MINISTRY OF SCIENCE, ENERGY & TECHNOLOGY

Integrated Resource Plan
A 20 Year Roadmap to Sustain and Enable Jamaica's Electricity Future

Draft, 8 January 2020, revised 20 January 2020

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2	**Transmission and Distribution Update**	**10-26-18**	**Steve Dixon**		
3	**Generation Update**	**11-5-18**	**Omar Stewart**		
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11	**Final IRP Document**				

Message from Honorable Fayval Williams, Minister of Science, Energy and Technology

The Ministry of Science, Energy and Technology (MSET) is pleased to provide limited release of the 2018 Integrated Resource Plan (IRP). This document provides a summary of the Preferred Portfolio of electricity resources describing a roadmap for resource mix in Jamaica over the next 20 years.

This IRP was developed with substantial collaboration with Jamaica Public Service, the Office of Utility Regulation, Independent Power Producers, customers, businesses and industry leaders, academia, and other stakeholders impacted by Jamaica's investment in its electricity future. The involvement of passionate and informed people with different views and priorities was an important part of the process. We thank those involved for contributing to a reliable, diverse, environmentally friendly, fiscally prudent and sustainable energy future.

Message from Mrs. Carol Palmer, CD, JP, Permanent Secretary

The Integrated Resource Plan provides a roadmap consistent with the objectives described in the Jamaica National Energy Policy: low cost and reliable electricity solutions for customers, a modern and resilient electricity grid, improve sustainability of indigenous energy resources, less reliance on imported energy resources, electricity grid efficiency and lower carbon footprint.

The process of developing the roadmap recommendations is the product of an enhanced governance and regulatory environment and stakeholder's collaboration. The Integrated Resource Planning Team collaborated in their efforts to produce an electricity roadmap with specific action items.

The summary Preferred Portfolio of electricity resources described herein provides guidance on future direction with respect to policy. We are looking forward to the necessary investments to make the recommendations in order to create organic job growth from lower electricity prices and stimulus from new investments to create new jobs. The resulting lower carbon footprint will enhance business climate and tourism. We look forward to working with our stakeholders to create a new sustainable future for energy.

Acknowledgements

The Integrated Resource Plan (IRP) requires extensive efforts from agencies and stakeholders to obtain data, ensure objectives are well defined and provide analytics and support. The dedicated individuals and teams below ensured that the IRP was successful.

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- Dr. Andrew Isaacs, University of Technology
- Mr. Carlos Albero, DNVGL

The IRP Technical Working Group and the Customer and Stakeholder Groups

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Glossary

Terms Defined	Abbreviation
Automotive diesel specification as fuel for generators	ADO
Barrels of Oil Equivalent	BOE
Biomass is a generation technology which converts agriculture waste projects into electricity	Biomass
Demand Side Management	DSM
Energy Efficiency	EE
Energy Information Agency of the US Department of Energy providing forecasts for the study	EIA
Gross National Income	GNI
Government of Jamaica	GoJ
Gigawatt hours or thousands of megawatt hours generated or consumed in the course of a year	GWH
Heavy Fuel Oil consumed in power plant generation specified by percent sulfur by weight.	HFO
Hydroelectricity generation using water flows to turn a generator turbine	Hydro
Wind and Solar generation which injects electricity into the electric grid without supplying inertia, or spin, to the system. Inertia is important to ensure reliable operation.	Inverter
Independent power producers who contract to produce electricity for Jamaica	IPP
Integrated Resource Plan for this document is defined for the electricity sector	IRP
Jamaica Public Service Company	JPS
Liquefied Natural Gas as an imported fossil fuel imported to Jamaica in tankers and re-liquefied to be burned as generator fuel	LNG
Long Term Avoided Energy Cost is the benchmark under which JPS can exercise the option to build generation	Long Term Avoided Cost
Ministry of Science, Energy and Technology	MSET
National Energy Policy	NEP
Natural Gas Combined Cycle a gas fired generator configuration which uses simple cycle generators and a steam generator to create a more fuel-efficient electricity generating source.	NGCC
Office of Utilities Regulation	OUR
Power Purchase Agreement	PPA
Preferred Portfolio: from the various forecast scenarios, the resource and transmission mix which best meets the objectives	Preferred Portfolio
Project Sponsor	PS
Photovoltaic electricity generation using solar radiation to produce electricity	PV, Solar
Quality of Service	QoS
Right of First Refusal, JPS' option to build electricity resources at lower than proposed levelized cost offered by a third party	ROFR

Short Run Avoided Cost is the short run ability to reduce supply of generation costs for the marginal resource	Short Run Avoided Cost
Transmission (above 69kV) and Distribution (below 69 kV) network used to convey electricity generation from source to load sinks	T&D
Transmission avoided cost is the cost to avoid network upgrades by locating resources nearer load centers or avoiding expensive transmission upgrades	T&D Avoided Cost
Capital upgrades which ensure efficient and controllable resources operate on the transmission and distribution system according to reliability standards	T&D or Network upgrades
Fossil fuel generation which provides inertia to the electric grid	Thermal Capacity
United States Dollars	US$
Renewable energy resources including hydroelectric, solar PV, wind, biomass and Waste to Energy	RE
weighted average cost of capital	WACC
Waste to Energy is a process of creating electricity from municipal waste streams	WTE

1. Executive Summary for the Jamaica 20 Year Integrated Resource Plan

1.1. Introduction

Jamaica is the third largest island in the Caribbean region with an area of 11,000 square kilometers (km^2) and a population of 2.72 million people. Jamaica produces very little energy from indigenous resources, relying primarily on fossil fuels imports that averaged 20.4 million Barrels of Oil Equivalent (BOE) per annum from 2010 to 2015. Jamaica's average electricity tariff of US$0.27 per kWh in 2015 is primarily due to electricity generation that still depends on old, inefficient Heavy Fuel Oil generators that run on expensive imported oil and a transmission and distribution system that continues to experience high technical and non-technical losses. This high level of energy imports exposes Jamaica to the impact of international oil price fluctuations and significantly weakens Jamaica's ability to make payments against its financial debts while placing additional pressure on other financial needs of the country.

The Government of Jamaica (GOJ) has made concerted efforts to push for diversification of the energy matrix. With over 119MW of additional renewable energy generation commissioned into the electricity grid and liquefied natural gas (LNG) - based generation expected to grow in the medium-term, the challenge in Jamaica will be how to manage the influx of new technologies for the electricity grid. Addressing this challenge will require grid upgrades to transmit additional energy without sacrificing quality standards, improved interconnection requirements applicable to different generation technologies, and new mechanisms to increase overall operational efficiency. Planning for these upgrades while minimizing costs to consumers and is an important part of Jamaica's overall strategic goal for the energy sector.

This document describes the preferred resource mix over the next 20 years which meets reliability of service, reduced cost of operation, fuel source diversity, electric grid flexibility and lowering of environmental (carbon) footprint, which are among the objectives expounded in Jamaica's National Energy Policy 2009-2030[1]. This Integrated Resource Plan (IRP), which is the electricity investment roadmap for Jamaica over the period 2018 – 2037 provides information concerning the process followed in developing and analyzing the preferred electricity resource mix and how this electricity resource mix meets the objectives stated. As new information and technologies become available, results will be analyzed relative to the resource mix and infrastructure investments required. Conclusions and next steps are also provided.

1.2. The Integrated Resource Planning Process

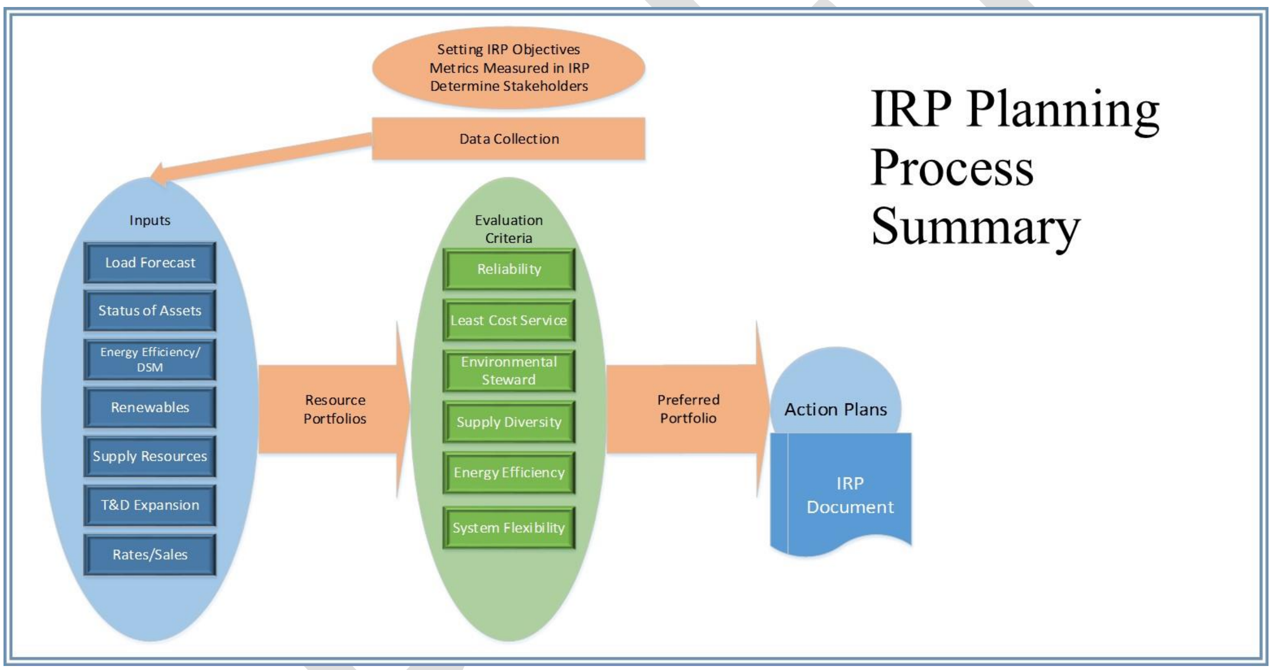


Figure 1: Steps in the Integrated Resource Plan Process

To develop the Integrated Resource Plan for electricity, the following steps shown in Figure 1 were taken as described below:

[1] https://www.mset.gov.jm/sites/default/files/National%20Energy%20Policy_0.pdf.

Setting IRP Objectives: Relative to Jamaica's Energy Policy, goals for the Preferred Resource Mix and Transmission portfolio were elaborated. For each goal, metrics were established. The IRP will guide Jamaica's Stakeholders[2] with options for the development of electricity sector over the next 20 years. Broad goals established by Jamaica's National Energy Policy serve as a compass in developing the plan. The Policy sets a target of overall 20 percent of energy from renewables, including 30 percent renewable electricity share by 2030 and for which progress has been made to date. Moving from a baseline of 4.5 percent renewable electricity in 2008 to 11 percent of electricity needs from renewable sources in 2018 is considered impressive, but more can be accomplished with lower capital costs over time as well as lower operating costs for renewables. Further development of its diverse renewable resource endowment of solar, wind, hydro and biomass, will allow Jamaica to comfortably achieve over 30% percent of its total anticipated electricity demand by 2030.

Inputs: Data was compiled and reviewed with the Integrated Resource Planning Team, and further analyzed in a model to compare the impacts of different scenarios and assumptions. Different forecast assumptions required sensitivities to determine the impact on resource mixes. In order to meet future Load demand, a twenty-year load forecast with different potential growth patterns was developed and analysed, taking into consideration that Demand Side Management/Energy Efficiency initiatives may alter load patterns over 20 years[3]. Renewable resources and new technologies (such as energy storage) may become viable over the next 20 years planning horizon. Over time, current assets may retire, power purchase agreements may expire, or different transmission configurations may be required to transport electricity. Customer rates (both retail and wholesale customers) are likely to be impacted by new or different types of grid investments, requiring data collection and

[2] Stakeholders are all ratepayers and third parties impacted by the electricity sector.
[3] How Demand Side Management/Energy Efficiency Programs impact the Preferred Portfolio are explored in future scenarios.

analyses. To incorporate these future uncertainties, three sensitivities were proposed and evaluated, being 1) a most likely economic growth sensitivity with most likely fuel prices; 2) a high economic growth sensitivity with low fuel prices; and 3) a low economic growth scenario with high fuel prices[4]. Several different sensitivities related to future options, reserve requirements and resource mix parameters were also investigated.

Resource Portfolios: All "Potential Capacity Expansion" resources and potential transmission corridor upgrades were based upon most recent or feasibility study configurations. Capital costs, fixed operating and maintenance cost and variable costs for "Potential Capacity Expansion" generators were based upon feasibility studies or US Energy Information Agency (EIA) forecasts. "Potential Capacity Expansion" generators were assumed to interconnect to the transmission grid where there is sufficient line capacity to ensure that the rated capacity could be used to meet load requirements. Later, network upgrade costs were added to derive total system costs.[5] Thermal generation resources were dispatched according to costs and operating constraints and variable resources were forecasted.

Evaluation Criteria: As noted in Figure 2 below, six main objectives for the electricity sector were identified from the Jamaica Energy Policy alongside priorities and metrics used in the Integrated Resource Plan.

[4] PLEXOS software (owned by Energy Exemplar) was used to calculate and compare impacts in the Integrated Resource Plan. Demand Side Management/Energy Efficiency programs will be developed as data becomes available.
[5] Good utility practice requires that all new interconnections be evaluated for equipment costs to support power flows, feasibility and voltage requirements. Jamaica is using DIgSILENT's Power Factory software for this analysis.

Evaluation Criteria for Scenarios

The IRP finds the "best" resource mix to meet demand for the next 20 years

#	Objective Described	What it Means?	Initial Weight	Metrics
1	Reliable Energy Supply Chain	Minimize Disruptions	25%	Reserve Margins {1}
				Loss of Load Probability {2}
				Unserved Energy {3}
				Transmission Shadow Price/Losses {4}
2	Diversity of Supply	Vulnerability to Disruption	25%	Renewable Energy Share {5}
				Fossil Fuel Percentage {6}
3	Least Cost Electric Service	Reduce Customer budgets	16.50%	Change in system operating cost {7}
				Rates Charged {8}
				Short Run Marginal Cost {9}
4	System Flexibility	Ability to meet a wide range of outcomes	16.50%	Minimize difference in various scenarios run (High, Medium, Low) {10}
5	Grid Efficiency	Reduce losses	8.50%	Average System Heat Rate {11}
				Technical Losses {12}
6	Environmental Stewardship	Minimize environmental footprint	8.50%	Reduce CO2 air emissions {13}

Figure 2: Evaluation Criteria for Resource Portfolios

The relative importance of each objective was discussed and ranked to provide focus (initial weights) and to help determine trade-offs[6]. The measurement of the objectives was then identified to quantify progress in meeting the goals:

1. Reliable Energy Supply Chain (minimizing disruptions) was chosen initially as a high priority objective of the Integrated Resource Plan measured by Reserve Margins[7], Loss of Load Probability and Customer Supply Disruptions (initially weighted by 25%). Metrics include:

   {1} Reserve margins are defined the North American Electric Reliability Council as a traditional measure of resource adequacy to meet peak load requirements given variations in load and grid operating conditions and measured as a ratio of excess generating capacity to forecasted peak load.

[6] MSET was used to set initial priorities/sensitivities. Future scenarios may be the result of focus groups.

[7] Additionally, synchronized spinning reserves are also required.

{2} Loss of Load Probability is the probability that load will exceed the capacity of resources. The reliability threshold is 2-3% per year based upon standards set by the North American Electric Reliability Council.

{3} Customer Supply Disruptions are approximated by energy not served across the electric grid[8].

{4} Transmission Shadow Price is the marginal cost of transmitting 1 more MW on the grid. The shadow price is a measure of congestion on the transmission grid. The higher the shadow price and congestion, the more likely additional transmission is required. Technical losses are measured within the transmission analysis power flow tools, representing which resource mix and placement reduces technical loss on the system.

2. Diversity of Supply (vulnerability to disruption) was initially chosen as an equally important objective of the Integrated Resource Plan measured by the extent of alternative generation fuel sources and share of distributed generation/back up generation capacity (initially weighted by 25%). Metrics include:

{5} Share of generation met by renewable resources: hydroelectric, wind, solar, waste to energy and biomass.

{6} Fossil fuel used by generators.

3. Least Cost Electric Service (least impact to electricity customer budgets) was chosen as an important objective of the Integrated Resource Plan measured by the net present value of variable costs and capital costs of the Integrated Resource Plan (initially weighted by 16.5%). Metrics include:

{7} Average nominal operating cost over time (total system cost over 20 years).

{8} Average customer rate impact.

[8] Future direct customer metrics include customer outage duration and frequency.

{9} Short run marginal costs of supplying generation (cost to supply and incremental MWh).

4. System Flexibility (most stable across alternative fuel and economic outlooks) is measured as the set of demand and supply side resources and grid updates which provides the most consistent set of outcomes across scenarios (initially weighted by 16.5%). Metrics include:

{10} Difference in high, medium and low scenarios to demonstrate ability to meet different grid conditions.

5. Energy Efficiency (efficiency of generation and transmission/distribution system[9]) measured as the sum of losses across the system (initially weighted by 8.5%). Metrics include:

{11} Heat content of fossil fuel divided by generation.

{12} Technical losses from the impacts on power flows.

6. Environmental Stewardship (minimizing the environmental footprint) measured by the impact on air emissions from electricity generation. Other considerations such as coastal management policy and spill/remediation probability as well as water cooling use in generation is beyond the current scope of the Integrated Resource Plan (initially weighted by 8.5%). Metrics include:

{13} CO_2 emissions per year. Future IRP efforts will include other air emissions.

Preferred Portfolio: After evaluating various scenarios during the process, a Preferred Investment Portfolio for electricity generation capacity was chosen which best meets the objectives identified. Thereafter, transmission analysis was conducted on the preferred portfolio to determine the least cost transmission plan for the preferred portfolio of generation resources.

[9] Future scenarios will incorporate broader measures of energy efficiency as well as distribution network efficiency.

Action Plans: To ensure a successful implementation of the Preferred Portfolio, several action items in support of the IRP as well as for future plans were identified.

IRP Document: A final IRP report will describe the generation, transmission and distribution plans and implications for future investment needs and tariffs across customer classes.

1.3. Objective for the 20 Year Future Resource Mix

To obtain the resource mix which meets various objectives, the IRP Team minimized total system costs subject to a variety of reliability constraints and reported metrics to meet the objectives described above.

- Minimize the Net Present Value of the following system costs:
  - Capital Cost for new units either from feasibility studies or from capital costs published by the U.S. Energy Information Agency (EIA) discounted at the chosen long term cost of capital
  - Variable Production Cost, including fuel and variable operating and maintenance costs at the generation plant sites. Sources for the data are actual plant operations, feasibility assessments and the EIA.
  - Fixed Operating and Maintenance Cost are various costs which do not vary with plant operations, but are required to sustain generation and transmission performance. Sources for the data are actual plant operations, feasibility assessments and the EIA.
  - Costs of obtaining/using reserves for contingencies. Contingencies are required by good utility operating practices. Generation Units not being used to meet hourly energy requirements are held in reserve (synchronous and planning) in sufficient quantity to meet those contingencies. The choice of which resources to use for reserves depends upon grid conditions but are co-minimized as part of the cost to serve energy.

  - Unserved Energy multiplied by the Cost of Unserved Energy is a penalty for not supplying energy to meet load based upon resources available. Planning requires the amount of unserved energy to be minimized. There are conditions under which load cannot be served, so these are investigated in order to inform the results. The cost of unserved energy used was $3500/MWh in real 2017 dollars.
- Subject to various conditions for meeting energy requirements in a reliable manner:
  - Generation = Load (including losses) + Unserved Energy: under this condition, generation is required to either meet forecasted load including losses or is listed as unserved energy and is tracked and reported. Losses are comprised of both technical (due to transmitting electricity over transmission lines) and non-technical.
  - All resources cannot produce more than maximum capacity: this constraint ensures that cheaper resources are not used more than their designed capacity. In addition, resources must meet transmission system transfer capacity limits.
  - JPS owned asset beyond their useful life are considered for economic retirement; this constraint will result in retirement decisions for utility generation units when those assets are not used in dispatch and similarly Independent Power Producers at the expiration of power purchase agreements for contracted resources.
  - New units require three years lead time on average to come on line but for some resources the timelines could be less than two years: this constraint reflects the lead time to bring new units on line, to study interconnections, obtain right of way and construct appropriate equipment.
  - No restrictions on Potential Capacity Expansion resource number of units sited (must be able to have full capacity injected into electric grid without transmission upgrades): this condition constrains both siting potential and is flexible enough to add resources that are low in cost and meet other objectives.

- LNG fuel prices for the IRP study period were developed using World Bank Forecast for Henry Hub Prices along with other sources such as the US EIA Forecast: this constraint assumes that fossil fuel prices are not impacted by Jamaica fuel use.
- Must maintain 20 percent of peak as firm capacity down from 25 percent due to siting of more reliable assets: to manage contingencies on the electric grid, JPS is required to have certain amount of capacity to ensure sufficient resources.
- Transmission capacity must be sufficient to transport energy to meet load. If not, additional transmission capacity investments will be required.

1.4. Summary of Results for the Initial Base Reference Case

The Base Reference Case results (not including transmission analysis) which minimize total system cost subject to the constraints are shown in Figure 3. It summarizes how the Base Reference Case impacts the objectives and metrics of the IRP electricity road map.

Objective Described	Reliable Energy Supply Chain				Diversity of Supply	Least Cost Electric Service		System Flexibility	Grid Efficiency		Environmental Stewardship			
Initial Weight	25%				25%	16.50%		16.50%	8.50%		8.50%			
Measures	Reserve Margin	Loss of Load Probability	Unserved Energy (GWh)	Transmission Shadow Price ($/MW)	Renewable Energy Share (%)	NPV Capital Costs (US$M)	Reduction in System Operating Cost (US$M)	Minimize Difference in Various scenarios	Average System Heat Rate (%)	Technical Losses	Reduce CO2 Air Emissions (%)			
Metric	Average from 2018-2037	Maximum (2018 - 2037)	Maximum (2018 - 2037)	Maximum Annual	Minimum Renewable Portfolio Standard by 2030	20 year NPV sum of Capital cost (millions)	Reduction in Average Total System	Qualitative	Improvement using Renewables	% Loss from Power Flow	20 Year Reduction			
Target	20% or 25%	2%	Zero	Avoided Cost of Generation		Minimum	Maximum	Least Difference in Scenarios	Maximum	3%	Maximum	Generation Capacity Sited (MW)	Retirements (MW)	Optional Transmission/ Storage
Reference Case 20% Reserve Margin N-1 Contingency	30%	1.10%	22.34	0.28	35% by 2030/41% by 2037	477		N/A	39%	N/A	49%	1610	485.2	3 Lines/2 Trans/No Storage
Implementation Plan of Updated Reference Case (2022 VRE MW Expansion spread over 2022 to 2027)	25%	0.70%	0	0.10	31% by 2030/49.4% by 2037	353		N/A	50%	N/A		1664	485.2 #	1 New Line/ 3 Reconductered Lines/11MVA Cap Banks/1 80MVA Trans/ 140MVA Storage

Figure 3 Summary Results of Reference Case

Minimize disruption and maintain system reliability:

- To minimize disruptions and maintain system reliability, a reserve margin of 20 percent of peak demand was required at all times[10]. The results show a Reserve Margin averaging 30 percent over the time horizon, exceeding requirements[11]. By minimizing total system cost to meet both energy and minimum capacity constraints, the low-cost mix uses newer, more efficient resources in energy dispatch as well as the capacity for firm reserves. New fossil fuel resources can meet both requirements. The new resources are more efficient than some resources, displacing higher cost resources in dispatch.
- Unserved energy observed during the 20-year resource plan was about 22 GWh, implying that some demand was not met by generation, triggering further transmission reliability analytics to reduce the level of unserved energy. Ensuring that all energy demand is met is an important result in the 20-year resource plan.
- The maximum annual transmission shadow price (cost of moving an additional MW through the electric grid) was quite small and lower than additional generation costs, indicating little congestion on the system. Technical losses (or the losses due to transmitting energy on the electric grid) was calculated with additional transmission reliability analysis.

Reduce Vulnerability to Disruptions by using Jamaica renewable resources to meet load obligations:

- Fossil fuel imports can create potential supply chain disruptions, increasing the vulnerability of generators using those fuels. In all sensitivities, siting renewable

[10] Reserve Margins are defined as firm capacity. New scheduled additions in 2019 increase reserve margins above 20%.
[11] Future scenarios may increase capacity in smaller increments.

resources reduced fuel consumed by generators. In the initial Base Reference Case, 35 percent of generation (and net load) in 2030 is met through renewable resources such as solar, wind, hydroelectric, waste to energy and biomass. By 2037, 41 percent of generation (and net load) is met with renewable mix.

- The projected new capacity sited is shown for the initial Base Reference Case in Figure 4. Of the 1630.0MW of new capacity sited, 959.0MW (or 59%) is wind/solar; 597.0MW (or 37%) is fossil fuel capacity to meet the 20 percent reserve margin and displace older, less efficient generation; and biomass, hydroelectric, and waste to energy comprise the remainder.

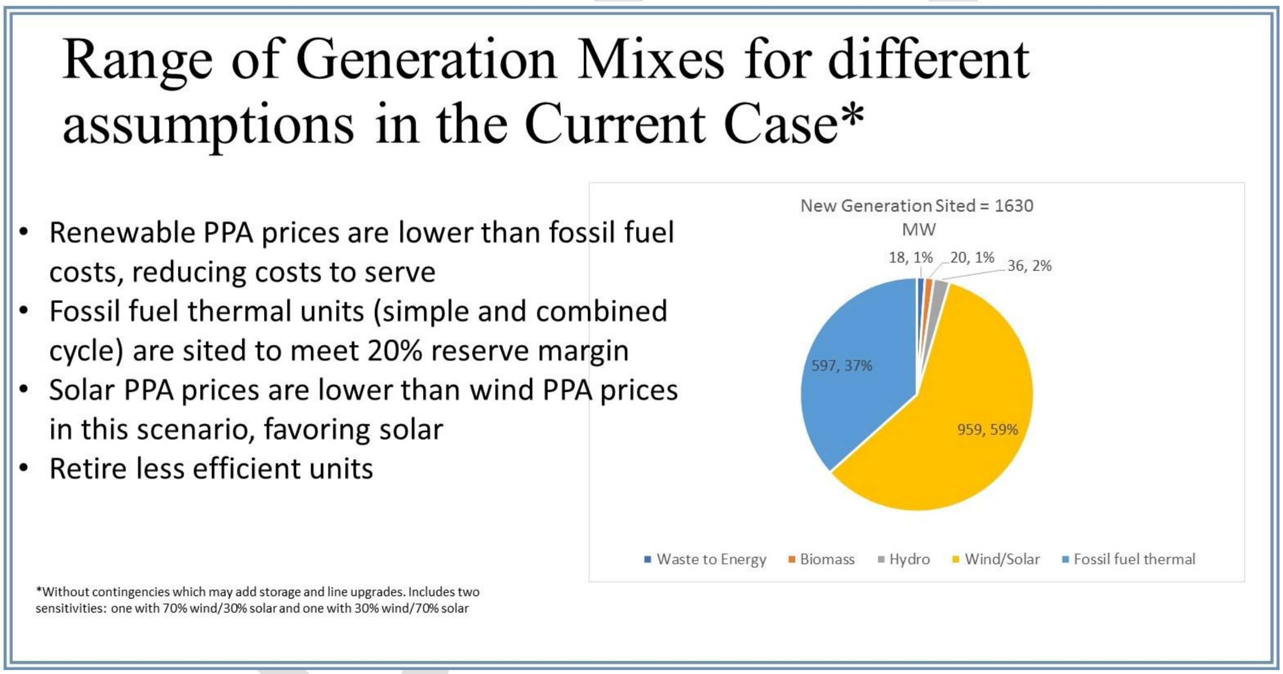


Figure 4: Initial Base Reference Case New Capacity Sited over 20 years

- For the initial Base Reference Case, older generation owned by JPS could retire if uneconomic and replaced by newer, more efficient generation if the efficiency savings were higher than capacity cost for the new units. Contracted generation (IPPs) could only be replaced after contract expiry. Candidate fossil units include both simple and combined cycle units burning natural gas with different fuel start up types and costs.

Reduce Customer Costs:

- In the long run, total system operating cost and net present value of capital costs is lower with renewable generation. Even with a net present value capital cost of $597 million for new generation over twenty years nominal operational cost savings of 17 percent could be realized (in real terms, savings would be higher).
- As shown in Figure 5, while capital cost of fossil units (including Natural Gas Combined Cycle, Combustion Turbine and Reciprocating Engine) are lower than renewable energy, the all-in levelized cost for renewable energy sources are lower when compared to the operating costs for fossil fuel units.

Why Lower Total System Costs with Renewables?

- Net Present Value of Capital Costs for Renewable Generation has fallen
- Lower Net Present Value of Operating Costs for Renewable Generation over IRP time horizon prioritizes renewable generation
- Operating reserve requirements adds new natural gas units
- Newer fossil generation is more efficient leading to dispatch changes

Unit Type	Overnight 2018 Capital Cost ($/kW)	2018 average estimated Variable cost ($/MWh)[1]	2018 Fixed Operating and Maintenance ($/kW)
New Capacity only; existing capacity is modeled at contracted rates			
Natural Gas Combined Cycle	1600	92.0	
Natural Gas Combustion Turbine	800	134.0	
Medium Speed Reciprocating Engine burning Natural Gas	1400	92.0	
Wind	Real, Levelized cost including capital, variable and fixed O&M and excluding profit = $105.8/MWh		
Solar	Real, Levelized cost including capital, variable and fixed O&M and excluding profit = $78.2/MWh		
Hydro	Real, Levelized cost including capital, variable and fixed O&M and excluding profit = $102/MWh		
Waste to Energy[2]	7200	9.3	
Biomass[3]	3837	5.6	

1) Varies by delivered cost
2) EIA 2012 estimates, assumes pre-sorting, and specific configurations
3) EIA 2016 estimates, highly varied variable costs due to inputs used

Figure 5: Renewables Lower System Cost

- Renewable resources place other risks on the system. Because renewable generation is variable, balancing energy is required. Further, voltage may fluctuate requiring additional operation constraints translating into more expenditures on equipment to control. Finally, renewable resources are often some distance from load centers (except distributed resources) requiring an analysis of losses and transmission of renewable energy across the network[12].

Grid Efficiency and Reduction of Losses:

- One measure of grid efficiency is the ability to convert energy into electricity. This metric is average system or generation fleet heat rate. Because renewable energy resources do not use fossil fuel inputs, system heat rates (ratio of fuel inputs to electricity outputs) decline, indicating a more efficient use of resources. For the initial Base Reference Case, there is a 39 percent reduction in heat rate, reflecting the shift in generation fleet to renewable energy sources.
- Other measures of grid efficiency, such as reduction of losses, may be calculated through additional transmission analysis.

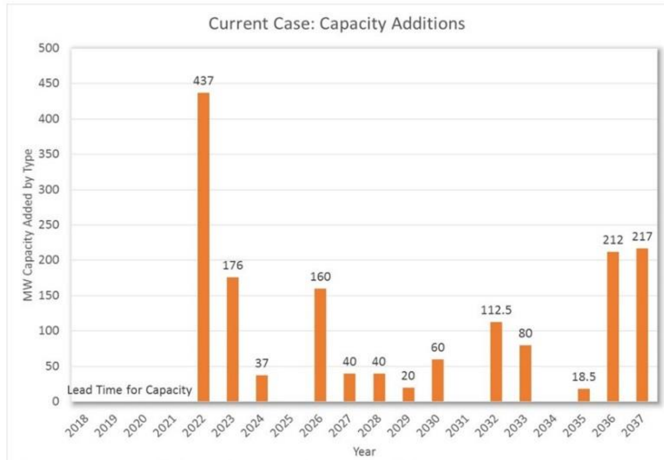
Minimize environmental footprint:

- CO_2 emissions contribute to global warming. Renewable resources reduce these emissions as opposed to fossil fuel generation that increases emissions. Due to increased renewable penetration and more efficient fossil generation, CO_2 emissions are reduced by 59 percent over time.
- Other measures such as reductions in NOx, SO_x, fuel spills and water used in cooling, were not available but may be assessed in future scenarios.

[12] Two sensitivities were run with wind/solar interconnected at 69kV and above. In one sensitivity, 70% of the new sitings were wind and 30% were solar. In a second sensitivity, 30% of the new sitings were wind and 70% solar.

Timing of new transmission and generation capacity additions in the Current Case*

Fiscal Year	Generation Capacity (MW)	Type of Addition
2018	0	
2019	0	
2020	0	
2021	0	
2022	437	Solar, Gas Turbine
2023	176	Hydro, Combined Cycle
2024	37	Solar
2025	0	
2026	160	Gas Turbine, Combined Cycle
2027	40	Solar
2028	40	Solar
2029	20	Solar
2030	60	Solar
2031	0	
2032	112.5	Solar, Gas Turbine
2033	80	Gas Turbine, candidate Transmission line
2034	0	Candidate Transmission line
2035	18.5	Gas Turbine
2036	212	Solar, Waste to Energy, Combined Cycle
2037	217	Solar, Candidate Transmission line



*Without contingencies which may add storage and line upgrades. Includes two sensitivities: one with 70% wind/30% solar and one with 30% wind/70% solar

Figure 6: New Generation Capacity over time – Initial Base Reference Case

The timing of new generation capacity additions depends upon the lead time to site each technology type and load growth/fossil fuel price projections as shown in Figure 6.

- New generation capacity siting requires an average of three years lead time to conduct interconnection studies, obtain right of way and install equipment. In the initial Base Reference Case no new generation is sited until 2022, when new capacity additions include renewable resources to reduce operating costs and new, more efficient fossil generation displacing older, less efficient and costly resources.
- In the Initial Base Reference Case, resource retirement schedules were fixed according to remaining plant economic life or expiration of the power purchase agreement.
- Because generation capacity size varies by type of resource, some larger, cost effective thermal resources such as natural gas combined cycle show discrete increases in particular years. Similarly, forecasted renewable capacity factors ranging from 31percent to 38 percent are generally lower than fossil generation

capacity factors, requiring more capacity to meet energy requirements.

- New Transmission lines are sited in 2033, 2034 and 2037 to accommodate contingencies and potential flows from renewable generation. Additional transmission analysis may require re-enforcements.
- Renewable generation provides significant cost savings and the Renewable Portfolio Standards for the most likely economic growth/fuel prices sensitivity provides potential targets for 2030 and for 2037 as shown in Figure 7.

Current Case Renewable Portfolio Standard Over Time

Year	Total Generation	Renewable Generation	Renewable Portfolio Standard
Most Likely Growth/Fuel Prices			
2030	5453 GWh	1913 GWh	35%
2037	5939 GWh	2435 GWh	41%

Figure 7: Renewable Portfolio Standards from the Initial Base Reference Case

1.5 Update of the Initial Base Reference Case

With regards to the Initial Base Reference Case, the optimal generation mix that was selected was further subjected to rigorous transmission analyses to establish the re-enforcements necessary to support the generation expansion proposition. After several iterations of transmission analyses, an Updated Base Reference Case was developed, allowing for greater penetration of renewables, due largely to the inclusion of infrastructure costs in the assessment as well as introduction of energy storage solutions to mitigate intermittencies, and support spinning reserves requirement, frequency smoothing, and peak shaving solutions.

Infrastructure costs associated with firm capacity generation plants is significant and when assessed, firm capacity generation plants compared unfavorably with renewables. The application of Battery Energy Storage Systems (BESS) mitigate against the intermittency associated with renewables and provide the additional benefits of providing spinning reserves and peak shaving. BESS technologies are still undergoing rapid development and the costs for these systems have maintained a downward trajectory.

In addition, technologies for wind and PV sources continue to improve and new options allow for such applications to provide grid support during steady state conditions by contributing to voltage control through the injection of reactive power; support grid disturbances and faults without being disconnected from the grid (LVRT); and support the grid when necessary, mainly during a fault, by generating/absorbing reactive power, as necessary.

As a result, the Updated Base Reference Case sited some 1655 MW of capacity over the planning horizon, representing 45MW more than in the Initial Base Reference Case due to full assessment and inclusion of capacity infrastructure cost, simulations of the applications of battery energy storage systems (BESS) for purposes including, spinning reserves, and frequency smoothing technology options.

1.6 The Preferred Implementation Plan

Considering that smart energy solutions continue to emerge, offering more robust solutions at cheaper costs, the decision was taken to implement the renewables solutions in phases so as to benefit from the expected reduction in the cost of the respective technologies. Accordingly, a Preferred Implementation Plan was assessed that would still meet the energy requirements through to 2037. The Preferred Implementation Plan was arrived at giving consideration to the need to:

1. Allow wide scale implementation of renewables;
2. Minimize the impact of intermittencies;
3. Provide energy storage options;
4. Ensure adequate spinning reserves;
5. Minimize the need for additional transmission infrastructure; and
6. Accommodation of firm capacities renewables (hydro and biomass / waste to energy)

The Preferred Implementation Plan satisfy the objectives for the IRP and is compared with the Updated Base Reference Case in the Figure 8 below:

Capacity Additions for the Reference Cases and the Implementaion Case

	Initial Reference Case			Updated Reference Case			Implementation Case	
Fiscal Year	Generation Capacity added (MW)	Type of Addition		Generation Capacity added (MW)	Type of Addition		Generation Capacity added (MW)	Type of Addition
2018								
2019								
2020								
2021								
2022	437	Solar/Wind, Gas Turbine		473	Solar/Wind		147	Solar/Wind
2023	176	Hydro, Waste to Energy, Combined Cycle		56	Hydro, Biomass		74	Hydro, Waste to Energy, Biomass
2024	37	Solar/Wind					173	Solar/Wind
2025				120	Combined Cycle		120	Combined Cycle
2026	160	Gas Turbine, Combined cycle		138	Combined Cycle, Waste to Energy		120	Combined Cycle
2027	40	Solar/Wind					111	Solar/Wind
2028	40	Solar/Wind						
2029	20	Solar/Wind		40	Gas Turbine			
2030	60	Solar/Wind					40	Gas Turbine
2031								
2032	112.5	Solar/Wind, Gas Turbine		37.5	Solar/Wind		122.5	Solar/Wind
2033	80	Gas Turbine		103	Solar/Wind, Gas Turbine		60	Solar/Wind
2034				20	Solar/Wind		37	Solar/Wind
2035	18.5	Gas Turbine		60	Solar/Wind		20	Solar/Wind
2036	212	Solar/Wind, Waste to Energy		35.5	Solar/Wind, Gas Turbine		50	Solar/Wind, Gas Turbine
2037	217	Solar/Wind, Candidate Transmission Line		572	Solar/Wind		589.5	Solar/Wind
TOTAL	**1610**			**1655**			**1664**	

Figure 8: Generation Capacity Requirements Schedule

1.7 Infrastructure Avoided Costs

In the eight and penultimate stage of the IRP process, the OUR was required to assess the Generation Avoided Cost and Tariff impact on customers over the 20 year period. The Generation Avoided Cost computed is 9.58 US cents/KWh, which is approximately 19.0 percent lower than the existing 11.76 US cents/KWh.

Further, the OUR has also indicated that they were not able to provide information on the tariff impact assessment at this time for the following reasons:

1. Pertinent information required from JPS on the distribution system and the characterization of the customers was not available; and
2. Since the OUR is presently giving consideration to JPS 5-Year Tariff Review, it was not considered prudent to opine on rate implications through the planning process, especially since the JPS Rate Application was submitted before the completion of the IRP.

1.8 Conclusion

Taking account of total system cost over the next twenty (20) years, including capital and Operational and Maintenance Costs, the IRP is indicating that the overall system costs will decrease to reflect retirement of the old and inefficient generators, achieve up to 50 percent reduction in fuel cost and commensurate reduction in CO_2 emissions projected over the next 20 year. The Plan also indicates that, with the proviso that it is implemented in the schedule outlined, 31 percent of electricity generation could come from renewables by 2030 and approximately 50.0 percent from renewables by 2037.

