generation* | $313 | $244 | $69 | $69 | $0 |
| *Transmission & distribution (down to 1kV)* | $133 | $0 | $133 | $75 | $58 |
| *Access (1kV and below) ** * | $132 | $0 | $132 | $30 | $102 |
| ***Total*** | **$578** | **$244** | **$334** | **$174** | **$160** |

** Indicative estimate – needs to be validated through electrification study. Estimate based on access rate of 47%, population of 2 million, average household size of 8 people, average cost of connection of approximately $1000 (including LV, meter and internal wiring)*

# 11. Institutional changes

Establishing NAWEC as an efficient, credit-worthy, and financially viable able to attract IPPs is essential to the long-term success of the Gambia's electricity sector. A financially viable utility is an important part of attracting IPPS into the power sector and NAWEC is currently D9 billion in debt. Activities to address this issue are already underway and the roadmap has helped expand and refine the set of activities to improve NAWEC's finances and governance.

**Short term (by end of 2017)**

The implementation of a debt restructuring plan is one of the foundations to turning around NAWEC's future. The GESP project is financing a debt consultant to explore options for debt restructuring and to develop a debt. Preliminary options to restructure NAWEC debt include one or a combination of:

(a) government assuming NAWEC debt through issuing T-bills;
(b) extending maturity of NAWEC debt;
(c) creditors extending a new grace period to NAWEC; and
(d) creditors writing off a portion of the NAWEC debt
(e) creditors reducing interest rate

Cooperating with the debt consultant to ensure the they have access to all the data required to complete this analysis is essential and will ensure the work is completed as soon as possible.

NAWEC must ensure that it is procuring the most competitive price possible on its fuel purchases and will have an opportunity to do this when they negotiate a new contract in September 2017.

A Management Improvement Plan (MIP) will be implemented by the NAWEC service contractor. This will include a Revenue Protection Program and a plan to manage T&D losses. The revenue enhancement will include a roll out of smart meters for 150 large customers and the scaling up of prepaid meters. Section 11.1 has more information on the scope of the MIP.

A Service Contractor (financed through GESP) will be brought into NAWEC. Their work is described in more detail below.

The Ministry of Petroleum and Energy (MoPE) will also undertake a restructuring.

**NAWEC Service Contractor**

A Service Contractor (SC) for NAWEC is being financed through GESP. The contract runs for approximately four years and will assist NAWEC to improve its technical, financial, and managerial capacity, as well as providing strategic advice. The scope of work for the SC covers:

**An organizational audit:** detailed assessment of the existing organizational situation of NAWEC, which will form the basis for the Consultant's recommendations on improvement of business processes, internal procedures, allocation of resources, and structure of NAWEC; and for the definition of the Integrated Management System (IMS) and capacity building of NAWEC.

**Providing advice on organizational improvement:** the consultant will deliver recommendations on organizational changes, including streamlining information flows within NAWEC and improvement of reporting system; and improvement of HR/administrative personnel's skills.

**Financial and commercial performance and reporting:** improvement of the Commercial Division's collection of payments, increase in efficiency of its work, and improvements in customer satisfaction through increased quality of service. Separation of accounts for electricity, water and sewerage services, so that NAWEC is able to analyze the true costs of each line of business.

**Advice on improving commercial performance**: improve the financial performance of NAWEC so that the company will become a commercially viable entity. Increasing efficiency by improving financial and management reporting systems is another goal. The consultant will prepare and implement a commercial improvement strategy by analyzing existing business processes and issues relevant to billing, customer relations management, and revenue collection and protection.

**Advice on improving financial performance and reporting:** SC will propose and assist in implementing efficiency improvement measures, resulting in reduction of costs. This will also be part of the preparation and implementation of a financial improvement strategy.

**Demand-side management and reactive power assistance:** analysis the reactive power situation on both the side of the large consumers and on the production/supply side. This will help inform NAWEC's application for a tariff review. An audit of large consumers (based on the spread of smart meters to 300 large consumers) will also identify other potential energy efficiency measures.

**Advice on technical performance improvement**: improve core NAWEC operating activities, and formulate a technical development strategy that includes recommendations for future investments into NAWEC's major operating assets. NAWEC will receive a detailed picture of the cost structure of generation and T&D, and recommendations for their optimization. A main objective is a transfer of skills that results in sustainable NAWEC's performing in accordance with best practices.

**Definition, procurement and deployment of IMS:** pre-feasibility study report for deployment of IMS, which will recommend and outline specific approach for IMS design and implementation.

**Develop and implement capacity-building/training program for NAWEC**: it is expected that on-the-job training and some formal training will be performed by SC. Other training (e.g. using of IT system) will be delivered by third party providers (e.g. supplier of IT system).

