Ricardo Energy & Environment

Generation Asset Lifecycle Review Report

A review of BELCO's existing operational electricity generation assets

Version for public domain

Report for the Regulatory Authority of Bermuda

ED 10123 | Revision 0 | Date 17/06/2017

Executive summary

This report has been prepared on behalf of the Regulatory Authority of Bermuda as part of a review into the condition of the existing electricity generation assets at the power plants located on BELCO's (the Utility) site in Pembroke Parish, Bermuda.

The island has a seasonal demand profile with the highest demand during the hottest months from June to September, lower demand during the milder months of Fall and Spring and a smaller secondary peak in the winter months. The daily demand profile is relatively stable and predictable and is not characterised by large fluctuations. This predictability allows the Utility to plan its maintenance activities with minimal risk and to manage the electricity grid accordingly.

The Utility has a total of 17 operational generation units. Eight of these are reciprocating engines that primarily use heavy fuel oil and a further 4 reciprocating engines use light fuel oil. The remaining 5 units are gas turbines operating on light fuel oil.

Seven of the units are more than 30 years old, which is normally considered to be the upper limit of the nominal service life for this technology. A further two units are older than 20 years and have been unreliable in recent years. The Utility is therefore planning to retire these 9 units as soon as possible.

The maintenance of the Utility's generation units is generally well-managed. It takes a reliability-centred approach using operational monitoring of critical plant and analysis to identify systems and equipment that require further investigation and/or maintenance. Regular services and overhauls are conducted on the units in accordance with the manufacturers' recommendations.

In spite of the Utility's prudent approach to maintenance, wear and tear from constant operation in an environment containing corrosive saline-laden air takes its toll on the generation units. Issues with the ancillary equipment are mainly responsible for reductions in unit reliability because the prime movers are serviced at regular intervals and components are repaired and replaced as required.

The ancillary equipment can be repaired or replaced, but when units reach a service life of between 20 and 30 years of age, replacement rather than repair tends to be the most cost effective option. Obsolescence is another common issue with older equipment and replacement parts can be difficult to obtain. This adds to the cost and lead time associated with maintenance activities.

This review finds that there is limited scope to extend the life of 5 of the 9 units that are planned for retirement, but additional investment would be required to address existing issues. Even with such investment, the units would probably not be suitable for continued operation in a base load application and could be expected to continue to degrade in terms of performance and reliability. Ongoing maintenance costs would also be expected to be high.

This review concludes that new generation capacity is required as a matter of urgency to replace the generating units that are planned for retirement in the next two to three years. Without new generation capacity, the security and reliability of Bermuda's electricity supply could be at risk in periods of high demand.

This review finds that the capacity margin will lower than the Utility's target level if all 9 units are retired when the new units are brought online in 2019. The reduced capacity margin could pose a risk to security of supply if there is a forced outage during a maintenance outage of a large unit. It is therefore recommended that the Utility should conduct a feasibility study and cost-benefit analysis to determine which of the older units can be kept operational to support electricity generation beyond 2019 in a part-time role.

It is suggested that Units E3, E4, D8, D10 and D14 could be considered as candidates to provide such part-time back-up capacity when the new generation units are installed.

Abbreviations

EPS	East Power Station
GT	Gas turbine
GWh	Gigawatt hours
HFO	Heavy fuel oil
GOC	Grid operations centre
LFO	Light fuel oil
MASB	Main Auxiliary Switchboard
MCC	Motor control centre
MW	Megawatts
NPS	North Power Station
OEM	Original equipment manufacturer
OPS	Old Power Station
PLC	Programmable logic controller

Table of contents

1 Introduction

This report has been compiled as part of a review into the condition of the existing electricity generation assets at the power plants located on BELCO's (the Utility) site in Pembroke Parish, Bermuda. The review was commissioned by the Regulatory Authority of Bermuda (the Authority).

2 Purpose and scope

The purpose of this report is to provide an overview of the condition of the operational power generation units that are currently installed at the Utility's site. It also discusses the potential risks to the electricity system if aging plant is retired, but not replaced.

3 Methodology

This report has been compiled using data provided by the Utility, observations during a site visit and interviews with the Utility's staff. Data were provided by the Utility in advance of the site visit. The site visit was conducted in March 2017.

The analysis and discussion provided in this report relies on information provided by the Utility in the form of data and in discussions. The site tours allowed for visual inspections of a cursory nature, but were not sufficient to verify the information provided by the Utility.

4 Electricity demand in Bermuda and approach to supply

The average annual electricity demand for Bermuda in 2016 was 74 MW, with a peak of 112 MW in August. The highest recorded peak demand was 123 MW, measured in August 2010. Figure 1 gives the monthly peak demand values for 2010 to 2016.