2 OBJECTIVES AND EVALUATION OF RESOURCE PORTFOLIOS[13]

2.1 Purpose

The Integrated Resource Plan (IRP) is a comprehensive decision support tool and road map for meeting Jamaica's electricity grid objectives over the next 20 years. The IRP is developed with considerable public involvement from OUR and JPS staff, other Jamaican agencies, customers and industry advocacy groups, project developers, and other third-party stakeholders (for example, credit agencies and financing groups). The key elements of the IRP include:

- a finding of resource need, focusing on a 20-year planning period,
- the preferred portfolio of supply-side and demand-side resources to meet this need, and
- an action plan that identifies the steps to be taken during each Integrated Resource Plan.

2.2 Mandate and Responsibility for Jamaica IRP

In July 2015, Jamaica passed a new Electricity Act simultaneously repealing the 1890 Electric Lighting Act, the Electricity Frequency Conversion Act and the Electricity Development Act. The Electricity Act clarify and codify the roles and responsibilities of the main actors in the sector, including the Government, the Regulator, the Electric Utility and the independent power producers. The Electricity Act repeals previous legislation, with the purpose of consolidating and modernizing the laws relating to the generation, transmission,

[13] This section uses the SUPPORT FOR DEVELOPMENT OF A COMPREHENSIVE ELECTRICITY PLANNING PROGRAM FOR JAMAICA, Jamaica IRP Report, Inter-American Development Bank, Revision G as a starting point. Stakeholder comments and corrections to that draft are included herein.

distribution, supply, dispatch and use of electricity. The objectives of the Act are, among others, to provide for a modern system of regulation of electricity activities, to provide clarity in the roles of the stakeholders of the sector and prescribed the required standards in the electricity sector.

The Act introduces the "Single Buyer" as the licensee responsible of purchasing the electricity generated by independent power producers at the transmission level and through net billing arrangements at the distribution level[14]. The Single Buyer should provide an adequate, safe and efficient service based on modern standards, to all parts of Jamaica at reasonable rates which meet the demands for electricity, and not show any undue preference to or unduly discriminate against any person. Tariffs charged by the Single Buyer are subject to approval and control of the Office of Utilities Regulation (OUR). The Single Buyer needs to keep separate accounts for its generation, transmission, distribution and supply activities. The "System Operator" is the licensee holding the dispatch license that is a department within the Single Buyer but with sufficient independence to ensure equal and fair access[15]. In addition, the Act creates a "Generation Procurement Entity" (GPE) to procure new generation capacity for the system.

The roles and responsibilities for the electricity sector include:

a) the Minister of Science, Energy and Technology (MSET) will carry out Integrated Resource Planning activities and issue licenses,
b) the Generation Procurement Entity will procure new generation capacity,
c) the Government Electrical Regulator (GER) will regulate electricity works, and
d) the OUR will regulate the electricity sector in general, including the operations of the Single Buyer.

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[14] The act defines distribution as below 69kV interconnection; transmission interconnections at 69 kV and above

[15] Electricity Act of 2015.

The integrated resource planning duties of the Minister include formulating an Integrated Resource Plan for the system. Also, the generation, transmission, distribution, dispatch and supply of electricity functions each need an operating license to be provided by the Minister. The licenses are non-exclusive for generation and may or may not be exclusive for the rest of activities. Licenses can include the conditions and restrictions that the Minister considers necessary. With the passage of the Electricity Act of 2015, the Ministry of Science, Energy and Technology has assumed new responsibilities for the planning of electricity grid requirements. The Minister is [Section 41] responsible for planning the development of the system, which shall include:

a) the collection of data from electricity sector participants;
b) consultations with the OUR, the single buyer and other electricity sector participants, and
c) the conduct of any relevant forecast, including but not limited to demand, supply and prices.

The planning process for transmission and distribution shall specifically consider the location of renewable energy resources and other generation sources, considering the potential for electrification of rural areas.

The Inter-Agency roles for integrated resource planning efforts are shown in **Error! Reference source not found.**.

Integrated Resource Planning – a team effort

Responsibility	MSET	JPS	OUR	GPE
Objectives and Metrics	Develop	Inform	Inform	Inform
Transmission & Distribution Planning Studies	Approve	Develop	Review for rates	Inform
Load Forecasting: Assumptions/Inputs supplied by MSET	Approve	Develop	Inform	Inform
Stakeholder Process: communication & policy	Develop	Inform	Inform	Inform
Supply Technologies and Feasibility Studies	Develop	Review for Technical Meeting	Review for rates	Inform
Third Party Supply/Demand Contracts	Agree/ Review	Develop	Approve	Inform
Sales Forecasting	Approve	Develop	Approve Rates	Inform
Energy Efficiency and Demand Programs	Develop	Inform	Approve Rates	Inform
Policy Action Plans	Develop	Inform	Inform	Inform
Environmental Impacts – NEPA compliance management interface with JPS	Develop	Inform	Inform	Inform
Generation Expansion Plan	Develop	Inform	Review for Rates	Inform
Procurement of Generation Capacity	Inform	Inform	Inform	Develop

Figure 9 Agency Roles in IRP

As shown, the objectives and metrics of the Integrated Resource Plan are the responsibility of MSET to develop and communicate to JPS and OUR. Transmission and Distribution Planning studies are developed by JPS and approved for use by MSET with rates impacts analyzed by OUR. The Generation Procurement Entity (GPE) is to be informed regarding the Objectives and Metrics as well as the Transmission & Distribution Planning Studies.

JPS has responsibilities to develop Load Forecasting projections; MSET would develop assumptions and inputs for use in the Load Forecast. The OUR is informed of Load projections. MSET is responsible for all stakeholder communications; informing both JPS and the OUR of status and outcomes. Supply Technologies modeled within the study and Feasibility Studies used to determine viable technologies are the responsibility of MSET; with approvals from JPS prior to the technical meetings used to review the technology. JPS approves the integration of any technologies for operational purposes and contracting for resources; the OUR will review rates impacts and will approve contracting for third party resources; MSET will approve/agree to ensure consistency with Integrated Electricity Planning results. For all the above the GPE will be informed.

Sales forecasts used in Integrated Resource Planning (including kWh energy sales and rates applied) are developed by JPS (with rates approved by OUR) and approved for use in Electricity Integrated Resource Planning efforts by MSET. Energy efficiency and Demand Side Management Programs are developed and approved by MSET; JPS is informed and OUR will approve rates. GPE is informed.

Policy Action Plans associated with the Electricity Integrated Resource Planning efforts are the responsibility of MSET; with both JPS and OUR being informed. MSET will manage the environmental process, ensuring NEPA compliance with activities. JPS and OUR are informed. GPE is informed.

The Generation Expansion Plan is developed by MSET and OUR approves rates impacts. The Procurement of Generation Capacity is developed by GPE whilst the other agencies are informed.

2.3 Setting Integrated Resource Planning Objectives

Providing some guidance on objectives, past efforts have focused upon three main areas: (1) government sponsored programs, (2) requirements for utilities filing plans with regulators, and (3) elements to include in an Integrated Resource Plan which inform the setting of objectives.

Prior efforts focusing upon a government sponsored Integrated Resource Plan (IRP) provide guidance in setting objectives. USAID, et al, recommends that the IRP process should set explicit objectives and how those objectives are measured[16]. The authors recommend the

[16] Best Practices Guide: Integrated Resource Planning For Electricity, Prepared for: Energy and Environment Training Program Office of Energy, Environment and Technology Global Bureau, Center for the Environment United State Agency for International Development.

specific objectives identified by the various stakeholders and regulatory bodies be incorporated directly and that the IRP be structured to specifically address said objects. The authors note that the IRP is a roadmap of specific investments which meet the objectives and ensuing policy initiatives to adhere to the roadmap. The California Department of Water Resources held a series of workshops with stakeholders to facilitate a discussion of objectives for a strategic plan for water resources[17]. The planning guide for South African communities[18] recommends that all municipalities produce an Integrated Development Plan (IDP). The municipality is responsible for the co-ordination of the IDP and must draw in other stakeholders in the area who can impact on and/or benefit from development in the area. Once the IDP is drawn up all municipal planning and projects should happen in terms of the IDP. The annual council budget should be based on the IDP. Other government departments working in the area should take the IDP into account when making their own plans. The IDP has a lifespan of 5 years, linked to the term of office for local councilors who may adjust the plans after elections. The IDP is drawn up in consultation with forums and stakeholders.

Many Integrated Resource Plans set objectives from the utility perspectives, with input from key stakeholders. Kind (2005) suggests that the actual outcomes from a resource planning process at utilities are determined by resource planning rules; analytical tools; involvement of stakeholders in the planning process; financial incentives; and policy decisions[19]. The US utility PacifiCorp[20] states that the integrated resource plan (IRP) is a comprehensive decision support tool and road map for meeting the company's objective of providing reliable and

[17] Strategic Plan for the Future of Integrated Regional Water Management in California, Stakeholder Input on Goals, Objectives, and Strategies, March 2014, Prepared by the California Department of Water Resources

[18] http://www.etu.org.za/toolbox/docs/localgov/webidp.html

[19] http://www.etu.org.za/toolbox/docs/localgov/webidp.html

[20] http://www.pacificorp.com/es/irp.html

least-cost electric service to customers while addressing the substantial risks and uncertainties inherent in the electric utility business. The IRP is developed with considerable public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders.

Key elements of the IRP include: a finding of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan that identifies the steps we will take during the next two to four years to implement the plan. Eskom[21], a South African utility; and Vectron[22], a US Utility in Indiana; and the Western Area Power Administration[23], offer similar advice. EPA (2015) and RAP (2013)[24] offers a survey of utility filed IRP plans and requirements imposed by US state utility commissions. Brattle, et al[25], focus upon IRP requirement filed with US state public utility commissions to set the basis for capacity and infrastructure planning and lists the following elements:

- Identify and evaluate all existing and new resource options to meet policy objectives, including renewable portfolio standards, distributed generation, energy efficiency requirements;
- Address costs for compliance with current and projected environment regulations and electricity market conditions;
- Develop the method and assumptions for assessing potential resources;

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21 Integrated Resource Plan for Electricity, 27 September 2013, Cape Town, Ntokozo Sigwebela Energy Planning, Eskom

22 https://www.vectren.com/Residential_Customers/Rates_&_Regulatory /Integrated_Resource_Plan.jsp

23https://www.wapa.gov/EnergyServices/IRP/Pages/irp.aspx

24 Best Practices in Electric Utility Integrated Resource Planning Examples of State Regulations and Recent Utility Plans, June 2013. http://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf

25 ELECTRIC UTILITY INTEGRATED RESOURCE PLAN (IRP) Demand-Side Resources THAI ENERGY REGULATORY COMMISSION, OERC, AND UTILITIES DELEGATION Boston, Massachusetts, Brattle Group, 2014.

- Identify and assess risks of key drivers such as load forecasts, costs of demand side management measures and power supply and fuel prices;
- Explain the procedures for soliciting public comments.

In summary, government sponsored electricity planning objectives are broader than those filed with regulators to support utility expansion plans. All authors advocate significant public involvement in the process to ensure success and ease approvals. In the remaining sections, a description of how objectives are set, measured and data sourcing for measurement is provided.

2.3.1 Setting IRP Objectives

Using USAID[26] as a starting point, objectives were presented by MSET and discussed.

- Reliable electric service to serve consumers with minimal disruptions in electric service
- Providing electric service to those without convenient access to electricity is a common objective in developing countries
- Minimize environmental impacts
- Energy security to reduce the vulnerability of electricity generation (and the energy sector in general) to disruptions in supply caused by events outside the country
- Use of local resources
- Diversify supply using several types of generation facilities, different types of fuels and resources, and/or using fuels from different suppliers
- Increase efficiency of electricity generation, transmission, distribution and use
- Minimize costs to the utility, costs to society (which may include environmental costs), costs to customers, capital costs, foreign exchange costs, or other costs
- Provide the social benefits of electrification to more people (for example, refrigeration and light for rural health clinics and schools, or light, radio, and television for domestic use)

[26] Best Practices Guide: Integrated Resource Planning For Electricity, United State Agency for International Development

- Minimize social harms, as from relocation of households impacted by power project development, are to be prevented or minimized
- Provide local employment
- Acquire technology and expertise with innovative demand/supply resources
- Develop plans that are flexible enough to be modified when costs, political situations, economic outlook, or other conditions change

For this project the following objectives, interpretations of those objectives are described in Figure 10.

Evaluation Criteria for Scenarios

The IRP finds the "best" resource mix to meet demand for the next 20 years

#	Objective Described	What it Means?	Initial Weight	Metrics
1	Reliable Energy Supply Chain	Minimize Disruptions	25%	Reserve Margins {1} Loss of Load Probability {2} Unserved Energy {3} Transmission Shadow Price {4}
2	Diversity of Supply	Vulnerability to Disruption	25%	Renewable Energy Share {5} Fossil Fuel Percentage {6}
3	Least Cost Electric Service	Reduce Customer budgets	16.50%	Change in system operating cost {7} Rates Charged {8} Short Run Marginal Cost {9}
4	System Flexibility	Ability to meet a wide range of outcomes	16.50%	Minimize difference in various scenarios run (High, Medium, Low) {10}
5	Grid Efficiency	Reduce losses	8.50%	Average System Heat Rate {11} Technical Losses {12}
6	Environmental Stewardship	Minimize environmental footprint	8.50%	Reduce CO2 air emissions {13}

Figure 10: Evaluation Criteria for Resource Portfolios

Reliable Energy Supply Chain (minimizing disruptions) was chosen initially as a high priority objective of the Integrated Resource Plan measured by Reserve Margins, Loss of Load Probability and Customer Supply Disruptions (initially weighted by 25%). Metrics include:

{1} Reserve margins are defined the North American Electric Reliability Council as a traditional measure of resource adequacy to meet peak load requirements given variations in load and grid operating conditions and measured as a ratio of excess generating capacity to forecasted peak load.

{2} Loss of Load Probability is the probability that load will exceed the capacity of resources. The reliability threshold is 2-3 percent per year based upon standards set by the North American Electric Reliability Council.

{3} Customer Supply Disruptions are measured by energy not served across the electric grid.

{4} Transmission Shadow Price is the marginal price of moving additional MW on the electricity grid, or a measure of how congested the system is. Very high numbers indicated more transmission capacity is required.

Diversity of Supply (vulnerability to disruption) was initially chosen as an equally important objective of the Integrated Resource Plan measured by the extent of alternative generation fuel sources and share of distributed generation/back up generation capacity (initially weighted by 25%). Metrics include:

{5} Share of generation met by renewable resources: hydroelectric, wind, solar, waste to energy and biomass.

{6} Fossil fuel used by generators was not calculated for this initial set of IRP results.

Least Cost Electric Service (least impact to electricity customer budgets) was chosen as an important objective of the Integrated Resource Plan measured by the net present value of variable costs and capital costs of the Integrated Resource Plan (initially weighted by 16.5%). Metrics include:

{7} Average nominal operating cost (total system cost over 20 years).

{8} Average Customer rate impact.

{9} Short run marginal costs of supplying generation (cost to supply and incremental MWh).

System Flexibility (most stable across alternative fuel and economic outlooks) is measured as the set of demand and supply side resources and grid updates which provides the most consistent set of outcomes across scenarios (initially weighted by 16.5%). Metrics include:

{10} Difference in high, medium and low scenarios to demonstrate ability to meet different grid conditions.

Energy Efficiency (efficiency of generation and transmission/distribution system) measured as the sum of losses across the system (initially weighted by 8.5%). Metrics include:

{11} Generation efficiency is calculated by the fleet average heat content of fossil fuel divided by generation and compared over time.

{12} Technical losses measured by the power flow.

Environmental Stewardship (minimizing the environmental footprint) measured by the impact on air emissions from electricity generation. Other considerations such as coastal management policy and spill/remediation probability as well as water cooling use in generation is beyond the current scope of the Integrated Resource Plan (initially weighted by 8.5%). Metrics include:

{13} CO_2 emissions per year. Future IRP efforts will include other air emissions.

2.3.2 *Setting Initial Weights for Objectives*

Comparing each of the scenarios requires some trade-offs among the metrics reported. For example, one scenario may demonstrate lower costs, but at the risk of reliability when compared to a similar scenario. To prioritize different metrics, prioritization weights can be established via Analytical Hierarchical Process (AHP) described[27] as follows:

[27] See Thomas Saaty, "Decision Making with the Analytic Heirarchy Process", International Journal of Services, Sciences, Vol 1, No. 1, 2008.

1. Define the problem and determine the knowledge sought [Setting importance “weights” to measure outcomes in the IRP].
2. Structure the decision hierarchy from the top down to alternatives [Focused upon important goals such as long-term Reliability and Diversity of supply, first].
3. Construct a set of pair-wise comparison matrices. [Reliability and Diversity were relatively of higher importance than Least Cost and System Flexibility, and in turn were more important that Efficiency and Environmental Stewardship].
4. Use the priorities obtained from the comparisons to weight the priorities to each lower element. [Weights were attributed equally across Reliability and Diversity; Least Cost and System Flexibility; and Efficiency and Environmental Stewardship].

For each objective, a measurement was initially assigned. In reporting the results for different scenarios, it is important to judge the trade-offs between the objectives (by altering the weights). For example, in the diverse supply scenario, what is the trade-off between diversity of supply and reliability? How expensive is system flexibility in the business as usual scenario? What trade-offs exist between renewable portfolio standard showing environmental stewardship and grid efficiency?

Each objective has at least one outcome which varies in scale and scope. For example, if customer reliability improves by 1 percent, what is the net present value cost of that improvement? Future scenarios will deploy this method in ranking alternatives to the Preferred Portfolio of resources presented in this report. Future ranking or prioritization may include focus groups in Jamaica.

3 IRP INPUTS [28]

The purpose of this section is to describe inputs for the Jamaica IRP over the course of the next twenty years. Inputs include economic and financial variables such as GDP growth, inflation and exchange rates, which can impact electricity demand and financing for new projects. Electricity and peak demand forecasts are described in Section 3.2.4, including a high, low and base case demand to account for the range of uncertainties in a 20-year forecast. The status of existing supply resources is described in Section 3.3. Current transmission and distribution infrastructure is the topic of Section 3.4 where forecasted supply options are described.

The inputs modelled and forecasted as described will be the basis for a discussion of scenarios and sensitivities for future Jamaica Electricity scenarios with policy implications to support the IRP road map described in Section 5.

3.1 Economic and Financial Variables

This section summarizes economic assumptions which support the Jamaican Ministry of Science, Energy and Technology (MSET) Integrated Resource Planning efforts for the 2018/2019 study cycle. Three economic growth scenarios are constructed to test the resource mix against different growth scenarios:

- A Most Likely Economic Growth case, using publicly available energy forecasts, considers a scenario of most likely economic growth;
- High Economic Growth considers a scenario with high economic growth which drives fuel prices to a higher level;

[28] Reference SUPPORT FOR DEVELOPMENT OF A COMPREHENSIVE ELECTRICITY PLANNING PROGRAM FOR JAMAICA, Jamaica IRP Report, Inter-American Development Bank, Revision G. Stakeholder comments and additional analysis were added where appropriate.

- Low Economic Growth in which lower demand drives lower fuel prices.

For each of these sensitivities, a separate forecast is provided based primarily on public data. This report provides a summary of and discussion surrounding:

1. ***Gross Domestic Product* (GDP), *GDP per capita* forecasts and *inflation* assumptions.** The study uses both nominal and real forecasts.
2. ***Current and projected exchange rates between the Jamaican national currency and US dollar are based upon current forward rate agreements*** and are stated in nominal terms**.**
3. For the ***discount rate***:
   a. All new JPS projects are assumed to use a weighted average cost of capital consistent with the financing typical for the IPP Model facility. Jamaica Public Service developed projects under the Right of First Refusal may be subject to the JPS weighted average cost of capital (WACC) from its OUR Approved Rate Case stated in nominal terms if the project is rate-based.

   b. Any third party financed projects are assumed to execute a Power Purchase Agreement with the utility in which rates are established. Third party PPA contracts are projected to use the IPP Model weighted average cost of capital to discount cash flows from capital in nominal terms.

   c. Credit enhancements and different financing arrangements by third parties are not forecasted within this project[29].

[29] The uncertainties surrounding credit and financing are captured within the range of High to Low economic growth scenarios.

3.1.1 GDP and Inflation

Over the last 30 years, real per capita Jamaican GDP increased at an average of just one percent per year. The government steadily accumulated debt, which reached 145 percent of GDP in 2012[30].

The slow growth has prompted the World Bank, the Inter-American Development Bank, the International Monetary Fund (IMF) and others to support public and private stimulus funding. Leading indicators suggest a GDP growth turnaround improving confidence in the economy, improvements in credit rating which has improved the quality of new bond issuance and retiring old debt. Total government debt will be only 128 percent of GDP by the end of fiscal year 2015/16.

The World Bank forecasts GDP growth accelerating to 1.7 percent in 2016 and to over 2 percent in 2017, aided by improving growth in the U.S., low oil prices, and reforms of investment climate.

The Jamaican economic long-term forecast is consistent with macroeconomic forecasts within the assumptions in the International Energy Agency Outlook, including macroeconomic indicators, crude oil prices, and global energy demand. Macroeconomic indicators (measured through GDP growth) include base case, high and low growth is shown in Figure 11.

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[30] Source: World Bank, September 2016. http://www.worldbank.org/en/country/jamaica/overview.

	Most Likely Economic Growth Case		High Economic Growth		Low Economic Growth	
Region	GDP by region expressed in purchasing power parity in real 2010 US dollars	Total Primary Energy Demand	GDP by region expressed in purchasing power parity in real 2010 US dollars	Total Primary Energy Demand	GDP by region expressed in purchasing power parity in real 2010 US dollars	Total Primary Energy Demand
OECD	2.0%	0.6%	2.3%	0.8%	1.6%	0.4%
Non-OECD	4.2%	1.9%	4.5%	1.6%	3.9%	1.7%
Non-OECD Americas	2.6%	1.5%	2.8%	1.7%	2.4%	1.3%
Brazil	2.4%	1.7%	2.6%	1.9%	2.1%	1.5%
Others (including Jamaica)	2.8%	1.4%	3.0%	1.5%	2.6%	1.2%

Figure 11: GDP and energy demand assumptions, EIA. Average annual percent change, 2012 to 2040

In the Most Likely Economic Growth case, Organization for Economic Cooperation and Development (OECD) GDP growth is projected at 2.0 percent while world consumption of primary energy is 0.6 percent. In the higher economic growth scenario, OECD GDP growth is projected to be 2.3 percent while world consumption of primary energy is 0.8 percent growth. In the lower economic growth scenario, OECD GDP growth is only 1.6 percent and primary energy consumption falls to 0.4 percent.

OECD growth is not as robust as those forecasted for Non-OECD Americas (including Jamaica). For the IRP study, the Most Likely Economic Growth case shows non-OECD Americas (including Jamaica) to have a GDP growth rate of 2.8 percent while total primary energy consumption is 1.4 percent. In the higher economic growth scenario, non-OECD Americas (including Jamaica) GDP growth is projected to be 3.0 percent while world consumption of primary energy is 1.5 percent growth. In the lower economic growth scenario, non-OECD Americas (including Jamaica) GDP growth is only 2.6 percent and primary energy consumption falls to 1.2 percent.

In contrast to the above World GDP Forecasts, Jamaica GDP annual growth from 2016 to 2020 in one scenario is projected to be 0.76 percent, which is not adjusted for purchasing power parity.[31] This lower GDP growth signals less petroleum demand than for the rest of Central/South America. To use the publicly available forecast for petroleum prices, there is an implicit assumption that the GDP of Jamaica is in line with Caribbean and South American forecasts.

Finalizing the GDP growth forecast, Figure 12 shows the forecasted real growth rate of Jamaica GDP in Purchasing Power Parity combining forecasts supplied by MSET and those used in the EIA International Energy Outlook for non-OECD Americas.

Scenario	2016-2017	2017-2018	2018-2019	2019-2020	2020-2025	2025-2030	2030-2035
Most Likely Economic Growth Case	1.3%	1.9%	2.8%	2.5%	3.3%	2.8%	2.7%
High Growth Case	1.5%	2.1%	3.0%	2.8%	3.5%	3.0%	3.0%
Low Growth Case	0.76%			2.9%			

Figure 12: GDP Growth Rates Used

Jamaica inflation is captured in the implicit GDP deflator and Consumer Price Index. The GDP deflator measures price changes over all the goods and services produced in Jamaica; the CPI measures price changes over consumer goods. Since results in the IRP focus upon quantifying impacts of policy decisions, CPI is a better indicator of inflation as it is felt by the general population; even though CPI is much more volatile than GDP deflator as shown in Figure 133.

[31] Source: World Bank and Trading Economics.com.

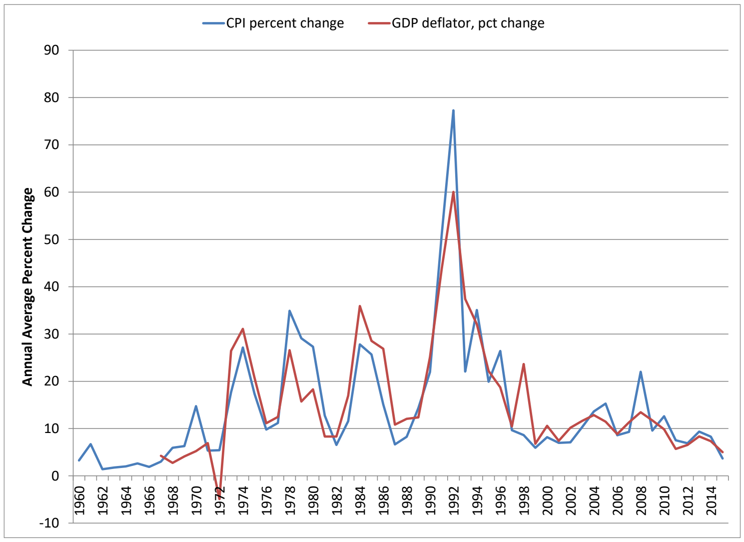

Figure 13: CPI and GDP deflator, percent change

In the long-term, the Jamaica CPI Inflation Rate is projected to trend around 3.50 percent in 2020[32].

3.1.2 Exchange Rates

Since goods and services imported to Jamaica are denominated in foreign currency, exchange rates are used to translate the impact in Jamaica dollars. As noted in Figure 14, the Jamaican dollar has depreciated in value relative to the US dollar.

32 http://www.tradingeconomics.com/jamaica/inflation-cpi/forecast.

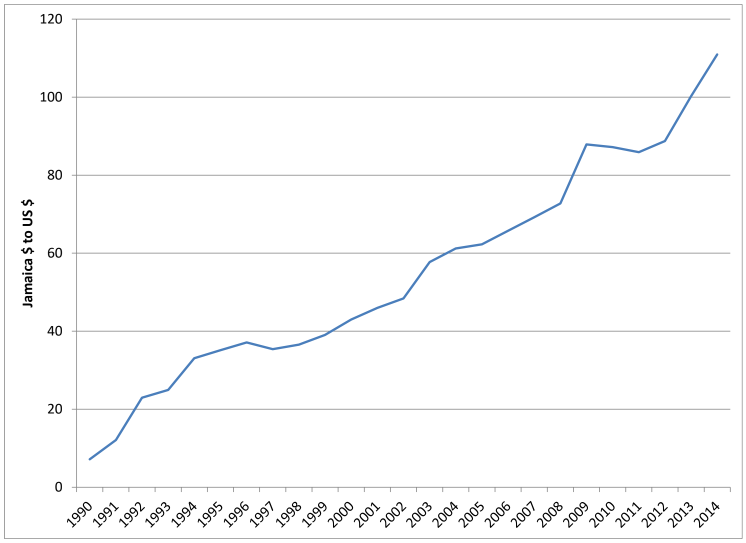

Figure 14: Historical exchange rate, US$ to Jamaica $

The forward exchange rate for the Jamaica dollar relative to the US dollar is calculated[33], as an additional input to the demand forecast. The forward rate is the exchange rate at which a party is willing to enter into a contract to receive or deliver a currency at some future date. Forward exchange rates are determined by the relationship between spot exchange rate and interest or inflation rates in the domestic and foreign countries.

Using the relative purchasing power parity, forward exchange rate can be calculated as shown in Figure 15.

[33] Note that this is not a forecast of exchange rates, but rather based upon current market conditions. While a forecasted rate and sensitivities is desired, a macroeconomic model is beyond the scope of the engagement.

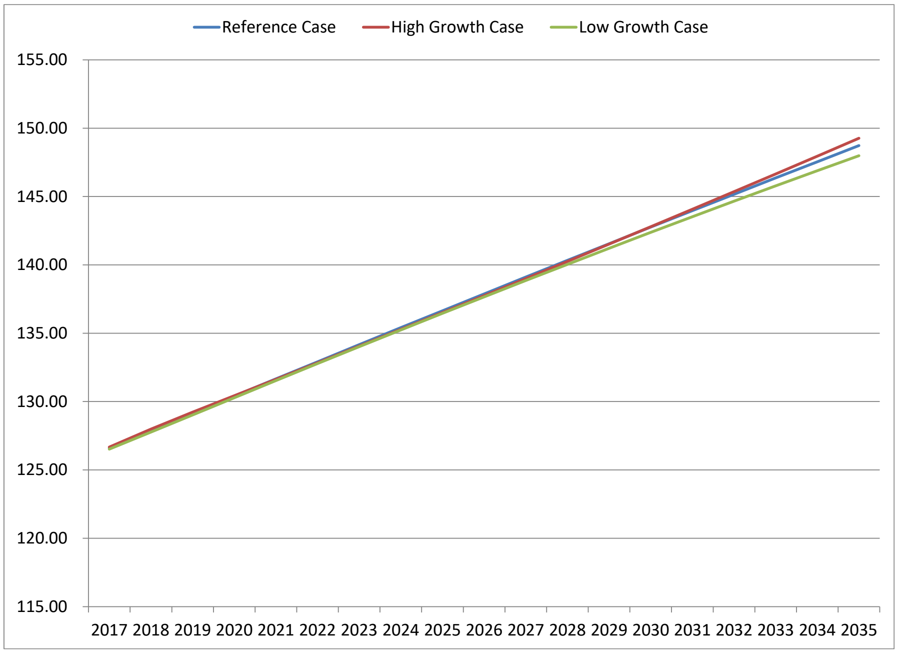

Figure 15: Forecasted exchange rates

3.1.3 Discount Rates for Cash Flows

Evaluating different costs and benefit streams to Jamaica for public projects involves selecting an appropriate discount rate. Two alternatives are discussed herein:

- the opportunity cost of drawing funds from the private sector; and
- a discount rate for public projects.

Since the Integrated Resource Plan is independent of the Jamaica tax structure and to avoid misallocation of funding for resources in Jamaica, a private sector opportunity cost discount rate is suggested.

Private Sector Opportunity Cost Rates: Market rates reflect the opportunity cost of investing in public projects, and there is rarely a case for allocating resources to low return investments in the public sector when higher returns are available in the private sector[34]. Energy infrastructure projects are normally characterized by high capital costs and tend to have a relatively long economic life[35] for which cost-benefit analysis and the discount rate chosen can have a number of uncertainties: regulatory changes; infrastructure investments with significant gestation periods and long benefit streams, whose magnitudes are positively related to general economic conditions; and climate change policies with cost and benefit streams extending over centuries, but with high uncertainty.

Public finance will generally be lower cost than private finance; there will always be a preference to use public funding even where a project may have occurred with private financing.

Discount rates should embody an appropriate compensation for risk. The rate should be equal to the rate of return on private projects with similar levels of risk. The market price of risk is what people must be paid to bear risk and reveals attitudes to risk even where markets are imperfect.

Taxes make a big difference in the choice of discount rate between the before-tax 'investment rate' that investments earn and the after-tax 'consumption rate' that lenders receive. For purposes of the Integrated Resource Plan, which is independent of the current tax structure, an after-tax return should be applied[36].

Treasury Rates of Financing for Public Projects: There is a tendency for certain government projects to choose a lower rate (or range of rates) to establish a lower

[34] Even the use of Treasury bond rates on public projects by the Government Account Office suggests the use of various discount rates depending upon how various projects are financed.
[35] See Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, US EIA, April 2013.
[36] Harrison, M. 2010, Valuing the Future: the social discount rate in cost-benefit analysis, Visiting Researcher Paper, Productivity Commission, Canberra.

threshold for acceptance of net present value[37]. For example, the US Congressional Budget Office uses 2 percent plus or minus 2 percent for sensitivity analysis while the General Account Office uses the average cost of Treasury Debt for various project financings. The theory is that the discount rate chosen for public investment projects reflects the rate at which society refrains from current consumption (i.e., saves). Some have suggested that a tax free municipal investment rate reflects an appropriate discount rate. The after tax real rate of return on fixed rate government Treasury bills is often taken as an approximation of this rate (specifically the interest rate on Treasury bills less inflation).

None of these lower social rates (inflation, Treasury bill or municipal debt) reflect taxes and assume bond financed projects equivalent to the Treasury bill rates. These projects assume some sort of US Treasury financing which incorporates the cost of financing.

For the Jamaica Integrated Resource Plan, the financing of infrastructure which supports Integrated Resource Planning efforts can impact both bond and equity financing. Even if the project is financed through only bond or equity, the financing can impact the cost of new debt reflected in a **Weighted Average Cost of Capital**[38]. Reflecting the opportunity cost of financing projects by private sectors is the most reasonable method to avoid misallocation of funds. The most common method reflecting financing decisions is the **Weighted Average Cost of Capital** as described in the next subsection.

[37] The Economics of Infrastructure Investment: Beyond Simple Cost Benefit Analysis, by Arthur Grimes, Motu Working Paper 10-05, Motu Economic and Public Policy Research, August 2010

[38] The Cost of Capital, Corporation Finance and the Theory of Investment by Franco Modigliani and Merton H. Miller, Source: The American Economic Review, Vol. 48, No. 3 (Jun., 1958), pp. 261-297. Published by: American Economic Association

3.1.3.1 Weighted Average Cost of Capital

The Weighted Average Cost of Capital combines the cost of equity and the after-tax cost of debt. The Capital Asset Pricing Model[39] and its variations is the common methodology used to estimate a company's cost of equity. Unlike fixed rate debt, equity cost includes the impact of the market upon the cost of equity[40]. The cost of equity is basically what it costs the company to maintain a share price that is satisfactory (at least in theory) to investors. The capital asset pricing model (CAPM) suggests that the Cost of Equity (Re) = Risk Free Rate (Rf) + Beta (Rm-Rf), where:

- Rf - Risk-Free Rate - This is the amount obtained from investing in securities considered free from credit risk, such as government bonds from developed countries. The interest rate of U.S. Treasury bills or the long-term bond rate is frequently used as a proxy for the risk-free rate.
- ß - Beta - This measures how much a company's share price moves against the market as a whole. A beta of one, for instance, indicates that the company moves in line with the market. If the beta is more than one, the share is exaggerating the market's movements; less than one means the share is more stable. Occasionally, a company may have a negative beta (e.g. a gold mining company), which means the share price moves in the opposite direction to the broader market.
- (Rm – Rf) = Equity Market Risk Premium - The equity market risk premium (EMRP) represents the returns investors expect, over and above the risk-free rate, to compensate them for taking extra risk by investing in the stock market. In other words, it is the difference between the risk-free rate and the market rate. It is a highly contentious figure. Many commentators argue that it has gone up due to the notion that holding shares has become riskier.

The cost of debt (Rd) is the current market interest rate paid on company debt. Because interest expenses are tax deductible, the net cost of the debt reflects a reduction of debt

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[39] Sharpe, W. (1964). "Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk, ", Journal of Finance, 19:425-442.

[40] Some, such as Fama and French, 2004 have argued feedback of debt and interest financing.

from tax savings. The weighted average cost of capital is based on the proportion of debt and equity in the company's capital structure.

In their 2004 review, Fama and French argue several problems with using the CAPM. Most of the criticisms involve the estimate of cost of equity and variations in the incorporation of uncertainty. To adjust for some of the problems, common shortcuts have been developed.

For JPS, the current allowed pre-tax Weighted Average Cost of Capital was set at 13.22 percent based upon the cost of debt of 8.07 percent pre-tax, the cost of equity of 12.25 percent post-tax and 18.4 percent pre-tax, an allowed debt/equity ratio of 50 percent and a tax rate of 33.33 percent.

Over the course of an Integrated Resource Plan horizon of twenty years, projects financed by JPS can be impacted by a wide variety of factors including changes to debt/equity financing structure (which may also impact rates charged to customers), dividend policy, investment in riskier projects, changing underlying interest rates. Market interest rates and taxes may also impact cost of capital. Projects which are larger or riskier from a financial or technical perspective may alter the long run weighted average cost of capital. Adjustments after Integrated Resource Planning scenarios are run can accommodate these changes.

3.1.3.2 Third Party Electricity Projects

In Integrated Resource Planning, independent power producers (IPPs) may have a different discount rate applied due to technology risks and financing that requires early payment of cash flows[41]. To finance these risky projects, alternative sources of cash flow require higher returns due to project risk[42].

A Venture Capital rate for new projects is difficult to determine since a variety of detailed assumptions are required about the financial condition of the IPP, the project type and various cash flow considerations.

A common approach is to increase the risk adder in the Capital Asset Pricing Model. A higher level of uncertainty in the Beta estimate of volatility relative to market can provide a substitute for incorporating this uncertainty. Depending upon the technology and market, a beta of 2 or 3 has been used after analyzing the financial condition of Independent Power Producer and market conditions.

Another approach is to assume that all financing is guaranteed by the government. This is often impractical and can create a series of contingency claims on government debt.

For the Integrated Resource Plan, any third party financed projects execute a Power Purchase Agreement (PPA) with the utility in which rates are established. Third party PPA contracts are projected to use the IPP Model weighted average cost of capital to discount cash flows. Any governmental guarantees provided to third party suppliers are not included in the analysis.

Computing costs in present value terms is a key feature of the PLEXOS model consequently the determination of the expansion plan is based on assumptions related to the economic life of the candidate plants and the discount rate assumed.

1. The base or reference year of the plan is the year 2018. All costs entered into the model were expressed in 2018 United States dollars. The cost excludes consideration of taxes and duties.

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[41] The True Cost of Venture Capital by Brian Hamilton, Forbes, 2006.

[42] Sanjai Bhagat , (2014) "Why do venture capitalists use such high discount rates?", The Journal of Risk Finance, Vol. 15 Iss: 1, pp.94 - 98

The economic discount rate employed by MSET is 7.44%. This represents the approximate value of the post-tax WACC. This is determined as shown in Table 1.

Economic Parameters	OUR-JPS 2014-2019 Tariff Determination	IRP IPP Model
Debt Cost (pre-tax)	8.07 %	8.07%
Return on Equity (pre-tax)	18.37%	18.37%
Return on Equity (post-tax)	12.25%	12.25%
Tax Rate	33.33%	33.33%
Gearing	50%	70%
WACC (pre-tax)	13.22 %	11.16%
WACC (post-tax)	8.82%	7.44%

Table 1 Economic Parameters

For the transmission plan it was assumed that all transmission assets are owned by JPS and expansion and upgrades were carried out by JPS. A post tax WACC of 8.82% was utilized to discount these costs.

In deriving the generation expansion plans, assumptions were made on the economic life of existing and candidate plants. These assumptions reflect international standards concerning plant performance as well as local experience with their operation. The assumptions are outlined in Table 2.

Plant Type	Fuel	Economic Life (Years)
Hydroelectric	n/a	50
Simple Cycle Combustion	NG/ADO	20
Combined Cycle	NG/ADO	30
Medium Speed Diesel	HFO/NG	30
Biomass	Biomass	30
Wind Turbines	n/a	20
Solar Photo Voltaic	n/a	20

Table 2 Plant Economic Life

3.1.3.3 Cost of Capital across Scenarios

While some of the investment projects contemplated within the Integrated Resource Plan may be "large enough" to alter parameters for calculation of the long term weighted average cost of capital, it is recommended that any potential change be conducted as a post processing adjustment.[43]

[43] No adjustment was made to cost of capital across high, most likely and low growth scenarios. Future scenarios may include sensitivities to the cost of capital across scenarios.