**Medium term (2018-20)**

In the medium term, NAWEC (with the assistance of the service contractor) will implement the separation of its accounts (electricity / water / sewerage), the implementation of a new IT system, and submit an application to PURA for a tariff review.

A Performance Contract is expected to be signed between the Ministry of Finance and Economic Affairs (MoFEA) and the NAWEC Board (including an agreement on bill collection from public entities such as municipalities). A Performance Contract would define certain performance targets to be met e.g. plant availability, T&D losses, bill collection rates, and service quality (e.g. SAIFI). It could also put in place incentives to meet the targets, including bonuses and maluses. At the moment, the tariff structure allows losses of 20 percent compared to actual losses of approximately 25 percent, but does not provide incentives to NAWEC management to meet the targets. Experience from other countries indicates that it is critical for performance contracts to have the right incentives through appropriate bonus and malus (e.g. annual salary bonuses for MDs and directors of up to 35% of salary and salary reduction or job loss in the opposite case). Several important design dimensions should be noted. It would be necessary for the Performance Contract to be signed following the approval of a complementary investment package to enable targets to be met. These would be included in a Management Improvement Plan which would outline the responsibility of each party in financing activities required to improve the performance of the sector e.g. reducing T&D losses will require significant investments.

A review of the tariff structure that looks at, among other issues, the automatic pass through mechanism for fuel prices and exchange rates and the allowed T&D losses will be undertaken.

Preparing the sector for the introduction of IPPs/PPPs will require technical assistance to aid with issues such as the review of sector's legal, regulatory, and tax framework (see section 9).

# 12. Preparing for IPPs

Under IPPs, private investors will operate power plants and feed the electricity into NAWEC's network. This model has been successfully established in many countries in the world. The IPPs will not compete with NAWEC, but they will complement it with additional generation capacity to stabilize the situation in the mid-term. IPPs will also bring know-how for new technologies into the country and help implement them.

An example of an IPP would be a solar plant build under a build-own-operate-transfer (BOOT) scheme. The IPP would be responsible for designing and constructing the power plant, which it will usually have experiences with from other markets. The IPP will also bring key personnel with the capability to operate the power plant in the country and usually also include local staff. The buyer is responsible to offer attractive circumstances such as fees and a take-or-pay arrangement within the framework of a PPA. Normally, the Government would be expected to provide some kind of a guarantee. At the end of the contract period, the asset is transferred to NAWEC. NAWEC already has experience for such arrangements from Brikama I, even though it was less than satisfactory because many of the requirements mentioned here were not met at the time.

**Public-Private Partnership framework**

IPPs are established as public-private partnerships (PPPs), so the regulatory framework for PPPs is an important consideration. There currently is a robust framework of incentives and process on paper for PPPs in the Gambia, but implementation is lacking. The recently developed National Policy on PPPs (NPPP) is a rigorous document but further capacity building in the PPP Unit in the MOFEA-PPP office is critical. Issues to be addressed includes developing a standard process for competitive tenders and standard PPA documents. Indeed, competitive tender are the GoTG preferred route to adding new capacity because of the clear evidence around the continent that a competitive tender gets the best prices[3]. Additional areas that require focus are the treatment of tax, VAT, and investment incentives for power (including renewable energy), which are among the most critical gaps to be addressed for private investment.

The six principle government policies and regulations that would directly influence an IPP include:

- The National Policy on PPPs (NPPPP), 2015
- The Renewable Energy Act (REA), 2013
- The National Energy Policy II (NEP-II), 2012
- The Gambia Import and Export Promotion Act (GIEPA), 2010
- Gambia Public Procurement Act (GPPA), 2014

The Renewable Energy Act (REA) is especially of interest to solar IPPs. An important part of the REA is exemptions for corporate and value-added taxes on RE projects for 15 years. It also mandates the Ministry of Energy establishes tax exemptions for RE with MOFEA and for the establishment of Feed-in-Tariffs (FIT) for renewable energy. REA also establishes the Renewable Energy Fund to promote the development of RE sources. It may also provide financial incentives, FITs, capital subsidies, and production based subsidies for RE. It specifically exempts RE electricity projects form import taxes and duties, has exemptions from corporate taxes for 15 years, exempts value-added and any retail tax for 15 years, and exempts proceeds from sale of carbon emission credits from sales taxes.

**Need for private financing**

NAWEC's current financial situation is severe and it affects the entire energy sector. Important steps are being taken to provide NAWEC with a strong financial situation through technical assistance as part of the GESP, but in the short-term NAWEC needs concessional loans or grants to address its immediate challenges. These concessional loans or grants should focus on areas that the private sector does not have an interest in to avoid 'crowding out' private investment.