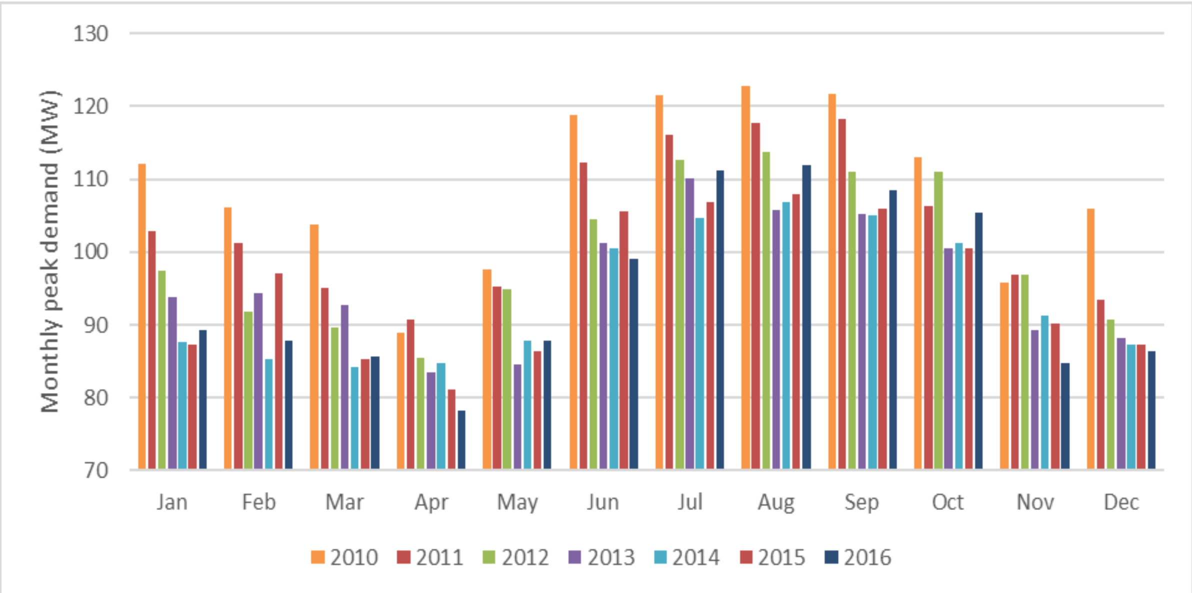

Figure 1: Monthly peak demand from 2010 to 2016.

The peak demand values follow a typical seasonal profile with the highest demand during the hottest months from June to September, lower demand during the milder months of Fall and Spring and a smaller secondary peak in the winter months. This is also reflected in the energy consumption values, as shown for 2016 in Figure 2.

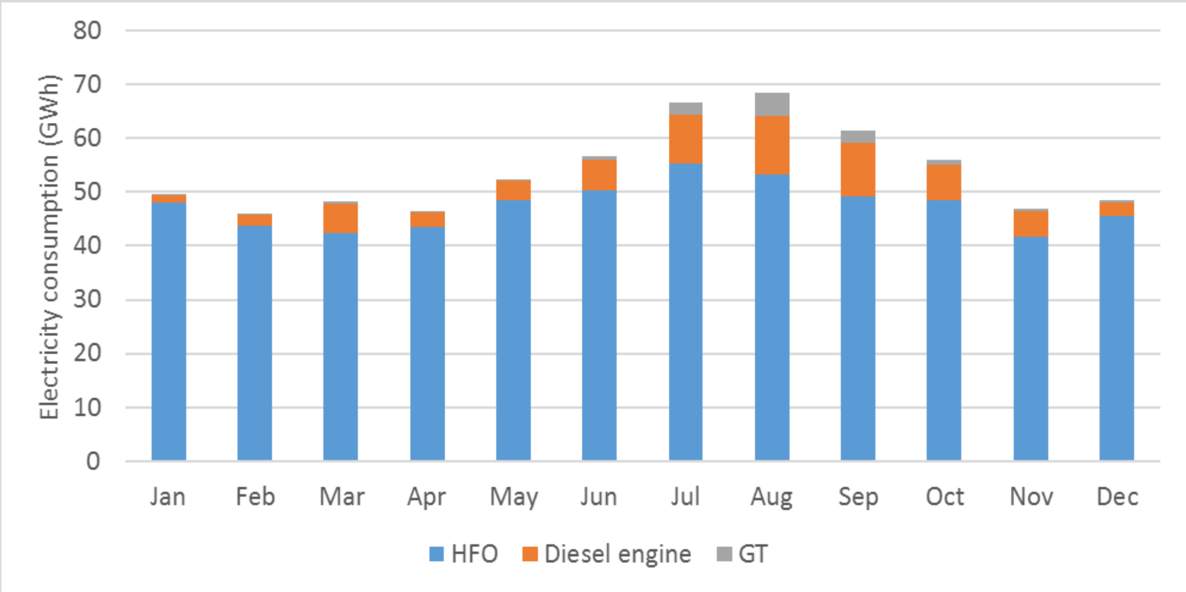

Figure 2: Generation mix to satisfy total monthly demand.

The peak demand values shown in Figure 1 indicate that monthly peak demand steadily decreased from the maxima of 2010 to minima in 2013/14, and that peak values have either stabilised from 2014 to 2016 or begun to increase again. This is in contrast to the previous six years when there was a steady increase in the peak demand year-on-year, especially during the summer months. This trend is shown in Figure 3.