3.1.4 Summary of Economic Forecasts used in the Integrated Resource Plan

Scenario	Jamaica GDP by region expressed in purchasing power parity in real 2010 US dollars (Average Annual percent change)	Exchange Rate (JMD to USD) (Average Annual percent change)	Jamaica CPI Inflation (Average)	Jamaica Public Service Cost of Capital (percent)
Most Likely Economic Growth Case	2.8%	1.7%	4.88%	13.22%
High Growth Case	3.0%	2.0%	5.99%	
Low Growth Case	2.6%	1.1%	3.92%	

Figure 16: Summary of economic forecasts used in the IRP, 2018 to 2037

Figure 16 compares the various values used in each forecast scenario. In the Most Likely Economic Growth case, Jamaica GDP (in real 2010 dollars with purchasing power parity) is projected to be 2.8 percent average annual growth rate over the 20-year time horizon for the IRP. In the high economic growth case, Jamaica GDP is 3 percent and in the low economic growth rate, the GDP growth is 2.6 percent. Small changes in GDP growth will impact consumption, which increases demand for goods and services, driving a commensurate change in Jamaica electricity demand.

The Jamaica dollar exchange rate to the US dollar in the Most Likely Economic Growth case average is projected to rise 1.7 percent per annum during the 20 year IRP horizon. In the high growth case, the exchange rate rises with a rise in demand for goods and services (to 2 percent per annum) while in the low economic growth case, the exchange rate has a lower trajectory (rising only 1.1 percent per annum).

Inflation is projected to be 4.88 percent in the Most Likely Economic Growth Case; 5.99 percent in the high growth case, and 3.92 percent in the low growth case.

3.2 Load Forecast

The objective of this section is to support the Jamaican Ministry of Science, Energy and Technology (MSET) in forecasting the energy and peak demand growths for the next 20 years until 2037, as part of the Integrated Resource Planning efforts. The section is organized as follows:

- in Section 3.2.1 a methodology for the economic forecast is described;
- in Section 3.2.2 key drivers impacting demand are described;
- in Section 3.2.3 definitions of different load growth sensitivities are discussed;
- in Section 3.2.4 key results of the energy forecast are provided and discussed;
- in Section 3.2.5 how the load is allocated to regions is discussed;

The electricity load forecast is a first step to estimate future power needs in the Jamaican system and long-term growth of sales and peak demand. The electricity demand forecasts within the scope of this IRP were developed for each customer segment: residential, small commercial and industrial, large commercial and industrial and others.

Historically, electricity consumption in Jamaica has been correlated with the country's economic activity and population growth until 1990, as shown in Figure 17 and 18. After 1990, electricity demand increased significantly due to the high development of tourism and mining industries (especially alumina and bauxite industries) in the country during this period. The economy of Jamaica is highly dependent on these factors, which means that any variability in the tourism sector or in alumina and bauxite prices may have a strong impact on the economy cycle.

However, Jamaica still relies on fossil fuel generation for a significant share of the total generation. Additionally, most of the power generation plants are old and inefficient, which, combined with a high share of fossil fuel generation leads to high generation costs. These high costs were transferred to the electricity rates and passed to consumers, which led to a decrease in electricity consumption after 2005 due to a significant increase in electricity rates during this period.

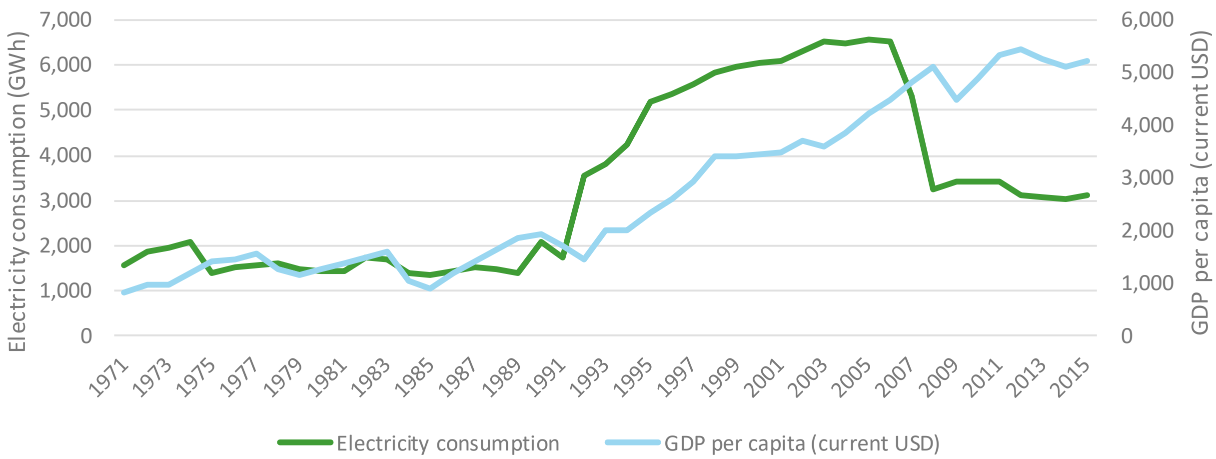
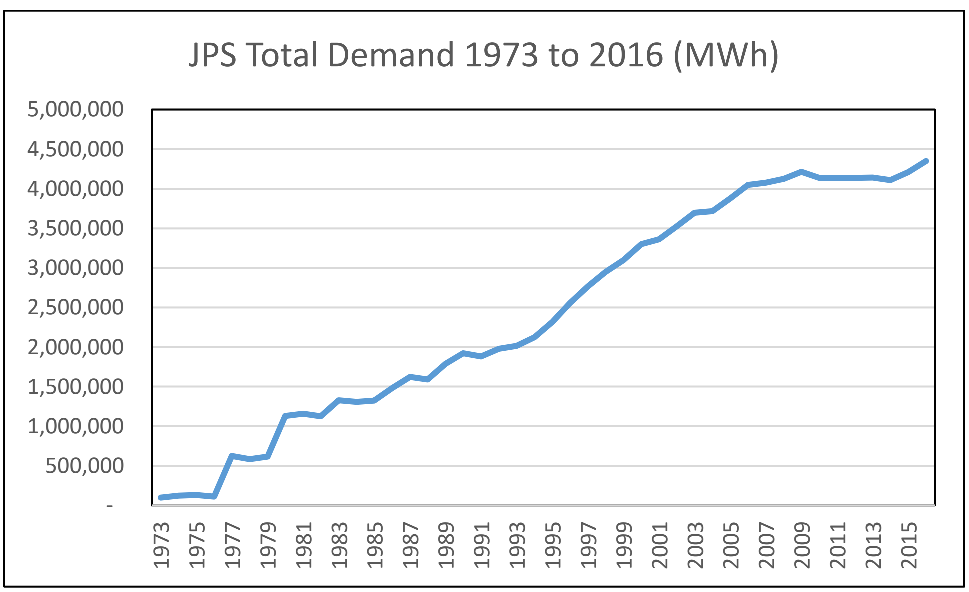


Figure 17: Historic development of electricity consumption and GDP per capita in Jamaica

Source: World Bank



Source: JPS Historical Demand and Generation (all existing records to Sept 17) from JPS

Figure 18: Total demand development between 1973 and 2016 (MWh)

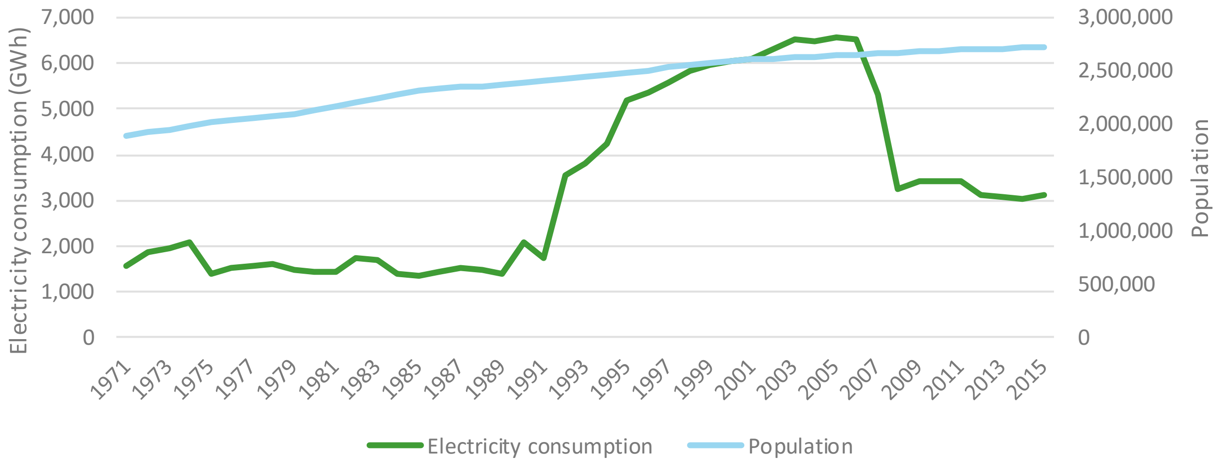


Figure 19: Historic development of electricity consumption and population in Jamaica (Source: World Bank)

Figure 19 presents that growth in population is correlated with increase in electricity consumption.

3.2.1 Methodology

There are several load forecast methods to estimate the long-term growth of energy and peak demand. Typically, statistical methods and tools are used based on historic values of relevant variables and their estimated development over time. On the other hand, there are other approaches that consider elasticities to estimate the average development over time based on historic elasticities for electricity demand. Each load forecast will depend on the specific characteristics of the electricity sector of the country and the variables that explain the development of electricity demand. Depending on the variable impacting the development of electricity demand, elasticity factors are determined by the following formula:

$$\varepsilon = \frac{\Delta ElectricityDemand(\%)}{\Delta HistoricVariable(\%)}$$

However, to have robust approaches for an electricity demand forecast, statistical methods require a set of data and assumptions that are not always available or is not fully reliable, such as:

- significant and relevant historic data publicly available;
- forecast of economic drivers publicly available from competent and recognized institutions worldwide or in the market being analyzed;
- uncertainty due to financial crises globally that may affect directly or indirectly the potential development of large industries in a region;
- volatility and high uncertainty around commodities prices around the world that may suffer significant variations, impacting main drivers and explanatory variables behind the electricity demand forecast.

Regarding some historic economic and demographic indicators, such as for instance, population, Gross Domestic Product and total electricity demand, data availability is not an issue given that a lot of national and international sources provide this type of data. The challenge is to find sufficient data for each customer segment (residential, large commercial and industrial, small commercial and industrial and other customers). The disadvantage of having very limited sets of annual historic data for economic, demographic and power indicators is that it becomes more challenging to obtain statistically significant variables that prove the correlation between the development of these variables and the development of electricity demand in Jamaica.

The approach considered in this IRP to identify the key drivers affecting demand growth is based on three major steps:

- **Statistical data analysis** – comprises a detailed analysis of historic data for economic, demographic and power indicators, by applying regressions using statistical and analytical tools in Excel[44], to investigate relevant correlations between economic/demographic indicators and electricity demand

- **Determinants selection** – includes the identification of selected variables that explain, for a certain period, the development of electricity demand, based on the statistical regressions analyzed before for each customer segment (residential, large commercial and industrial, small commercial and industrial and other customers)
- **Elasticities computing** – based on the identified determinants, compute the historic elasticities to derive the average elasticities factors to be applied for the forecast of electricity demand for each customer segment

The following section will describe in more detail for each customer segment the drivers for electricity demand in Jamaica applied in the load forecast. For each customer class, historic electricity sales values published by Jamaica Public Service Company (JPS) were used as a basis for the electricity demand procured by each customer class.

3.2.2 Key drivers affecting demand growth

Residential customers

Typically, the electricity demand for the residential customers' class depends on the available budget of households associated with their purchasing power of goods/services and the population growth of a country. Population is a key driver that indicates the average number of people using electricity for residential lighting.

Within the scope of this IRP load forecast, several indicators were assessed in the statistical data analysis, such as:

- Gross Domestic Product (in current USD);
- Gross Domestic Product per Capita (in current USD);

[44] Data Analysis Tools

- Gross Domestic Product Purchasing Power Parity (in current USD);
- Population.

Given that there was a limited data set for historic electricity sales in MWh for residential customers (only 14 years[45]), the statistical data analysis was used to identify potential explanatory variables, by assessing the correlation as well as other statistics (for instance, significance, standard error, R square and p-value) between the variables and electricity sales.

Based on the analysis of the regressions, the most explanatory variables for the development of electricity sales of residential customers were the Gross Domestic Product Purchasing Power Parity and population.

For the computation of elasticities for residential customers, two elasticity factors were determined for the number of customers and specific consumption (in MWh/customer). The elasticity factor for the number of customers is based on the population, while the elasticity factor for the specific consumption is based on Gross Domestic Product Purchasing Power Parity. The elasticity factors are given by the following formulas, where t represents a given year and t-1 the previous year. It is therefore considered there is a certain delay between a change in an explanatory variable and its impact on the number of customers or specific consumption.

$$\varepsilon_{Number\ of\ customers} = \frac{\Delta Number\ of\ customers_t(\%)}{\Delta Population_{t-1}(\%)}$$

[45] a). Sales data is available going back to the 1990's. To get the best possible estimates more data points should be included for each rate class.
b.) Normalized sales (the sales data used matched that of JPS' annual report) may not be the best proxy for sales since it includes both the unbilled sales and the billed. Billed sales data is available up to 1990's.
c). The historical period goes from 2002 to 2015. Actuals exist for 2016/2017. 2016 actuals should be considered for inclusion to give better estimates. A new methodology is proposed for future analysis. See Section 5.

$$\varepsilon_{Specific\ consumption} = \frac{\Delta Specific\ consumption_t(\%)}{\Delta GDP\ PPP_{t-1}(\%)}$$

Small commercial and industrial customers

This customer class represents small businesses mostly located in urban and semi-urban areas. Typically, the potential drivers for long-term electricity demand are mostly related to economic activity, households' purchasing power for goods/services, willingness to invest and to borrow money from financial institutions, among others.

Within the scope of this IRP, the statistical data analysis assessed several indicators to investigate which variables could potentially explain the development of electricity sales for small commercial and industrial customers. The following indicators were assessed:

- Urban population;
- Gross Domestic Product (in current USD);
- Gross Domestic Product per Capita (in current USD);
- Gross Domestic Product Purchasing Power Parity (in current USD);
- Interest rates (commercial credit annual average);
- Exchange rates JMD/USD.

Based on the detailed analysis of several regressions of all these variables, two variables were identified that potentially affect the growth of electricity for small commercial and industrial customers: urban population and interest rates.

The interest rates were used to derive the elasticity factor for the number of customers, considering that the level of interest rates affects the growth of small businesses. For instance, low interest rates are a potential driver for new small businesses or entities in urban and semi-urban areas, such as general stores, restaurants, etc.

The urban population is a key driver for the consumption per customer, providing an indication on the consumption level per business. Therefore, it was used to derive the elasticity factor for the specific consumption of small commercial and industrial customers.

The elasticity factors for this customer class are given by the following formulas, where t represents a given period and t-1 the previous period.

$$\varepsilon_{Number\ of\ customers} = \frac{\Delta Number\ of\ customers_t(\%)}{\Delta Interest\ rate_{t-1}(\%)}$$

$$\varepsilon_{Specific\ consumption} = \frac{\Delta Specific\ consumption_t(\%)}{\Delta Urban\ population_{t-1}(\%)}$$

Large commercial and industrial customers

This customer class consists of medium to large commercial and industrial customers, which includes for instance large hotels and large mining industries of alumina and bauxite. The potential drivers for electricity demand are mainly related to economic activity and performance of the Jamaican economy.

Additionally, Jamaica is highly dependent on its strong tourism sector, representing around 30% of the total GDP (as shown in Figure 20), which means that electricity demand from most large commercial and industrial customers (i.e. large hotels and resorts) are dependent on the number of arrivals of tourists every year. According to a WTTC – World Travel & Tourism Council study, the average contribution of tourism for GDP in the world is around 3 percent. This clearly shows the importance of tourism for the economy of Jamaica.

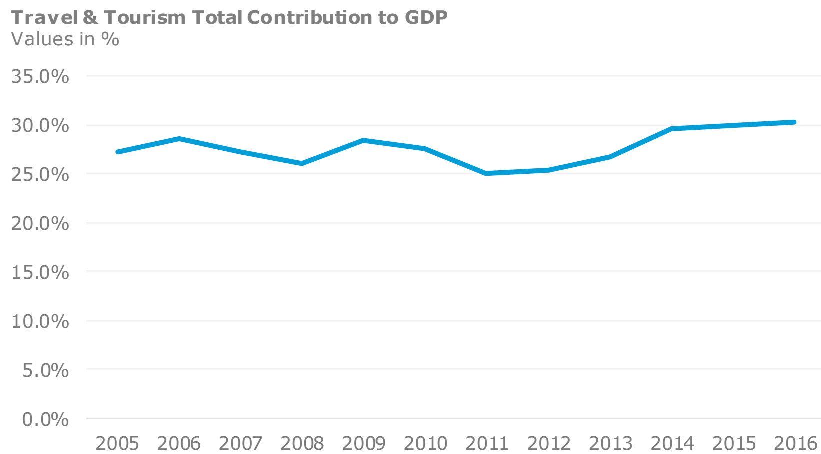


Figure 20: Travel and tourism total contribution to GDP in Jamaica

Source: Knoema46

Therefore, the following indicators were assessed:

- Gross Domestic Product (in current USD);
- Gross Domestic Product per Capita (in current USD);
- Gross Domestic Product Purchasing Power Parity (in current USD);
- Population;
- Tourism (number of arrivals per year);
- Exchange rates JMD/USD.

The regression analysis concluded that the potential drivers for the development of electricity sales for large commercial and industrial customers are the Gross Domestic Product Purchasing Power Parity and the number of tourist arrivals per year.

The Gross Domestic Product Purchasing Power Parity was used to estimate the elasticity factor for the number of customers, based on the assumption that a good economic performance is correlated with new investments in the economy and the connection of new large customers. On the other hand, the number of tourist arrivals per year was used

[46] https://knoema.com/atlas/Jamaica/topics/Tourism/Travel-and-Tourism-Total-Contribution-to-GDP/Total-Contribution-to-GDP-percent-share

to derive the elasticity of specific consumption per customer. A high number of tourist arrivals per year would lead to higher electricity demand and electricity sales.

The elasticity factors for this customer class are given by the following formulas, where t represents a given period and t-1 the previous period.

$$\varepsilon_{Number\ of\ customers} = \frac{\Delta Number\ of\ customers_t(\%)}{\Delta GDP\ PPP_{t-1}(\%)}$$

$$\varepsilon_{Specific\ consumption} = \frac{\Delta Specific\ consumption_t(\%)}{\Delta Number\ of\ tourist\ arrivals_{t-1}(\%)}$$

Other customers

Regarding other customers, such as public lighting and municipalities, their electricity sales is mainly dependent on the population growth in Jamaica over time, and therefore, annual population was used to compute the average elasticity factor for other customers. The elasticity factor for this customer class is given by the following formula, where t represents a given period and t-1 the previous period.

$$\varepsilon = \frac{\Delta Electricity\ sales_t(\%)}{\Delta Population_{t-1}(\%)}$$

A summary of the key drivers affecting the electricity sales growth per customer class described before is shown in Figure 21.

Elasticity of number of customers

Elasticity of specific consumption per customer

Residential	Population	Gross Domestic Product Purchasing Power Parity
Small commercial & industrial	Interest rates	Urban population
Large commercial & industrial	Gross Domestic Product Purchasing Power Parity	Tourism, number of arrivals per year
	Elasticity of electricity sales	
Other	Population	

Figure 21: Summary of key drivers affecting load forecast per customer class

3.2.3 Definition of Future Scenarios and Assumptions

To provide different views including pessimistic and optimistic approaches for the development of electricity demand in Jamaica, the load forecast was developed for the three main scenarios within the scope of this IRP, described in previous chapters, such as:

- most likely case;
- high economic growth scenario with low fuel prices;
- low economic growth scenario with high fuel prices.

The forecast will be based on assumptions for each explanatory variable identified before as key drivers for the development of electricity sales over time. The following paragraphs will describe in more details the assumptions considered for each variable and their estimated projections based on public sources.

Gross Domestic Product Purchasing Power Parity

The Gross Domestic Product Purchasing Power Parity is a main economic indicator that provides an indication of the performance of an economy in a specific period. The historic values were based on data published by the World Bank. The assumptions for the annual growth rates for GDP Purchasing Power Parity (2007 Real Dollars) were based on the forecasts prepared by the Ministry of Science, Energy & Technology of Jamaica, for the period between 2016 and 2035. Figure 22 shows the forecasted values for three different scenarios.

	2016-2017	2017-2018	2018-2019	2019-2020	2020-2025	2025-2030	2030-2035
Reference case	1.30%	1.90%	2.80%	2.50%	3.30%	2.80%	2.70%
High growth	1.30%	2.10%	3.00%	2.80%	3.50%	3.00%	3.00%
Low growth	0.76%	0.76%	0.76%	2.90%	2.90%	2.90%	2.90%

Figure 22: Assumptions of annual growth rates for GDP Purchasing Power Parity (2007 Real Dollars)

Source: Planning Institute of Jamaica

Interest rates

The assumptions for interest rates in Jamaica for the period between 2016 and 2035 are shown below in Figure 23. It should be noted that the annual growth rates considered for the period 2021-2035 are based on the rates assumed for inflation in the IRP assumptions book. These forecasts for interest rates are based on a report prepared by the International Monetary Fund (IMF) "Request for stand by arrangement and cancellation of the current extended arrangement under the extended fund facility". This report prepared different scenarios for the evolution of the Jamaican economy. For the load forecast, the assumptions for the scenarios selected within this IRP are based on IMF's scenarios indicated in the figure 23 below:

	2016	2017	2018	2019	2020	2021	2021-2035(1)
Reference case (based on IMF's Baseline Scenario)	7.20%	6.90%	7.30%	7.30%	7.60%	8.00%	0.25%
High growth (based on IMF's Interest Rate Shock Scenario)	7.20%	6.90%	7.40%	7.60%	8.00%	8.70%	0.40%
Low growth (based on IMF's Historical Scenario)	7.20%	6.90%	7.10%	7.00%	7.10%	7.40%	0.12%

Figure 23: Assumptions for interest rates in Jamaica for the period 2016-2035

Source: Planning Institute of Jamaica

(1) Growth rates per year assumed during this period

Source: IMF, Request for stand by arrangement and cancellation of the current extended arrangement under the extended fund facility, Baseline Scenario

Population and urban population

The assumptions for the population growth in Jamaica are based on the figures published by the Planning Institute of Jamaica. It was assumed the same annual growth rate for the urban population, for the three scenarios as shown in Figure 24.

	2020	2025	2030	2035
Population	2,806,000	2,845,000	2,872,000	2,883,000

Figure 24: Assumptions for the development of populations in Jamaica

Source: Planning Institute of Jamaica

Tourism

Based on the figures published by the World Bank, during the period from 1996 to 2014, the number of tourist arrivals per year has grown 3.24% per year on average. The same average annual growth rate of the tourist arrivals was assumed for the three scenarios.

Elasticity factors

Per the methodology, the forecast of electricity sales for each customer class was based on elasticity factors for the number of customers and on the specific consumption per customer. These elasticities were computed considering historic evolution of the explanatory variables, as described before. Figure 25 shows the assumed values for these elasticities. Note that for other sales, there is only one elasticity factor given that other sales are explained by only the population growth. The assumed values are based on the average elasticities for the period between 2003 and 2015.

	Elasticity factors
Elasticity of number of customers	
Residential	3.81
Small Commercial & Industrial	0.21
Large Commercial & Industrial	0.43
Elasticity of specific consumption per customer	
Residential	0.69
Small Commercial & Industrial	-0.05
Large Commercial & Industrial	-0.18
Elasticity of other sales	
Other	4.77

Figure 25: Elasticity factors assumed for the load forecast

3.2.4 Energy and Peak Demand Forecasts

The energy demand forecast was determined using the combination of electricity sales forecasts for each customer class (residential, small commercial and industrial, large commercial and industrial and other sales).

The peak demand forecast was based on the historic development of the load factor (defined as the average annual load divided by the maximum load in each period). The forecast assumed that the load factor would remain constant at 78 percent, per JPS recommendations. The forecast results for the period between 2018 and 2038 are shown below in Figure 27, and are a result of the application of the load factor assumed for the whole period until 2037 to the value for the total electricity demand forecasted.

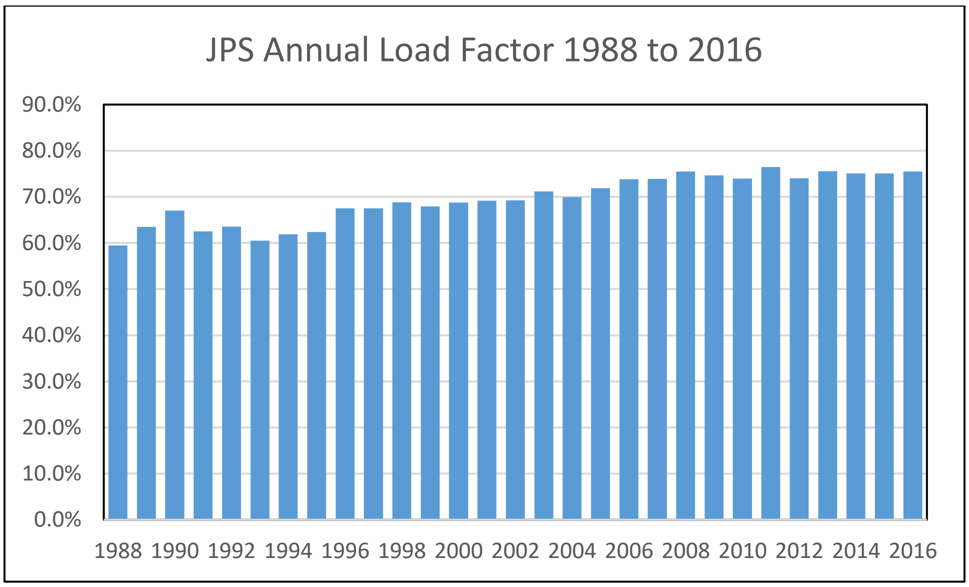


Figure 26: Historic load factor development in Jamaica

Source: JPS Historical Demand and Generation (all existing records to Sept 17) from JPS

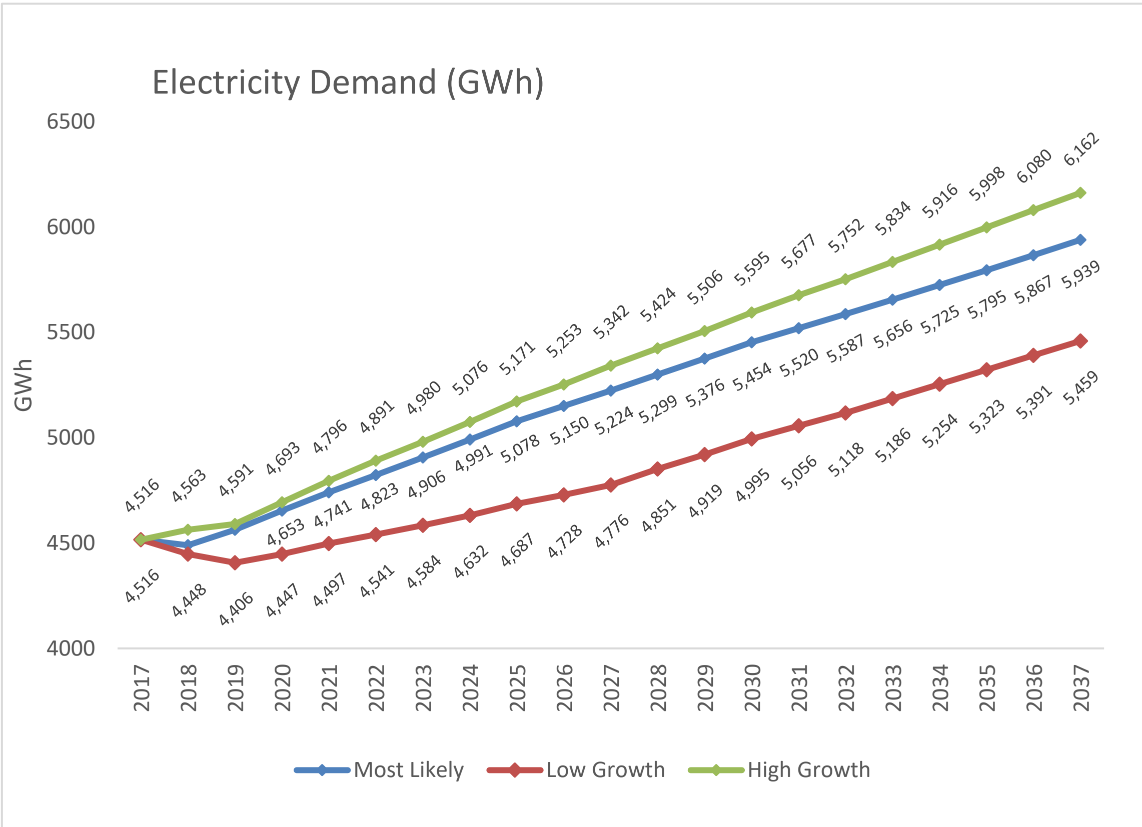


Figure 27: Total electricity demand forecast for Jamaica across different assumptions

Figure 27 - 30 show the electricity and peak demand forecasts from 2017 to 2038 for the base, high and low load forecasts. The trend line in growth is steady over this time period and for each of the forecasts.

	Most Likely	Low Growth	High Growth
2017	4515.8356	4515.8356	4515.83561
2018	4489.5373	4447.721	4563.221
2019	4563.671	4406.461	4590.577
2020	4653.4313	4447.128	4693.125
2021	4741.4101	4497.201	4795.533
2022	4822.7517	4540.534	4891.245
2023	4905.8655	4583.583	4980.008
2024	4990.836	4631.803	5075.631
2025	5077.7488	4686.661	5171.356
2026	5150.3301	4728.06	5253.29
2027	5224.1476	4776.062	5342.187
2028	5299.2526	4851.183	5424.157
2029	5375.6959	4919.476	5506.113
2030	5453.5291	4994.673	5594.947
2031	5520.0131	5056.18	5676.934
2032	5587.412	5117.605	5752.212
2033	5655.758	5186.015	5834.152
2034	5725.0832	5254.401	5916.144
2035	5795.4195	5322.696	5998.133
2036	5866.7806	5390.975	6080.19
2037	5939.2104	5459.301	6162.079
2038	6012.7408	5527.706	6244.024

Figure 28: Electricity Demand Forecast (GWh)

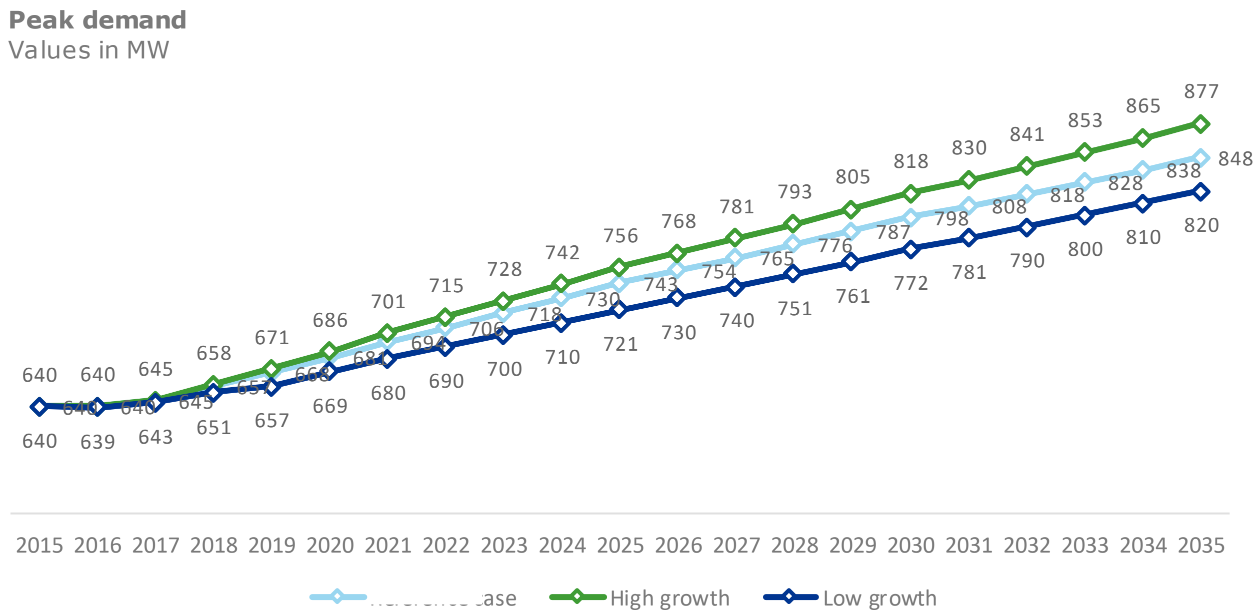


Figure 29: Peak demand forecast for Jamaica by scenario

	Base (MW)	Low (MW)	High (MW)
2007	629	629	629
2008	621	621	621
2009	644	644	644
2010	638	638	638
2011	617	617	617
2012	635	635	635
2013	625	625	625
2014	624	624	624
2015	640	640	640
2016	655	655	655
2017	667	667	667
2018	667	667	667
2019	668	657	671
2020	681	669	686
2021	694	680	701
2022	706	690	715
2023	718	700	728
2024	730	710	742
2025	743	721	756
2026	754	730	768
2027	765	740	781
2028	776	751	793
2029	787	761	805
2030	798	772	818
2031	808	781	830
2032	818	790	841
2033	828	800	853
2034	838	810	865
2035	848	820	877
2036	859	830	889
2037	869	840	901
2038	880	850	913

Figure 30: Peak Demand Forecast by scenario

Additionally, electricity demand was forecasted for each sector[47]. These results are shown in the following figures 31 – 33.

[47] Future IRP scenarios will estimate sector electricity demand directly.

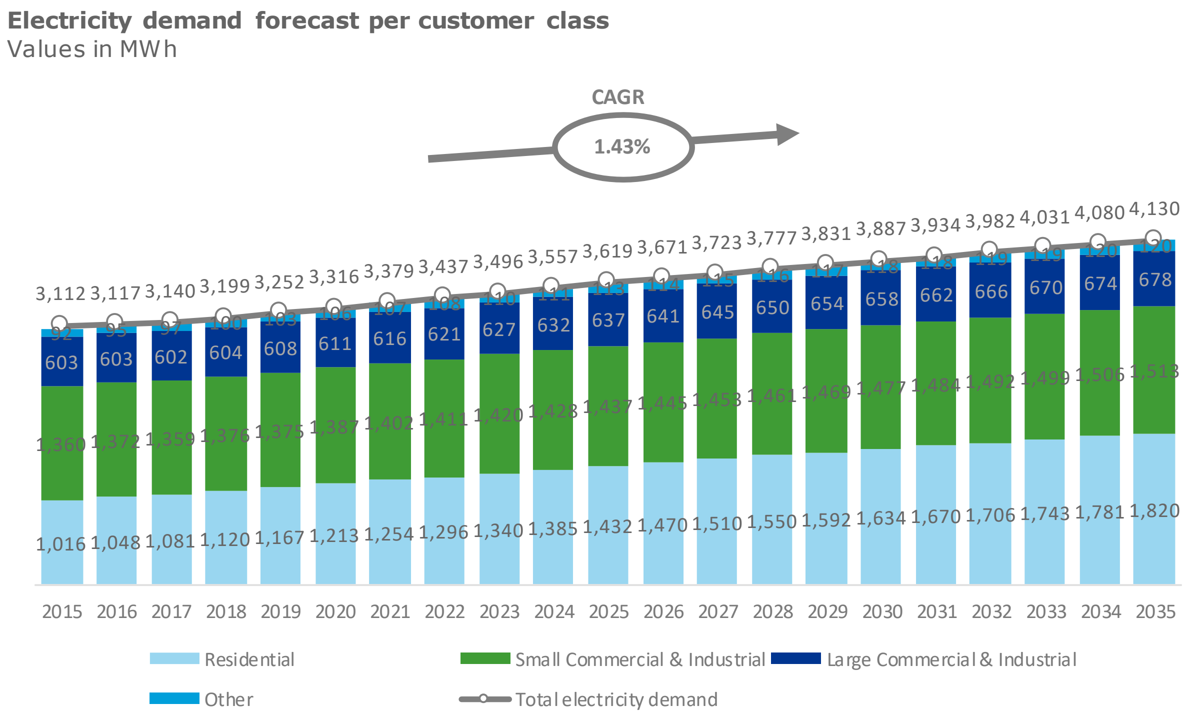


Figure 31: Electricity demand forecasted by sector for the most likely case

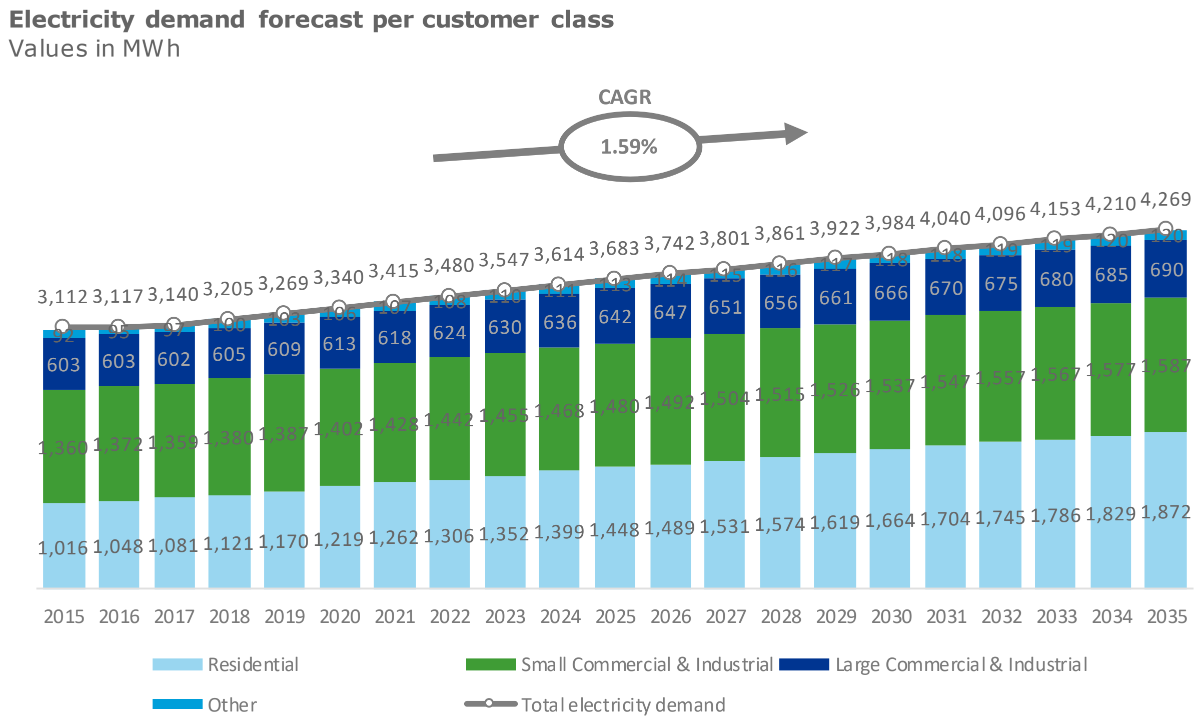


Figure 32: Electricity demand forecasted by sector for the high growth case

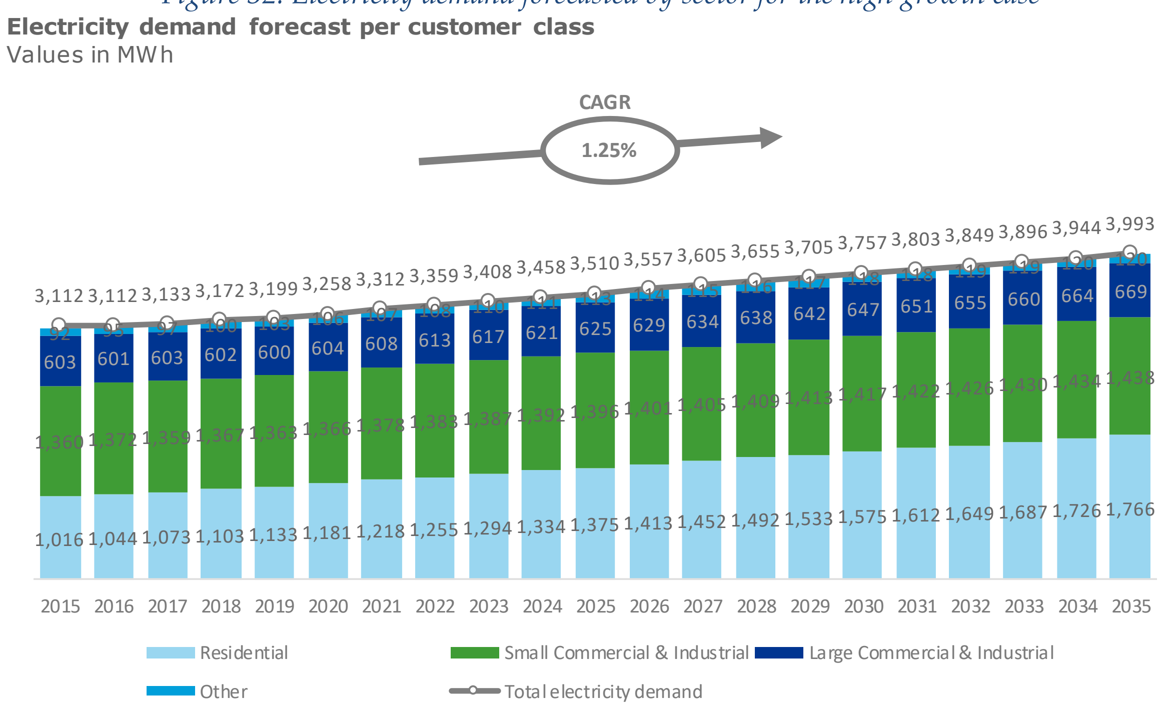


Figure 33: Electricity demand forecasted by sector for the low growth case

The electricity demand forecasts results shown in **Error! Reference source not found.** -33, show an average annual growth rate of around 1.43 percent for the Most Likely Case. Assuming more optimistic figures as the ones highlighted in the High Growth Scenario, this annual growth rate increases slightly to 1.59 percent. This is mainly driven by the effect of the GDP PPP (Gross Domestic Product Purchasing Power Parity) assumptions and of assumptions for interest rates. For the Low Growth Scenario, results show an average annual growth rate of around 1.25 percent.