**Preparations**

Given its financial situation, NAWEC is unable to invest in new power sector infrastructure. Competitively tendered IPPs will therefore become the main source of new domestic generation.

[3] See pages 91-93 of "Independent Power Projects in Sub-Saharan Africa: Lessons from Five Key Countries" (https://openknowledge.worldbank.org/handle/10986/23970)

- Many measures will need to be taken to de-risk investments. Among them:
    - Convert NAWEC into a financially viable off-taker (supported by the institutional support efforts outlined above, especially a credible plan for debt restructure and debt sustainability plan)
    - Stable policy legal, regulatory, and tax framework
    - Access to data: financial and operational performance data routinely published online (e.g. websites of NAWEC / MoPE / PURA)
- Adequate standards, among them:
    - Standard governments guarantee/support agreements to PPA documents
    - Standard credit enhancement mechanism to back stop off taker obligations
- There is a robust framework of incentives and process on paper for PPPs, but implementation is lacking
    - The National Policy on PPPs (NPPP) is a recent and rigorous document
    - Capacity building in the PPP Unit in the MOFEA-PPP office is critical
- Need to develop standard process for competitive tenders, standard PPA documents etc. Technical Assistance from African Legal Support Facility supporting this effort.
- Reputable advisor to Gov/NAWEC to support that process
- The treatment of tax, VAT, and investment incentives for power (including renewable energy) are among the most critical gaps to be addressed for private investment
- Establish mechanism/conditions for adequate fuel supply arrangements

# 13. Conclusions

In 2017, Gambia's power sector is in a crisis mode. However, there is real reason for hope on the horizon with a new political chapter and real opportunities to improve generation capacity and make the sector more financially viable. This update has provided an opportunity for the new government and all stakeholders in the sector, existing and new, domestic and international, to take stock of the current situation and lay out a vision for the development of the sector.

Of the scenarios presented, the GoTG has chosen Scenario 2a as the preferred scenario. This is an ambitious scenario for several reasons. First, the government is committed to pursuing new generation through IPPs and imports. Neither will be easy. Not only will bold reforms of NAWEC be necessary to attract reasonably priced IPPs to the sector, but the government does not have experience of running competitively tendered IPPs so will need strong Transaction Adviser support to make this happen

In addition to enabling successful IPPs, the GoTG will also need to aggressively pursue import options through the OMVG interconnection line. Energy provided in the current proposals for Kaleta and Souapiti will not be not sufficient. The GoTG needs to purchase another 270GWH per year (equivalent to 30MW average capacity) in order to complement what will be provided through the OMVG MoU.

The chosen scenario also commits the country to make a bold transition towards renewables, away from 100 percent HFO today, to less than 60 percent in 2025. Beyond two new HFO plants of 50 MW each for baseload capacity, all new capacity is planned to come from solar IPPs and hydro imports. This will help The Gambia achieve its COP 21 INDC commitments.

Finally, the chosen scenario helps to put the sector on a track to bring down costs. Tariffs are amongst the highest on the continent so even though NAWEC is not financially viable today, it will be very difficult to increase tariffs. The roadmap therefore charts a course for costs to be substantially reduced over the medium term, particularly as imports become available when the OMVG interconnection is commissioned. This will help create space to allow tariff reductions over time.

The roadmap also highlights the need for substantial investments in T&D. These investments will be critical to help reduce T&D losses on the network from 23 percent today to a target of 15 percent (to be complemented with tighter oversight by management to track and reduce T&D losses). The T&D investments are also critical to allow the network to absorb new capacity including IPPs, renewables, and imports from OMVG. Finally, they will be critical to enable expansion of access to electricity in The Gambia from 47 percent today towards the universal access target.