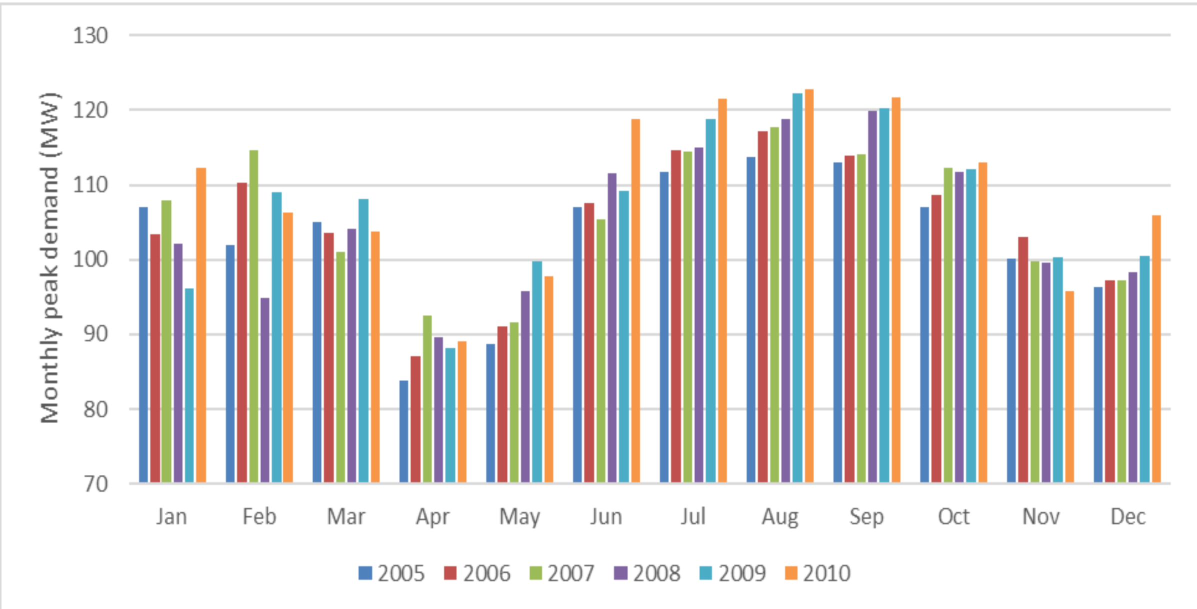

Figure 3: Monthly peak demand from 2005 to 2010.

It is likely that an economic recession in the wake of the global economic crisis of 2008 to 2010 is the main reason for the abrupt change in the electricity consumption trend around 2010.

Bermuda's daily demand profile is shown in Figure 4.

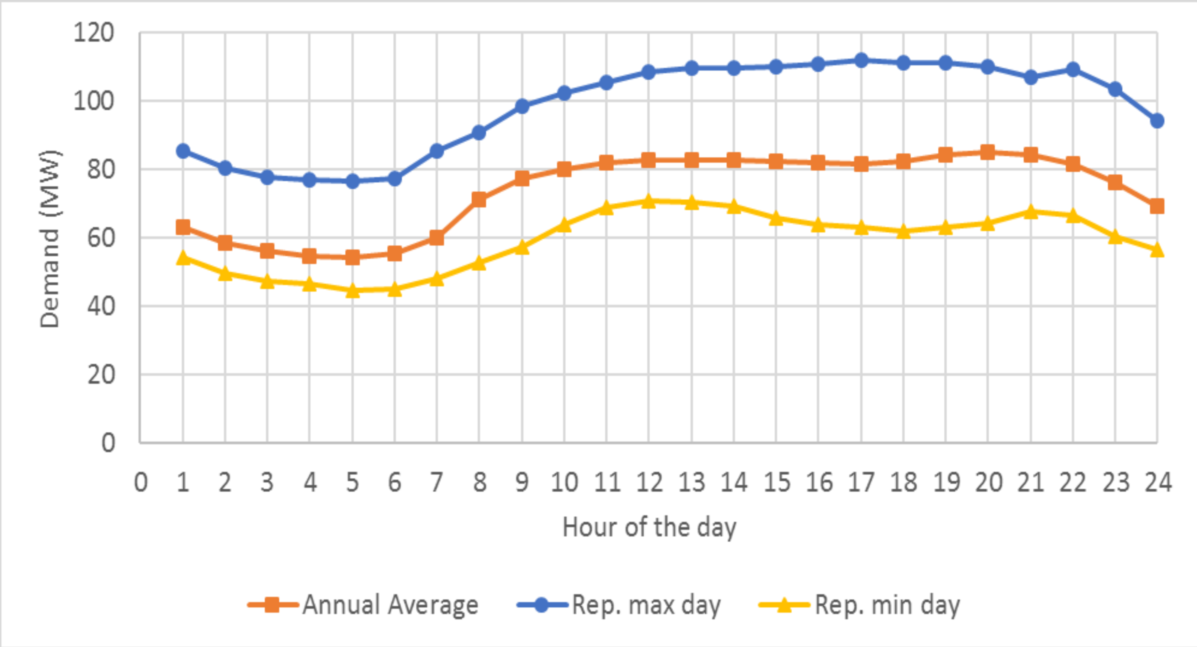

Figure 4: Daily demand profiles for Bermuda (2016 data).

The annual average demand has a flat profile during the day with a barely discernible peak in the evening at around 20.00. Demand typically decreases steadily from 20.00 until 05.00 when it reaches a minimum before steadily increasing again to the daytime levels. The top curve represents a typical day in the summer months. It has a very similar profile to the annual average values, but is at consistently higher levels. The bottom curve represents a typical day in Fall or Spring. The minimum still occurs at about 05.00, but there is are noticeable peaks around midday and late evening with a slump between them, which is not present in the other two curves.

This suggests that the daily demand profile is relatively stable and predictable and is not characterised by large fluctuations. There was no evidence of transient peaks not normally detected by conventional metering instruments. This predictability allows the Utility to plan its maintenance activities with minimal risk and to manage the electricity grid accordingly.

5 Overview and condition of generation units

5.1 Overview of existing generation units

There are currently 17 operational electricity generation units at the Utility’s main site. Eight of the units run primarily on heavy fuel oil (HFO) and use light fuel oil (LFO) as a secondary fuel for start-up and shut-down. The remaining 9 units run on LFO only. A summary of the existing units is given in Table 1.

Table 1: Summary of existing electricity generation assets on the BELCO site.

Location	Type	Quantity	Primary Fuel	Total generation capacity (MW)
East Power Station	Reciprocating engines	8	HFO	98.9
Old Power Station	Reciprocating engines	4	LFO	27.5
GT Area	Gas turbines	5	LFO	35.5

The total installed net generation capacity of the existing 17 units is 161.9 MW. As shown in Table 1, the units are located in three separate areas on the Utility’s site: The Old Power Station (OPS), the East Power Station (EPS) and the gas turbine area.

Summaries of the technical details of the various engines are provided in Tables 2 to 5. The data in the tables was provided by the Utility and is correct as of the end of January 2017. The heat rate values have been reported by the Utility based on the most recent performance tests conducted on the units, which typically occur after major overhauls.

Table 2: Details of existing reciprocating engines in the EPS operating primarily on HFO.