3.2.5 Allocation of Load to Regions

Recognizing that different regions have different growth rates, the load forecasts above are allocated to different regions following a two-part process: allocation of load growth by customer segment, and allocation of load growth to substations or nodes within regions. For the purposes of the IRP, the annual load forecast by customer type (residential, commercial, industrial and other) is allocated to regions per load analysis[48]. The percentage of population in each geographic area that falls under the following rate classes are presented in Figure 34.

[48] Proprietary Study

Geographic Region	Percent of Rate Class Population in Geographic Area			
	Rate 10	Rate 20	Rate 40	Rate 50
Region 1: Kingston	27.5%	32.4%	45.4%	35.9%
Region 2: East	25.0%	15.6%	15.9%	23.1%
Region 3: North	20.5%	23.7%	20.4%	19.2%
Region 4: West	27.0%	28.3%	18.3%	21.8%

Figure 34: Percent of Rate Class Population in Geographic Area

In the second phase, the regional load is allocated regionally based upon historical patterns. Obviously, different nodes in the system may vary within region and future IRP efforts will explore some of those variations.

3.4 Supply Resources and Fuel Forecasts

Jamaica energy matrix is dominated by fossil fuels, as the general trend in the Caribbean. Despite this, Jamaica started an ambitious move towards renewables. This resource is available in the country and could represent a reliable and cost-effective solution for the short term, due to its quick deployment and decreasing costs. A summary of the renewable resources available, is presented below in Figure 35.

3.4.1 Wind

Like the rest of the Caribbean, Jamaica experiences consistent easterly trade winds throughout the year. Jamaica is located just to the north of the region of highest wind speeds generated by the Caribbean Low Level Jet, and thus wind speeds are moderate. As shown in Figure 35 below, the highest winds occur during two periods: December to February, and July to August. Typical winds at 50 meters above sea level during these windier periods are between 5.0 – 7.0 meters/second depending on terrain. During the rest of the year, weaker winds of between 3.5 – 5.0 meters/second are more common.

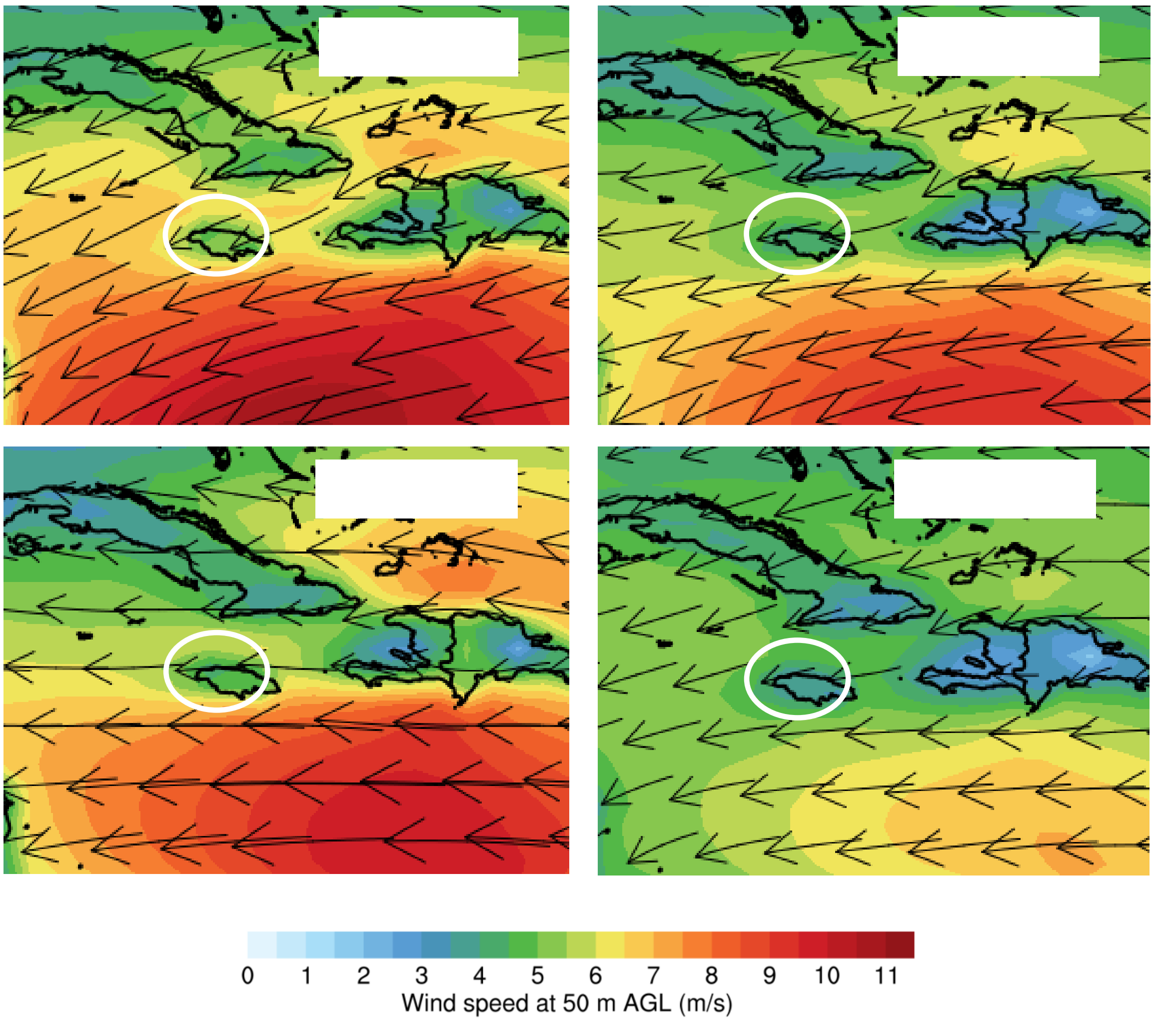


Figure 35: Jamaica seasonal wind speeds (from NASA MERRA dataset, 2004-2014)

The Blue Mountains on the eastern end of the Island rise to over 2000 meters and are well exposed to the predominant easterly winds, however the very rugged mountain terrain would make it extremely difficult to construct a wind project. Of more interest is the south west of the Island around Spur Tree and Malvern which have large areas of open land sloping gently towards the east as shown below in Figure 37. Here the combination of wind resource and ease of construction are likely to result in more attractive wind farm economics.

There are 101 MW of existing wind in Jamaica. These wind plants are in the same local area; connected to the same substation'; and use the same wind profile. The generation per MW installed that is used for each of the wind plant locations is shown Figure 366 below. The average capacity factor for the wind plants is 38 percent. For the 101 MW, the projected annual energy is 336,208 MWh.

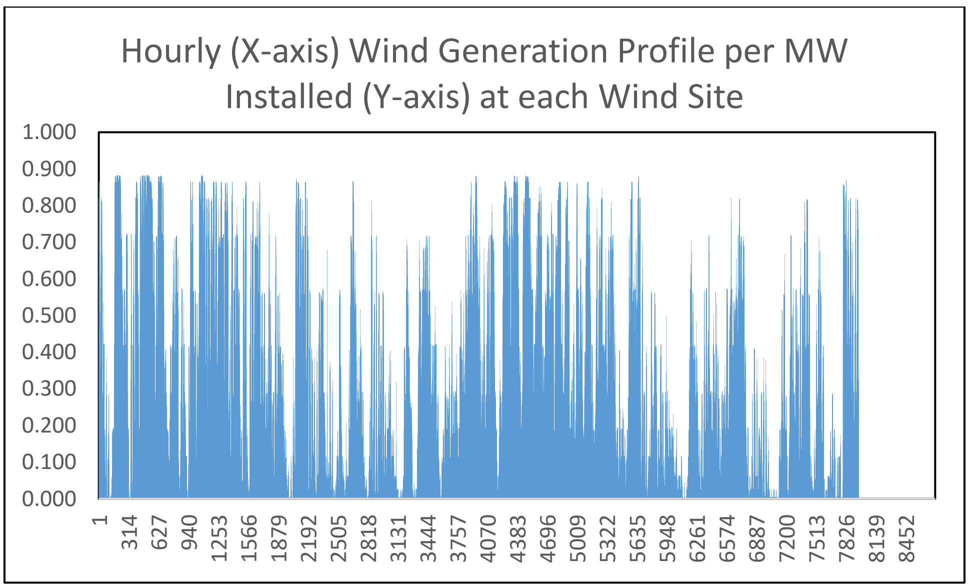


Figure 36: Wind Generation profile per MW installed

Figure 37: Jamaica Terrain Map

3.4.2 Solar Photo-Voltaic (PV)

For the purposes of this study, the solar resource is measured using the NASA and NREL Global Horizontal Irradiance (GHI) datasets. Across the study area, the solar resource is greater than the minimal solar irradiance for viable solar PV installation as defined by NREL and therefore the solar resource is not considered as the principal barrier for solar energy development in the study area. However, a spatial variation in the solar resource can still be observed from country to country; in general, eastern Caribbean islands have a higher solar energy resource than Central America.

Jamaica experiences relatively strong solar resource, with an average yearly GHI of 5.8 kWh/m2/day. The resource is relatively consistent across the island in the range of 5.5-6.0 kWh/m2/day, though the southern and western parts of the island exhibit the strongest resource.

There are two solar sites located in Jamaica. The first site is an existing 20 MW plant. The second is a 37 MW plant which was commissioned in 2019. These two sites are located in the same general location and therefore will use the same annual capacity factor and generation profile. The combined average hourly generation profile (MWh) per MW of solar installed is shown in the figure 38 below to show the potential impacts of solar of system generation.

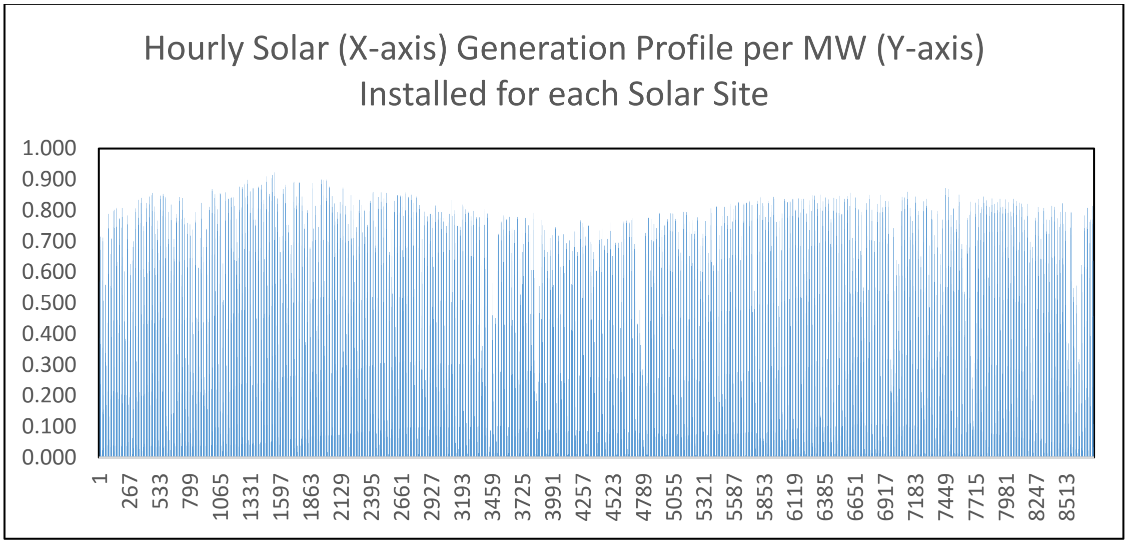


Figure 38: Hourly solar generation profile per MW installed

The two sites combined have a generating capacity of 57 MW with an annual capacity factor of 21 percent. The projected annual energy from these two plants is 104,457 MWh.

3.4.3 Biomass

In undertaking a high-level analysis of the available biomass resource, data from the Food and Agriculture Organization of the United Nations (FAOSTAT) have been used. Biomass from both forestry and agricultural sources is considered.

Biomass resource in Jamaica is relatively low, with an average annual energy production of less than 100 GWh. Sugar cane is the primary biomass resource. Major sugar cane areas are in the north western, eastern (St. Thomas), south western (Frome) and south-central parts of the island.

There is one biomass plant with a generating capacity of 5 MW. It is modelled as a must run unit with a capacity factor of 95 percent for an annual energy generation of 46,105 MWh.

3.4.4 Small Hydro

Jamaica has small hydro resources with a potential in the order of 6,000 GWh per annum; however, the length of the rivers in general limits the small hydro potential.

There are 28.67 MW of existing hydroelectric power plants. The hydro plants are modelled as must run plants with a maximum generation of 26.7, an annual generation of 152,612 MWh and a capacity factor of 60.7 percent. The hourly hydro generation profiles were provided by JPS for each hydro unit. These were combined and averaged to produce one profile. The average hourly hydro generation profile (MWh) per MW installed is shown in Figure 39 below. This hydro generation profile represents the average of all the hydro generation plants to show the combined contribution of hydro generation to the grid.

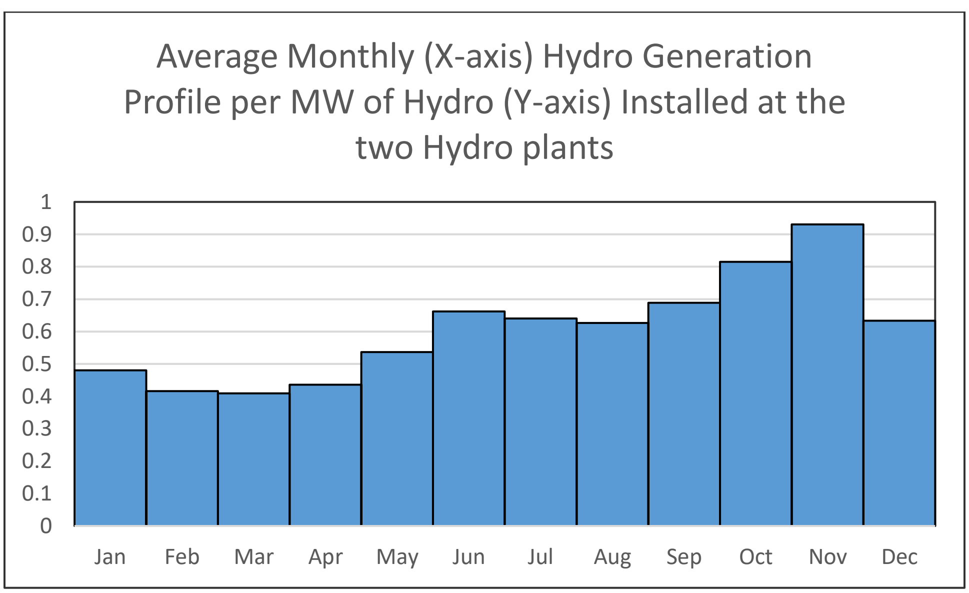


Figure 39: Hydro generation profile

3.4.5 Generation assets

As it is shown in Figure 40, Jamaica's generation capacity has steadily increased over the past 50 years.

Capacity exceeded 400MW in 1985 with the opening of the Rockfort power station. Eight years later capacity exceeded 500MW for the first time with the expansion of the Bogue power station. In 1996 and 1997 there was the entry of two IPPs in the market (JEP and JPPC) increasing the capacity to 650 MW. With the installation of the first combined cycle units in 2002-2003 capacity reached 805MW.In 2014 the generating capacity reached 932.5MW due to the commissioning of JPS' Maggotty Hydro Plant, which increased JPS' capacity by 1 percent to 640.6 MW.

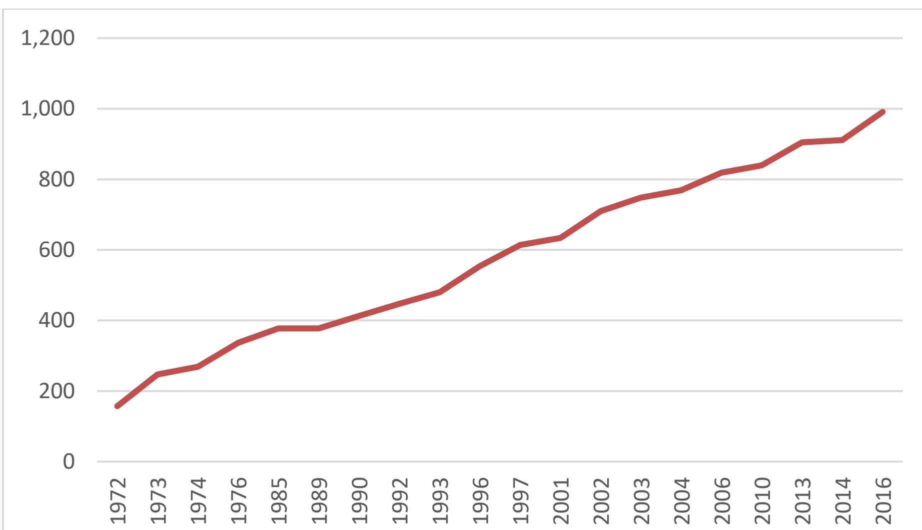


Figure 40: Jamaica installed capacity, 1970-2016, MW (Y-Axis) and year (X-axis)

Source: Inter-American Development Bank, RG-T2386 Energy Dossier, Humpert, 2015

The Jamaica Public Service Company is the largest operator with a capacity of 643.14MW. It has signed several Power Purchase Agreements with seven Independent Power Producers (IPP). These IPPs contribute for an additional capacity of 298.36MW. The largest of the IPP are the Jamaica Energy Partners (JEP) operating 124.36MW, followed by West Kingston Power Partners (WKPP) with 65MW, Jamaica Private Power Company (JPPC) with 60MW, Jamaica Aluminum Company (JAMALCO) with 11MW and Wigton Windfarm Limited (Wigton) with 38MW. 2016 additional capacity adds up to 80.3MW The general comment about the assets operating today is they are quite old and inefficient power plants. Therefore, one of the main targets of the Jamaica National Energy Plan is to decommission old facilities while converting some of them into LNG consumers, improving their efficiency.

3.4.6 Electricity Generation

Figure 41 below shows the evolution of the installed capacity in Jamaica as it should be by the end of 2018. Despite recent efforts to diversify its generation capacity, Jamaica continues to rely heavily on fossil fuel-based electricity generation.

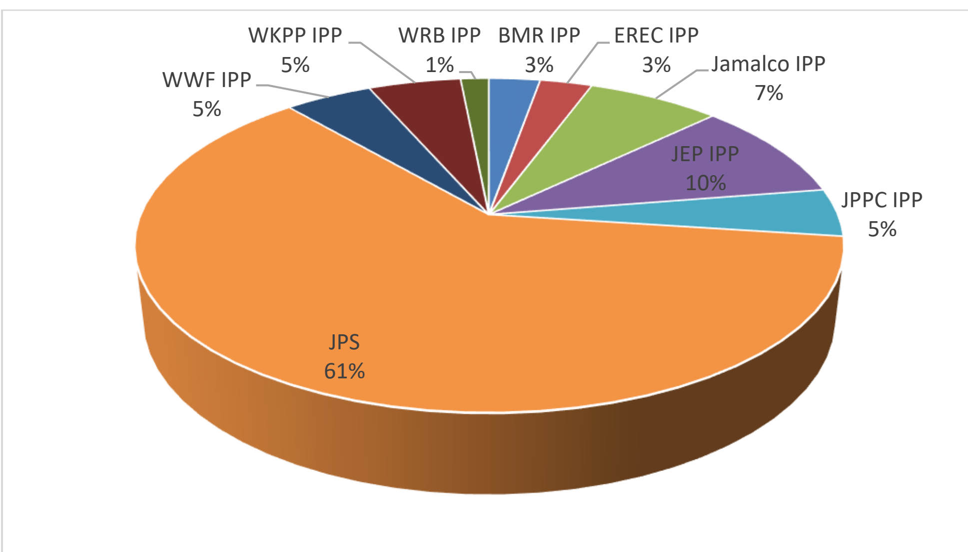


Figure 41: 2018 Installed power in Jamaica by Owner

Source: Office of Utilities Regulation

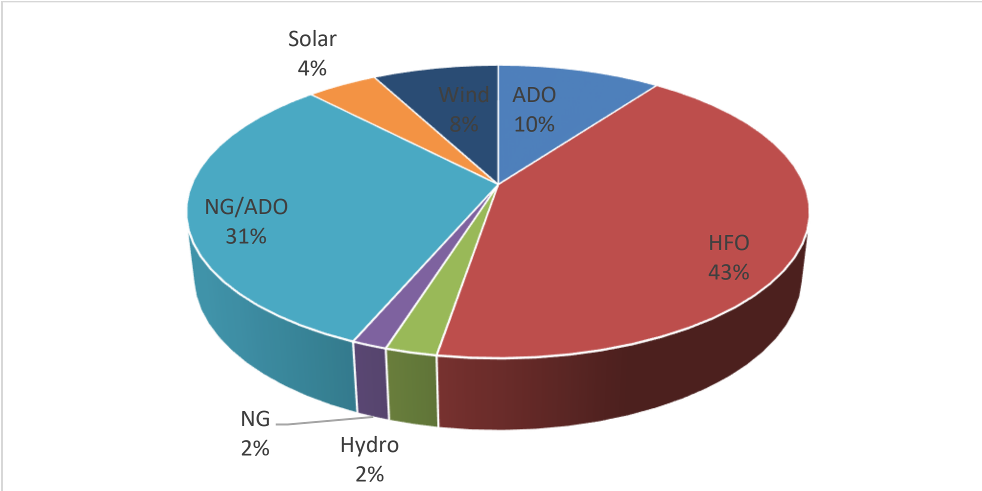


Figure 42: 2018 Installed power in Jamaica by fuel type

Source: Office of Utilities Regulation

Regarding the fossil fuel assets, these are in good condition, although a lot of capacity is saved for peak hours. The refurbishment of the Automotive Diesel Oil (ADO) and Heavy Fuel Oil (HFO) burning plants to Liquefied Natural Gas (LNG) fueled plants has already happened at Bogue; and Old Harbor is expected to be decommissioned in the coming years to be replaced with the new 190MW LNG-powered plant. These changes should increase the efficiency (conversion of fuel to electricity) for the system. Besides this, the penetration of renewables, through wind and solar facilities, should also act as a cost reducing factor, as Renewable Energy (RE) costs are lower and avoid imports of fossil fuels. This might have a positive effect not only on the power sector, but on the national economy. Regarding hydro, Jamaica's assets have been refurbished in the recent past, and their capacity factors are quite high in most of the cases (above 75%). This allows a higher penetration of other intermittent sources of energy.

Most of the units provide power factor in the inductive side, around 0.9-0.95, Going forward reactive power management will be crucial to the operation of the grid. There will be the need to provide the relevant support to the grid infrastructure in terms of additional investments to be done in the reactive power regulation.

The system has limited low voltage ride through capabilities, in terms of plants that could cope with a low voltage fault. This has proven to be an issue in other island markets, and low interconnected systems, especially on the ones in which renewable power plants, such as photovoltaic (PV) plants or wind farms, does not have these capabilities. It is recommended that this is evaluated to avoid issues in the future as renewable energies penetrate the system.

3.5. Fossil Fuel Forecast

This section describes fuel specifications and forecast assumptions which support the Jamaican Ministry of Science, Engineering and Technology (MSET) Integrated Resource Planning efforts. A forecast is provided based on public data sources[49]. Fossil fuel prices

To date, most Caribbean fuel use is supplied by refined petroleum products such as diesel fuel oil and heavy fuel oil refined products[50]. Recently alternative fossil fuels have included Natural Gas and Liquefied Petroleum Gas (LPG).

Refined petroleum product (i.e., diesel, heavy fuel oil, liquefied petroleum gas) spot forecasts are recommended to be derived from a publicly available source[51] and to capture international market influences driving fuel economics.

Natural gas spot price forecasts are driven from supply/demand trends and tanker and storage implications for natural gas markets.

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[49] Energy Information Agency, International Energy Outlook.

[50] Heavy Fuel Oil-Is that the final measure? Raj Mahadevaiah, P.E., C.G.W.P. Presented at The 2006 CARILEC CEO Symposium, Tampa, Florida

[51] Energy Information Association, Annual Energy Outlook, 2016, http://www.eia.gov/outlooks/aeo/.

3.5.1 A note on Power Purchase Agreement Costs for Fossil Fuel Plants

Jamaica Public Service (JPS) owns 72 percent of generation capacity (510 MW of the 836 MW total generation capacity is fossil fuel generators) of which two plants (114MW at Bogue and the 190MW at Old Harbour) are combined cycles. The remaining capacity is owned by private generators (Independent Power Producers) under Power Purchase Agreements. These ventures include Jamaica Energy Partners (JEP), Jamaica Private Power Company (JPPC) and Jamalco. Jamaica Energy Partners is an Independent Power Provider that began commercial operations in October 1995, through its ownership of the Doctor Bird Power Plant, burning Heavy Fuel Oil. Jamaica Private Power Company Ltd (JPPC) owns and operates two 29.8MW slow speed generation units, two heat recovery steam generators burning heavy fuel oil, and a 4.2 MW steam turbine generator at a plant located in Kingston. JPPC has a 20-year PPA with Jamaica Public Services Company to sell all its capacity and electricity production. This PPA expires in January 2018, but has been extended to December 2024. JPPC represents over 20 percent of the power needs of Kingston and provides power to the eastern half of the island.

Jamalco is a HFO fired cogeneration plant as part of bauxite mining operations but today it barely serves energy to the grid. The existing cogeneration plant will be replaced with a new 94 MW grid connected LNG-fueled CCGT power plant in 2020.

Renewable power plants such as Wigton Wind Farms and Blue Mountain Renewables, also have power purchase agreements. There are also two solar plants consisting of WRB, which started operations in 2017, and Eight Rivers in 2019. Integration of the renewable energy is done by the dispatch center in Kingston, operated by JPS.

In the IRP, each of these PPA plants, excluding renewable plants, will be modelled as dispatchable generation alongside utility owned generation. The renewable power plants of wind and solar are non-dispatchable and must be scheduled before any other resources. Fuel prices are discussed herein. Dispatch rules for renewable generation will be aimed to maximize the penetration in the grid of these energies, therefore unless technical issues appear, these will be dispatched on a 100% basis.

3.5.2 Automotive Diesel (ADO) Forecast

The U.S. Energy Information Administration (EIA) provides a refined petroleum product forecast for the Annual Energy Outlook (AEO)[52] using the National Energy Modelling System (NEMS), a large-scale model of energy supply, demand, prices, and technologies. One component of NEMS is the Petroleum Marketing Module (PMM), which describes the petroleum refining industry and petroleum product transportation and marketing[53]. The forecast is presented and correlated to Jamaican spot fuel prices for US Gulf Coast and for Caribbean Cargoes.

Using this reference, in consultation with the OUR, the forecast of ADO prices and trends for the IRP study is shown below in Figure 43 and Figure 43A. In US$, the ADO fuel prices grow from $13.27/MMBtu in 2018 to 21.35$/MMBtu in 2038.

3.5.3 Heavy Fuel Oil (HFO) Pricing

In consultation with the OUR, HFO fuel prices were derived for the IRP study. The year by year costs is displayed in Figure 43 below with the ADO prices for comparisons. It is projected that HFO will be priced at US$9.09/MMBtu at Old Harbour in 2018 and increase to US$15.41/MMBtu in 2038. Figure 43A below graphically display the fossil fuel costs and the trends used in the study.

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[52] U.S. Energy Information Administration, Annual Energy Outlook 2017 (AEO2017), DOE/EIA-0383(2017) (Washington, DC, January 2017).

[53] U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2017

	Old Harbour HFO	Hunts Bay HFO	Rockfort HFO	ADO
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2018	9.09	9.19	9.09	13.27
2019	10.19	10.29	10.19	13.94
2020	12.32	12.42	12.32	16.80
2021	13.07	13.17	13.07	18.02
2022	13.21	13.31	13.21	18.44
2023	13.24	13.34	13.24	18.71
2024	13.30	13.40	13.30	18.88
2025	13.38	13.48	13.38	18.96
2026	13.60	13.70	13.60	18.94
2027	13.76	13.86	13.76	19.08
2028	13.82	13.92	13.82	19.24
2029	14.06	14.16	14.06	19.53
2030	14.23	14.33	14.23	19.68
2031	14.52	14.62	14.52	19.92
2032	14.62	14.72	14.62	20.11
2033	14.76	14.86	14.76	20.35
2034	14.88	14.98	14.88	20.60
2035	15.02	15.12	15.02	20.72
2036	15.04	15.14	15.04	20.85
2037	15.33	15.43	15.33	21.29
2038	15.41	15.51	15.41	21.35

Figure 43 HFO and ADO Fuel rates for the study term of the IRP

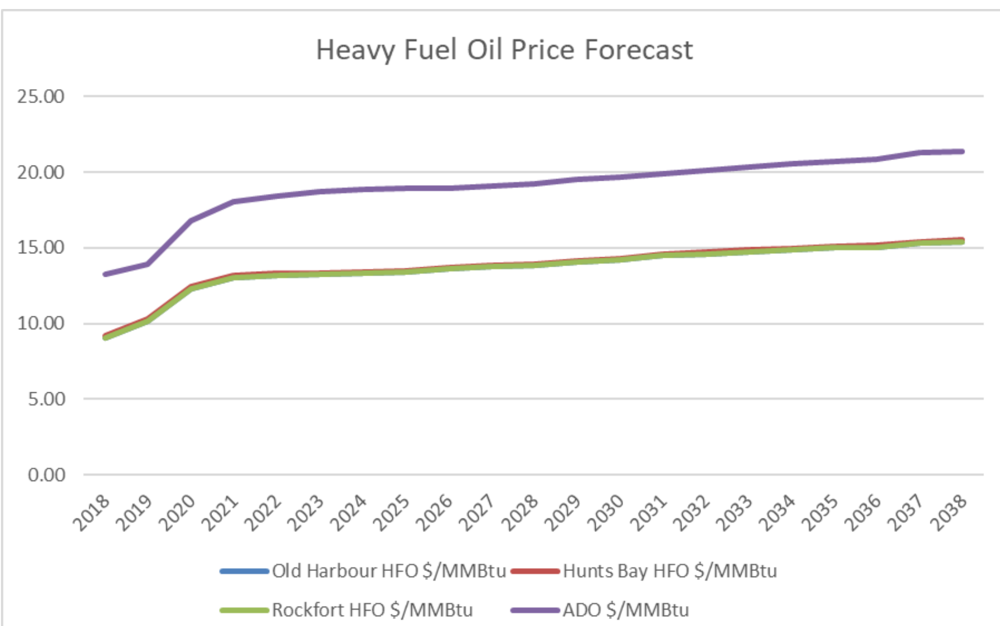

Figure 43A HFO and ADO Fuel rates for the study term of the IRP

3.5.4 Caribbean Natural Gas (NG) Pricing

In consultation with the OUR, LNG fuel prices for the IRP study period were developed using World Bank Forecast for Henry Hub Prices along with other sources such as the US EIA Forecast. The terms of the Existing Fuel Contracts for Bogue, Jamalco, and the JPS 190MW Plant were used to derive of a fully loaded LNG fuel rate. The LNG rate for the JPS CCGT at Bogue is 10.30/MMBtu in 2018 and increases to 11.95 $/MMBtu in 2038. The LNG price for the Jamalco plant is 8.32$/MMBtu in 2018 and increases to 9.57$/MMBtu in 2038.

	NG Henry Hub $/MMBtu	Bogue Fuel Price $/MMBtu	SJPC Fuel Price $/MMBtu	NFE Jamalco Fuel Price $/MMBtu
2018	2.80	10.30	8.36	8.32
2019	2.90	10.05	8.46	8.42
2020	3.00	10.15	7.81	8.52
2021	3.10	10.25	7.91	8.62
2022	3.20	10.35	8.01	7.97
2023	3.30	10.45	8.11	8.07
2024	3.40	10.55	8.21	8.17
2025	3.50	10.65	8.31	8.27
2026	3.60	10.75	8.41	8.37
2027	3.70	10.85	8.51	8.47
2028	3.80	10.95	8.61	8.57
2029	3.90	11.05	8.71	8.67
2030	4.00	11.15	8.81	8.77
2031	4.10	11.25	8.91	8.87
2032	4.20	11.35	9.01	8.97
2033	4.30	11.45	9.11	9.07
2034	4.40	11.55	9.21	9.17
2035	4.50	11.65	9.31	9.27
2036	4.60	11.75	9.41	9.37
2037	4.70	11.85	9.51	9.47
2038	4.80	11.95	9.61	9.57

Figure 44 Summary of Natural Gas Spot Fuel and Delivered Costs Used

Figures 44 and 44A compare the LNG fuel rates for different sites used in the IRP study.

The LNG fuel rates are significantly lower than the ADO and HFO fuel rates. However, the fuel escalation rates tend to follow the same annual escalation rates.

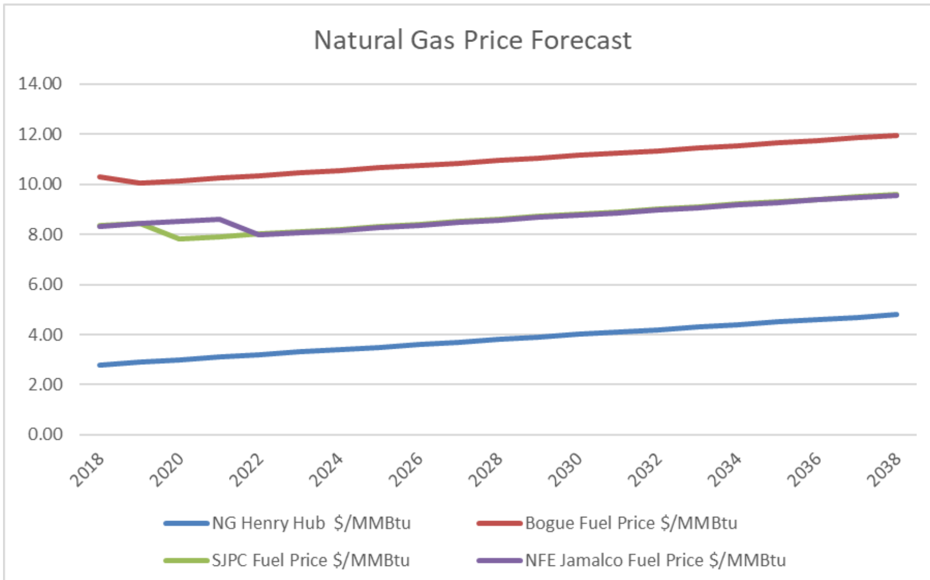

Figure 44A Summary of Natural Gas Spot Fuel and Delivered Costs Used

3.6 Modeling Existing and Future Supply in the IRP

All the available existing supply technologies were reviewed based on the lifecycle stages of the technologies. Most mature technologies were considered that fit the criterion of energy reliability. The Revolutionary technologies will be considered for future updates to the IRP when further information is available, and Technology tested and proven. The model selected the technologies for future supply was based on the capital cost and variable costs of the units. All the technologies do have varying degrees of constraints and are described below, with detail provided in Appendix C, ranging from cloud cover intermittencies to drought periods. These constraints will affect the capacity factors which will also impact the selection by the model to meet the anticipated demands.

An overview of the Jamaica Electricity sector is provided in Figure 45 below.

Interconnected System Context			
Installed Capacity, 2018 Expected (MW)	974	**Peak (MW)**	657
Electric Consumption Growth 2015-2020	1.93%	**Electricity Rates (US$/MWh)**	100-350 depending on the consumer. No wholesale cost of energy.
Interconnection & Permitting			
Permit needed for interconnection?	Yes	**Interconnection Permit issued by:**	JPS
Regional interconnection	No	**Grid Code**	Yes. Rules and regulations in place but additional being built by OUR
Environmental Permits?	Yes	**Environmental Permit issued by:**	National Environment and Planning Agency (NEPA)
Other permits	Yes	**Permit issued by:**	Municipalities

Figure 45: Overview of current Jamaican electricity sector

The commissioning of the Maggotty Hydro Plant in 2014 brought renewables as a proportion of net electricity generation to 6.3 percent. There are plans for further expansion of new renewable energy projects. These advances are expected to increase renewable energy in more than 11.5 percent contributing for the government's renewable target.

3.6.1 PLEXOS[54] Modeling of Capacity Expansion

To simulate future electricity grid conditions, PLEXOS and Power Factory was used. The objective function of seeks to minimize the net present value of capital costs plus fixed operations and maintenance costs plus production costs.

In PLEXOS, the core formulation for capacity and transmission expansion includes the seven equations and parameters below:

[54] PLEXOS is a commercially available software owned and licensed by Energy Exemplar.