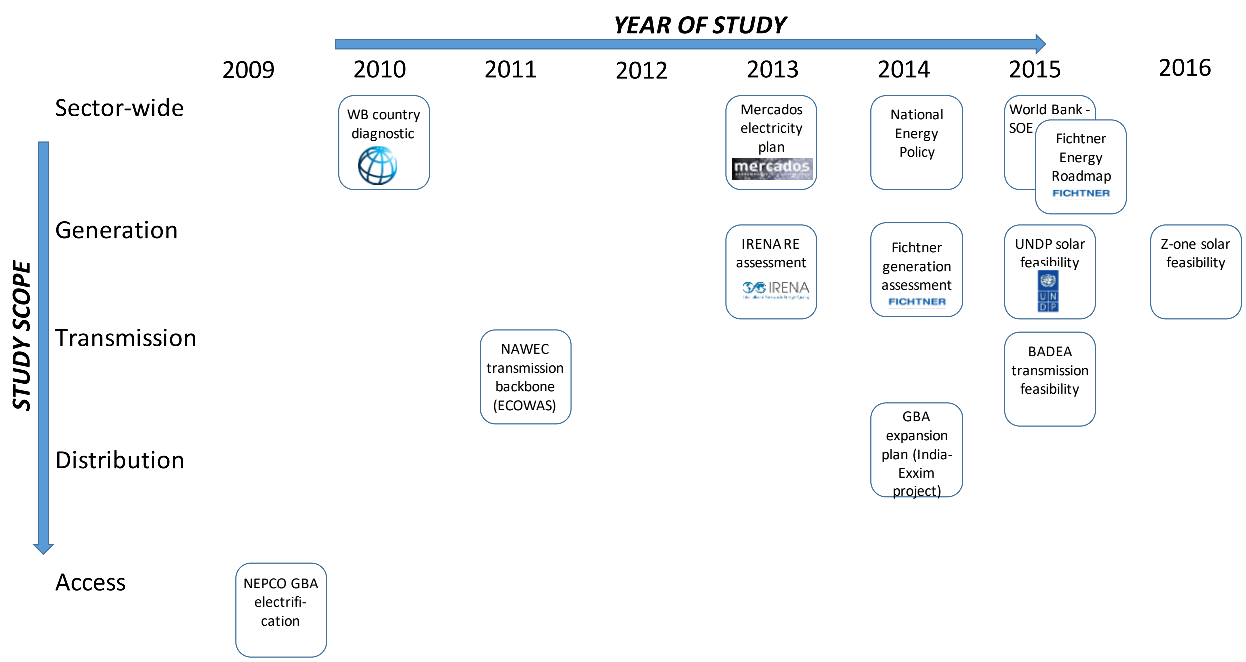
Additional work is needed to define the path and investment needs to reach universal access. Other areas for follow up studies include exploring the opportunity for The Gambia to benefit from Gas-to-Power as a source of baseload capacity. As outlined in the roadmap, there are various opportunities that could be explored especially given the recent off-shore discoveries in neighboring Senegal.

The roadmap should be updated regularly to take new information into account, including from the studies. The MoPE, with overall responsibility for implementation of the roadmap, will need to develop the capacity with NAWEC to build its planning function and be able to update the roadmap regularly. This will maximize the opportunities to expand generation at the lowest cost to all in The Gambia.

# Annex 1: Key Reference Documents

Key reference documents are summarized in Figure 42. Additional details can be found below.

*Figure 42: overview of reference documents*




**<u>Sector strategic documents (most recent first)</u>**

***Development of a National Energy Sector Strategy Study or The Gambia***

- Scope of work included:
  - Demand forecast
  - Assessment of NAWEC's existing assets
  - Energy roadmap and action plan
  - Least cost power development plan determined the OMVG scenario is preferable scenario, with investment costs of US$ 113m
  - Prepared by Fichtner on behalf of GoTG Ministry of Finance and Economic Affairs. Financed by the World Bank.
- Background:
  - Document date: April 2015
  - Prepared by Fichtner
  - Financed by the World Bank

***State-Owned Enterprises in The Gambia: a Country Policy Note***

- Key points:
    - Confirms that SOE sector is in serious crisis and that urgent action is needed, given high a rising risks to fiscal sustainability and economic growth
    - Establishes the extent of NAWEC’s financial troubles and proposed solutions
    - Establishes a detailed set of recommendations to address The Gambia‘s SOE’s needs, tailored to the country’s particular situation and consistent with international best practices for SOE reform
- Background:
    - Document date: November 2015
    - Prepared by World Bank

***Electricity Strategy and Action Plan***

- Key points:
    - Study summarizing main issues and restrictions in The Gambia’s energy sector
    - For expansion needs a complex least-cost model approach is chosen including various parameters and many data assumptions; these values have highly uncertain development over 20 years
    - The modelled scenarios are to a certain extent very theoretical, an approach based on more strategic decisions should be preferred
    - Emphasizes a clear commercial framework, good governance and system efficiency as pillars of the action plan
- Background:
    - Document date: August 2012
    - Prepared by Mercados
    - Financed by the European Union

***World Bank Energy Sector Diagnostic Review***

- Key points:
    - An overview of the energy market and general situation in the Gambia
    - Delivers good and comprehensive data buy many figures are outdated
    - The critical financial situation at that time was discussed including measures to improve
- Background:
    - Document date: November 2010
    - Prepared by: World Bank

***National Energy Policy 2015-2020***

- Key points:
    - Part I is an overview of the energy sector and its potential
    - Recommends building a sustainable energy platform for growth and building renewable energy capacity
    - Part II provides policies and strategies to help achieve these goals
- Background:
    - Document date: 2014