Unit name	E1	E2	E3	E4	E5	E6	E7	E8
Type	Slow speed recip. Engine	Slow speed recip. Engine	Med. speed recip. Engine	Med. speed recip. Engine	Med. speed recip. Engine	Med. speed recip. Engine	Med. speed recip. Engine	Med. speed recip. Engine
Application	Base load	Base load	Mid-merit	Mid-merit	Base load	Base load	Base load	Base load
Year commissioned	1984	1985	1989	1989	2000	2000	2005	2005
Primary Fuel	HFO	HFO	HFO	HFO	HFO	HFO	HFO	HFO
Secondary Fuel	LFO	LFO	LFO	LFO	LFO	LFO	LFO	LFO
Net generation capacity (MW)	11.7	11.0	9.5	9.5	14.3	14.3	14.3	14.3
Net heat rate (kJ/kWh)	8,934	8,931	8,519	8,517	8,500	8,500	8,235	8,234
Lifetime cumulative running hours (h)	229,181	215,385	184,725	180,123	126,743	125,956	86,036	90,186
Remaining useful life (estimated) (years)	2	2	2	2	13	13	18	18

Table 3: Details of existing reciprocating engines in the OPS operating on LFO only.

Unit name	D3	D8	D10	D14
Type	Med. speed recip. Engine	Med. speed recip. Engine	Med. speed recip. Engine	Med. speed recip. Engine
Application	Mid-merit / two-shifting	Mid-merit / two-shifting	Mid-merit / two-shifting	Mid-merit / two-shifting
Year commissioned	1982	1979	1980	1995
Primary Fuel	LFO	LFO	LFO	LFO
Secondary Fuel	N/A	N/A	N/A	N/A
Net generation capacity (MW)	7.5	7.5	7.5	5.0
Net heat rate (kJ/kWh)	9,140	9,071	9,116	9,718
Lifetime cumulative running hours (h)	205,694	213,660	214,629	55,243
Remaining useful life (estimated) (years)	2	2	2	3

Table 4: Details of existing gas turbines.

Unit name	GT4	GT5	GT6	GT7	GT8
Type	Gas turbine	Gas turbine	Gas turbine	Gas turbine	Gas turbine
Application	Peaking	Peaking	Peaking	Peaking	Peaking
Year commissioned	1989	1995	2010	2010	2010
Primary Fuel	LFO	LFO	LFO	LFO	LFO
Secondary Fuel	N/A	N/A	N/A	N/A	N/A
Net generation capacity (MW)	11.0	11.0	4.5	4.5	4.5
Net heat rate (kJ/kWh)	14,665	14,602	13,646	13,646	13,646
Lifetime cumulative running hours (h)	53,215	34,408	3,247	3,453	3,125
Remaining useful life (estimated) (years)	2	8	23	23	23

The nominal service life of medium and low speed reciprocating engines in continuous operation is about 30 years. When a unit reaches about 27 years of age, the owner must decide whether it is feasible to extend the life of the unit by refurbishing it or replacing the components that are limiting its performance or reliability. Gas turbines of the scale owned by the Utility typically have a service life of between 25 and 30 years.

The ages of the generation units are shown in Figure 5.

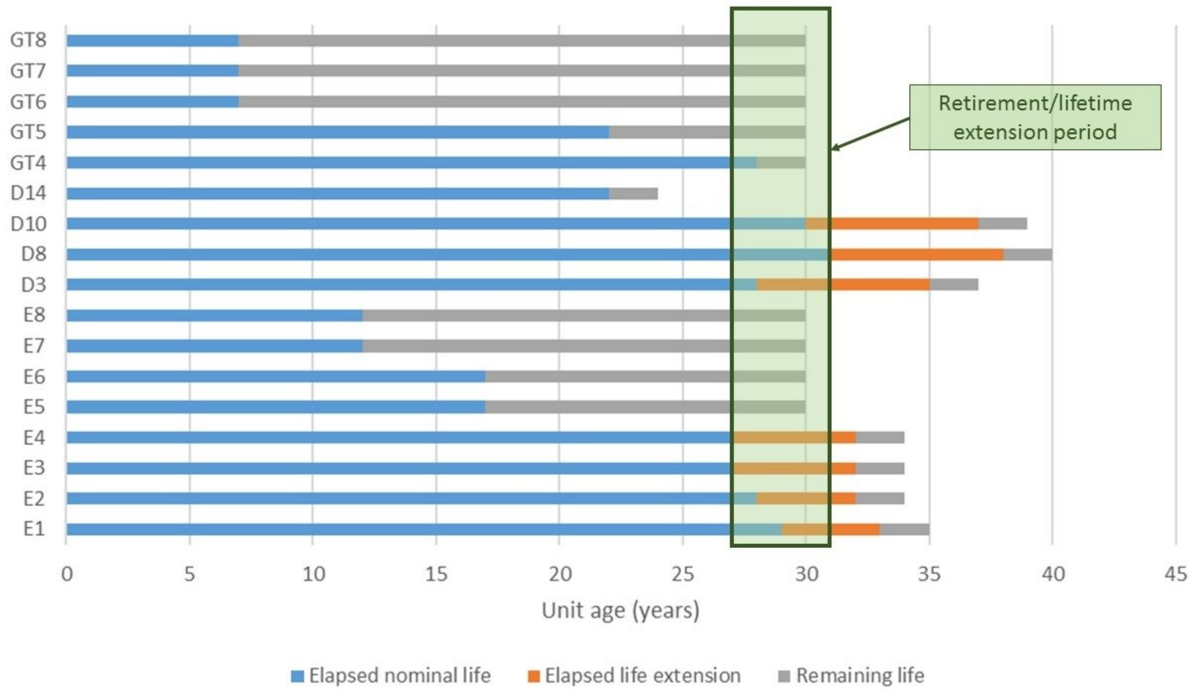

Figure 5: Age of generation units.