Equation 1: Minimize the cost to serve load from various supply sources:

$$\sum (y) \sum (g) DFy \times (BuildCostg \times GenBuild(g,y))$$
$$+\sum (y) DFy \; X \; [FOMChargeg \times 1000 \times PMAXg (Unitsg + \sum i \leq y \; GenBuild \; g,i)]$$
$$+\sum (t) DFt \in y \times Lt \times [VoLL \times USE \; t + \sum g \; (SRMCg \times GenLoadg,t)]$$

Where DF = Discount Factor (cost of capital) in year y

BuildCostg = capital cost of the unit in $/KW for generator type g

GenBuild (g,y) is the capacity of generator type g sited in year y for units in a plant

FOMChargeg is the fixed operating and maintenance charge of generation type g in $/kW multiplied by 1000 to convert to MW units

PMAXg is the Maximum Capacity of generator type g

Unitsg is the number of units sited

Lt is the load at time t

VOLL is the value of lost load (for this IRP, $3,250/MWh was used)

USEt is the unserved energy at time t

SRMCt is the short run marginal cost of generation to serve the energy

GenLoadg,t is the generation loading by generator type g at time t subject to the following constraints

Equation 2: Load and Energy must balance across generator type g and year t

$$\sum (g) \; GenLoad(g,y) + USEt = Demandt \; \forall t$$

Equation 3: Generator dispatch cannot exceed its limits

$$GenLoad(g,t) \leq PMAX (Unitsg + \sum i \leq y \; GenBuild \; g,i)$$

Equation 4: New Generation Capacity cannot exceed the candidate generation offered:

$$\sum i \leq y \; GenBuild \; g,i \leq MaxUnitsBuiltg,y$$

Equation 5: Integrality, or ensuring that only capacity of a certain size is sited:

GenBuild(g,y) integer

Equations 6: Electricity storage charge and discharge limits are respected and used only for relief of transmission congestion or as a substitute to balance variable generation such as solar or wind resources.

The formulation of the battery expansion is very similar to a generator. All the cost of a battery (Build Cost, VOM, FOM and other costs (UOS Charge)) are captured when a battery is decided to be built. The main difference of the battery expansion logic is that the storage capacity is also expanded whenever a unit is built.

Similar to generator, the charging & discharging power is expanded.

Generation (Discharge)≤ MaxPower (Unitsg + ∑ i≤y GenBuild g,i)

Load(Charge) =< MaxLoad(Unitsg + ∑ i≤y GenBuild g,i)

The MaxVolume of the storage side is also extended.

EndVolumn =< MaxCapacity(Unitsg + ∑ i≤y GenBuild g,i)

Constraints 7: The Transmission network model is derived from recent Digsilent Power Factory[55] models and represents the 69kV and 138kV transmission system. Each substation at that voltage and the transfer limits in MW will limit electricity flows on the electric grid. In addition to current transmission lines, optional transmission lines and corresponding transformers were also included in the cost optimization.

In Power Factory, contingencies, additional constraints, transient and dynamic stability, re-enforcement upgrades and equipment costs were developed and implemented as noted in Section 3.7.

[55] Power Factory is a commercial available software product owned and licensed by DIgSILENT. Additional constraints and/or investments were added from the power flow stability analysis.

Existing and Future Candidate Generators are modeled as:

- [56]dispatchable, technologies which by their design and/or use, are able to respond to requested changes in output;
- non-dispatchable, or forecasted output which are technologies unable to respond to requested changes in output;
- must-run which are resources required to run due to technical constraints;
- firm generation capacity reserves.

The IRP simulates Jamaica's current dispatch process[57]. Historical planned outages are incorporated into hourly dispatch. Any outages which restrict safety, reliability and system security are restricted or will have contingencies to substitute. While JPS uses a similar day load forecasting; dispatch is based upon daily historical patterns across the IRP time horizon. Dispatch will use day ahead Resource Scheduling and Unit Commitment, and hourly schedules are calibrated to actual results. In the following, how current generation technologies are dispatched and operating constraints modeling is described. Future generation capacity is modeled as candidate units and will be selected according to cost minimizing algorithms

Steam Turbines

Steam turbine plant capacity includes Old Harbour 2, 3 and 4 and Hunts Bay B6. Old Harbour Units 2, 3 & 4 and Hunts Bay B6 were scheduled to be retired in 12/31/2018 but have been extended to after (2020/21) the OH 190 MW CCGT is commercial. Old Harbour Unit 1 has been out of service since 2008.

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[56] MacFarlane, Raymond, System Planning and Control: Generation Dispatch Process, February 25, 2008

[57] ibid

Existing Reciprocating engines

Reciprocating engines are found at the Rockfort, JPCC and Doctor Bird plants. JPCC and Doctor Bird plants are under power purchasing agreements. Rockfort units 1 and 2 provide 40 MW of total capacity using slow speed diesel turbines (heavy fuel oil).

Existing Simple Cycle Gas Turbines

Simple cycle gas turbines include Hunts Bay and Bogue units. The Hunts Bay units of GT5 and GT10 have a generating capacity of 53.7 MW. Bogue GT 8 has been out of service from 2011. The Bogue GT3, GT 6, GT7, GT 9 have a total generating capacity of 77.5MW. The total gas turbines capacity to-date (before the 190MW) is 130.5 MW, Excluding GT 12 (38 MW) & GT 13 (38MW) which are part of the Bogue Combined Cycle. It is dispatched respecting forced, planned outage rates and ramp rates. Startup costs, variable, fuel (using heavy fuel oil) and operating and maintenance costs are used to derive the merit order the unit in dispatch. Hunts Bay and Bogue simple cycle configurations can also be used for spinning reserves.

Combined Cycle Gas Turbines

There are two combined cycle plant and two planned plants .The existing plants are the Bogue plant consisting of two Gas turbines and one steam turbine and the 190MW Old Harbor plant. In December 2016, the two Bogue Gas Turbines were converted from automotive diesel oil (ADO) to natural gas (LNG). The OH CCGT consists of three turbines, each with a capacity of 37.7 MW, and a steam turbine with a capacity of 80 MW for a total generating capacity of 193 MW. All three plants burn LNG. An additional Combined Cycle Plant, New Fortress Energy (NFE) CCGT plant (NFE CCGT 94) is scheduled for commercial operation in 2020. The NFE CCGT consists of two 32.5 MW turbines and one 29.1 MW steam turbine for a total generating capacity of 94 MW.

Cogeneration

Cogeneration is modeled as separate steam and combustion turbine cycle. Jamalco cogeneration facility was initially contracted to supply firm capacity to System, however, this capacity has been unavailable due to the reconfiguration of the plant by Jamalco, which has resulted in Jamalco incurring liquidated damage charges going back more than 5 years. Based on JPS generation data, the average capacity being exported to the System is diminished to a level of approximately of 0.5 MW. There is another cogeneration plant named Jamaica Boilers that has a generating capacity of 1.7 MW. This plant can be used by JPS during emergencies and produces only dump energy to JPS. This plant will not be included in the IRP study.

Hydro

Hydroelectric resources consist of Maggotty, Upper and Lower White River, Roaring River, Rio Bueno A/B and C/Spring plants with capacities as shown in Figure 46. The plants maintain high capacity factors which are above 70 percent. Some hydroelectric stations underwent retrofits in the early 2000s where electronics and controls were updated.

Plant	MW
C/ Spring	0.77
L/ White River-0	4.75
Maggotty -1	3.15
Maggotty -2	3.15
Maggotty -3	6
Rio Bueno A-0	2.5
Rio Bueno B-0	1.1
Roaring River-0	4.05
U/ White River-0	3.2
Total	28.67

Figure 46: Existing Hydro units

The generating capacity was held constant for each plant based on a historical year generation data. The total monthly generation capacity for all the hydro plants is shown in Figure 47. Annual hydro generation varies from year to year based on the hydrological conditions. For the IRP study, the hydro units were modeled as run-of-river as shown in Figure 46.

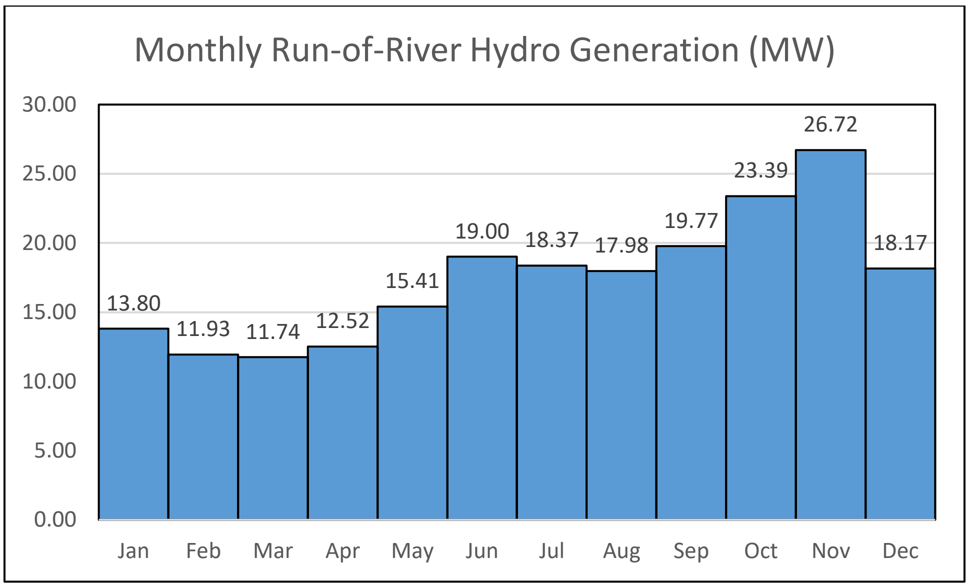

Figure 47: Monthly run of river generation (MW on Y-Axis)

Power Production Agreement Resources

All purchase power agreements (PPA) signed by JPS are bilateral contracts between the utility and third parties. Commercial terms of those contracts are not provided with this IRP document, but a description of the technology and how they are modeled (forecast or dispatched) is provided below.

JPS has signed several PPAs with independent power producers (IPP) contributing an additional capacity of 325.7 MW. JEP contributes a total of 124 MW through two barges, Doctor Bird Power Barge 1 and 2, which run on low or medium speed Diesel using HFO. West Kingston Power Partners' (WKPP) Hunts Bay-connected plant contributes 65.5 MW of capacity through a reciprocating engine using Medium Speed Diesel burning Heavy Fuel Oil (HFO). Jamaica Private Power Company (JPPC)'s two reciprocating engines using Slow Speed Diesel contribute 60 MW of capacity in the Rockfort Area (East Kingston).

Planned and Potential Battery Storage Systems

In the Jamaican context, the most viable applications for stand-alone Battery Energy Storage System (BESS) are:

- Customer sited – Customer bill management;
- Utility sited – Renewable management through renewable smoothing and time-shifting or avoiding more expensive transmission line builds or re-enforcements.

For the analysis in the Integrated Resource Plan, only transmission interconnected BESS will be used[58] (utility sited) and the following parameters are used:

- Capital Cost in 2018 US dollars: $816/kW
- Operating and Maintenance Cost in 2018 US dollars: $50/kW per year
- Power: 24.5 MW
- Energy: 6 MWh
- Efficiency: 91%

It is assumed that a combination of two technologies are used: (mechanical, or flywheel) and chemical (Lithium/Ion). The expected life of the hybrid storage system is ten years. For modelling purposes, storage has a 15-minute duration. The unit will be sited on the Hunts Bay 6 node on October 1, 2018 and provide regulating balancing reserves. Future potential BESS systems based upon the parameters used are modeled on the electricity grid.

[58] Future scenarios may include customer sited storage as noted in Chapter 5.

Current and Future Candidate Stand-Alone Solar PV

Rapidly falling costs, evolving business models, social consciousness of green technologies, and government incentives have led to a boom in solar PV deployment around the world. Most solar PV systems presently are equipped with an inverter interface that maximizes Alternating Current (AC) power output to the electric grid. The IRP modeled configuration based upon existing configurations. There are two existing solar plants; the WRB plant of 20 MW and the Eight River plant of 37 MW. Both are in the same general location and therefore use the same solar generation profile. The hourly solar generation profile for the 57 MW of installed solar is shown below in Figure 48.

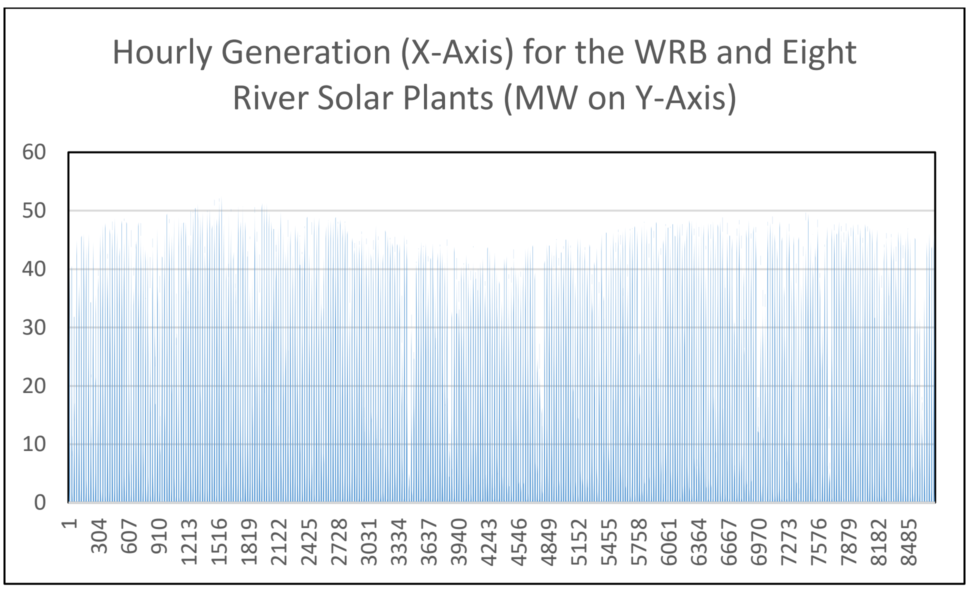

Figure 48: Solar Generation Profile for WRB and Eight Rivers Solar Plants

The two solar plants together produce energy at an annual capacity factor of 21.7 percent that is sold to JPS. This estimated solar produce is based on clear day average conditions. Solar generation will vary depending on the seasons and environmental conditions such as cloudiness, temperature, precipitation.

Current and Future Stand-Alone Wind Turbine Generators

When evaluating wind generation locations, it is important to consider siting constraints such as setback requirements due to noise and vibration limits, requirements for residential or commercial areas, roads, water bodies, provincial parks or conservation reserves. There are three wind plants that are located at the same general location. These are the Munro 3.2 MW, Wigton 1-2-3 and the BMR MW plants. These produce 101.3 MW of wind power at an annual capacity factor of 35 percent. The average hourly wind generation per MW of installed wind capacity is shown in Figure 50 below.

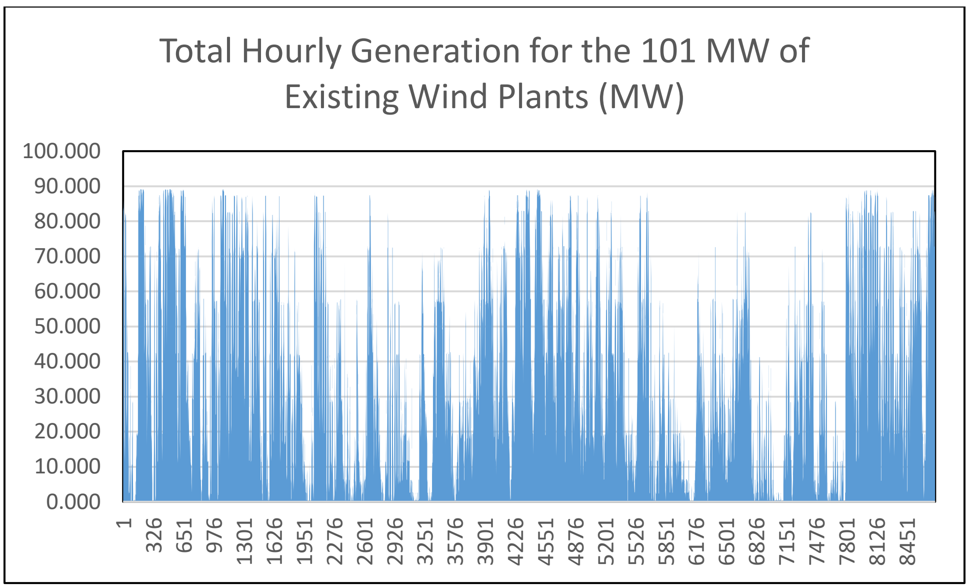

Figure 49: Total hourly wind generation for 101 MW existing wind plants

Candidate Thermal Plants

To meet future expansion needs both for firm capacity for reserves and to replace older units, a series of candidate thermal units are also modeled for various locations on the electric grid with capability of siting them (based upon feasibility studies or capability to connect to transmission[59]). A full list of candidate thermal plants is provided in Appendix B.

3.6.2 Grid Operating Conditions Used in the IRP

Within the Jamaican Electric Grid, several operating conditions are respected. Operating conditions are described in Figure 5051.

[59] Interconnection costs are calculated separately and discussed in Chapter 5.

Constraint	Operating Assumption	Rationale
Feasibility studies	Model limits on 69 kV and above.	Insufficient data at distribution level
Line Flow Limits	From Power Factory analysis	Standard Practice
Value of Unserved Energy	US $3500/MWh	OUR estimates
Loss of Load Probability to check siting of new capacity	2 days per year	JPS
Reserves: Planning	Firm, or thermal capacity at 20% of peak load	JPS
Generation Ramping Pmax, Pmin, planned maintenance, start up, min down times enabled	JPS	Based on JPS & OUR data, and typical values for generation types.
Planned maintenance	Generation only	No scheduled transmission outages
Generation Forced outage	Triangular distribution for outages duration and frequency set by generation type	Best Practice is to model forced outages by generation type

Figure 50: Plant Operational Constraints Modeled

Reserves

Reliable grid operation requires sufficient generating capacity be available to maintain frequency within limits and avoid load loss following transmission and generation contingencies[60]. For the purposes of the IRP, only firm capacity is specified as reserves (thermal and hydro).

Emissions

The guidelines for stack emissions from fuel combustion (i.e. generation of electricity from fossil fuels) focuses on three primary pollutants; Particulate Matter (PM), SO2 and NOx.[61] SO2 and NOx is monitored based on fuel source (i.e. HFO, ADO or LNG) rather than by sampling of stack emissions. Limits are established for the input sources for existing and new / proposed power plants. PM monitoring is required only for coal fired plants, oil fired plants and bagasse fired boilers. The guidelines established for these quantities are given in Figure 51 below. CO2 emissions are also of concern, but are not explicitly regulated.

Source	Segment	Pollutant	Target Value
Fuel Combustion	Oil Fired	PM	20% opacity with 40% opacity for 6 minutes per hour
	Oil Fired	NO_x	200 ng / J input
	Liquid Fuels	SO_2	3% Sulphur HFO 0.5 % ADO
	Gas Turbines > 50 MW	NO_x	140 ng / J input (water injection)
	Gas Turbines 20 - 50 MW	NO_x	300 ng / J input (water injection)
	Gas Turbines < 20 MW	NO_x	300 ng / J input
	Gas Turbines (All)	SO_2	1.1%
	Bagasse Boilers	PM	To be established

Figure 51: Emissions Guidelines

[60] NERC BAL-STD-002-0 Operating Reserves
[61] Ambient Air Quality Guideline Document, Natural Resources Conservation Authority, National Environment and Planning Agency, November, 2006

Maintenance Cycles

The maintenance cycles for the fossil fuel units were included in dispatch as part of the overall generation model. Annual maintenance days were provided by OUR and turned into annual percentages for inclusion in the PLEXOS model. Because no specific maintenance schedules were provided, PLEXOS uses a “distributed maintenance” concept which distributes the minimum repair time (another maintenance input) throughout the year until the requisite number of maintenance hours necessary to meet the maintenance rate are allocated. Obviously, during these periods, the subject generator is unavailable for dispatch during these periods. Other units experience both start-up and out of merit order operation as higher merit order units are outaged for maintenance. Figure 523 and Figure 534 below lists the inputs used for the PLEXOS model for maintenance outages.

Unit	Maintenance Outage Hours	Maintenance Outage Rate	Repair Time (hrs)
OH2	40	0.46%	15
OH3	40	0.46%	15
OH4	40	0.46%	15
HB6	30	0.34%	15
RF1	25	0.29%	4
RF2	25	0.29%	4
GT5	10	0.11%	4
GT10	10	0.11%	4
GT3	10	0.11%	4
GT6	10	0.11%	4
GT7	10	0.11%	4
GT9	10	0.11%	4
BOCC	20	0.23%	4
JPPC	26	0.30%	4
JEP	24	0.27%	4
WKPP	24	0.27%	4
JAMALCO	18	0.21%	4
SJPC	14	0.16%	4
JAMALCO2	14	0.16%	4

Figure 52: Maintenance Rates Used in the IRP

Generator	Maintenance Rate [%]	Forced Outage Rate [%]	First Outage Duration	Second Outage Duration
Hunts Bay-B6	8.2	7	18	4
OldHarbor-2	11	7	18	4
OldHarbor-3	11	7	18	4
OldHarbor-4	11	7	18	4
Rockfort-1	6.8	8	18	4
Rockfort-2	6.8	8	18	4
Bogue-GT3	2.7	5	8	4
Bogue-GT6	2.7	5	8	4
Bogue-GT7	2.7	5	8	4
Bogue-GT9	2.7	5	8	4
Hunts Bay-GT10	2.7	5	8	4
Hunts Bay-GT5	2.7	5	8	4
JEP	6.6	3	18	4
JPPC_1-2	7.1	5	18	4
WKPP_1-6	6.6	3.5	18	4
Bogue CC	5.5		8	4
NFE-Jamalco	3.8	2.2	8	4
SJPC	3.8	2.2	8	4

Figure 53: Unit Specific Outage Information

Forced Outage Rates

The forced outage rates of the fossil fuel units were included explicitly in the PLEXOS model as part of the overall generation model. Forced outage rates for the renewable resources were included implicitly in their generation profiles and capacity factor calculations and therefore were not explicitly model within PLEXOS. The forced outage rates represent the percentage of hours each year during which an individual generator is shut down due to an equipment failure or other unforeseen / unplanned event that necessitates it being taken out of service. The duration of the forced outage is based on the mean time to repair. For example, if a Forced Outage Rate of 2.5 percent implies that on average a unit will be out of service (OOS) 0.025 × 8760 = 219 hours per annum. The repair time distribution is constant, thus if the mean time to repair is 36 hours, there will be on average 219 / 36 = 6 random outage events per annum each of 36 hrs. These outages will be randomly distributed throughout the year, and are seeded independently, meaning that they do not respect outages of other generators. As such it is possible for multiple generators to be in a forced outage mode simultaneously, just as in a real operating scenario. As with maintenance outages, out of merit order units will be forced to start and operate for the duration of the forced outage of higher merit order units. This of necessity results in higher production costs and / or lower system efficiency. Figure 54 below lists the inputs used in the PLEXOS model for forced outages.

Unit	Maintenance Outage Rate	Repair Time (hrs.)
OH2	7.00%	18
OH3	7.00%	18
OH4	7.00%	18
HB6	7.00%	18
RF1	8.00%	18
RF2	8.00%	18
GT5	5.00%	8
GT10	5.00%	8
GT3	5.00%	8
GT6	5.00%	8
GT7	5.00%	8
GT9	5.00%	8
BOCC	4.00%	8
JPPC	5.00%	18
JEP	3.00%	18
WKPP	3.50%	18
JAMALCO	5.00%	8
SJPC	2.20%	8
JAMALCO2	0.16%	4

Figure 54: Forced Outage Rates

Resource Adequacy

Resource adequacy is described as the ability of the generating resource mix to respond to system disturbances without causing a reduction in stability, voltage, frequency and reliability[62]. Historically, JPS maintained a level of spinning reserve and system planning reserves that were based on a fossil derived generating mix. In this IRP study, the overall system generating mix will change significantly due to the high penetration of variable generating renewable resources needed to meet a 30 percent penetration by 2030.

JPS will still be required to maintain a certain level of fossil fueled conventional resources comprised of CCGT, GTs, and reciprocating engines to respond to rapid changes in generation from unplanned unit outages and the variability in wind and solar generation. To conduct a detailed evaluation of resource adequacy, the study time horizon should be 5 minute or less, and in some scenarios, less than a minute.

System Heat Rate

The system heat rate is generically defined as the aggregate amount of input energy necessary to serve the system load, typically expressed as BTU / kWh or KJ/kWh. The system heat rate will vary as a function of the resource mix, and attendant fuel types and individual unit heat rates. Note that a lower heat rate is inherently preferable as it indicates a lower amount of energy input to create each unit of output.

Measuring Grid Efficiencies

Like system heat rate, grid efficiencies can be determined based on a direct comparison or ratio of output energy (generation or load) to input energy (fuel). If the load is measured at the customer meter, the efficiency will be inclusive of system losses (i.e. T&D losses). If measured at the substation level, the efficiency will be inclusive of transmission

[62]See NERC, operating definitions.

losses, but not distribution losses. Finally, if measured at the generator terminals, the efficiency will only recognize the relative efficiency of the generating portfolio. Loads for production cost modeling that were derived from the substation load data, and as such incorporate transmission and substation transformer losses. Because PLEXOS does not incorporate a detailed distribution system model, distribution system losses are excluded. As such, the system overall efficiencies are perhaps higher than would normally be expected.

3.7 Transmission Grid

The transmission system is comprised of 138kV and 69kV lines, of which the 138kV is the bulk power transmission network and spans 382km in length. The 69kV circuits, which operate as the sub-transmission system, span a length of 811km and include 1.6km of underground cable. The Corporate Area, which is the main load centre, is served by 105km of 69kV lines that accounts for 18% of the total sub-transmission network. There are currently no 138kV lines in this region. There are 55 (JPS and privately owned) substations of which 44 provide distribution supply.

There are nine (9) bulk power 138kV transmission substations connecting the 138kV system to the 69 kV voltage level by twelve (12) interbus transformers with a total capacity of 798 MVA. With the exception of two, Old Harbour and Bellevue, these nine substations also provide distribution supply.

The following sections describe the performance of the existing transmission network in exporting power from major generation zones and to primary load centres (such as Corporate Area).

3.7.1 Transmission Lines - Old Harbour Power Station

The Old Harbour Power Station which is the largest on the grid and also the site of the largest base load facility has four (4) 138kV lines and two (2) 69 kV lines emanating from that station. The total MVA capacity of the 138kV and 69kV lines is 740 MVA and 37.5 MVA respectively.

There are four (4) generating units connected to the 138kV bus and one (1) on the 69kV bus. Figure 55 summarizes the unit capacity and grid connections for the five units at Old Harbour.

Grid Connection (kV)	# of Units	Total Unit MCR Rating (MW)	% of Total
69	1	30	9.5
138	4	267.65	90.5
Total	**5**	**317.9**	**100**

Figure 55: Grid Connections - Old Harbour Generating Units

Hence on any given day, about 90 percent of the power generated at Old Harbour will flow on the four (4) 138kV circuits coming from that station. The Old Harbour to Duhaney and the Old Harbour to Tredegar 138kV lines, which take the bulk of this power to supply the North Central and Eastern sections of the island, are usually loaded to about 40 percent and 35 percent of their capacity respectively.

The Old Harbour to Parnassus 138 kV line is a double circuit, steel tower construction that supplies the central and western sections of the Island. These lines are usually 30 percent loaded, and provide backup for each other should either be out of service.

3.7.2 Transmission Lines - Corporate Area

The Corporate Area, which is marginally the second largest zone of generation, is the island's largest load centre. Within this region there are five (5) 69kv lines emanating from Hunts Bay power station switchyard with a capacity of 337 MVA, while at the Rockfort power station switchyard there are five (5) 69 kV circuits from that location with a capacity of 377 MVA. The generating capacity at Hunts Bay and Rockfort are 122.5 MW and 96 MW respectively. At Hunts Bay 68.5 MW is provided by based load generation, while the remaining 54 MW is provided by gas turbines, which are mainly peaking units. All the generating capacity at the Rockfort Power Plant is provided by base load diesel units.

The three most heavily loaded lines are the *Hunts Bay to Three Miles* and *Rockfort to Up Park Camp* 69kV and *Duhaney to Washington Boulevard* 69kV lines. These lines will experience loading in excess of 40% of their thermal capacity, during either the day or evening peak period. However, the *Duhaney to Washington Boulevard* 69kV, which is the most heavily loaded during the day period, will experience loading in excess of 60% of its thermal capacity.

One of the major constraints on the existing transmission system in this region is that there is only one (1) transmission substation (the Duhaney substation) importing bulk power into the Corporate Area, which is the island's major load center (see figure 4). Duhaney is a 138/69/24 kV substation with three (3) interbus transformers of total capacity 280 MVA. Two (2) 138 kV transmission lines and six (6) 69 kV emanate from this station, of which four (4) 69kV lines take power into the Corporate Area (inclusive of Naggo's Head substation). The *Old Harbour to Duhaney* 138kV line provides the main link between the Old Harbour Power Station and the Corporate Area (via Duhaney).

The Corporate Area demand generally varies in the region of 55% in the day to 45 percent in the evening, System peak occurs in the evening, as such, on any given day the Duhaney substation will see about 100 MVA passing through it therefore the loss of this substation or the 2 x 138 kV line emanating from it (*Duhaney to Tredegar* 138 kV & *Old Harbour to Duhaney* 138kV) can be catastrophic to Corporate Area sub-system.

3.7.3 Transmission Lines – Bogue

At Bogue, there are four (4) 69kV circuits; each with a thermal rating of 61MVA, and a 155 MVA rated 138kV line, which is limited to 100 MVA due to the rating of the 138/69kV interbus transformer. The two most heavily loaded circuits are the two (2) *Bogue to Queen's Drive* 69kV lines, which are loaded to about 35 percent of their thermal capacity under normal dispatching condition.

3.7.4 Existing Customers Supplied at Transmission Voltages

There are no customers currently supplied at the 138kV level however the following customers are supplied directly from the 69kV network:

- Cement Company: Cement manufacturer
- Port Authority of Jamaica (PAJ): Shipping Port Administrator
- Jamalco (Halse Hall): Bauxite Processing Facility
- Windalco (Kirkvine): Bauxite Processing Facility
- Windalco (Ewarton): Bauxite Processing Facility

Figure 56 below shows the geographic layout of the transmission system.

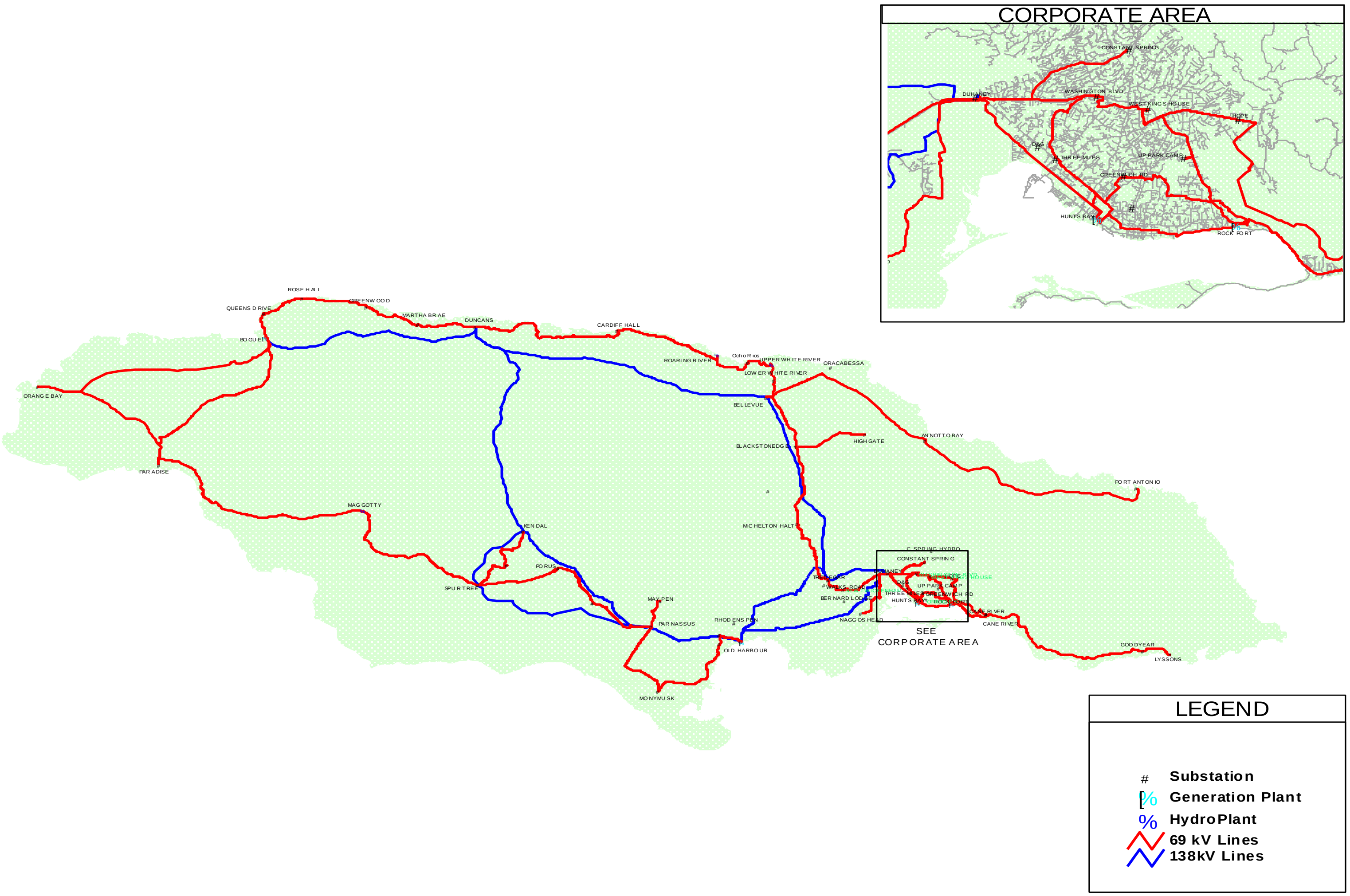

Figure 56: 2018 Transmission System

3.7.5 Transmission Grid Development

Looking over the short and medium to long term planning horizon the solutions to mitigate violations of the transmission planning criteria seeks to find a balance between expansion due to instantaneous impact and that of the system operation requirements. This involve solutions to modernize both the transmission and distribution grid, where smart grid and battery energy storage plays a key part in the system development. Increasing variable renewable energy (VRE) penetration from an existing 15 percent to over 70 percent for the medium term requires fundamental changes to the grid. These fundamental changes involve a shift from traditional plans and solutions (building new lines, re-conductoring existing lines, centralize supply and annual peak demand planning) to the application of battery technology, smart grid, decentralize supply and demand response. In addition, due consideration for VRE providing ancillary services and flexible thermal generators with synchronous condenser functionality is required.

For the first 10 years (2018 – 2027) the primary developments include the following:

1. Operating the transmission grid at 98 percent load power factor (PF) from the traditional 95 percent. This recommendation addresses the reduction in MVARs from the retired thermal plants while increasing VRE penetration.
2. All new wind and PV generation plants should provide grid support during steady state conditions by contributing to voltage control through the injection of reactive power. That is, solar and wind plants should operate at 0.95 power factor during steady state conditions.
3. All new wind and PV generation plants should support grid disturbances and faults without being disconnected from the grid by the principle of Low Voltage Ride Through (LVRT).

4. All new wind and PV plants should support the grid when necessary, mainly during a fault, by generating/absorbing reactive power.
5. All new gas plants should have synchronous condenser capability to provide voltage and inertia support during high instantaneous VRE penetration.
6. The application of smart grid technology to manage and provide the necessary MVARs support from the distribution grid to operate at 98 percent power factor.
7. The application of Battery Energy Storage (BESS) technology to provide system transient stability, intermittency, peak shaving and delayed transmission line expansion during emergency situation.
8. A shift from centralized to de-centralized generation (distributed generation) for thermal, VRE and BESS.

3.7.6 Transmission Planned Upgrades

Studies were carried out to determine the necessary transmission system additions and reinforcements to deliver the generation mix (thermal and renewable) to the load in a secure and efficient way. Regardless of the generation expansion sequence that will be implemented, the most likely location to place the new generation will be in the area of the existing power plant at Old Harbour, Hunts Bay, Bogue and Rockfort for thermal plants and for renewables in locations where feasibility studies were performed. For medium to large base load, natural gas is the selected fuel to be utilized in the generating units.

Thus, the fuel and technology for future thermal generation should not have a significant impact on the transmission additions and/or reinforcements because the location of the generating units would be relatively close to existing facilities being retired. The selected generation expansion sequence for the transmission studies is based on the PLEXOS 20 years' generation expansion plan inclusive of technology mix and size of units for each year of study. This takes into consideration the retirement of existing plants over the planning horizon. The transmission plan detailed grid impact studies were prioritized around the first 10 years 2018 – 2027 and in particular, years 2022, 2024 and 2027.

3.7.7 *Steady State and N-1 Contingencies Analysis*

A series of load flow studies and contingency analysis were carried out to verify the steady state performance with the proposed transmission additions/reinforcements and to verify the adequacy of such additions and reinforcements as well as to assist in determining additional equipment needs. The load flow studies were carried out for the following conditions (1) peak loads, light day load (typical Sunday) and week day load for 2022, 2024, 2027 and 2030. The PLEXOS generation expansion tool's short term (ST) generation dispatch was utilized for each year, respective days and hours to establish the respective dispatch MW information as shown in Figure 58.

All bus voltages, line and inter-bus transformers loading were within limits with the exception of three (3) 69 kV transmission lines interconnecting the Corporate Area scheduled for re-conductoring and three (3) substations requiring bulk capacitor banks to improve bus voltages during N-1 contingency condition as shown in Figure 58.

Year	Scenario	Generation (MW)	Load (MW)	% Loss	Power Factor
2018 Base Case	Light Load Day (Sunday)	400	394	1.43%	95%
	Week Day Load	586	11.2	1.91%	95%
	Evening Peak	659	644	2.26%	95%
2022	Light Load Day (Sunday)	431	421	2.40%	98%
	Week Day Load	633	618	2.40%	98%
	Evening Peak	705	686	2.70%	98%
2024	Light Load Day (Sunday)	491	479	2.50%	98%
	Week Day Load	643	628	2.40%	98%
	Evening Peak	734	714	2.70%	98%
2027	Light Load Day (Sunday)	593	574	3.10%	98%
	Week Day Load	688	670	2.60%	98%
	Evening Peak	763	745	2.30%	98%
2030	Light Load Day (Sunday)	587	569	3.08%	98%
	Week Day Load	719	697	2.90%	98%
	Evening Peak	801	782	2.31%	98%

Figure 57: Power Flow Steady State Summery Results

3.7.8 Transient Stability Study

Stability studies were carried out for the years 2022, 2024, 2027 and 2030 with the proposed transmission thermal and VRE plant additions. The studies were carried out to verify the transient behavior of the system under selected disturbances. Typical values for the existing system and new equipment were used. The results of the stability analysis are presented herein in graphical format in the form of the system frequency response, voltages for the buses, VRE response during faults and also the BESS response.

The results of the stability analysis are presented herein in graphical format in the form of frequency and voltage response for the buses identified for the results. The voltages are given in p.u., the frequencies are presented in Hz and the power flow in MW/MVAR. The transient stability studies are carried out for the following selected disturbances.

1. Trip the largest plant for each test period. The event comprises:

- At 1 second, open generating plant(s), i.e. tripped permanently;

2. The application of three phase fault near all 138kV buses for each study period. This event comprises:

- At 1 second, a three-phase fault is applied near 138 kV buses for 5 cycles;
- The corresponding line with fault is tripped permanently and fault successfully cleared at 0.1 seconds;

3. The application of three phase fault is near Hunts Bay 69 kV bus and Bogue 69kV bus for each study period. This event comprises:

- At 1 second, a three phase fault is applied near Hunts Bay 69 kV bus for 5 cycles;
- Hunts Bay – The corresponding 69 kV line is tripped permanently and fault is successfully cleared at 0.1 seconds.
- Bogue – The corresponding 69 kV line is tripped permanently and fault is successfully cleared at 0.1 seconds.