    - Prepared by Sahel Group

***The Gambia: Renewables Readiness Assessment 2013***

- Key points:
    - Overview of the enabling environment for renewable energy and opportunities for deployment
    - Proposals to further renewables include RE law enactment, standards and labels for RE equipment, resource mapping, establishing an RE fund, capacity building, and land allocation for RE use
- Background:
    - Document date: 2013
    - Prepared by: IRENA

***Technical Assessment on Power Generation in the Gambia***

- Key points:
    - An assessment of power generation assets as well as T&D infrastructure
    - Transmission recommends include implementing (n-1) criteria
    - Generation recommends prioritizing rehabilitating existing power plants
- Background:
    - Document date: 2014
    - Prepared by Fitchner

**<u>Feasibility studies</u>**

***PV Solar Power Project at Brikama / The Gambia Network Integration Study and concept Design***

- Key points:
    - Feasibility study for a new 10 MW PV solar farm being developed by Emerging Power Gambia
    - Assesses the impact of the PV plant on the grid and the design of the network integration
    - Includes concept design, network calculation study and results analysis
    - Concludes there are no reasons against the realization of the PV plant and even the measure of a step by step installation will be feasible
- Background:
    - Document date: May 2016
    - Prepared by: Eproplan

***Feasibility study for a Public-Private Partnership (PPP) for Grid-Connected Solar Power Generation in The Gambia***

- Key points:
    - Proposes installing grid-connected solar power stations at Basse (1,260 kWp) and Farafeeni (1,470 kWp)
    - Investment costs for Basse US$ 2,390,000 and US$ 2,700,000
    - Proposes a 15-year Build, Own, Operate, and Transfer (BOOT) PPP agreement
    - Shows there is a robust framework of incentives and process on paper, but not fully utilized in a larger scale

- Background:
  - Document date: July 2016
  - Funded by: UNDP and MOFEA

***Feasibility Study for National Transmission Line and Dispatch Center of The Gambia***

- Key points:
  - A detailed feasibility study of the national transmission network (limited distribution i.e. 132kV and above)
  - Covers design and financing for proposed transmission lines, substations, and dispatch center
  - Includes economic analysis of all investments and estimates a total project cost of US$ 52m Funded by: the Arab Bank for Economic Development in Africa (BADEA)
- Background:
  - Prepared by: Al-Abdulhadi Engineering Consultancy (AEC)

***Detailed Project Report for Electricity Expansion Project for GBA (for project with India Exxim Bank)***

- Key points:
  - Develops a power systems master plan for GBA
  - Covers load forecasts, generation, and T&D expansion plans
  - Includes 33kV and 11kV expansion plans
  - Recommends expanding generation through IPPs outside GBA
  - Recommends extensive T&D planning and incorporation of high voltage transmission network
- Background:
  - Document date: 2013-14 (??)
  - Prepared for NAWEC in 2013-14

***Project Proposal for a 132KV Power Transmission Backbone line and Reinforcement of 33KV Transmission Systems in the GBA***

- Key points:
  - Feasibility study for first phase of national transmission grid, a 32 km 132 kV line and substations
  - Estimated cost of the project US$ 33.9m, funded by ECOWAS

***Feasibility Study for Electrification and Network Upgrading in the GBA and the western region of The Gambia***

- Key points:
  - NEPCO study on network upgrading
  - A least cost generation and transmission plan for 2008-2025
  - Recommends additional generation in the Kotu power plant or alternatively the Brikama power plant
  - Most assumptions are out of date
- Background:
  - Document date: 2009