The Utility has conducted lifetime extension works on the following units:

- Units E1 and E2: Upgrades of fuel and electrical systems,
- Units E3 and E4: Replacement of cooling water radiator banks,
- Units D3, D8 and D10: Replacement of cooling water radiator banks.

The scope for extending the service life of units and the timing of proposed retirements are discussed in Section 6.2 of this report.

5.2 The Utility's approach to maintenance

The Utility has a well-organised and structured approach to maintenance of its generation units. It takes a reliability-centred approach to maintenance, using operational monitoring of critical plant and analysis to identify systems and equipment that require further investigation and/or maintenance.

Reciprocating engines have a maintenance cycle that includes minor and sometimes intermediate services at hourly intervals recommended by the original equipment manufacturer (OEM) for each model. The maintenance cycles also include major overhauls, where more comprehensive inspections are conducted. The alternators are also typically inspected by the OEMs during outages for major overhauls.

The majority of the work required during services and overhauls is done by the Utility's staff, but overhauls are typically supervised by specialist contractors. The condition of engine components is checked during services and overhauls. Based on the condition, the Utility decides which components should be replaced or reconditioned during that outage or the next outage and makes plans accordingly. In this way, the Utility seeks to maximise the value and service life of all components in an effort to minimise maintenance costs.

The typical durations of outages for minor services and major overhauls are 10 and 30 days respectively. These can be a few days longer depending on the scope of replacement and reconditioning works required on the units. The units are not available to generate electricity during outages.

Performance testing is typically conducted on units after major overhauls and profiles of efficiency against load are developed during these tests.

The Utility has five dedicated staff members whose responsibility it is to plan for and manage scheduled services of generation units and maintenance of auxiliary plant. With 8 base load units each requiring outages every 5 to 10 months and the other units requiring maintenance approximately annually, careful planning and management of the outages is vital to ensure that there is enough generation capacity to reliably meet the island's electricity demand. The planners generally aim to schedule the planned maintenance activities to avoid outages in August so that the full generation fleet can be available in that month.

The Utility has 6 major outages scheduled for 2017 as well as 5 minor/intermediate outages on the reciprocating engines.

5.3 General comments about units more than 25 years old

Figure 5 shows that 8 of the 17 existing units are more than 25 years old. In spite of the Utility's prudent approach to maintenance, wear and tear from constant operation in an environment containing corrosive saline-laden air takes its toll on the generation units. The components of the prime movers themselves are not typically the main source of issues from a maintenance and reliability perspective because they are periodically inspected and maintained in the planned maintenance regime. It is rather issues with the ancillary equipment that are mainly responsible for reductions in the reliability of the units.

Typical examples of ancillary equipment issues faced by the Utility in the case of units that are approaching or in excess of 25 years of age are:

- Failure of control system components,
- Leaks in the jacket cooling water system,
- Leaks in the fuel system,
- Failure of cooling water pumps,
- Failure of fuel oil and lube oil pumps,
- Failure of fuel oil and lube oil treatment systems.

The ancillary equipment can be repaired or replaced, but when units reach a service life of between 20 and 30 years of age, replacement, rather than repair tends to be the most cost effective option. For the 8 units that are older than 25 years, the Utility has had to perform cost/benefit analyses to determine the feasibility of replacing ancillary components. The cost of replacement can be significant, and judgement is required to determine whether the investment is justified for a unit that has only a few years of remaining life. Maintenance costs could escalate if ancillary components were replaced without cost/benefit analyses.

Another issue with equipment older than 25 years is that manufacture has sometimes been discontinued and replacement parts are difficult to obtain. This is a particularly issue for Bermuda considering its remote location. This adds to the cost and lead time associated with maintenance activities.

The Utility seeks to mitigate the risk of sourcing obsolete components by using its own workshops as far as possible and by monitoring the second hand market to identify available spare parts that might be required in the future. This requirement for increased holding of spare parts further increases the maintenance costs.

A related issue is that when old equipment is replaced with new, modern equipment other associated plant also requires upgrading for it to be compatible.

5.4 Common plant and surrounding environment

A canal that runs past the OPS burst its banks in January, causing flooding in the MCC room of the OPS. The MCCs had to be isolated to prevent damage or harm, which rendered Units D3, D8, D10 and D14 unavailable for generation until the MCC room was safely drained. Despite being on the opposite bank of the canal, the EPS does not experience flooding because it is elevated.

A summary of significant upgrades to common plant in the OPS and EPS is given in Table 5.

Table 5: Summary of significant upgrades of common plant in the power stations.

Year(s)	Location	Description
2014	OPS	Upgrade of the Raw Water System
2014	EPS	Upgrade of the Raw Water System
2011	EPS	Installation of a new RO Plant with Electronic De-ionization for engine cooling water system make-up

5.5 Issues with existing generation units

The majority of the issues are associated with the 8 units that are greater than 25 years old (E1 to E4, D3, D8, D10 and GT4) and Unit D14. The units that are older than 25 years all exhibit negative effects associated with age, as described in Subsection 5.3 of this report. In addition, the units experience issues related to the following aspects of their design:

- E1 to E4 – The 13.8kV Main Auxiliary Switchboard (MASB) in the East Power Station, which provides auxiliary power to Units E1 to E4 is old and has limited redundancy provisions,
- E1 to E4, D3, D8, D10 and D14 – The units are rigidly mounted on their foundations without any vibration attenuation,
- E3 and E4 – The concrete seismic blocks are prone to distortion and surface cracking,
- D14 – The unit was intended for emergency back-up and not continuous operation,
- D3, D8, D10 and D14 – Insufficient height of exhaust stack to eject gaseous emissions effectively from the Pembroke basin,
- D3, D8, D10 – Noise from high gas velocity out of the exhaust stack and noisy components on cooling water radiator bank.