3.7.9 Transient Stability Results

The first disturbance serves to verify the overall performance of the system to a major generation rejection. The system is stable with the support of the Battery Energy Storage System (BESS) for each year of analysis. The frequency response of the system indicates a fall in frequency before the system recovers with the support of the BESS. The second disturbance is represented by three phase short circuit faults on respective 138kV bus/lines. The frequency response of the system shows a reduction in frequency before increasing above 50Hz then modestly oscillating to the nominal frequency after 4-6 seconds. The individual solar and wind plants MW and MVAR response in each year clearly demonstrates both the injection of MVAR to reduce the rate of fall in voltage and the reduction in MW to reduce the fault current in mitigating the rate of change in frequency and subsequent recovery of the system to nominal frequency. Figure 59 shows the necessary BESS additions for the respective years.

Description	Year	Type	Voltage (kV)
Transmission Projects			
Old Harbour - Hunts Bay	2022	Expansion	138
Duhaney - Washington Blvd	2024	Re-conductor	69
Twickenham - Duhaney	2027	Re-conductor	69
Hunts Bay - Three Miles	2027	Re-conductor	69
New Transformer /BESS/VAR	**Year**	**Rating (MVA)**	**Qty.**
Hunts Bay 138kV	2022	80	1
Bulk Cap Bank	2024	6	1
Bulk Cap Bank	2024	5	1
BESS	2022	20	1
BESS	2024	20	1
BESS	2030-2037	100	5

Figure 58 Transmission System Expansion Plan

3.8 Distribution Grid

Experience across the U.S. and globally has highlighted the need to address changes to distribution planning proactively in order to satisfy customer service expectations, guide DER development and ensure long-term infrastructure investments will continue to serve customers' needs safely and reliably. The government of Jamaica (GOJ) recognize the need for grid modernization and the evolution of distribution planning.

The GOJ recognizes that "planning efforts will be an integral part of a systematic approach to grid modernization." As such, a necessary requirement for planning is clear objectives' which is:

"A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Jamaica to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network."

The realization of the value of DER adoption and grid modernization for all customers necessitates a proactive approach to distribution system planning. Elements such as multiple scenario forecasts, hosting capacity analysis and locational net benefits analysis can enhance traditional planning processes and help establish a standardized, transparent planning framework that proactively addresses the full set of impacts and values of DER on the grid. These capabilities will help utilities to better identify necessary distribution investments, inform the continued evolution of the interconnection process and better quantify DER's value to the system as well as their benefit to all customers. The GOJ recognizes that new planning approaches will be "an integral part of a systematic approach to grid modernization." The successful implementation of these elements will ultimately help Jamaica meet public policy objectives and enable safe, reliable and affordable service that satisfies customers' changing expectations and use of distributed resources.

3.8.1 Distribution Grid Evolution

Across the world, the adoption of DER is changing customers' service expectations and use of the distribution grid. Over the next decade in the Caribbean and elsewhere, the distribution system is expected to evolve from a one-way delivery system to a network of interconnected resources. Achieving this integrated grid "will require planning and operating to optimize and extract value throughout the electric grid." However, the adoption of DER is uneven, with certain countries having significant adoption while others have nearly none. This is true within a territory and even within a utility service area. This patchwork of adoption is currently driven by policy, technological cost-effectiveness, local economic factors and consumer interest. The adoption patterns observed in several countries over the past 10 years, along with the related impacts to distribution system operation, can help identify the key issues and decisions regulators and utilities are likely to face as DER adoption increases. For example, growth in adoption of DERs will change the amount, shape and predictability of net load, and at higher levels may introduce local multi-directional power flows.

Figure 60 shows a simplified three-stage evolutionary framework for the distribution system. This framework is based on the assumption that the distribution system will evolve in response to both top-down (public policy) and bottom-up (customer choice) drivers. The yellow line represents a classic technology adoption curve as applied for DER. The Stages represent the levels of additional functionalities needed to support the greater amounts of

DER adoption in relation to the level of power system integration desired. The result is an increasingly complex system.

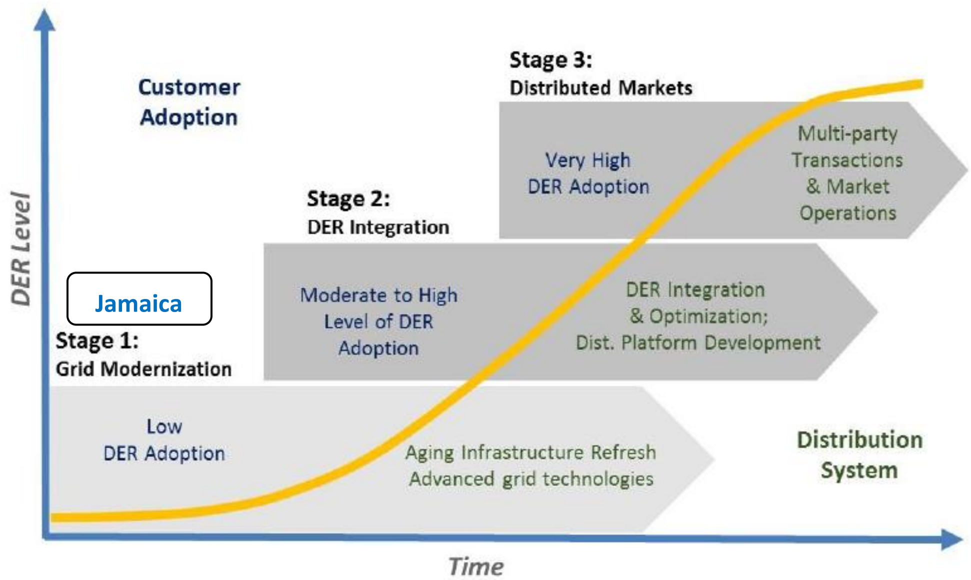

Figure 59 **Distribution System Evolution**

3.8.2 Modern Distribution Grid Planning Process

Integrated distribution system planning in the 21st Century needs to assess physical and operational changes to the electric grid necessary to enable safe, reliable and affordable service that satisfies customers' changing expectations and use of DERs. "Updates to the distribution planning process [through a standardized planning framework] will be needed to support a reliable, efficient, robust grid in a changing (and uncertain) future; should be coordinated with resource and transmission planning; could incorporate stakeholder informed planning scenarios." An Integrated Distribution Planning (IDP) framework would include the following core components and is illustrated in Figure 61 below:

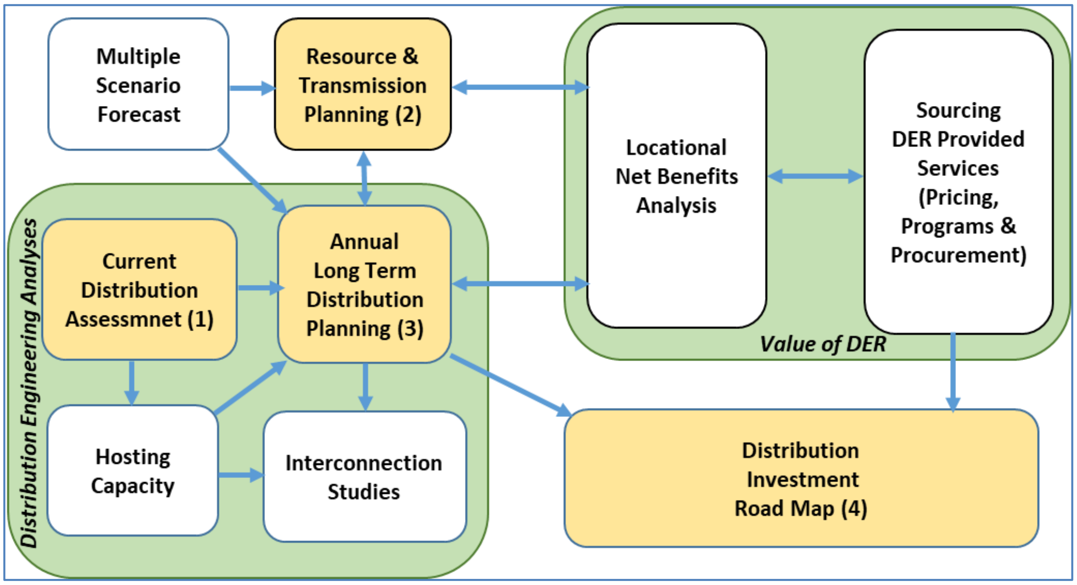

Figure 60 ***Integrated Distribution Planning Process***

At present the IRP Distribution Grid investment plans and costs only considers blocks 1 to 4 with an emphasis on grid modernization in preparation for the increasing levels of DER.

The next steps will involve the application of the integration distribution planning process to ensure the full benefit of DER is achieved over the medium to long term period.

3.8.1 Grid Modernization and Technological Advancement

As part of its strategic plan for modernization of the nation's electricity sector and its Licence requirement for an intelligent network, JPS gave a commitment to create a smarter grid. In the past four years, the Company upgraded its Grid Control Systems to improve reliability and to accommodate the integration of more variable sources of energy such as solar and wind. Below are some of the initiatives which were completed or underway to achieve this objective.

3.8.1.1 Smart City Technology

In 2016, the country took the first steps towards the introduction of smart city technology in Jamaica’s capital, with the roll-out of AMI smart meters in the New Kingston commercial district, smart streetlighting, and the implementation of a web portal energy management solution. The Company also unveiled the country’s first smart home in Western Jamaica in 2016.

3.8.1.2 Smart Meter Technology

Since 2016, JPS installed over 144,000 smart meters in communities across the island at a cost of approximately US$28.3M. The smart meter roll-out is a critical component in the development of the smart grid. These smart meters will provide customers with their own “Energy Portal” that allows them to view and manage their energy consumption providing usage data in shorter time intervals, for example hourly as opposed to monthly. They also give customers the ability to observe how their habits contribute to their electricity costs and make adjustments where necessary. This offers other critical benefits of losses management and detection as it provides analytics which help to improve the Utility’s ability to identify energy losses at all levels of the network and provide greater efficiency and flexibility for billing operations and improving service delivery to customers. Customers have been benefiting from fewer estimated bills, and more timely reconnections.

3.8.2 Planned Upgrades and Modernization Costs

This represent the capital and operating and maintenance costs for the medium to long term planning horizon of the primary and secondary distribution network.

3.8.2.1 Distribution Avoided Costs

The next step is the computation of the distribution (primary and secondary) grid avoided costs, which is based on the annual long term distribution plan (upgrade plans and modernization projects). This information is being developed by JPS for review and approval by MSET.

3.9 Current Grid Codes

This Codes covers the guiding principles, operating procedures, and Technical Standards governing operation of the Jamaican Electric Power Grid and all interconnected Generating Facilities. There are five Grid Codes developed and designed to provide a comprehensive framework for the development, maintenance and operation of an efficient, safe, and reliable Jamaican Power Grid.

3.9.1 Generation Code

The Generation Code governs Generation activities in the electricity sector and interconnected to the Grid. The Generation Code covers the guiding principles, operating procedures and Technical Standards governing all Generating Plants interconnected to the Grid. The Generation Code seeks to facilitate the economic, safe and reliable operation of the Grid. The Generation Code facilitates the System being made available to persons authorized to generate electricity and to interconnect with the System, and is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the System. It seeks to avoid any undue discrimination between Users and categories of Users.

3.9.2 Transmission Code

The Transmission Code applies to the conveyance of electricity by means of the Transmission System, which includes electric power lines operating at 69kV and higher, including the secondary circuit breakers and up to the outgoing Isolators at Transmission Substations transforming to 24kV, 13.8kV and 12kV. The Transmission Code provides the guidelines controlling the development, maintenance and operation of an efficient, coordinated and economic Transmission System in Jamaica. The Transmission System being made available to persons authorized to supply or generate electricity and is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the Transmission System. It seeks to avoid any undue discrimination between Users and categories of Users. The procedures and principles governing the System Operator's relationship with all Users of the Transmission System are set out in the Transmission Code. The Transmission Code specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances. The Transmission Code will cover the System from the point of the outgoing isolators on the Transmission Substations as described above, to the point of Interconnection with the Customer's system.

The Transmission Code covers the Generator Interconnections to the Transmission or Distribution Systems. The responsibility boundary between the Generator and the System Operator will normally be the High Voltage side of the Generating Unit transformer.

3.9.3 Distribution Code

The Distribution Code governs the distribution system and activities related thereto. It is designed to (a) permit the development, maintenance and operation of an efficient, coordinated and economic Distribution System in Jamaica; and (b) facilitate the Distribution

System being made available to persons authorized to supply or generate electricity. The Distribution Code is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the Distribution System. It seeks to avoid any undue discrimination between Users and categories of Users.

The procedures and principles governing the System Operator's relationship with all Users of the Distribution System are set out in the Distribution Code. The Distribution Code specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

The Distribution Code will cover the Distribution System from the point of the outgoing isolators on the Transmission Substations as described above, to the point of Interconnection with the Customers system.

3.9.4 Supply Code

The Supply Code specifies the rules governing the obligations of the Licensee and consumers vis-à-vis each other. The purpose of the Supply Code is to specify the set of practices that shall be adopted by the Licensee to provide efficient, cost effective and consumer friendly service to the Customers.

This Supply Code shall be applicable to:

a. the Licensee and all consumers in the Island of Jamaica as covered under the Act; and

b. unauthorized supply, unauthorized use, diversion and other means of unauthorized use/ abstraction/theft of electricity.

3.9.5 Dispatch Code

The Dispatch Code governs the Dispatch activities of the System Operator. The Dispatch Code is designed to (a) permit the development, maintenance and operation of an efficient, coordinated and economic Grid; and (b) facilitate the Transmission and Distribution Systems being made available to persons authorized to supply or generate electricity. The Dispatch Code is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the System. It seeks to avoid any undue discrimination between Users and categories of Users.

The purpose of the Dispatch Code is to:

a. set out the roles, responsibilities and process for the scheduling and Dispatch of Generation and demand-side resources in meeting the electricity demand;

b. enables the System Operator to coordinate maintenance outages as far as possible in advance to allow the System Operator to maintain system integrity and reliability;

c. set out the process of investigation followed by the OUR in response to significant power outages; and ensures fair and equitable treatment of all Generators connected to the Grid.

3.10 Summary of Input Data Modeling Assumptions for Power Simulations

This section of the report will gather all the input data together and discuss the importance of the information.

In Section 3.2, the base (most likely), high and low load forecasts were discussed and presented. Briefly, the load factor is set at an annual load factor of 78 percent for all three forecasts. Figure 62 displays the historical actual peak demand and energy to the three projected load forecasts.

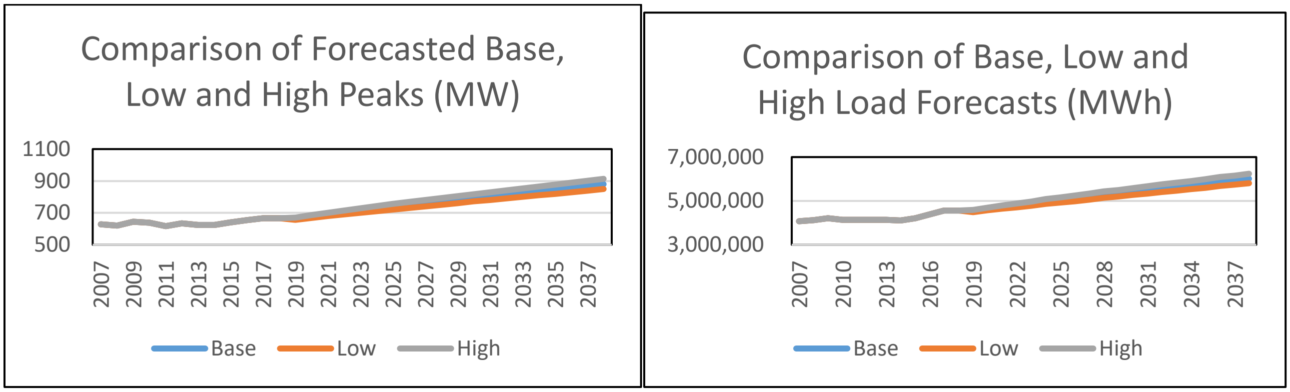

Figure 61 Summary of Historical and Actual Peak and Energy Forecast

The graphed lines for forecasted annual peak demand and annual energy look very similar since the load factor remains constant over the 20 year IRP study. There are three fuel types used by the conventional generating power plants. These are the ADO, HFO and LNG. There are two different fuel costs for the LNG; one for the JPS owned resources and one for the Jamalco PPA plant. The fuel prices were provided by JPS. Figure 63 below compares the fuel prices and escalation rates. The LNG fuel prices are projected to remain constant over the study period but the ADO and HFO are to increase over the study period.

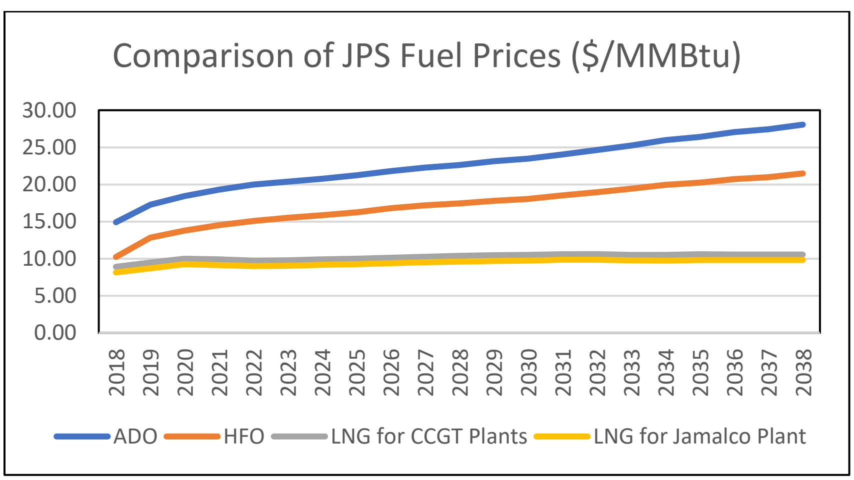

Figure 62 Comparison of JPS Fuel Prices Forecasted

The input required for the simulated dispatch and costs are the conventional resources and the existing renewable technologies. There are four existing renewable technologies in the base case: Wind, Solar, Hydro and Biomass comprised of 9 hydroelectric units, 5 wind parks, 2 solar parks and 1 biomass unit. The figure below summarizes the capacity, capacity factor and unit type. Additional Proposed or Candidate Units modeled on existing units are provided in more details in the Appendix B.

Existing	Type	In-Service Date	Installed Capacity	Capacity Factor
Maggoty 3	Run of River	1966	6	75.0%
Maggoty Falls 1	Run of River	2014	3.15	73.0%
Maggoty Falls 2	Run of River	2014	3.15	71.0%
Lower White River	Run of River	1945	4.75	33.0%
Upper White River	Run of River	1952	3.2	39.0%
Roaring River	Run of River	1949	4.05	72.0%
Rio Bueno A	Run of River	1949	2.5	82.0%
Rio Bueno B	Run of River	1949	1.1	57.8%
Constant Spring	Run of River	1989	0.77	49.3%
Munro	Wind	2010	3.2	12.9%
Wigton phase 1	Wind	2004	20.7	32.7%
Wigton phase 2	Wind	2010	18	37.6%
Blue Mountain Renewables	Wind	2016	36.3	38.0%
Wigton Phase 3 (Rose Hill)	Wind	2016	24	39.2%
WRB Enterprise	Solar	2016	20	25.0%
8 River	Solar	2018	37	25.0%
Frome	Biomass	2016	5	91.7%
Total			192.87	

Figure 63 Capacity factor and service dates of Renewable Energy plants

In the IPP renewables (Wind and Solar), the capacity factors have been adjusted as per the data provided by the owners of these facilities. There are five conventional power plants that are under a PPA agreement as shown in Table below. The fuel types are either ADO of HFO. The OH CCGT will be commercial in 2019 and the NFE CCGT will be commercial in 2020 and burn LNG.

PPA Units	MW	$/MW/Start	$/MWh	$/kW/yr	$/MMBtu		$/Start
Unit Name	Capacity	Startup Cost	VOM	FOM	Fuel Cost	Fuel Type	Start Cost
NFE-GT12	32.5	$ 52.66	$ 3.60	$ 13.17	$ 8.90	LNG	$ 1,046.83
NFE-GT13	32.5	$ 52.66	$ 3.60	$ 13.17	$ 8.90	LNG	$ 993.53
NFE-ST14	29.1		$ 3.60	$ 13.17			
CC1_as_GT12	37.7	$ 52.66	$ 3.60	$ 13.17	$ 8.90	LNG	$ 83.89
CC2_as_GT12	37.7	$ 52.66	$ 3.60	$ 13.17	$ 8.90	LNG	$ 127.69
CC3_as_GT12	37.7	$ 52.66	$ 3.60	$ 13.17	$ 8.90	LNG	$ 138.04
ST_as_ST14	80		$ 3.60	$ 13.17			
JPPC_1-2	60	$ 5.36	$ 11.60	$ 0.23	$ 14.91	HFO	$ 321.30
Jamaica Broilers-0	1.7	$ -	$ -	$ 159.88	$ 10.23	HFO	$ -
JEP_1-8	9.27	$ 5.36	$ 22.60	$ 0.04	$ 10.23	HFO	$ 49.64
JEP_9-11	9.27	$ 5.36	$ 14.63	$ 0.04	$ 10.23	HFO	$ 49.64
WKPP_1-6	10.92	$ 7.26	$ 14.60	$ 0.04	$ 10.23	HFO	$ 79.32

Figure 64 IPP Conventional Generation Modeled

The last group of generating plants are the JPS owned conventional plants as described in Section 0. The OH 2, 3, and 4 steam plants will be retired in 2019. All the remaining JPS owned resources may remain available over the study period but may be retired on economic grounds and in accordance with the JPS plant retirement schedule as at Appendix D.

JPS Units	MW	$/MW/Start	$/MWh	$/kW/yr	$/MMBtu		$/Start
Unit Name	**Capacity**	**Startup Cost**	**VOM**	**FOM**	**Fuel Cost**	**Fuel Type**	**Start Cost**
OH -2	57.6	$ 35.19	$ 0.94	$ 9.84	$ 10.23	HFO	$ 2,026.94
OH-3	61.8	$ 32.21	$ 0.61	$ 10.66	$ 10.23	HFO	$ 1,990.58
OH-4	65.1	$ 30.57	$ 0.56	$ 11.24	$ 10.23	HFO	$ 1,990.11
Bogue-GT3	69.86	$ 7.47	$ 2.46	$ 1.81	$ 14.91	ADO	$ 155.45
Bogue-GT6	17.97	$ 2.23	$ 4.84	$ 1.52	$ 14.91	ADO	$ 60.86
Bogue-GT7	17.97	$ 3.39	$ 4.84	$ 1.52	$ 14.91	ADO	$ 65.80
Bogue-GT8	13.97	$ 3.66	$ 4.84	$ 1.18	$ 14.91	ADO	$ 16.22
Bogue-GT9	19.95	$ 1.16	$ 3.40	$ 1.69	$ 14.91	ADO	$ 131.07
Hunts Bay-GT10	32.3	$ 6.57	$ 0.80	$ 7.75	$ 14.91	ADO	$ 257.75
Hunts Bay-GT5	21.45	$ 7.98	$ 1.68	$ 5.12	$ 14.91	ADO	$ 114.86
Rockfort-1	19.5	$ 1.26	$ 1.37	$ 29.85	$ 10.23	HFO	$ 24.57
Rockfort-2	19.5	$ 1.26	$ 2.09	$ 29.85	$ 10.23	HFO	$ 24.57
Bogue-GT12	37.7	$ 52.66	$ 3.60	$ 13.17	$ 8.90	LNG	$ -
Bogue-GT13	37.7	$ 52.66	$ 3.60	$ 13.17	$ 8.90	LNG	$ 201.88
Bogue-ST14	33.8		$ 3.60	$ 13.17			

Figure 65 JPS Conventional Generation Summary

4. RESULTS

4.1 IRP Reference Cases and Implementation Plan Summary of Impacts Relative to Objectives

Capacity Additions for the Reference Cases and the Implementaion Case

	Initial Reference Case			Updated Reference Case			Implementation Case	
Fiscal Year	Generation Capacity added (MW)	Type of Addition		Generation Capacity added (MW)	Type of Addition		Generation Capacity added (MW)	Type of Addition
2018								
2019								
2020								
2021								
2022	437	Solar/Wind, Gas Turbine		473	Solar/Wind		147	Solar/Wind
2023	176	Hydro, Waste to Energy, Combined Cycle		56	Hydro, Biomass		74	Hydro, Waste to Energy, Biomass
2024	37	Solar/Wind					173	Solar/Wind
2025				120	Combined Cycle		120	Combined Cycle
2026	160	Gas Turbine, Combined cycle		138	Combined Cycle, Waste to Energy		120	Combined Cycle
2027	40	Solar/Wind					111	Solar/Wind
2028	40	Solar/Wind						
2029	20	Solar/Wind		40	Gas Turbine			
2030	60	Solar/Wind					40	Gas Turbine
2031								
2032	112.5	Solar/Wind, Gas Turbine		37.5	Solar/Wind		122.5	Solar/Wind
2033	80	Gas Turbine		103	Solar/Wind, Gas Turbine		60	Solar/Wind
2034				20	Solar/Wind		37	Solar/Wind
2035	18.5	Gas Turbine		60	Solar/Wind		20	Solar/Wind
2036	212	Solar/Wind, Waste to Energy		35.5	Solar/Wind, Gas Turbine		50	Solar/Wind, Gas Turbine
2037	217	Solar/Wind, Candidate Transmission Line		572	Solar/Wind		589.5	Solar/Wind
TOTAL	**1610**			**1655**			**1664**	

Table 3 Capacity Addition for Reference and Implementation Cases

The results of the Integrated Resource Planning exercise are summarized in the Table 3 above. The results of the Reference Cases recommended the addition of over 400MW of Solar/Wind capacity in 2022, however, given the current trend of reducing cost for these technologies and the reducing cost of battery storage needed to support large scale penetration of renewable, an Implementation Plan was developed to manage the renewable capacity implementation over a period of five years. The results of this Implementation Plan show the need for 1664.0MW of new generation to be added to the grid from 2022 to 2037. Solar and Wind generation comprise 76 percent (1270MW) of the proposed Implementation Plan. A total of 514 mw of new generation capacity will be required up to 2025, comprising of 394.0MW of renewable generation (Wind, Solar, Biomass and Waste to Energy) and

120MW of gas fired Combined Cycle. During the period 2026 to 2030, another 111.0MW of solar/wind, 120MW of gas fired Combined Cycle and 40MW of simple cycle Gas turbines are proposed. In the last seven years of the planning horizon, 839.0MW of solar/wind capacity and 40.0MW of gas fired simple cycle gas turbines is proposed to be built.

Four Hundred and Eighty-Five (485MW) of Private Power Capacity is earmarked for retirement and replacement over the planning horizon, 250MW (JEP, WKPP, JPPC) of which are HFO fueled Private Power (IPPs) generators. The decision on their retirement and replacement is governed by their Power Purchase Agreements (PPA) and their operation

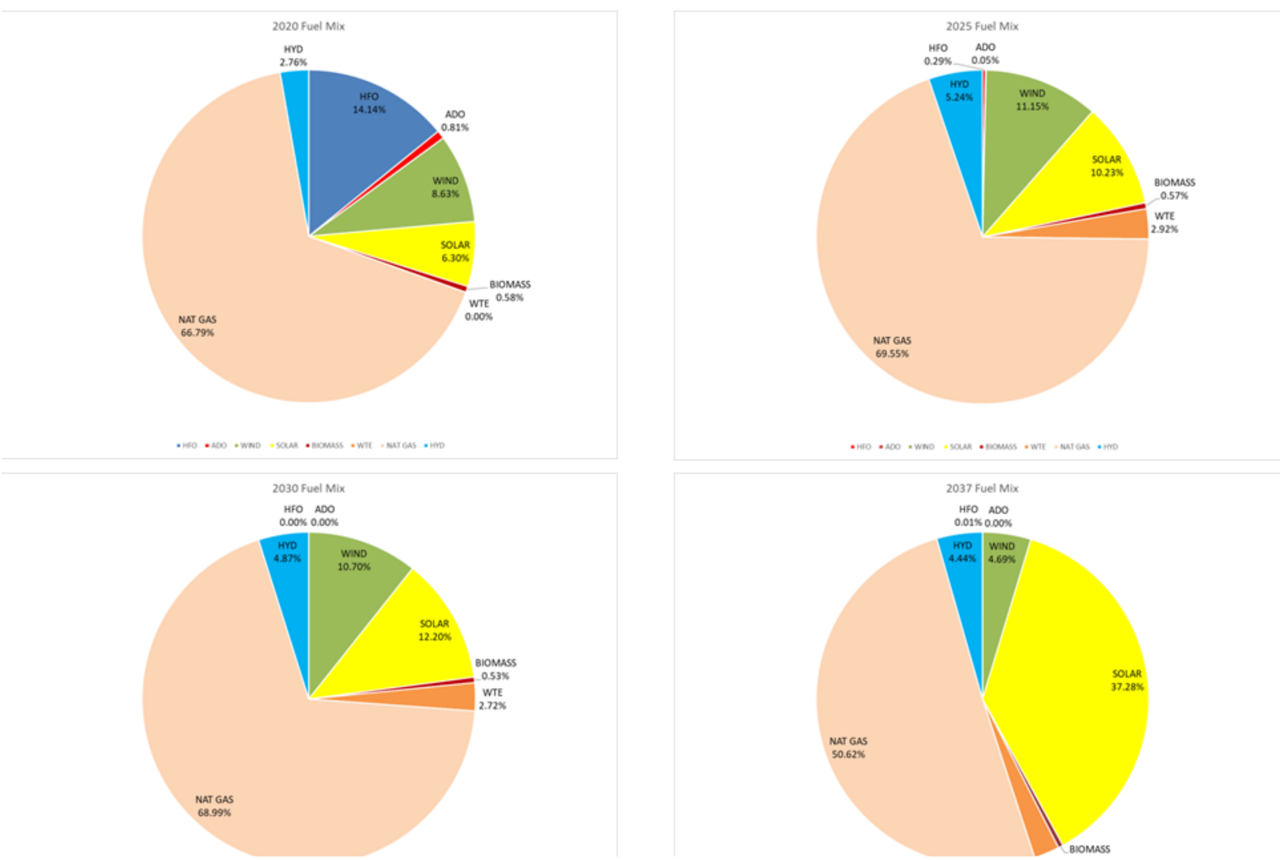

Figure 66 Fuel Mix, 5-Year

could be extended based on negotiations and an assessment of their suitability to meet future needs proposed by this or subsequent IRPs. Additionally, JPS owned thermal generators may be identified for replacement throughout the planning horizon based on their economic performance and the needs of the system. JPS has the Right of First Refusal (ROFR) to do these replacements subject to the System Avoided Cost.

4.11 Percentage Share of Generation (MWh)

Figure 67 above shows the change in the share of generation (MWh) over the planning horizon. The Implementation Plan, when fully executed to 2037 will result in renewable providing 31 percent of the generation required by 2030 and 49 percent at the end of the planning horizon in 2037. Solar will comprise the largest share of renewable energy while Natural Gas fired plants will provide 51 percent of the electricity system energy needs.

4.12 System Heat Rate

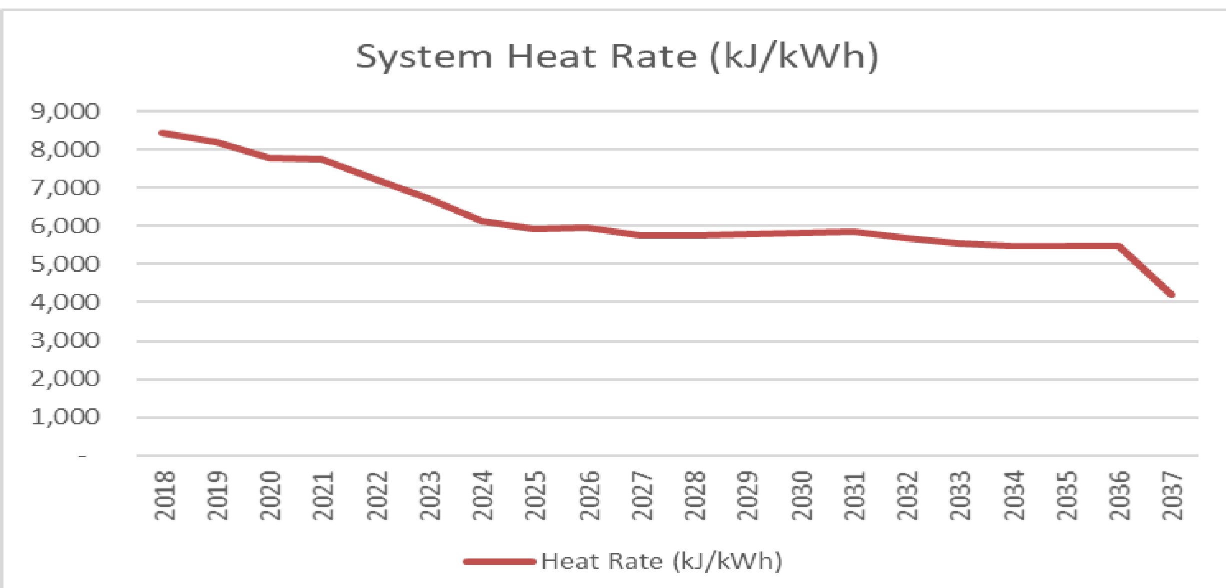

Figure 67 System Heat Rate

The System Heat Rate indicates the overall Generating System efficient in converting fuel into useful electrical energy. The Figure 68 above shows that the system heat rate reduces by 30 percent over the first six years of the plan as old and inefficient oil fired steam generators are replaces by gas fueled combined cycles and renewable. At the end of the planning horizon, the System Heat rate has been reduced by 50 percent compared to the start in 2018. This significant reduction is directly attributable to the level of penetration of renewable energy plants into the supported by efficient gas fired generators.

4.2 Generation Avoided Cost Calculations

Based on the Implementation Plan, MSET requested that the OUR conduct an Avoided Cost Study. The results of the study are shown in the Figures 68 and 69 below.

Period	Total	Fuel	Var. O&M	Capacity	
	US c/kWh	US c/kWh	US c/kWh	US c/kWh	$/kW-mth
20-Year	9.58	5.48	2.33	1.77	10.06
15-Year	9.70	7.24	1.56	0.90	5.11
10-Year	9.71	8.65	0.80	0.26	1.50
5-Year	10.79	9.62	1.17	0.00	0.00

Figure 68 Avoided Cost of Generation 5Year Interval

The Long Run Generation Avoided Cost is calculated to be 9.58 US cents/kWh and is approximately 19.0 percent lower than the existing 11.76 US cents/KWh. It comprised of an Avoided Fuel Cost of 5.48 US cents/kWh which is 43% lower than the 9.62 US cents/kWh in the first five years. Both the Avoided O&M (1.16 US cents/kWh increase) and Capacity (1.77 US cents/kWh increase) Costs exhibited a much smaller increment of increase over the period compared to fuel. The existence of more fossil fueled IPPs and a large fuel component of costs results in an increasing Generation Avoided Cost over the first six years of the planning horizon. The Generation Avoided

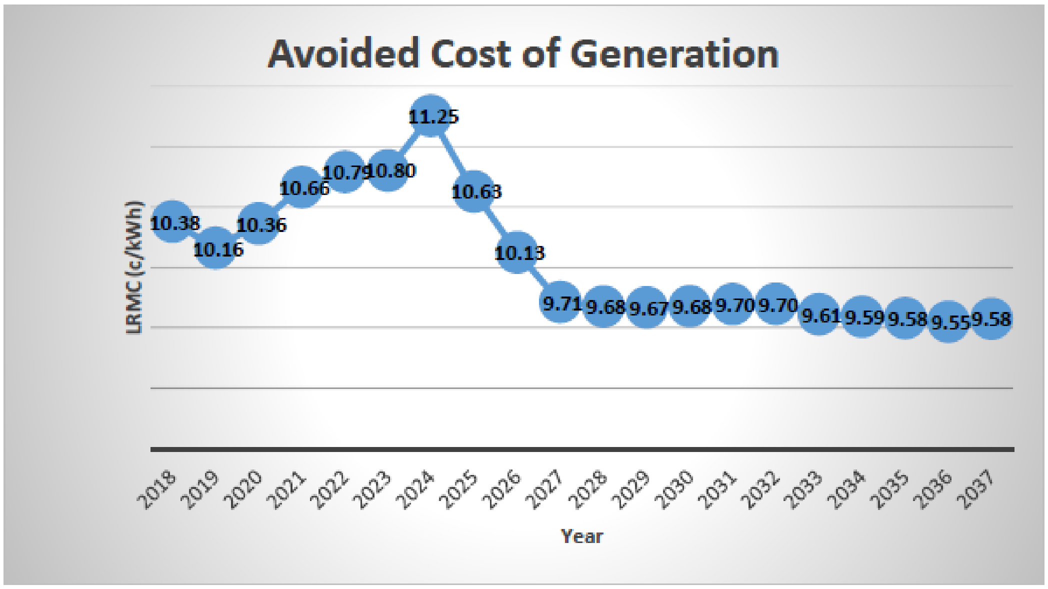

Figure 68 Avoided Cost of Generation 2018-2037

cost then dramatically reduces as these IPPs are replaced at the end of their PPAs and replaced with more efficient gas fired plants and renewable.

The OUR has also indicated that they were not able to provide information on the tariff impact assessment at this time for the following reasons:

1. Pertinent information required from JPS on the distribution system and the characterization of the customers was not available; and
2. Since the OUR is presently giving consideration to JPS 5-Year Tariff Review, it was not considered prudent to opine on rate implications through the planning process.

4.3 Summary

#	Objective Described	What it Means?	Initial Weight	Measures
I	Reliable Energy Supply Chain	Minimize Disruptions	25%	Required Reserve Margin Reduced (< 20%)
II	Diversity of Supply	Vulnerability to Disruption	25%	Renewable Share 33% by 2030 and 49% by 2037.
III	Least Cost Electric Service	Reduce Customer budgets	16.50%	Generation Cost of Plan US$ 6.3B. Generation Avoided Cost reduced from US11.76 c/kWh to US 9.58 c/kWh. Customer Rates will be reduced.
IV	System Flexibility	Ability to meet a wide range of outcomes	16.50%	Better management of fuel volatility and improved resilience with distributed generation. Reduced Transmission requirements and constraints.
V	Grid and Energy Efficiency	Reduce losses	8.50%	Average System Heat Rate improved by 50%
VI	Environmental Stewardship	Minimize environmental footprint	8.50%	Reduce air emissions by more than 50%

Table 4 Summary of Objectives, weightings and Measures

The projected success of the Integrated Resource Plan can be determined from the combined quantitative and qualitative assessment of its achievement with respect to the key objectives identified at the start. The IRP projects to reduce the need for installed reserve margin from the current 25 percent to less than 20 percent at the end of the planning period. In the latter years, with the expected move to distributed generation, the use of smaller size plants, and the routine inclusion of energy storage solutions as part of the implementation, it is anticipated that the required installed reserve margin could reach single digit percentages. Consistent with the Energy Policy targets (30% of electricity from renewable by 2030), the IRP meets the threshold for diversification of fuel sources and achieves 31percent share of electricity generation being provided by renewable energy sources by 2030 and goes further to achieve a renewable penetration percentage of 49 percent by 2037. It is anticipated that with the emergence of new high demand technologies like electric vehicles over the next decade, the level of penetration of renewable sources of energy could easily surpass current policy projections.