- Prepared by: NAWEC, for NEPCO

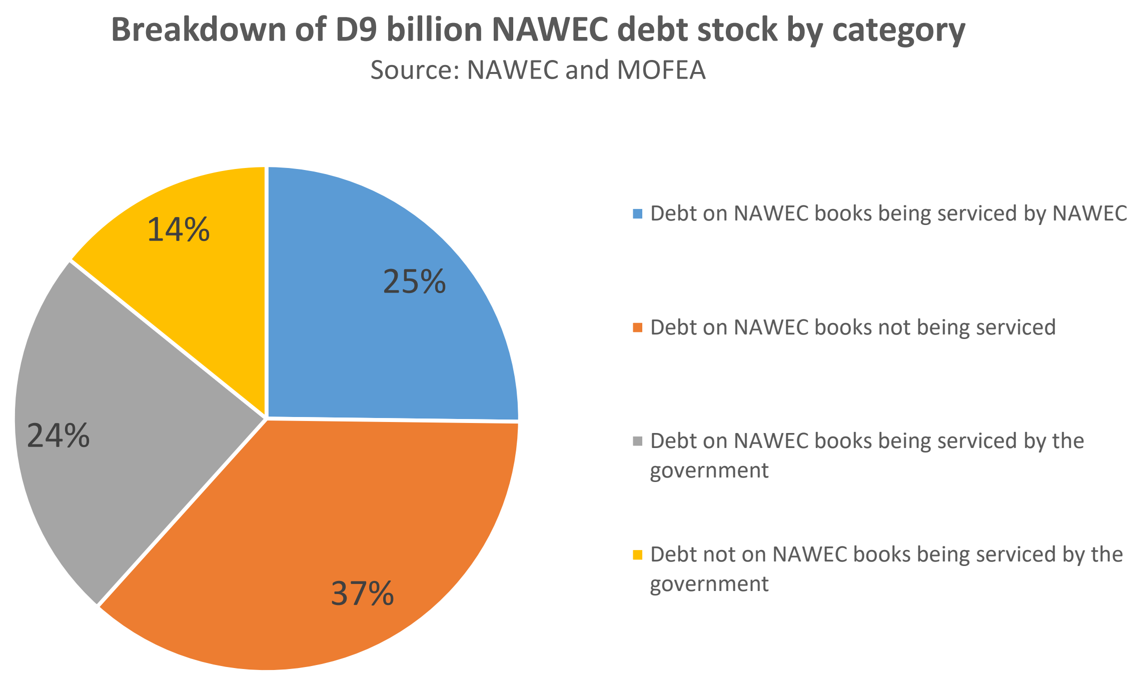
# Annex 2: Snapshot of NAWEC Debt

*a) Breakdown of NAWEC debt by category*

Total debt stock was D9.5 billion at December 31 2016. NAWECs exposure for 2017 on the loans it is servicing is approximately D60 million per month, against revenues of approximately D200 million per month (note fuel payments are approximately D110 million per month).

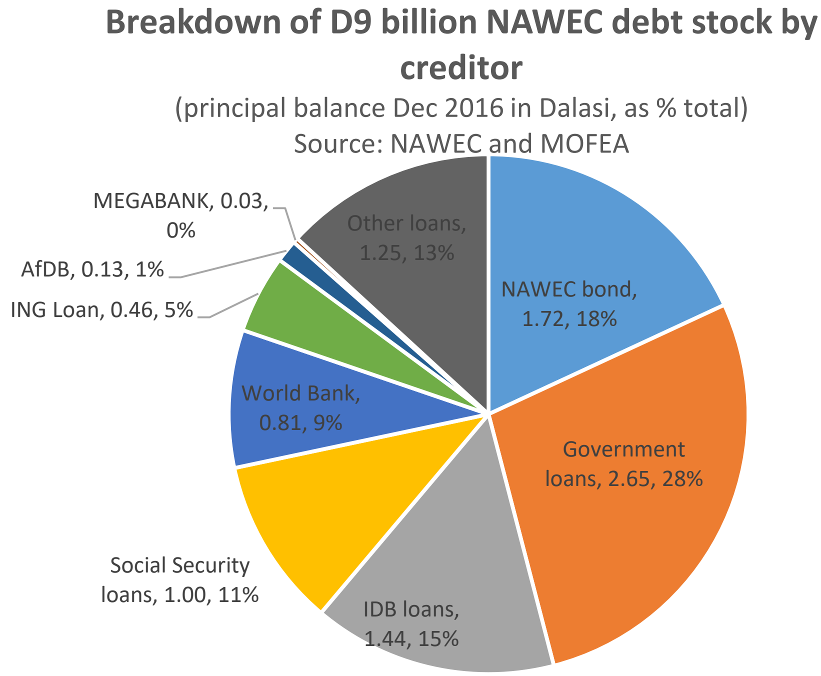
However, Figure 43 illustrates that NAWEC is only servicing 26% of the debt taken out on its behalf (mainly the NAWEC bond and an ING loan). The balance is either being serviced by the government (40%, mainly project finance) or not being serviced (36%). The latter group includes debt NAWEC has with the government, and with the Social Security Fund. Figure 44 shows a breakdown of the D9 billion debt by creditor.

*Figure 43: NAWEC debt stock by category*



*b) Breakdown by creditor*

*Figure 44: breakdown of NAWEC debt stock by creditor*




*c) NAWEC bond*

By the end of January 2017, NAWEC were 6 months in arrears on their bond with six commercial banks. The bond started in March 2015 for 2 billion Dalasi for a period of 60 months at 15 percent interest rate. NAWEC have made a transfer into the Central Bank escrow account almost every month since the loan started, but only paid the full amount of D51 million or more in three months. The bond is now in arrears of six months, with the most recent payment from the Central Bank escrow account to the creditors applying to the July 2016 payment.

Payments to the bond have slipped in the most recent three months in part because of the cash and carry fuel arrangements entered into with the national fuel supplier GNPC, which has reduced cash flow available to NAWEC. In addition, some key engines broke down in December and January, reducing sales and therefore revenues.