5.6 Reliability of existing units

Qualitative evaluations of each unit's reliability are presented in Table 6. These have been determined based on the reviews of their operating characteristics in 2016 (including number of trips and unplanned outages). A "trip" can be defined as "an unexpected shutdown resulting from error(s) in the control/monitoring system or error(s) imposed on the control/monitoring system originating from the environment or people."[1]

Table 6: Summary of qualitative evaluation of unit reliability.

E1	E2	E3	E4	E5	E6	E7	E8
Average	**Average**	**Poor**	**Poor**	**Good**	**Good**	**Good**	**Good**
D3	D8	D10	D14				
Average	**Average**	**Average**	**Very poor**				
GT4	GT5	GT6	GT7	GT8			
Insufficient data	**Poor**	**Good**	**Good**	**Good**			

The 7 units that are less than twenty years old have good reliability, and 5 of the 7 units that have had life extensions have average reliability. Units E3 and E4, which have had life extensions, have poor reliability because they had a total of seven trips between them in 2016 and one of those trips resulted in a major forced outage of E3 in October. As described in Subsection 5.5, Units E3 and E4 have experienced deformation and surface cracking of their seismic blocks, which required outages for realignment of engine components in 2016.

The poor reliability of D14 is mainly attributable to its intended original purpose as a back-up emergency generator rather than for continuous operation.

GT5 has poor reliability because it is approaching 22 years of operation, which is relatively old for a small gas turbine. As a peaking unit, it is idle for extended periods, which makes it susceptible to accelerated corrosion. GT4 was operated for insufficient time in 2016 to make a judgement on its reliability, but the Utility is attempting operate without the unit in 2016/2017 in preparation for its retirement.

5.7 Approach to operation

The generation units are generally operated by staff located in control rooms in the vicinity of the units. The local operators are coordinated from a central generation control room and are responsible for the start-up, shut down and stable running of the units and their ancillaries. When the units are synchronised to the grid, loading of the units is controlled remotely from the central grid operations centre (GOC) to meet the island's electricity demand. The GOC does not have control of any aspects of the units other than their load.

[1] Adapted from IADC (http://www.iadclexicon.org/spurious-trip/)

The units are typically operated at between 80 and 85% of their capacity so the units are not being overstressed and this approach also provides sufficient spinning reserve for units to respond rapidly if another operational unit trips unexpectedly. The Utility aims to have spinning reserve equivalent to approximately 14.3 MW, which is the capacity of the largest units on the site (E5 to E8).

The Utility takes a least-cost approach to dispatching, using commercial software (Plexos®) to model the optimum combination of unit loads for different levels of demand. The model is run by staff in the Utility's generation team and is sent to the GOC each day in advance, taking known current outages into account.

Units E5 to E8 are capable of black starting in the event of an island-wide grid event.

6 Outlook and risks to the grid of unit retirements

6.1 Short term outlook for electricity supply

As shown in Figure 5 (Subsection 5.1) of this report, 9 of the 17 units are planned for retirement by the end of 2019. This section discusses the implications on the electricity grid if all of the older generation units are retired.

The Utility attempts to manage its generation portfolio with a capacity margin of 3 times the capacity of the largest installed unit. That is, the Utility aims to have 42.9 MW (3 x 14.3 MW) of capacity in excess of the peak loading requirement. This is equivalent to a capacity margin of 44.6% on the 2016 peak load (112 MW), which is relatively high compared to other markets. The higher-than-usual margin is because the capacity of largest generators each represent a relatively high proportion of the peak demand (12.8%).

This margin has been selected to ensure security of supply in a worst case scenario where i) a large unit trips during a period of peak demand while ii) another large unit is undergoing planned maintenance and iii) allowing for a 14.3 MW spinning reserve to prevent black-outs while stand-by units are brought online. This is a form of N+3 redundancy on the peak capacity.

Figure 6 indicates the projected generation capacity for 2017 to 2020 assuming that the 7 units are retired as planned without installing new generation units.