YEAR	Peak Load	Energy Demand	Installed Capacity	Installed Firm Capacity	PV-Capital Cost	PV-Fixed O&M Cost	PV- Var. O&M Cost	PV- Fuel Cost	TOTAL
	MW	GWh	MW	MW	$'000'	$'000'	$'000'	$'000'	$'000'
2018	657.0	4,490	974	843	-	79,792	74,426	329,099	483,317
2019	667.9	4,569	1217	1065	-	95,501	60,695	328,546	484,742
2020	681.0	4,656	1047	890	-	123,288	51,912	293,317	468,518
2021	693.9	4,741	1047	885	-	113,918	50,051	282,155	446,124
2022	705.8	4,824	1194	880	-	106,029	64,076	244,327	414,431
2023	718.0	4,906	1268	912	144,130	102,476	66,755	204,724	518,085
2024	730.4	4,991	1441	925	16,839	97,505	79,064	175,217	368,625
2025	743.1	5,078	1501	980	116,182	93,955	72,488	158,173	440,798
2026	753.8	5,150	1497	971	54,068	81,597	67,463	150,976	354,105
2027	764.6	5,224	1608	966	-	75,946	69,555	139,128	284,629
2028	775.6	5,299	1608	961	-	70,881	65,014	133,001	268,896
2029	786.7	5,376	1605	956	-	65,792	60,006	127,651	253,449
2030	798.1	5,454	1645	991	13,526	63,471	55,923	122,149	255,069
2031	807.9	5,520	1645	986	-	59,076	52,120	116,611	227,806
2032	817.7	5,646	1729	1026	0	55,135	50,861	108,108	214,104
2033	827.7	5,751	1724	990	0	43,957	49,970	100,662	194,588
2034	837.9	5,821	1761	987	0	40,913	48,091	94,639	183,644
2035	848.2	5,865	1781	958	0	38,080	45,568	89,680	173,328
2036	858.6	5,912	1831	968	8,794	36,997	42,926	85,372	174,089
2037	869.2	6,078	2226	935	0	30,976	53,002	59,495	143,472
TOTALS		**105,349**			**353,538**	**1,475,286**	**1,179,966**	**3,343,031**	**6,351,820**

Table 5 Implementation Plan Costs

Table 5 above shows the overall cost of the Implementation Plan proposed by this IRP. Generation Capital Present Worth (2018 dollars) Investment for firm capacity gas fueled plants is US$354 Million over the planning horizon. An additional US$6 Million dollars is required to pay the fuel, operating and maintenance cost for all generating plants including the energy payments for renewable plants. Assuming an average installed cost of $1500/kW for wind and solar renewables, the capital investment for the projected 1270MW over the planning horizon is approximately US$1.9 Billion.

Over the next five years to 2025, solar and wind projected new installed capacity is 320MW at an estimated cost of US$480 Million.

The overall expected significant reduction in generation cost is anticipated to translate to a reduction in the cost of electricity to consumers. This will be confirmed as the OUR conducts its long term distribution avoided cost study and estimates the rate impact of the IRP.

The system expansion when implemented according to the IRP will result in a more flexible Jamaican Power system capable of withstand any shocks from fluctuation in global fuel prices. The Distributed Generation approach will result in a power system more resilient to wide-scale interruptions that characterize the current system comprised of large centralized generators delivering power through high voltage transmission lines. The Distributed generation approach should also result in reduced transmission losses as less power is transported from bulk sources to load.

The Jamaican Power System will see a marked improvement in efficiency as the generating system average heat rate improves by 50 percent by the end of the planning horizon driven predominantly by the large penetration of renewable sources of energy. Attendant with this approach and the replacement of the current fleet of fossil fuel generators by cleaner natural gas burning generators, it is anticipated that there will be up to a 50 percent reduction in harmful emission to the environment.

5. NEXT STEPS AND FUTURE SCENARIOS

In Section 5.1, next steps or additional analytics involving IRP results are discussed. These sections include a discussion of interconnection and network modernization and upgrade costs; customer billing impacts; long run avoided cost and tranches for new generation solicitation; and short-run marginal cost calculations to construct short run supply curves.

In Section 5.2, future IRP efforts are described including measuring the impact of energy efficiency and demand response on the preferred portfolio; developing and analyzing various incentives for hydro capacity costs and waste to energy technologies; analyzing distributed resource impacts on the preferred portfolio; grid code revisions supporting the IRP preferred portfolio; future resiliency scenario; revising the load forecasting methodology; minimizing technical losses from new plant siting; and re-visiting the objective weightings with focus groups.

5.1 Next Steps

5.1.1: Determine grid modernization and network upgrade costs.

The adoption of DER is changing customers' service expectations and use of the distribution grid worldwide. Over the next decade in the Caribbean and elsewhere, the distribution system is expected to evolve from a one-way delivery system to a network of interconnected resources. Achieving this integrated grid "will require planning and operating to optimize and extract value throughout the electric grid.

In order to facilitate further development of wind and solar resources, an Integrated Distribution Planning study will be required to:

1. Identify the full operational impact of the DER on the Jamaica transmission and distribution network. Siting new renewable generation which is variable in nature requires locational net benefits analysis studies to ensure the electrical integrity of the electric grid.
2. Determine network upgrades, which may be required to accommodate the power output from the proposed renewable sites. The current Jamaica transmission and distribution system was designed for a specific resource mix of fossil generation units. Power flows on the grid are required to determine the impacts on other resources.
3. Determine cost estimates to facilitate interconnection to the distribution network and network upgrade costs. Distribution costs to ensure performance of the electric grid are allocated to both developers and customers who benefit from DER.

5.1.2: Determine the customer billing impacts of the Preferred Portfolio

Aside from the network upgrade costs, the customer billing impacts are a necessary component. For the Preferred Portfolio, it is then possible for customers to compare the impact of the Preferred Portfolio on electricity expenditures. There are two components, a fuel charge pass through and an average customer billing impact.

For the average customer bill, there are several parameters that are included in these calculations. Demand charges are fixed, per customer charges do not vary with the usage of electricity. These include the costs of metering, billing, and payment processing. The bundled cost of distribution service, as well as the power supply cost, is bundled into a usage charge, calculated as a price per kilowatt-hour. Depending upon rate class and usage, there are different customer charges and variable rates. Residential rates include several customer classes: small-use customers, such as apartment dwellers, low-income households; urban area residents who use more electricity for space and water heat will receive much higher electric bills; and large-use customers, including large single-family homes in suburban and rural areas without access to natural gas most often will receive lower electric bills. Commercial and Industrial rates have similar components but are lower per kilowatt demand charges and usually lower variable rates for usage, although total bills are higher. Special rates can apply to those who site distributed resources and public usage of lights, etc. The intent is to take the final results of the Preferred Portfolio and determine average customer billing impacts by rate class.

Because the Preferred Portfolio deploys a high percentage of renewable generation, reducing fossil fuel costs will impact the fuel pass through calculation. The combined impact of the average customer bill and fuel pass through can then be approximated in addition to any network upgrade costs allocated to the customer.

5.1.3: Determine Long Run Avoided Costs by Technology

The avoided cost is most important for the replacement of existing generation sets by the JPS. The law states that the JPS must match the avoided cost in order to be able to replace its existing generating sets or else the capacity to be replaced goes to the market by way of an RFP. For new generation procured by the Generation Procurement Entity, the avoided cost would merely be a comparative estimate because the RFP process will determine the successful bidder and by extension, the price. Therefore, because the right to replace existing generation is a special facility and the Minister's imperative is to lower the price of electricity, we should utilize the methodology that yields the lower avoided cost. Recent experience with the first of the replacements for JPS (Gas Turbine siting) is that the JPS was able to significantly lower its price. The only scenario in which the avoided cost will be used, is when JPS chooses to exercise its Right of First Refusal (ROFR)[63]. If JPS chooses to

[63] Right of First Refusal accords JPS the option to develop a generation resource if it can be done more cheaply than the developer.

exercise the ROFR with a thermal plant replacing a thermal plant, the system avoided cost would be relevant, however; if JPS were to exercise its ROFR by replacing a thermal plant with a renewable resource (wind or solar), and was allowed a cost only slightly less than avoided cost, then the company would receive supernormal profit because the cost of those technologies are much lower. Therefore, the Long Run Avoided Cost of Energy should be technology specific.

5.1.4: Determine Short Run Supply Curves by Technology

Aside from the issue of which resource mix to use in the long term, investment is fixed in the short run and supply curves based on short run marginal cost can be ascertained by simulating dispatch and comparing operating costs, ranking the outcomes to create a supply curve. These short run supply curves are useful in analyzing the impact of resources such as direct load control programs, energy efficiency, pumped and electricity storage technologies. To estimate short run marginal operating costs, cost minimizing hourly dispatch is performed in PLEXOS constrained by the results of the longer run capacity cost, maintenance and operating parameters of the resources. Some combinations of planned and forced outages and/or weather will create demands in excess of capacity, leading to voltage reductions or power cuts (lost load).

5.2. Future Scenarios

5.2.1 Energy Efficiency and Demand Response Programs [64]

DNV GL has outlined a methodology to develop the impact of energy efficiency and demand response for future scenarios.

System Load Analysis

The first step in the process is to identify the system peak characteristics of the load to be served to assess the most likely future occurrences of annual system peaks, which will inform the decision on when peak hours are likely to occur. To determine this, the most recent 2-5 years' hourly system loads can be analyzed. Each year's peak months and hours will be identified, defined as within 2 percent – 5 percent of the annual peak for identifying the frequency of both peak hours and months.

For JPS, the system peak typically occurs in the summer, with 7 of the last 10 years (2007-2016) occurring in either July or September, but as early April and as late as October.

Weather Data

Daily weather, including a summary of the temperature data can be used for the analysis. For the monthly analysis, monthly cooling degree days on a 65^{o}F base are used and a monthly pattern developed to identify/confirm the summer weather-sensitivity.[65]

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[64] Reference SUPPORT FOR DEVELOPMENT OF A COMPREHENSIVE ELECTRICITY PLANNING PROGRAM FOR JAMAICA, Jamaica IRP Report, Inter-American Development Bank, Revision G.

[65] For analysis and estimation of the distribution of loads for weather-sensitive end uses, such as cooling, distribution of cooling is typically highly correlated to weather conditions. For summer, a standard unit for such a correlation is to use daily cooling degree days, calculated as the difference between the average temperature of a day and a base temperature where cooling is not expected, such as 65 degrees Fahrenheit or 18 degrees Celsius.

Class Load Estimates

The development of class load profiles can be used to estimate total class load shapes, used as the basis for building audit profiles and to calibrate the end use load profile development. For utilities with established load research programs, samples can be drawn by class, meters are deployed, interval data collected, validated, processed and analyzed, and a complete set of accurate load profiles with a measurable and acceptable precision can be available. JPS is currently installing and has started data collection on a new major sample of customers for their Residential and Commercial rate classes. Virtually all the larger Commercial & Industrial customers already have hourly monitoring conducted, which would be combined with the sample data in developing class load profiles.

Methodology

In the interim before the current load research sample is completed, there are a few options for estimating class loads to use in supporting estimates of demand-side potential.

DSM/EE Feeder Load Model

JPS Co could identify specific feeders that were dominated by specific rate classes, which could then be used to scale the resulting full year (8760 hour) load shape to match the total annual sales for each rate class. Several calibration steps would then be used, including checking that the resulting sum of rate classes was reasonably close to the system load curve for hours throughout the year. Since system load is measured at the generator and the class loads are built from the bottom up at the customer level, the difference between the totalized class loads and system loads should be consistent with system loss estimates, consisting of technical load losses and other unaccounted-for loads. This procedure has been used for several other regional load studies (Belize, LUCELEC) with success, with the Belize Electric LLC further confirmed by a class sampled load study immediately after the initial feeder load model can be developed and used to verify the successful estimate and error bounds of the feeder model.

The method developed for the interim load profile development is based on the following components:

- metered feeder data from as many feeders as available on the JPS system;
- a street lighting model assuming dusk-to-dawn lighting to estimate the contribution of street lighting, which is unmetered, instead based on annual kWh sales totals. A traffic light and other 24-hour loads estimate could be added, as well, to the dusk-to-dawn component.

For each feeder, an estimate of the percentage of total annual consumption that each feeder contained for each of the rate classes:

- 10-Residential,
- 20-Small Commercial, and
- 40-Large Commercial was developed.

For several feeders dominated by a specific class, these would be combined, then estimated street lighting load would be subtracted to produce the class load shape, which is then scaled to the known class annual consumption. Ideally, billing data with each customer's feeder assignment would be used to produce exact usage by feeder by class, but that data may not be readily available. Feeder SCADA data would be obtained for the most recent full year period. These were used to generate an average 8,760 load shape by day type for the test year, which would then be applied to each subsequent year of interest, scaled to match actual or projected monthly and/or annual sales from billing records by month.

DSM/EE Street Lighting Model

Using a street lighting model previously developed by DNV GL, combined with the mid-month sunrise and sunset times for Kingston, Jamaica, a modeled load shape of street lighting load profiles were developed. The assumption would be that street lights are sensor-activated and would turn on 30 minutes after sunset and turn off 30 minutes before sunrise, which has been shown to be the pattern from previous studies. A typical hourly profile for high and low hours of daylight is provided in Figure 69.

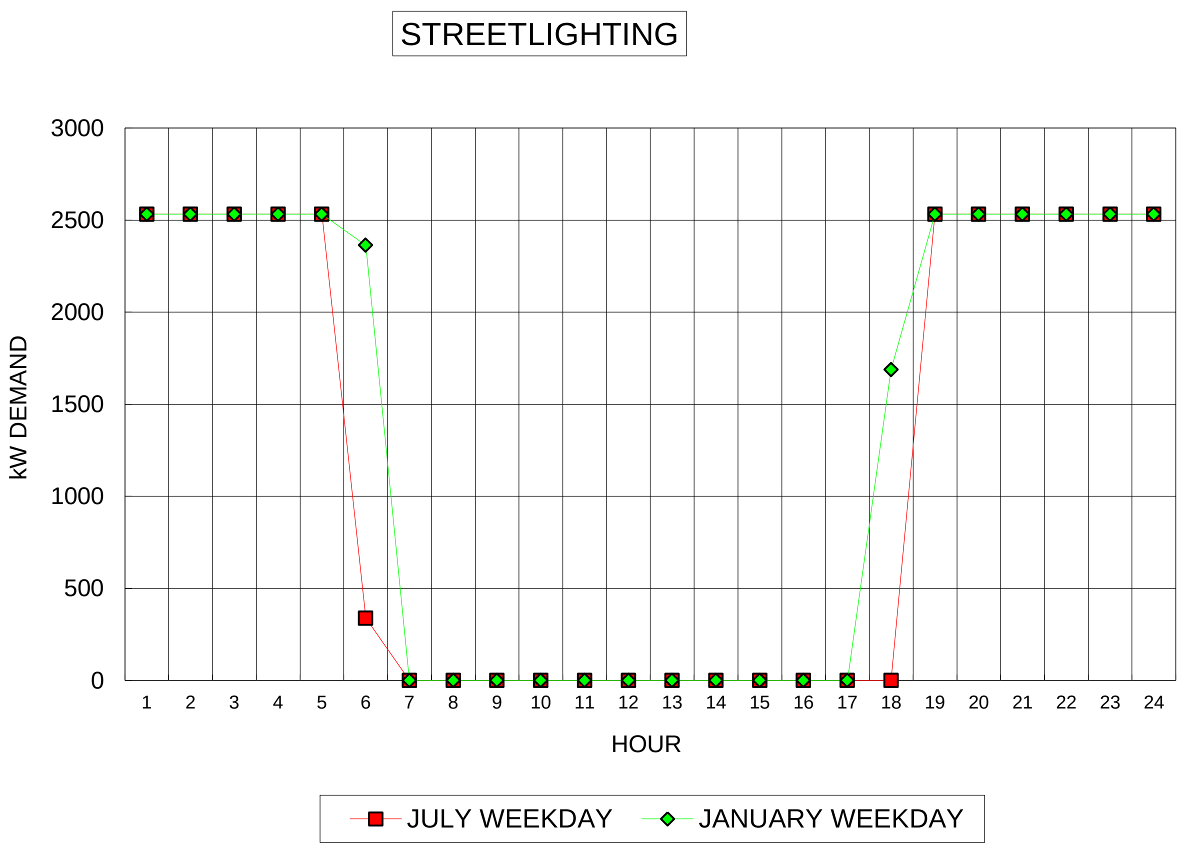

Figure 69: Street Lighting Load Profile

For Jamaica and most of Caribbean countries, the proximity to the Equator means that the difference between winter and summer is minor. Both seasons would indicate that street lighting is not coincident with common daylight system peak coincident hours.

Once class loads are estimated or developed from sample class load studies, key end use load components would need to be developed. This process starts with extraction of weather-sensitive loads from each class, as determined from weather-based regression analysis, based on variation in loads by weather across months and seasons. To develop annual baseline consumption and load shapes by end use and by sector (Residential, Commercial and Industrial), the best available sources can be used from other studies in the US and in the Caribbean. Where needed, weather adjustments were made for both daily and seasonal weather-sensitive end uses.

Knowing the average annual consumption by customer class provided a means for calibration of the estimates of both energy use intensity (EUI) and saturations. The starting point can be a recent DSM potential study or regional study which can provide initial estimates of breakdowns of total loads by end use, combined with end use saturations and units per household. From there, estimates can be increased or decreased to match the average annual usage for JPS, to produce an annual component breakdown.

DNV GL assumes from experience, the key residential end uses expected for Jamaica are space cooling, lighting, refrigeration, and water heating (including solar thermal). For Commercial, cooling, lighting and refrigeration are the key components.

The result would be a component breakdown of total annual consumption per end use, such as the example below.

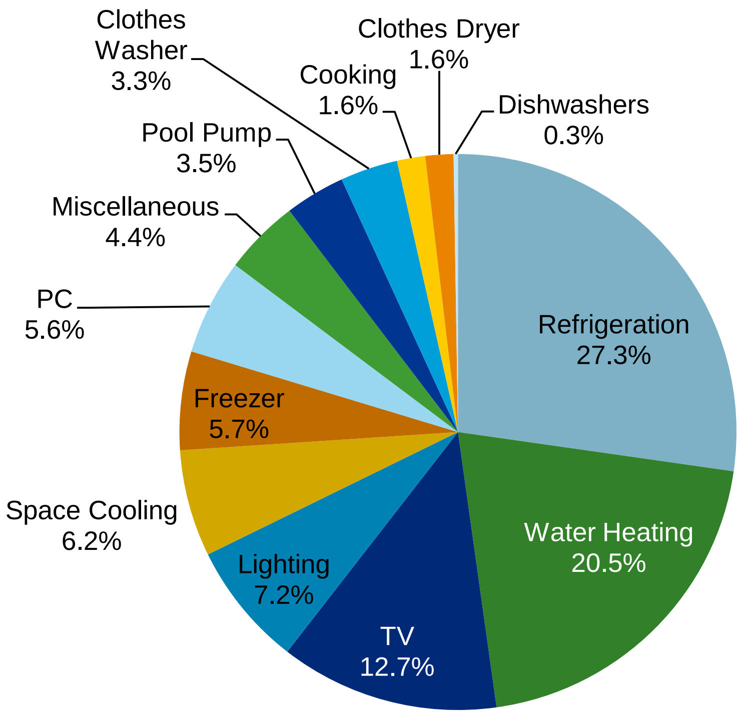

Figure 70: Energy Consumption by End Use (sample)

Based on borrowed load shapes by end use for each key component, the modeled annual consumption breakdown can then be converted down to hourly per-unit load shape estimates, to which assumptions for savings can then be applied, based on regional or U.S. experience in reductions for high efficiency units.

For Commercial end uses, a similar estimate would be made, first by backing out the modeled cooling load component from the class loads and then by using regional or other sources to estimate non-cooling end uses, as illustrated in the example below.

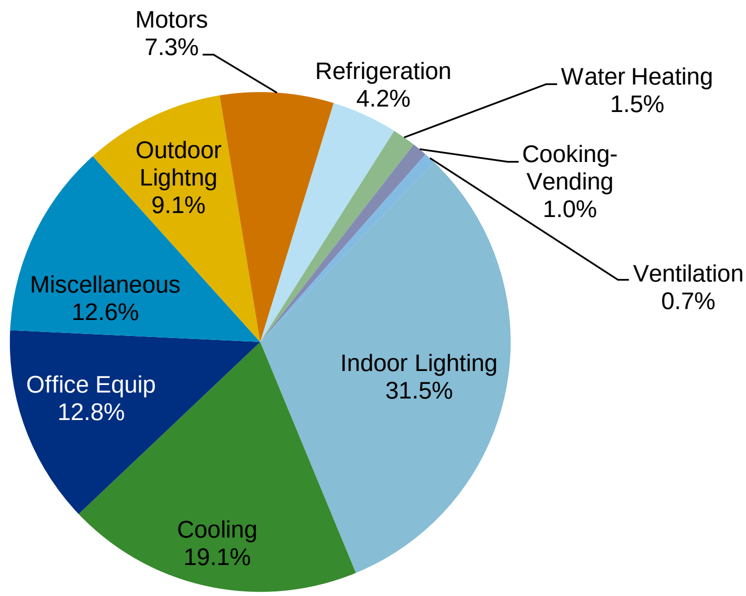

Figure 71 Total Commercial End Use Breakdown (Sample)

Demand Side Management (DSM) programs include both energy efficiency and peak reduction. To that extent, Demand Side Management programs can impact load forecasts and provide cost saving efficiencies.

The approach to identifying DSM Savings is as follows:

1. ***Identify potential measures for consideration***

General approach – choose measures with very likely positive cost-benefit success given the utility, weather, total potential.

- residential refrigeration – upgrade efficiency (vs. standard);
- residential lighting – upgrades to LED lighting instead of incandescent and CFL;
- solar water heating – replacement of tank and point-of-use with solar thermal;
- residential water heating – replacement of storage tank water heaters with tankless or high efficiency units (rather than standard);
- residential high-efficiency cooling – replacement of central and room A/C with higher than standard efficiency units;

- commercial audits – identifying opportunities for cooling, lighting and refrigeration upgrades.

2. ***Develop assumptions for existing, base case and DSM case options for efficiency/technology***

- Generally, Identify any data/studies on:
    - current unit and customer saturations;
    - current, base and DSM energy consumption per unit;
    - current, base and DSM energy efficiency;
    - measure lifetimes;
    - incremental savings percentage and cost for one or more high-efficiency options;
    - Load shapes by end use/technology (annual energy vs. peak definitions).
- For specific measures/equipment:
    - refrigerators – percent with one vs two refrigerators;
    - lighting – number of high-use lighting fixtures per house;
    - saturation of incandescent vs. CFL vs. LED usage;
    - water heating – percentage of tank vs. point-of-use vs. existing solar thermal systems
    - cooling – count/saturation of room A/C's, room A/C's per customer, central A/Cs, split systems;
    - commercial customer types: Hotel, Office, Health;
    - commercial audit savings performance assumption (e.g. 5%).
- Sources for assumptions:
    - Jamaica or Regional studies;
    - JPSCO sales for calibration of end use breakdowns with sales data;
    - experience from other Caribbean projects;
    - experience from North American Projects.

3. ***Program assumptions***

- Incentive levels (e.g. 50%, 75%, and 100%)
- Number of years (one, measure life, defined)

4. ***Low and high efficiency cases***

- Vary by efficiency improvement for "efficiency case"
- Vary by percentage of potential participants by year, i.e. achievable (e.g. 20% of replacements vs. 50% of replacement)
- Only use "replace on burnout" and not accelerated turnover

Data Required for Analysis

- Population and GDP/capita from the last 10 years
- Forecast of GDP/capita growth for the coming 10 years
- Forecast of population growth for the coming 10 years
- Historical data (last 10 years) of yearly consumption (kWh) and customer counts by rate class/customer segment
- Monthly sales/consumption (last 3 years), and customer counts (last 3 years) per rate class and customer segment. Examples of customer segments are:
    - residential;
    - commercial;
    - street lights;
    - industrial;
    - government;
    - water companies;
    - tourism (Hotels and other tourism related amenities).
- Historical yearly peak consumption in Jamaica for the last 10 years, hourly system loads for past 3-5 years
- Gross generation, generation losses, energy sales (metered), network losses for at least the last 3 years
- Number of clients in each segment previously identified per MV feeder in Jamaica
- Consumption of each client segment per MV feeder (if available) or estimate of percentage consumption by customer segment per MV Feeder
- Foreseen large interconnections (for example resorts or large hotels) in 10-year horizon (installed power 10 times higher than average client peak consumption), for each customer segment, indicating the MV feeder they are connected or if they are

connected through a new dedicated MV feeder, and their forecast of yearly energy consumption

- Description/status of Load Research Program, including any design parameters, population segmentation, sample sizes. Count of customers by rate class with availability of hourly load data
- Any hourly load profiles available for the above customer groups (preferably by rate class). This will depend on how often JPS does their energy balance. If they close the balance monthly then we will get monthly profiles, I they close it daily we will get it 365 data points. Ideal would be hourly profiles for the whole year or at least typical hourly profiles by day type (peak day, weekday, weekend day) depending on the season of the year
- Availability of hourly load profiles by feeder (e.g. from SCADA)
- Description, rates, conditions and typical bills for each rate class
- Any saturation surveys identifying incidence of appliances and end uses within Residential and Commercial/Industrial segments
- Any surveys/studies/reports of energy conservation, energy efficiency or demand response/load management
- Descriptions/links of any energy programs recently, currently or planned for Jamaica, whether by JPS, independent Jamaican organization or regional/international entities

5.2.2: Develop scenarios for adopting hydroelectric energy resources and waste to energy

Jamaica has extensive hydro resources which could be developed. Hydro plants have relatively low operating costs, but also have significant capital costs and licensing requirements. Hydro plant adds additional uncertainties because the amount of water available can fluctuate from year to year, as river flow records will reveal. If the hydro capacity has a large storage reservoir, selecting the optimal timing of the use of the water for generation, to maximize the expected fuel cost of the thermal generation which it displaces, is a complex matter. One reason is that the height of the water in the reservoir, as well as the quantity of water flowing over the turbine at any point of time, affects the rate at which energy is generated. A hydro plant can be used to balance renewable resources and load changes in the short run. It may be worthwhile installing more generation capacity at the hydro sites for use in peak periods and even to use the sites for pumped storage.

Waste to Energy plants burn municipal waste streams and as a by-product, produce electricity. Several parameters will be investigated in future scenarios including variations in:

1. Input fuel schedule
2. Energy content characteristics of the thermal conversion stage
3. Modeling electrical (and) thermal energy production in the post-treatment stage through one of the following technologies:
    a. gas or steam turbine generator or engine generator;
    b. output heat capture mechanism to generate usable thermal product in the form of hot water or steam.
4. Output in the form of electric production profile to be normalized and scaled for inclusion in IRP
5. Sorting of waste streams
6. Tipping fees to offset capital costs

The input technology characteristics of the fuel to electric (and) thermal system are:

1. Heat rate curve at different electric loading levels;
2. Power to heat ratio at different electric loading levels;
3. Operational paradigm and load profile if plant is operating in load following mode.

The outputs of the W2E plant will be modeled per the plant characteristics specified above and one of the following operational modes:

1. Thermal load following – The Combined Heat and Power (CHP) plant follows a specified thermal load and produces electric as per the given power to heat ratio and efficiency characteristics;

2. Electric load following – The CHP plant follows a specified electric load and produces thermal output as per given power to heat ratio; and
3. Constant heat or constant electric output.

Some of the challenges foreseen with this source of energy faced by developing countries are the caloric value of the garbage and volume keep the incinerator going. For combustion technologies to succeed they would need about 2000 to 3000 cal / kg. Failing to have steady quality inputs will see the need for axillary fuel which would not meet our objectives of cheaper energy. Further policy adjustments culminate with social incentives may allow for this technology to be competitive viable in future updates.

5.2.3: Future distribution resource interconnections

Distributed resources are energy resources that are located and interconnected at the customer side of the meter or on the distribution grid[66]. To the extent deployed in the IRP, these resources use forecasted schedules. These resources may be metered separately or placed behind the utility meter of the customer. Customer sited resources are operated for customer applications such as backup during grid outage, utility bill management and offsetting fuel costs. Utility sited distribution system connected resources may be operated to serve specific distribution system functions such as renewable intermittency management, renewable time shifting, and distribution asset upgrade deferral. Taking into consideration existing distributed resource deployment, planned projects, long term energy

[66] The North American Electric Reliability Council defines distributed resources as electricity producing resources coordinated and/or controlled by a utility *not currently controlled, monitored or dispatched as part of the bulk electric power system (resources at or above 69 kV).* NERC includes distributed generation controlled by the utility or merchant, behind the meter retail electricity supply, energy storage including electric vehicles, aggregator or micro-grid/"self-optimizing" customer, cogeneration, and/or emergency or standby generation. NERC, Distributed Energy Resources Task Force Report, February 2017. Demand Side Management/Energy Efficiency programs are treated separately following this convention.

goals of the Jamaica Ministry of Energy, and availability of technical feasibility studies, the following five technologies are recommended for inclusion in the IRP study:

- stand-alone Solar PV;
- stand-alone Wind turbine generators;
- solar PV + batteries or storage system;
- stand-alone batteries or storage system;
- waste to energy technologies;
- biomass from sugar cane.

Subsequent sections contain detailed descriptions, applicability, and modeling methodology for IRP evaluation of the five technologies. Other relevant distributed resource technologies are anaerobic digesters, micro-grids, and electric vehicles. DNV GL recommends technical feasibility studies before evaluating these resources for IRP.

Distributed Resource Modeling Overview

To evaluate the impact of distributed resources on system planning and operations, the production of individual technologies will be assessed and scaled up to transmission node level. Representative sites for resource deployment on the distribution system will be selected based on customer class, site conditions, and location on feeder. Characteristic technology parameters will be selected for modelling or forecasting the output of the distributed technology. The production output will be determined at 1-hour or 15-min granularity for an entire year. This site production output will be normalized based on selected nameplate capacity and customer peak load. The normalized profile will be scaled and distributed within wholesale nodes based on assumptions of technology penetration within each node. The net-load impact of distributed resources can then be assessed for planning purposes through production costing analysis. Figure 72shows the overview for integrating distributed resource impact within IRP analysis.

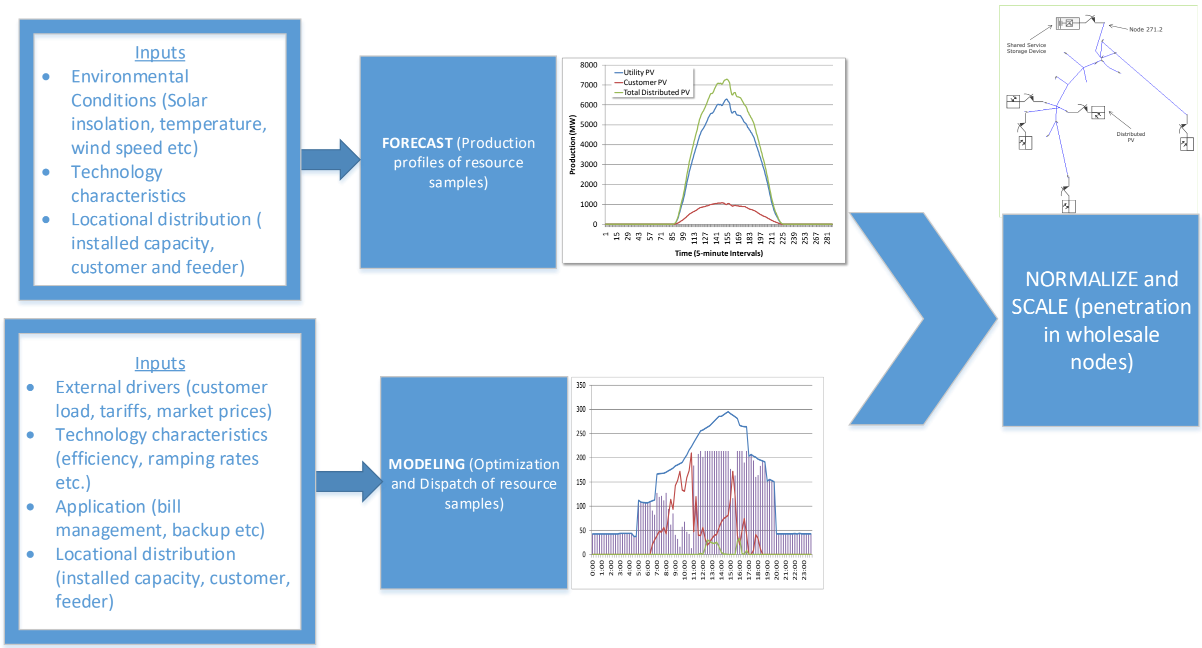

Figure 72 Distributed Resource Modeling Overview

Distributed resources may be classified into exogenous and controllable resources. Examples of exogenous distributed resources are stand-alone Solar PV and stand-alone wind turbine generators. The output of these resources cannot be explicitly controlled or shaped to target specific benefits. Factors such as site conditions, interconnection requirements, location, environmental conditions, and technology specifications direct the output of these resources. Thus, the production output of these resources is forecasted rather than modeled.

In case of resources such as Battery Energy Storage Systems (BESS) and waste-to-heat technologies, the control and operational methodology needs to be modeled to determine outputs. Modeling the control system is based on the requirements of specific applications to which devices are operated, as well as external drivers such as utility tariffs, market signals and circuit conditions.

The net load impact of forecasted and modeled distributed technologies is illustrated in Figure 73. The graphics show 15-minute site operation at a small commercial customer over

24 hours. In the top-left graphic solar production is forecasted and net load at the utility meter is assessed as the PV output subtracted from the original customer load. It is noticeable that the variability of PV outputs is transferred to the net load profile and hence affects the utility distribution system. The top right graphic shows operation of a Solar + Storage system where the storage operates to reduce customer demand charge as assessed by the utility. The storage system charges from the solar plant and discharges such that the peak net load is reduced. In this example, Solar + Storage is a controllable resource whose output is modeled on demand charge reduction application requirement. As a result of storage operation, the variability of net load measured at the utility meter is also reduced.

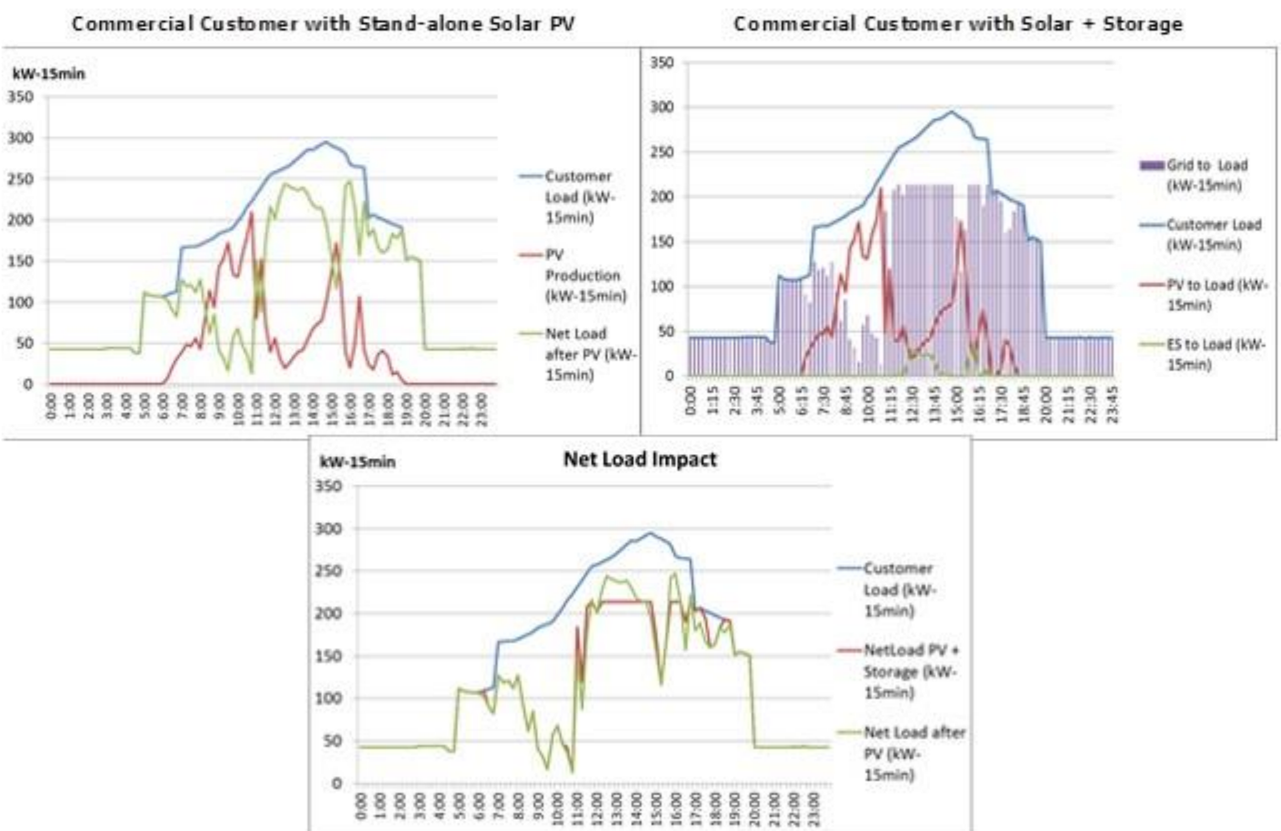

Figure 73 Output and net load impact of forecasted and modeled technologies

Subsequent sections will detail the forecasting or modeling methodology of individual technologies.

Solar + Storage

Battery Energy Storage Systems (BESS) may be co-located with Solar PV plants to increase the financial viability and grid integration performance of the combined system. Solar + Storage systems are rapidly commercializing due to precipitous reductions in cost of BESS and incentives for co-locating batteries with Solar PV. A unique aspect of Solar + Storage systems is dispatch controls layered on top of the storage technology hardware. Dispatch controls are a fundamental link between technology and application and allow the Solar + Storage system to generate requisite revenue streams. Customer bill management, which includes energy charge and demand charge reduction, is a very viable application for distributed Solar + Storage in Jamaica. This is particularly applicable in jurisdictions with high demand charges, such as dense urban environments in New York, California, Hawaii and Massachusetts in U.S.

In specific geographic locations and utility jurisdictions commercial customers are subject to capacity and/or demand charges by the electric utility or distribution system operator. These charges may comprise of two separate tariffs – a non-coincident demand charge assessed on the maximum demand of the monthly billing cycle and, a peak demand charge assessed on the maximum customer demand during peak hours over the monthly billing cycle. Generally, these charges are additive. In dense urban areas subject to transmission and distribution system congestion, such as New York City, the bay area in California, San Diego, Los Angeles, Boston, and others, these charges may be quite high – in the range of US \$20 - \$45 per kW customer demand recorded. Thus, demand reduction can result in substantial savings, making this application very attractive for the customer as well as integrators.

Standalone behind-the-meter solar PV systems can reduce customer demand by a limited amount. However, this reduction cannot be guaranteed and the savings that may be accrued cannot be 'banked' upon. The reason is that the output of a solar PV system is intermittent, and dependent on atmospheric and ground conditions. For example, a sudden cloud cover during the customer peak demand hour may jeopardize the demand reduction potential from the stand-alone solar PV system over the entire month. Battery Energy Storage Systems can complement Solar PV systems to reduce the peak demand. They guarantee the demand reduction that may be naturally accrued to solar PV systems as well as reduce demand on their own. The volume of demand reduction achieved by Solar + Storage systems is generally higher than the sum of the demand reduction possible through stand-alone solar and BESS system.

The operation of behind-the-meter energy resources is simulated at 15-min intervals over the entire year under inputs of customer load, renewable production, utility energy and demand tariffs, as well as performance characteristics of the solar modules, solar inverter, battery modules, inverter interface and interconnection constraints. BESS dispatch controls are optimized over each 24-hour horizon to maximize customer energy and demand charge savings.

The modelled BESS dispatch considers perfect foresight and perfect controls. The perfect foresight assumption implies that load and renewable production is perfectly known over the optimization horizon. Perfect controls assume that there are no measurement errors or other disturbances that affect the system and control outputs are perfectly actuated. These assumptions help derive the maximum savings potential for a resource configuration at a facility. Savings may be reduced due to forecasting and control errors, to the tune of 10 – 30 percent.