The total principal balance at the end of 2016 was D1.7 billion compared to an initial loan of D2.1 billion.

# Annex 3: Committed and pipeline projects

**Committed:**

**US$18.5M Gambia Electricity Support Project (GESP) ($18.5 million, approved May 2016).**

GESP provides basic investment and institutional support to NAWEC as part of its strategy to redress financial and operational performance in the short to medium term. The GESP complements other short-term and medium-term interventions by IDA and other donors. The project supports investments to improve generation capacity and the T&D network. It also supports the development of the technical, commercial, financial, and IT capacity of NAWEC. This operation focuses on GBA, where the vast majority of The Gambia's electricity is consumed.

GESP consists of the three components:

- Component 1: Expansion of Available Generation Capacity at Kotu and Brikama (US$7 million equivalent). This component is financing improvements to NAWEC's generation capacity and efficiency in the existing Kotu and Brikama thermal power plants. This is being done through rehabilitation and replacement of required equipment, provision of critical spare parts, and financing urgent maintenance activities. This support is critical in view of the worsening generation scenario in The Gambia.
- Component 2: Reduction of Technical and Commercial Losses in the GBA (US$4.5 million equivalent). This component is financing improvements in the T&D network in the GBA. The project will contribute to reducing forced outages and diminishing voltage drops, thus improving customer satisfaction. It will also generate higher supply continuity and quality, and increase prepayment metering, which will result in higher returns. The improvements of the network will have a positive impact on the operations of NAWEC, reducing technical and commercial losses through the following two subcomponents:
- Component 3: Institutional Strengthening and Project Implementation Support (US$7 million equivalent). This component includes a service contract for NAWEC management support, a new NAWEC IT system, and project implementation support.

**OMVG Interconnection project ($47 million, approved April 2015).**

The OMVG interconnection consists of: 1,677 km of power transmission line in 225 kV; 8 15 substations HV / MV for powering loads from national utilities; and two dispatching centers. The project also partly finances the operations and maintenance (O&M) contract costs for the first five years of operations (FY2018-2022).

OMVG represents a strategically critical means for The Gambia to close its supply/demand gap and reduce the average cost of supply. OMVG offers The Gambia a low cost means to expand base load capacity by 59 MW. The Gambia is expected to be able to access new capacity at a cost of US$0.09-0.15 per kWh, compared to its alternative of power from small diesel plants at US$0.30-40 per kWh. This will reduce average cost of supply in The Gambia by at least 20 percent. Other benefits from OMVG specific to The Gambia include:

- $700m total project costs or which $200m IDA ($86m for The Gambia, of which $47m is IDA)
- New lines connecting The Gambia in 225 kV with Senegal, Guinea-Bissau and Guinea.
- Backbone within The Gambia (substations at Soma and Brikama)

- Will provide energy from hydro sources at low price (USc12/kWh): 14 MW in 2020 and 45 MW in 2023

**Kuwaiti Fund***
- Financing two sub-stations in The Gambia for the OMVG interconnection project

**Arab Fund for Economic Development in Africa (BADEA) and the OPEC Fund for International Development (OFID)**
- Kotu expansion: 11MW HFO engine, on track to be commissioned at the end of 2017
- Co-financed by BADEA ($12m) and $9m OPEC

**Islamic Development Bank (IsDB)**
- Brikama expansion ($25 million): 20 MW HFO engines, expected to be commissioned in 2018.
- ITFC: $25 million Credit Facility for HFO purchase by NAWEC. Was in default until recently.

**India Exxim Bank***
- US$22.5 million T&D expansion and rehabilitation project in the GBA

**EBID (ECOWAS BANK for Investment and Development)**
- Rural electrification extension project (with an Indian line of credit $30m; requested additional funding). 5MW HFO plus access. 36 villages connected (6 to be done)

**UNDP**
- Financed a feasibility Study on rural hybrid systems (solar / diesel)

**<u>Pipeline:</u>**

**Gambia Restoration and Modernization Project (World Bank / EIB / EU)**
The World Bank has kicked off preparation of a new Restoration and Modernization Project which is expected to be co-financed by the EIB and EU for a total cost of approximately $80-90 million. The project is expected to be approved in 2017 and would likely include:
- 10-20MW of grid connected solar PV
- T&D investments to absorb solar capacity including upgrade of Brikama-Kotu to 132 kV with a dispatch center
- Off grid solar PV for schools and health clinics
- Institutional support including a Service contractor and Owners Engineer for NAWEC

**Regional Access Project (World Bank)**
As mentioned above, regional World Bank-implemented electricity access project could benefit The Gambia. The project will build on the substation infrastructure from regional transmission projects (OMVG, OMVS, and CLSG) to provide electricity to 500,000 households in West Africa. The project will therefore be focused on last-mile connections and have two phases.
- Phase 1: will expand medium- and low- voltage networks and bring connections and meters to households
- Phase 2: will bring in a private operator under a PPP for O&M

The Gambia is estimated to be receiving around US$30 million from this project. The total regional estimates are: ~US$ 500 million total; Guinea (~$100m), Guinea Bissau (~$100m), Gambia (~$30m), Mali (~$100m), Senegal (~$100m). Sierra Leone and Liberia might also be incorporated in the project.