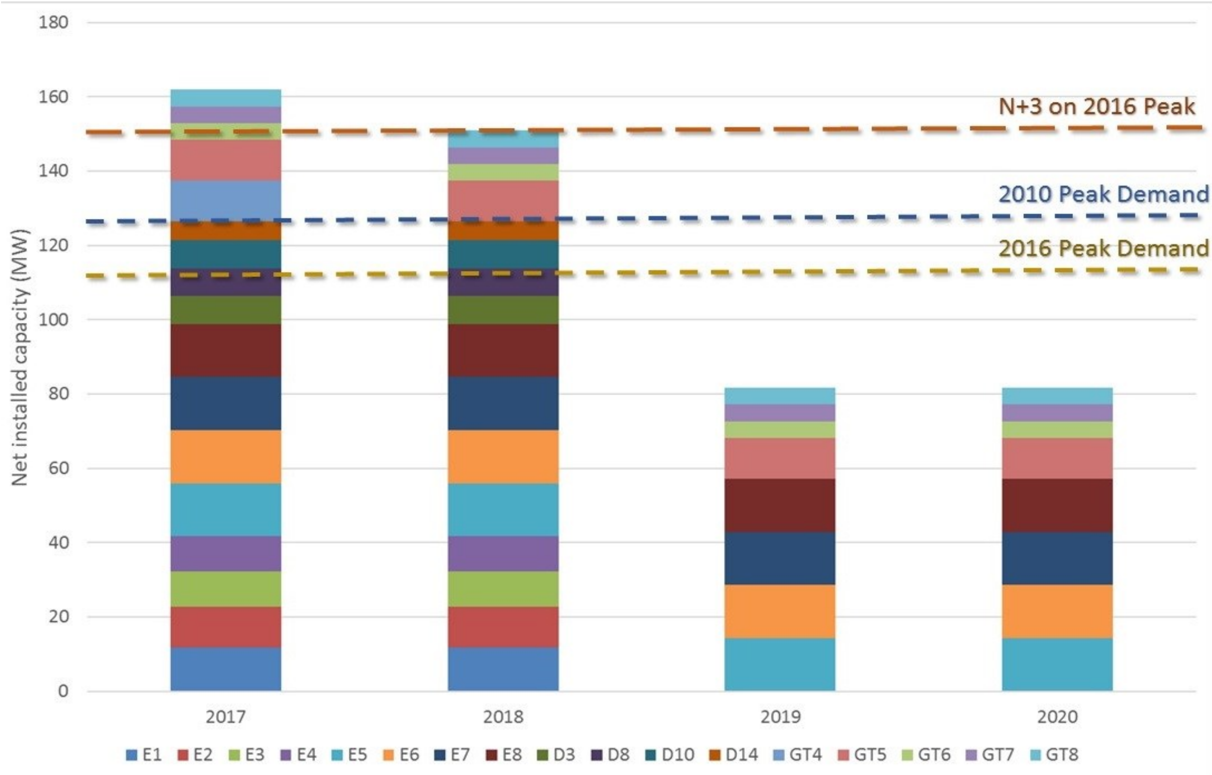

Figure 6: Projected generation capacity from 2017 to 2020 without investment in new units.

The column in 2018 is slightly lower than for 2017 because it has been assumed that GT4 will be retired early in the course of 2017/18 since the Utility is already attempting to operate without it. There is a dramatic decrease in installed capacity from 2018 to 2019 because it is in this period that the other 8 units are planned to be retired (E1 to E4, D3, D8, D10, D14).

The peak demand values for 2016 and 2010 (representing the highest peak demand on record) have been superimposed on the columns to indicate the level of generation that would be required. The additional 42.9 MW (N+3) reserve margin on the 2016 peak demand is also indicated in the figure. It is clear that the installed capacity will adequate to meet the Utility's capacity margin requirements in 2017 and 2018, but that the installed capacity would only make up 72.3 and 66.5% of the peak demands in 2016 and 2010 respectively.

There is clearly a need to assess the options available to ensure that there will be adequate generation capacity installed to satisfy the island's demand for electricity beyond 2019.

The Utility is proposing to install five new generation units in 2019, comprising of 4 reciprocating engines with 14.3 MW capacity each and 1 additional gas turbine with 4.5 MW capacity. The group of 4 new reciprocating engines is provisionally known as the "North Power Station" (NPS) and the gas turbine as "GT9". Figure 7 indicates the projected generation capacity in 2019 and 2020, assuming that the NPS and GT9 are installed on schedule as planned.

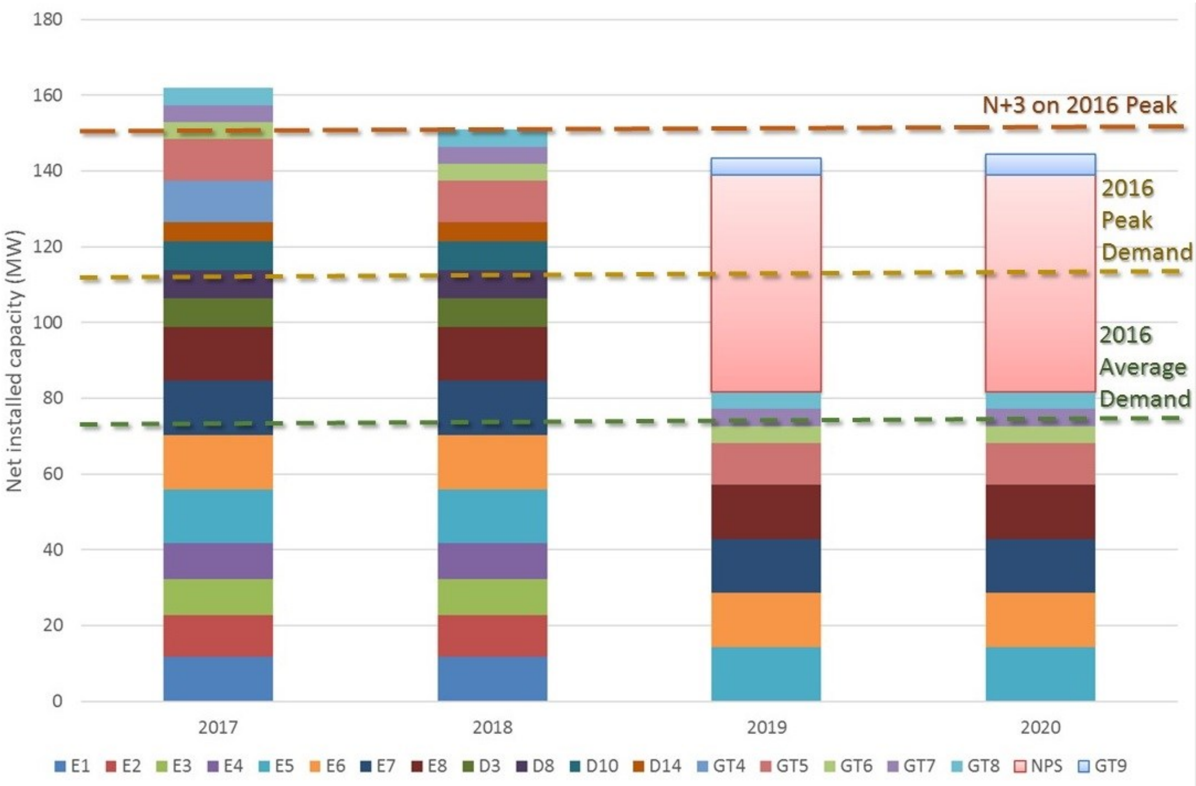

Figure 7: Projected generation capacity from 2017 to 2020 assuming installation of NPS and GT9.

With the NPS and GT9, the Utility's total installed capacity will be 143.4 MW. This would provide a capacity margin of 31.4 MW (28%) over the peak demand in 2016, which is less than the Utility's standard of 42.9 MW.

The outlook for electricity generation capacity in Bermuda must account for the liberalisation of generation as described in the Government's National Electricity Sector Policy of 2015 and the Electricity Act of 2016. At present, 2 significant generation facilities are planned in addition to those owned by the Utility. Firstly, the existing Tyne's Bay waste-to-energy plant will be upgraded to export about 3 - 4 MW to the grid (up from 1 to 1.5 MW at present). Secondly, the Government is in the process of procuring a new solar farm with a peak capacity of 6 MW, which will be owned by an independent power producer. It is understood that the solar farm will not be provided with electricity storage facilities, so the actual output will vary depending on the solar irradiance and will drop to zero at night.

It should be noted however, that the electricity generated at Tyne's Bay and the new solar farm will be subject to output fluctuations that are out of the control of the Utility's GOC. As the entity responsible for guaranteeing security of electricity supply in Bermuda, the Utility is unlikely to consider these generators as firm capacity in their margin calculations.

6.2 Scope for delaying retirement of existing units

Before conclusions are drawn about the need for investment in new generation plant, it is necessary to consider whether there is scope for the Utility to delay the retirement of its existing units. This is discussed for the various unit groups in the paragraphs below. Final conclusions are presented in Section 0 of this report.

6.2.1 Scope for delaying retirement of E1 and E2

Units E1 and E2 are 32 and 33 years old respectively, having upgraded key equipment to extend their lives in 2013. They currently have average reliability, but they are more mechanically complex than the newer units and hence more expensive to maintain. They are also rigidly mounted to their foundations, which is likely to aggravate wear and tear of components.

They would require significant investment in the following aspects to extend their service lives further:

- New switch gear,
- New control (PLC) hardware,
- New main transformers, and
- New cooling water radiator banks.

Although the costs associated with these upgrades are not available, it seems unlikely that it would be feasible to make such significant investment for units that have already exceeded their nominal service life. These units are therefore **not good candidates for further life extension**.

6.2.2 Scope for delaying retirement of E3 and E4

Units E3 and E4 are both 28 years old, having had service life extensions in 2012. They currently have poor reliability and have ongoing issues with deformation and surface cracking of their seismic blocks.

These units would require significant investment in the following aspects to extend their lives further:

- New switch gear, and
- New control (PLC) hardware,

If these units were retained and Units E1 and E2 were retired, then it is likely that spare parts for the switch gear and PLC could be obtained from E1 and E2 to sustain Units E3 and E4 for a few more years. **These units could be considered as candidates for limited life extension to act as support generation** if required as a last resort. It is unlikely that they can be relied upon for base load operation beyond the next few years and would have significantly higher operation and maintenance costs than new plant.

6.2.3 Scope for delaying retirement of D3, D8 and D10

Units D3, D8 and D10 are 35, 38 and 37 years old respectively, having had lifetime extensions in 2010. They currently have average reliability, but are also rigidly mounted to their foundations, which is likely to aggravate wear and tear of components. They are also sources of noise and gaseous pollution that affect the Utility's neighbours. In addition, the OPS where they are housed is susceptible to flooding.

They would require significant investment in the following aspects to extend their lives further:

- New main transformers,
- Repair of the crankcase and grouting of D3, and
- Rewinding of the alternator of D10.

Units D8 (and D10 if the condition of alternator does not degrade further) might be considered for limited life extension to act as support generation if required as a last resort. These would have significantly higher operation and maintenance costs than new plant.

6.2.4 Scope for delaying retirement of D14

Although D14 has only been in operation for 22 years, it has very poor reliability and low thermal efficiency because it was not designed for continuous operation. It is also a source of noise and gaseous pollution that affect the Utility's neighbours. In addition, the OPS where it is housed is susceptible to flooding.

If it is retained in operation beyond 2019, failure of PLC components would be an ongoing risk due to obsolescence of equipment. However, spare parts from E1 and E2 would be available after retirement. **It is plausible for Unit D14 to be retained in its current role supporting generation at times of high demand**, but it will continue to be unreliable and have high operation and maintenance costs.

7 Conclusions

The following conclusions are drawn from the preceding discussions in this report.

1. New electricity generation capacity is required as a matter of urgency to replace the generating units that are planned for retirement in the next two to three years. Without new generation capacity, the security and reliability of Bermuda's electricity supply could be at risk in periods of high demand. If it had sufficient alternative generation units available, the Utility would retire 9 of the existing 17 generation units by 2019 due to unreliability and increasing maintenance costs.
2. There is limited scope to extend the life of 5 of the 9 units that are planned for retirement, but additional investment would be required to address existing issues. This is likely to require investment in new ancillary equipment that will only be in service for a few years. Even with such investment, the units would probably not be suitable for continued operation in a base load application and would be expected to continue to degrade in terms of performance and reliability. Ongoing maintenance costs would also be high.
3. The capacity margin will be lower than the Utility's target level of 42.9 MW, assuming that the new units are brought online in 2019 and if all 9 units are retired as planned. This could pose a risk to security and reliability of supply if there is a forced outage during planned maintenance of a large unit. It is therefore recommended that the Utility should conduct a feasibility study and cost-benefit analysis to determine which of the older units can be kept operational to support electricity generation beyond 2019.
4. It is suggested that Units E3, E4, D8, D10 and D14 could be considered as candidates to provide emergency back-up capacity, but the final decision should be based on a comprehensive cost-benefit analysis.

Ricardo
Energy & Environment

The Gemini Building
Fermi Avenue
Harwell
Didcot
Oxfordshire
OX11 0QR
United Kingdom

t: +44 (0)1235 753000
e: enquiry@ricardo.com