**African Development Bank**

- Starting to engage in the sector. Exploring physical investments in mini grids and grid extension, and institutional support
- Legal advisory service to develop standard PPA documents etc.

## Annex 4: Roadmap action plan for 2017

*Note: action plan beyond 2017 to be developed*

| No. | Action/activity | Tasks | Cost (US$) | Responsible |
|---|---|---|---|---|
| **Immediate (2017)** | | | | |
| 1. | Task-force to track roadmap implementation | | | |
| | Task force would likely include MoPE, NAWEC, MoFEA, PURA, Office of the President. Terms of reference to include regular tracking of roadmap actions, developing action plan beyond 2017, building planning function within MoPE and NAWEC for future updates | 1. Roadmap implementation adopted as a Presidential Priority<br>2. Monthly task force meetings<br>3. Monthly public communication on roadmap implementation (incl. customers and partners)<br>4. Draft detailed action plan for 2017 and beyond | (gap) | MoPE |
| 2. | Rehabilitation of HFO engines | | | |
| | Priority rehabilitation and expansion of up to 15MW of Kotu and Brikama plants | 1. Procure spare parts to rehab Brikama G4 | 3m | NAWEC |
| 2. | Cross border transmission lines | | | |
| | Three 30kV transmission lines, 30 km | 1. Approval of PPA with SENELEC<br>2. Update of GESP ESMP<br>3. Restructure GESP | 1.1m | NAWEC / World Bank (GESP) |

| | | | | |
|---|---|---|---|---|
| | | 4. Construct lines | | |
| 4. | Communications campaign | | | |
| | Execute communications strategy | 1. Implement a Power Alert System<br>2. Ramp up social media presence<br>3. Animated infographic<br>4. Production of an energy savings film<br>5. Weekly updates/briefs to the press | 0.4m | NAWEC / World Bank (GERMP) |
| 5. | Energy efficiency measures | | | |
| | | 1. Replace street lamps with LED lighting<br>2. Get an estimate for the number of bulbs in government offices | 0.6m | NAWEC/local councils |
| 6. | Reduce non-technical losses | | | |
| | | 1. Smart meters for larger customers (4-6 months)<br>2. 13,000 pre-paid meters | 0.8m | NAWEC |
| 7. | Reduce technical losses | | | |
| | | 1. Power Transformer Upgrade and Installation of new switch gear | 1m | NAWEC / World Bank (GESP) |
| 8. | Kick off preparation for 50 MW HFO IPP | | | |
| | | 1. Recruit Transaction Adviser<br>2. Kick off project preparation studies (feasibility and safeguards) | 1m<br>(gap) | MoPE / NAWEC |
| 9. | NAWEC Service Contractor | | | |

| | | | | |
|---|---|---|---|---|
| | Mobilize consultant firm | 1. Recruit individual consultant to draft Management Improvement Plan<br>2. Recruitment Service Contractor | 2m | NAWEC/World Bank (GESP) |
| 10. | NAWEC Debt restructure | | | |
| | Mobilize individual consultant | 1. Kick off mission (Aug 2017)<br>2. Identify debt restructure options<br>3. Update NAWEC financial model and debt sustainability plan | 0.1m | NAWEC |
| 11. | Kick off strategic studies for the sector | | | |
| | | 1. Electrification study (define access goals, develop demand forecast, confirm investment requirements etc.)<br>2. Study to explore options for Gambia to benefit from Gas-to-Power<br>3. Solar mapping study | 1.5m<br>(gap) | MoPE / NAWEC |
| 12. | MoPE re-organization | | | |
| | | 1. Draft ToRs<br>2. Tender study and award contract<br>3. Supervise implementation | 0.1 | MoPE / World Bank (GERMP) |
| 13. | Kick off preparations for future imports | | | |
| | A key conclusion from the roadmap is the need to leverage the opportunity of the OMVG interconnection to access low-cost imports from the sub-region | 1. Initiate discussions with SENELEC on possibility of additional imports (e.g. gas to power?). Need an additional 30MW / 270 GWH to complement Kaleta / Souapiti seasonality. | 0 | MoPE / NAWEC |