In the United States of America BESS can take advantage of Federal Investment Tax Credits (FITC) when co-located with and charging from Solar PV systems. The maximum FITC of

30 percent on the all-in capital cost of the BESS can be obtained if the batteries derive 100 percent of charging energy from solar output. Our modelling may consider BESS to charge exclusively from the Solar PV system or both Solar PV and the utility grid. Figure 74 shows 24-hour site operation with 160 kW Solar PV and 58 kW 4-hour BESS at a commercial facility. The Solar + Storage system is controlled to maximize bill savings at the facility. Storage primarily charges from Solar PV during peak renewable production period between 9 am to 4:30 pm. The BESS has two distinct discharge periods – between 7 am and 9 am and, 4:30 pm to 8:00 pm. During these periods, solar production is low or zero, and storage discharges to ensure that net facility load is below the demand target for the day. The original customer demand of 145.5 kW is reduced to 78.1 kW, in effect reducing demand by 67.4 kW.

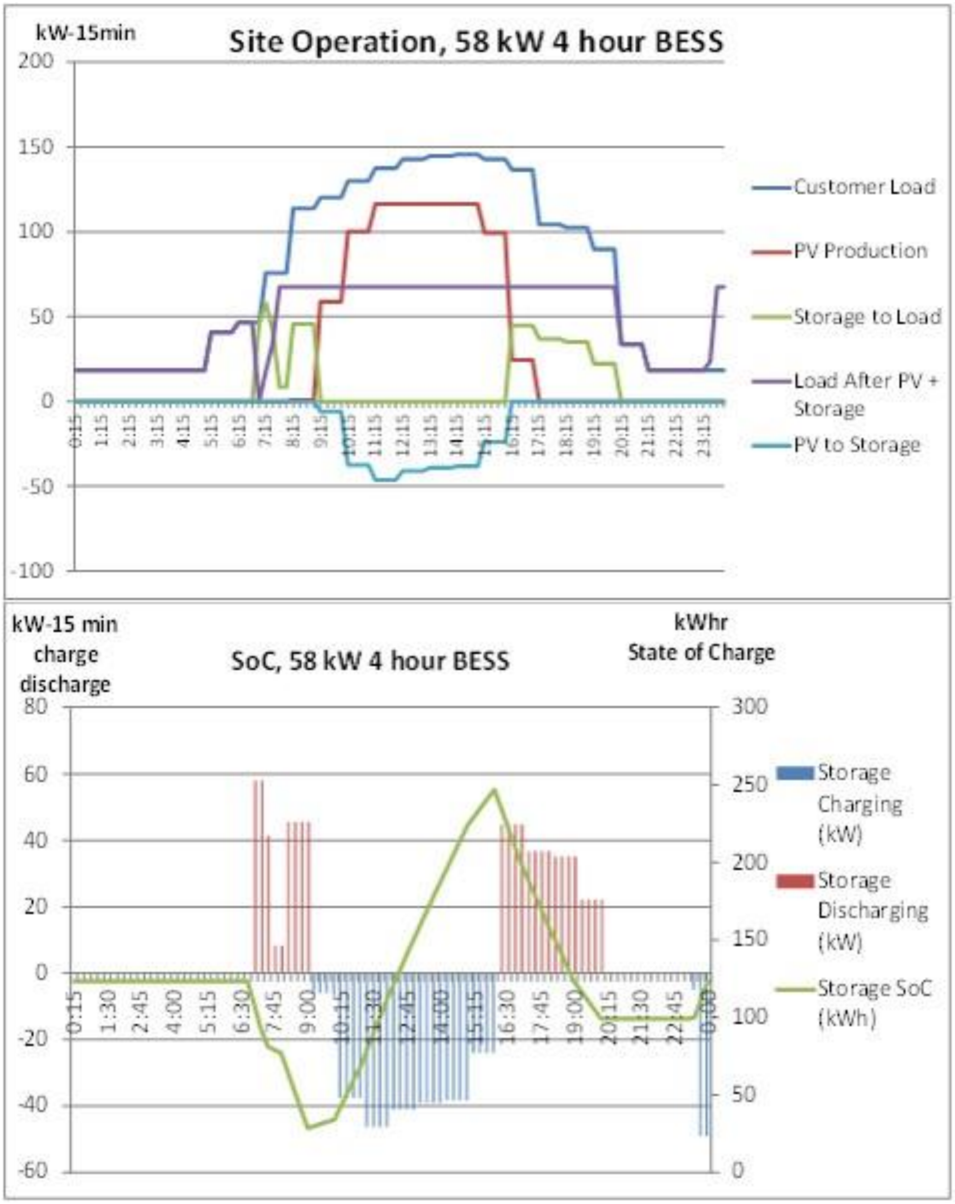

Figure 74 Example of Site and BESS operation at a small commercial facility

5.2.6: Grid Code Revisions

To facilitate the high levels of variable renewable penetration within the grid the following are recommendations for the next review and update of the Grid Codes by the OUR:

i. Distribution feeders to operate at 98 percent load power factor (PF) from the traditional 95 percent.
ii. All new wind and PV generation plants should provide grid support during steady state conditions by contributing to voltage control through the injection of reactive power. That is, solar and wind plants should operate at 0.95 power factor during steady state conditions.
iii. All new wind and PV generation plants should support grid disturbances and faults without being disconnected from the grid (LVRT). In that way, they will help to maintain the voltage stability of the grid.
iv. All new wind and PV plants should also support utility grid when necessary, mainly during a fault, by generating/absorbing reactive power.
v. All new gas plants should have synchronous condenser capability to provide voltage and inertia support during high instantaneous VRE penetration.

5.2.7: Resiliency future scenario:

Storm hardening substations

Wind turbine disconnect and restore impacts

Towers impacted by high winds

Standby and backup generators (industrial clients as well)

Distributed resources and independent control

Emergency fuel preparations

Grid resilience is the ability of a power grid to bounce back from a major incident. The incident can be a man-made incident, such as a terrorist attack, or a natural disaster such as a major hurricane. A resilient grid may suffer a disruption at the height of the event, but it will be back up quickly, sending electricity to customers. As part of an IRP, grid resilience includes:

1. **Identify and rank critical assets**. This is an enterprise-wide ranking of the vital systems, facilities, processes, and information necessary to maintain continuity of electricity service. The objective is to focus the assessment and support the risk analysis process (a process that culminates in ranked options for action). Lists created for contingency planning can be a helpful starting point, but a careful analysis of critical assets is needed to ensure that current threats and new critical infrastructure assurance considerations, such as interdependencies, are addressed.
2. **Identify vulnerability assessment methodology.** These include the following steps:

a) Network architecture
b) Threat environment
c) Penetration testing
d) Physical security
e) Physical asset analysis
f) Operations security
g) Policies and procedures
h) Impact analysis
i) Infrastructure interdependencies
j) Risk characterization

3. **The post-assessment phase.** This involves prioritizing assessment recommendations, developing an action plan, capturing lessons learned and best practices, and conducting training. The risk characterization element results

provide the basis for the post-assessment by providing prioritized lists of recommendations that are ranked by key criteria.

5.2.8: Load Forecasting Methodology Revision

Rather than use a fixed load factor forecast, future IRP scenarios will use a variable load factor forecast.

20 Years Forecast Average Growth Rate

Description	MHI	DVN_GL	JPS
Demand	1.62%	1.60%	1.70%
Energy	1.80%	1.60%	1.70%

Note: DNV_GL & JPS utilize a fixed load factor

5.2.9: Loss Optimization

5.2.10: Re-Visit Objective Weightings with Focus Groups

Appendix A: Load Forecast Results

Historic data

Indicator	Units	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Economic indicators															
Population	-	2,615,253	2,624,695	2,634,145	2,643,601	2,653,042	2,662,481	2,671,934	2,681,386	2,690,824	2,699,838	2,707,805	2,714,669	2,720,554	2,725,941
Population	%/year	0.37%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.35%	0.35%	0.33%	0.30%	0.25%	0.22%	0.20%
Urban population (% of total)	%	52%	52%	53%	53%	53%	53%	53%	54%	54%	54%	54%	54%	55%	55%
Urban population	-	1,366,496	1,376,311	1,386,219	1,396,112	1,406,059	1,416,014	1,426,038	1,436,070	1,446,130	1,456,023	1,465,654	1,475,043	1,484,225	1,493,489
Urban population	%/year	0.75%	0.72%	0.72%	0.71%	0.71%	0.71%	0.71%	0.70%	0.70%	0.68%	0.66%	0.64%	0.62%	0.62%
GDP (current USD)	USD	9.69E+09	9.4E+09	1.02E+10	1.12E+10	1.19E+10	1.28E+10	1.37E+10	1.2E+10	1.32E+10	1.44E+10	1.48E+10	1.43E+10	1.39E+10	1.43E+10
GDP per capita (current USD)	USD	3,707	3,581	3,854	4,238	4,487	4,817	5,119	4,490	4,903	5,349	5,467	5,259	5,108	5,232
GDP Purchasing Power Parity (current USD)	USD	6,805	7,155	7,409	7,676	8,100	8,394	8,449	8,108	8,052	8,326	8,395	8,542	8,723	8,873
GDP Purchasing Power Parity (current USD)	%/year	2.92%	5.13%	3.55%	3.60%	5.53%	3.62%	0.66%	-4.04%	-0.69%	3.41%	0.82%	1.75%	2.13%	1.72%
Tourism (number of arrivals)	-	1,266,000	1,350,000	1,415,000	1,479,000	1,679,000	1,701,000	1,767,000	1,831,000	1,922,000	1,952,000	1,986,000	2,008,000	2,080,000	
Tourism (number of arrivals)	%/year	-0.86%	6.64%	4.81%	4.52%	13.52%	1.31%	3.88%	3.62%	4.97%	1.56%	1.74%	1.11%	3.59%	
Interest rates (commercial credit annual average)	%	13.10%	8.85%	8.30%	8.97%	9.26%	9.35%	8.83%	8.53%	8.77%	8.40%	7.65%	7.06%	6.91%	6.91%
Interest rates (commercial credit annual average)	%/year	7.54%	-32.47%	-6.23%	8.11%	3.27%	1.01%	-5.61%	-3.41%	2.84%	-4.23%	-8.96%	-7.72%	-2.14%	0.07%
Electricity															
Electricity consumption (per capita)	kWh	2,415	2,486	2,462	2,484	2,462	2,003	1,208	1,274	1,270	1,261	1,154	1,126	1,118	1,146
Electricity consumption	GWh	6,316	6,526	6,486	6,568	6,533	5,334	3,228	3,417	3,418	3,405	3,126	3,058	3,034	3,112
Peak demand	MW				616	626	629	622	644	638	618	636	626	625	640
Load factor	%				122%	119%	97%	59%	61%	61%	63%	56%	56%	55%	56%
Number of customers															
Residential	-	452,388	462,107	480,665	491,452	511,039	520,085	526,492	521,837	509,660	513,970	531,827	541,691	531,363	536,462
Small Commercial & Industrial	-	54,881	54,276	55,480	56,700	59,694	61,419	62,347	62,029	60,782	61,401	63,740	64,559	62,294	62,517
Large Commercial & Industrial	-	98	103	94	92	101	116	124	130	138	145	151	150	150	150
Other	-	193	195	195	202	211	208	199	222	221	246	253	254	389	401
Electricity sales															
Residential	MWh	842,972	1,110,794	1,089,691	1,123,274	1,103,225	1,064,068	1,048,399	1,082,599	1,090,619	1,064,535	1,035,377	996,429	981,730	1,016,428
Small Commercial & Industrial	MWh	934,911	1,282,777	1,332,462	1,382,303	1,417,327	1,416,149	1,432,323	1,435,285	1,402,748	1,437,283	1,383,296	1,366,797	1,347,514	1,360,131
Large Commercial & Industrial	MWh	392,418	542,628	497,815	464,020	510,882	561,602	599,850	589,560	593,360	615,041	615,314	605,402	589,236	602,618
Other	MWh	52,441	73,262	79,672	85,557	89,235	89,675	98,506	96,435	100,761	99,131	99,979	101,060	94,499	92,172
Specific consumption															
Residential	MWh/cust.	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Small Commercial & Industrial	MWh/cust.	17	24	24	24	24	23	23	23	23	23	22	21	22	22
Large Commercial & Industrial	MWh/cust.	4,004	5,268	5,296	5,044	5,058	4,841	4,838	4,535	4,300	4,242	4,075	4,036	3,928	4,017
Other	MWh/cust.	272	376	409	424	423	431	495	434	456	403	395	398	243	230

Forecasts

Reference case

	Units	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Economic indicators forecast																						
Population	-	2,725,941	2,741,768	2,757,687	2,773,698	2,789,802	2,806,000	2,813,757	2,821,535	2,829,335	2,837,157	2,845,000	2,850,380	2,855,769	2,861,169	2,866,580	2,872,000	2,874,197	2,876,395	2,878,595	2,880,797	2,883,000
Population	%/year	0.20%	0.58%	0.58%	0.58%	0.58%	0.58%	0.28%	0.28%	0.28%	0.28%	0.28%	0.19%	0.19%	0.19%	0.19%	0.19%	0.08%	0.08%	0.08%	0.08%	0.08%
GDP Purchasing Power Parity (current USD)	USD	8,873	8,988	9,105	9,278	9,538	9,776	10,099	10,432	10,776	11,132	11,499	11,821	12,152	12,493	12,843	13,202	13,559	13,925	14,301	14,687	15,083
GDP Purchasing Power Parity (current USD)	%/year	1.72%	1.30%	1.30%	1.90%	2.80%	2.50%	3.30%	3.30%	3.30%	3.30%	3.30%	2.80%	2.80%	2.80%	2.80%	2.80%	2.70%	2.70%	2.70%	2.70%	2.70%
Tourism (number of arrivals)	%/year	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%
Interest rates (commercial credit annual average)	%	6.91%	7.20%	6.90%	7.30%	7.30%	7.60%	8.00%	8.25%	8.50%	8.75%	9.00%	9.25%	9.50%	9.75%	10.00%	10.25%	10.50%	10.75%	11.00%	11.25%	11.50%
Interest rates (commercial credit annual average)	%/year	0.07%	4.19%	-4.17%	5.80%	0.00%	4.11%	5.26%	3.13%	3.03%	2.94%	2.86%	2.78%	2.70%	2.63%	2.56%	2.50%	2.44%	2.38%	2.33%	2.27%	2.22%
Customers																						
Residential	-	536,462	548,329	560,458	572,855	585,527	598,479	604,783	611,152	617,589	624,093	630,667	635,210	639,786	644,395	649,037	653,713	655,618	657,528	659,444	661,366	663,293
Small Commercial & Industrial	-	62,517	63,071	62,515	63,282	63,282	63,832	64,542	64,968	65,385	65,791	66,189	66,578	66,958	67,331	67,696	68,054	68,405	68,749	69,087	69,419	69,745
Large Commercial & Industrial	-	150	151	152	153	155	156	159	161	163	166	168	170	172	174	176	178	181	183	185	187	189
Specific consumption																						
Residential	MWh/cust.	1.89	1.91	1.93	1.95	1.99	2.03	2.07	2.12	2.17	2.22	2.27	2.31	2.36	2.41	2.45	2.50	2.55	2.59	2.64	2.69	2.74
Small Commercial & Industrial	MWh/cust.	21.76	21.75	21.74	21.74	21.73	21.72	21.72	21.72	21.71	21.71	21.71	21.71	21.70	21.70	21.70	21.70	21.70	21.70	21.69	21.69	21.69
Large Commercial & Industrial	MWh/cust.	4,017.45	3,994.52	3,971.72	3,949.05	3,926.51	3,904.10	3,881.82	3,859.66	3,837.63	3,815.73	3,793.95	3,772.29	3,750.76	3,729.35	3,708.06	3,686.90	3,665.86	3,644.93	3,624.13	3,603.44	3,582.87
Electricity sales																						
Residential	MWh	1,016,428	1,048,292	1,081,155	1,119,653	1,166,675	1,213,187	1,254,063	1,296,316	1,339,993	1,385,141	1,431,810	1,470,170	1,509,557	1,549,999	1,591,525	1,634,163	1,669,659	1,705,925	1,742,979	1,780,838	1,819,519
Small Commercial & Industrial	MWh	1,360,131	1,371,773	1,359,279	1,375,529	1,375,117	1,386,650	1,401,882	1,410,945	1,419,783	1,428,409	1,436,833	1,445,132	1,453,249	1,461,193	1,468,972	1,476,593	1,484,150	1,491,563	1,498,839	1,505,982	1,512,999
Large Commercial & Industrial	MWh	602,618	602,554	602,491	603,985	607,825	610,904	616,104	621,349	626,639	631,973	637,353	641,405	645,484	649,588	653,718	657,874	661,774	665,696	669,642	673,611	677,604
Other	MWh	92,172	94,723	97,344	100,038	102,806	105,651	107,044	108,454	109,883	111,331	112,798	113,814	114,840	115,875	116,920	117,973	118,403	118,835	119,268	119,703	120,139
Demand forecast																						
Total electricity demand	MWh	3,112,049	3,117,342	3,140,269	3,199,204	3,252,423	3,316,393	3,379,093	3,437,064	3,496,297	3,556,853	3,618,794	3,670,521	3,723,129	3,776,655	3,831,134	3,886,604	3,933,986	3,982,019	4,030,728	4,080,134	4,130,262
Total electricity demand	GWh	3,112	3,117	3,140	3,199	3,252	3,316	3,379	3,437	3,496	3,557	3,619	3,671	3,723	3,777	3,831	3,887	3,934	3,982	4,031	4,080	4,130
Peak demand	MW	640	640	645	657	668	681	694	706	718	730	743	754	765	776	787	798	808	818	828	838	848
Load factor	%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%

High growth

	Units	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Economic indicators forecast																						
Population	-	2,725,941	2,741,768	2,757,687	2,773,698	2,789,802	2,806,000	2,813,757	2,821,535	2,829,335	2,837,157	2,845,000	2,850,380	2,855,769	2,861,169	2,866,580	2,872,000	2,874,197	2,876,395	2,878,595	2,880,797	2,883,000
Population	%/year	0.20%	0.58%	0.58%	0.58%	0.58%	0.58%	0.28%	0.28%	0.28%	0.28%	0.28%	0.19%	0.19%	0.19%	0.19%	0.19%	0.08%	0.08%	0.08%	0.08%	0.08%
GDP Purchasing Power Parity (current USD)	USD	8,873	8,988	9,105	9,296	9,575	9,843	10,188	10,544	10,913	11,295	11,691	12,041	12,403	12,775	13,158	13,553	13,959	14,378	14,810	15,254	15,711
GDP Purchasing Power Parity (current USD)	%/year	1.72%	1.30%	1.30%	2.10%	3.00%	2.80%	3.50%	3.50%	3.50%	3.50%	3.50%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Tourism (number of arrivals)	%/year	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%
Interest rates (commercial credit annual average)	%	6.91%	7.20%	6.90%	7.40%	7.60%	8.00%	8.70%	9.10%	9.50%	9.90%	10.30%	10.70%	11.10%	11.50%	11.90%	12.30%	12.70%	13.10%	13.50%	13.90%	14.30%
Interest rates (commercial credit annual average)	%/year	0.07%	4.19%	-4.17%	7.25%	2.70%	5.26%	8.75%	4.60%	4.40%	4.21%	4.04%	3.88%	3.74%	3.60%	3.48%	3.36%	3.25%	3.15%	3.05%	2.96%	2.88%
Customers																						
Residential	-	536,462	548,329	560,458	572,855	585,527	598,479	604,783	611,152	617,589	624,093	630,667	635,210	639,786	644,395	649,037	653,713	655,618	657,528	659,444	661,366	663,293
Small Commercial & Industrial	-	62,517	63,071	62,515	63,473	63,836	64,546	65,741	66,380	66,997	67,593	68,171	68,731	69,274	69,802	70,315	70,815	71,302	71,777	72,240	72,693	73,135
Large Commercial & Industrial	-	150	151	152	153	155	157	159	162	164	167	169	171	174	176	178	181	183	185	188	190	193
Specific consumption																						
Residential	MWh/cust.	1.89	1.91	1.93	1.96	2.00	2.04	2.09	2.14	2.19	2.24	2.30	2.34	2.39	2.44	2.49	2.55	2.60	2.65	2.71	2.77	2.82
Small Commercial & Industrial	MWh/cust.	21.76	21.75	21.74	21.74	21.73	21.72	21.72	21.72	21.71	21.71	21.71	21.71	21.70	21.70	21.70	21.70	21.70	21.70	21.69	21.69	21.69
Large Commercial & Industrial	MWh/cust.	4,017.45	3,994.52	3,971.72	3,949.05	3,926.51	3,904.10	3,881.82	3,859.66	3,837.63	3,815.73	3,793.95	3,772.29	3,750.76	3,729.35	3,708.06	3,686.90	3,665.86	3,644.93	3,624.13	3,603.44	3,582.87
Electricity sales																						
Residential	MWh	1,016,428	1,048,292	1,081,155	1,121,188	1,169,866	1,218,997	1,261,780	1,306,064	1,351,902	1,399,349	1,448,462	1,489,294	1,531,277	1,574,443	1,618,827	1,664,462	1,704,093	1,744,668	1,786,210	1,828,740	1,872,283
Small Commercial & Industrial	MWh	1,360,131	1,371,773	1,359,279	1,379,694	1,387,162	1,402,180	1,427,919	1,441,596	1,454,787	1,467,530	1,479,857	1,491,864	1,503,510	1,514,818	1,525,811	1,536,506	1,547,011	1,557,252	1,567,245	1,577,002	1,586,535
Large Commercial & Industrial	MWh	602,618	602,554	602,491	604,504	608,868	612,740	618,484	624,282	630,135	636,042	642,005	646,640	651,309	656,011	660,748	665,518	670,323	675,163	680,038	684,948	689,893
Other	MWh	92,172	94,723	97,344	100,038	102,806	105,651	107,044	108,454	109,883	111,331	112,798	113,814	114,840	115,875	116,920	117,973	118,403	118,835	119,268	119,703	120,139
Demand forecast																						
Total electricity demand	MWh	3,112,049	3,117,342	3,140,269	3,205,423	3,268,703	3,339,568	3,415,227	3,480,396	3,546,707	3,614,252	3,683,121	3,741,612	3,800,935	3,861,148	3,922,305	3,984,459	4,039,830	4,095,919	4,152,760	4,210,393	4,268,851
Total electricity demand	GWh	3,112	3,117	3,140	3,205	3,269	3,340	3,415	3,480	3,547	3,614	3,683	3,742	3,801	3,861	3,922	3,984	4,040	4,096	4,153	4,210	4,269
Peak demand	MW	640	640	645	658	671	686	701	715	728	742	756	768	781	793	805	818	830	841	853	865	877
Load factor	%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%

Low growth

Economic indicators forecast																						
Population	-	2,725,941	2,741,768	2,757,687	2,773,698	2,789,802	2,806,000	2,813,757	2,821,535	2,829,335	2,837,157	2,845,000	2,850,380	2,855,769	2,861,169	2,866,580	2,872,000	2,874,197	2,876,395	2,878,595	2,880,797	2,883,000
Population	%/year	0.20%	0.58%	0.58%	0.58%	0.58%	0.58%	0.28%	0.28%	0.28%	0.28%	0.28%	0.19%	0.19%	0.19%	0.19%	0.19%	0.08%	0.08%	0.08%	0.08%	0.08%
GDP Purchasing Power Parity (current USD)	USD	8,873	8,940	9,008	9,077	9,146	9,411	9,684	9,965	10,254	10,551	10,857	11,172	11,496	11,829	12,172	12,525	12,889	13,262	13,647	14,043	14,450
GDP Purchasing Power Parity (current USD)	%/year	1.72%	0.76%	0.76%	0.76%	0.76%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Tourism (number of arrivals)	%/year	3.24%	3.24%	0.00%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%
Interest rates (commercial credit annual average)	%	6.91%	7.20%	6.90%	7.10%	7.00%	7.10%	7.40%	7.52%	7.64%	7.76%	7.88%	8.00%	8.12%	8.24%	8.36%	8.48%	8.60%	8.72%	8.84%	8.96%	9.08%
Interest rates (commercial credit annual average)	%/year	0.07%	4.19%	-4.17%	2.90%	-1.41%	1.43%	4.23%	1.62%	1.60%	1.57%	1.55%	1.52%	1.50%	1.48%	1.46%	1.44%	1.42%	1.40%	1.38%	1.36%	1.34%
Customers																						
Residential	-	536,462	548,329	560,458	572,855	585,527	598,479	604,783	611,152	617,589	624,093	630,667	635,210	639,786	644,395	649,037	653,713	655,618	657,528	659,444	661,366	663,293
Small Commercial & Industrial	-	62,517	63,071	62,515	62,899	62,711	62,901	63,463	63,680	63,895	64,107	64,317	64,524	64,729	64,931	65,131	65,329	65,524	65,717	65,909	66,098	66,285
Large Commercial & Industrial	-	150	150	151	151	152	154	156	158	160	162	164	166	168	170	172	174	177	179	181	183	186
Specific consumption																						
Residential	MWh/cust.	1.89	1.90	1.91	1.92	1.94	1.97	2.01	2.05	2.10	2.14	2.18	2.22	2.27	2.32	2.36	2.41	2.46	2.51	2.56	2.61	2.66
Small Commercial & Industrial	MWh/cust.	21.76	21.75	21.74	21.74	21.73	21.72	21.72	21.72	21.71	21.71	21.71	21.71	21.70	21.70	21.70	21.70	21.70	21.70	21.69	21.69	21.69
Large Commercial & Industrial	MWh/cust.	4,017.45	3,994.52	3,994.52	3,971.72	3,949.05	3,926.51	3,904.10	3,881.82	3,859.66	3,837.63	3,815.73	3,793.95	3,772.29	3,750.76	3,729.35	3,708.06	3,686.90	3,665.86	3,644.93	3,624.13	3,603.44
Electricity sales																						
Residential	MWh	1,016,428	1,044,396	1,073,133	1,102,660	1,133,001	1,181,388	1,217,875	1,255,490	1,294,267	1,334,241	1,375,449	1,413,261	1,452,112	1,492,031	1,533,048	1,575,192	1,611,601	1,648,851	1,686,962	1,725,955	1,765,848
Small Commercial & Industrial	MWh	1,360,131	1,371,773	1,359,279	1,367,200	1,362,720	1,366,426	1,378,438	1,382,967	1,387,436	1,391,845	1,396,197	1,400,556	1,404,861	1,409,114	1,413,315	1,417,466	1,421,651	1,425,790	1,429,882	1,433,930	1,437,934
Large Commercial & Industrial	MWh	602,618	601,152	603,132	601,665	600,201	604,276	608,378	612,509	616,667	620,854	625,069	629,313	633,585	637,887	642,217	646,577	650,967	655,387	659,836	664,316	668,826
Other	MWh	92,172	94,723	97,344	100,038	102,806	105,651	107,044	108,454	109,883	111,331	112,798	113,814	114,840	115,875	116,920	117,973	118,403	118,835	119,268	119,703	120,139
Demand forecast																						
Total electricity demand	MWh	3,112,049	3,112,044	3,132,888	3,171,564	3,198,728	3,257,742	3,311,736	3,359,420	3,408,253	3,458,270	3,509,513	3,556,944	3,605,398	3,654,907	3,705,499	3,757,209	3,802,623	3,848,862	3,895,949	3,943,903	3,992,747
Total electricity demand	GWh	3,112	3,112	3,133	3,172	3,199	3,258	3,312	3,359	3,408	3,458	3,510	3,557	3,605	3,655	3,705	3,757	3,803	3,849	3,896	3,944	3,993
Peak demand	MW	640	639	643	651	657	669	680	690	700	710	721	730	740	751	761	772	781	790	800	810	820
Load factor	%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%

Summary of Statistics and Regressions Results

Electricity sales (residential)

Regression Statistics	
Multiple R	0.997084472
R Square	0.994177445
Adjusted R Square	0.993012934
Standard Error	0.023835182
Observations	13

ANOVA

	df	*SS*	*MS*
Regression	2	0.970034685	0.485017342
Residual	10	0.005681159	0.000568116
Total	12	0.975715844	

	Coefficients	*Standard Error*	*t Stat*
Intercept	-136.1851422	6.023137014	-22.61033443
GDP PPP	-0.409335717	0.167858518	-2.438575784
Population	10.40294787	0.494460625	21.03898135

Electricity sales (small commercial & industrial)

Regression Statistics	
Multiple R	0.864032456
R Square	0.746552084
Adjusted R Square	0.683190105
Standard Error	0.019836883
Observations	11

ANOVA

	df	*SS*	*MS*
Regression	2	0.009272744	0.004636372
Residual	8	0.003148016	0.000393502
Total	10	0.012420759	

	Coefficients	*Standard Error*	*t Stat*
Intercept	-9.063626243	4.955787521	-1.828897265
Urban population	1.706081125	0.360892548	4.727393608
Interest rates	0.392795296	0.099653396	3.941614733

Electricity sales (large commercial & industrial)

Regression Statistics	
Multiple R	0.945760373
R Square	0.894462682
Adjusted R Square	0.859283576
Standard Error	0.03635565
Observations	9

ANOVA

	df	*SS*	*MS*
Regression	2	0.067212685	0.033606342
Residual	6	0.0079304	0.001321733
Total	8	0.075143084	

	Coefficients	*Standard Error*	*t Stat*
Intercept	-4.471142037	3.589520734	-1.245609754
Tourism	0.699014385	0.18003109	3.882742621
GDP PPP	0.849162892	0.541837858	1.567190036

Electricity sales (other)

Regression Statistics	
Multiple R	0.927672647
R Square	0.86057654
Adjusted R Square	0.845085044
Standard Error	0.042342844
Observations	11

ANOVA

	df	*SS*	*MS*
Regression	1	0.099599283	0.099599283
Residual	9	0.016136248	0.001792916
Total	10	0.115735531	

	Coefficients	*Standard Error*	*t Stat*
Intercept	-118.2833254	17.40292534	-6.796749573
Population	8.76529585	1.176030274	7.453290997

Appendix B: Existing Generation Modeled

JPS Existing Renewable Plant					
	MW	GWh	(MW)	ap Factor %	
Maggotty	6.0	40.0	4.6	76.0%	
RBNA	2.5	17.0	1.9	78.0%	
LOWR	4.8	28.0	3.2	67.0%	
UPWR	3.6	23.6	2.7	75.0%	
RBNB	1.1	6.0	0.7	62.0%	
COS	0.8	2.5	0.3	36.0%	
RRV	4.1	29.0	3.3	81.0%	
Total	**22.9**	146.1			
					COD
NEW Maggotty	6.4	26.0	3.0	46.0%	2014
Munro	3.0	5.3	0.6	20.0%	2010

IPP Renewable Plants

Project	Technology	Fuel	Installed Capacity (MW)	Net Firm Capacity (MW)	Status	Forced Outage Rate	Capacity Factor %	Net energy output(GWh)	Maintenance Days	Fixed O&M Cost (US$/kW-M)	Var O&M Cost (US$/MWh)	C.O.D	PPA Expiry/ Retirement
Wigton 1&2	Wind	N/A	38.00	0		N/A	29.00%	96.5				2011	2031
BMR	Wind	N/A	34.00	0		N/A	33.47%	99.70				2016	2036
Wigton III	Wind	N/A	24.00	0		N/A	30.01%	63.10				2016	2036
WRB Solar	Solar	N/A	24.00	0		N/A	19.45%	40.90				2016	2036
EREC Solar	Solar	N/A	37.00	0	committe	N/A	23.12%	74.94				Dec 2018*	2038

Appendix C: Capacity Expansion Generation Modeled

Child Name	Category	Fiscal Ye
CapEx Hydro	CapExHydro	2019
Great River	CapExHydro	2019
Green River	CapExHydro	2019
Laughlands	CapExHydro	2019
Martha Brae	CapExHydro	2019
Negro River	CapExHydro	2019
Rio Cobre - Bog Walk	CapExHydro	2019
Rio Cobre - NIC Dam	CapExHydro	2019
Rio Grande 1	CapExHydro	2019
Rio Grande 2	CapExHydro	2019
Spanish River	CapExHydro	2019
Swift River	CapExHydro	2019
Wild Cane River	CapExHydro	2019
Appleton	CapExBiomass	2019
Everglades	CapExBiomass	2019
Golden Grove	CapExBiomass	2019
Monymusk	CapExBiomass	2019
BMR2	CapExWind	2019
CapEx Wind	CapExWind	2019
Great Valley	CapExWind	2019
Top Lincoln 1	CapExWind	2019
Top Lincoln 2	CapExWind	2019
Top Lincoln 3	CapExWind	2019
Winchester 1	CapExWind	2019
Winchester 2	CapExWind	2019
Winchester 3	CapExWind	2019
CapEx Solar	CapExSolar	2019
Duncans	CapExSolar	2019
Goodyear	CapExSolar	2019
Old Harbour North	CapExSolar	2019
Old Harbour North 2	CapExSolar	2019
Old Harbour West	CapExSolar	2019
Paradise 1	CapExSolar	2019
Springvillage	CapExSolar	2019
WRB2	CapExSolar	2019
Soapberry	CapEx Waste 2 Energy	2019
GTX_Bogue_69KV_Bus	Thermal Candidates	2019
GTX_Hunts Bay_69KV_Bus	Thermal Candidates	2019
GTX_Old Harbour_69KV_Bus	Thermal Candidates	2019
GTX_Rockfort_69KV_Bus	Thermal Candidates	2019
HFO_Bogue_69KV_Bus	Thermal Candidates	2019
HFO_Hunts Bay_69KV_Bus	Thermal Candidates	2019
HFO_Old Harbour_69KV_Bus	Thermal Candidates	2019
HFO_Rockfort_69KV_Bus	Thermal Candidates	2019
NG_Bogue_69KV_Bus	Thermal Candidates	2019
NG_Hunts Bay_69KV_Bus	Thermal Candidates	2019
NG_Rockfort_69KV_Bus	Thermal Candidates	2019
NG_Old Harbour_138KV_Bus	Thermal Candidates	2019
NGCC_Bogue_69KV_Bus	Thermal Candidates	2019
NGCC_Hunts Bay_69KV_Bus	Thermal Candidates	2019
NGCC_Old Harbour_69KV_Bus	Thermal Candidates	2019
NGCC_Rockfort_69KV_Bus	Thermal Candidates	2019

Notes

* Hydro Construction Cost is very site specific so PCJ need to supply the data from Feasibility Studies

Description	Technology	Nameplate Capacity (MW)	Capacity Factor	Potential Net Annual Energy Output(GWh)	Fixed O&M Cost (US$/kW-mth)	Variable O&M Cost (US$/MWh)	Capital Cost/kW (exc. IDC)	Planning, Procurement Period(Yrs)	Plant Construction Period (Yrs)	Lead Time (Yrs)	PPA Contract Term (Yrs)	Plant Life Useful Life(Yrs)
Martha Brae	Run of River Hydro	4.4	43.30%	16.69	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Laughlands	Run of River Hydro	2.0	60.00%	10.51	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Great River	Run of River Hydro	8.0	50.20%	35.18	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Negro River	Run of River Hydro	2.3	34.74%	7.00	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Rio Cobre (Bog Walk)	Run of River Hydro	1.3	43.20%	4.92	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Spanish River	Run of River Hydro	8.0	25.60%	17.94	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Green River	Run of River Hydro	2.9	37.00%	9.40	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Wild Cane River	Run of River Hydro	2.5	31.90%	6.99	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Rio Grande 1	Run of River Hydro	0.9	40.58%	3.20	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Rio Grande 2	Run of River Hydro	0.8	38.52%	2.70	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Swift River	Run of River Hydro	2.9	32.67%	8.30	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Rio Cobre (NIC Dam)	Run of River Hydro	1.0	26.25%	2.30	10.00	0.0	SET needs to get from PC	2.5	3.0	5.5	20.0	50.0
Great Valley	Wind	27.0	32.50%	76.87	3.00	2.5	1870	2.5	1.0	3.5	20.0	50.0
Retrieve	Wind	20.0	25.50%	44.68	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Top Lincoln	Wind	20.0	40.30%	70.61	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Top Lincoln (Wigton Phase 4)	Wind	24.0	40.30%	84.73	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Kemps Hill	Wind	20.0	30.50%	53.44	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Fair Mountain	Wind	20.0	25.50%	44.68	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Blue Mountain Renewables pha	Wind	10.0	25.50%	22.34	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Blue Mountain Renewables pha	Wind	12.0	25.50%	26.81	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Winchester phase 1	Wind	20.0	41.30%	72.36	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Winchester phase 2	Wind	20.0	41.30%	72.36	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Winchester phase 3	Wind	20.0	41.30%	72.36	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Great Valley Phase 2	Wind	10.0	32.50%	28.47	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Retrieve Phase 2	Wind	17.0	25.50%	37.98	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Top Lincoln Phase 3	Wind	17.0	43.30%	64.48	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Kemps Hill Phase 2	Wind	17.0	30.50%	45.42	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Fair Mountain Phase 2	Wind	17.0	25.50%	37.98	3.00	2.5	1870	2.5	1.0	3.5	20.0	25.0
Paradise 1	Solar	37.0	24.37%	78.99	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
WRB Enterprise (extension of ph	Solar	20.0	25.00%	43.80	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
Springvillage	Solar	20.0	24.35%	42.66	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
Old Harbour (West)	Solar	17.0	24.35%	36.26	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
Old Harbour (North)	Solar	30.0	24.35%	63.99	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
Duncans	Solar	17,5	25.00%	38.33	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
Goodyear	Solar	10.0	24.37%	21.35	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
Old Harbour (North) Phase 2	Solar	30.0	24.35%	63.99	2.60	0	1350	2.5	1.0	3.5	20.0	25.0
Monymusk	Biomass	5.0	91.70%	40.17				2.5	2.5	5.0	20.0	25.0
Everglades	Biomass	5.0	91.70%	40.17				2.5	2.5	5.0	20.0	25.0
Golden Grove	Biomass	5.0	91.70%	40.17				2.5	2.5	5.0	20.0	25.0
Appeleton	Biomass	5.0	91.70%	40.17				2.5	2.5	5.0	20.0	25.0
Soapberry	Waste to Energy	18.0	100.00%	143.80	16.60	7.0	7200	2.5	2.5	5.0	20.0	25.0

Description	Fuel	Net Max Capacity (MW)	Net Min Capacity(MW)	Planned Outage Days	Maintenance Class (MW)	Forced Outage Rate (%)	Net Heat Rate at Max. Capacity (kJ/kWh)	Net Heat Rate at Min. Capacity (kJ/kWh)	Net Heat Rate at Max. Capacity (kCal/kWh)	Net Heat Rate at Min. Capacity (kcal/kWh)	Avg. Incremental Heat Rate kcal/kwh	Fixed O&M Cost (US$/kW-Month)	Variable O&M Cost (US$/ MWh)	Capital Cost/kW ((inc IDC)	Planning, Procurement Period(Yrs)	Plant Construction Period (Yrs)	Lead Time (Yrs)	PPA Contract Term (Yrs)	Plant Life (Yrs)
Combustion Turbine (GTX)	Natural Gas/ADO	40.00	8.00	10	30	2.00%	10,200	22,500	2,438	5,378	2,795	1.0	1.0	800.0	2.5	1.5	4.0	20.0	25.0
Combined Cycle(NGCC)	Natural Gas/ADO	120.00	24.00	21	120	5.00%	6,800	14,985	1,625	3,582	1,957	1.2	2.6	1600.0	2.5	2.0	4.5	20.0	25.0
Medium Speed Diesel (HFO)	Natural Gas/HFO	18.50	5.00	28	20	6.00%	7,700	7,800	1,840	1,864	2,315	3.0	6.5	1400.0	2.5	1.5	4.0	20.0	25.0
Medium Speed Diesel (NG)	Natural Gas	18.00	5.00	28	20	6.00%	8,500	8,600	2,032	2,055	2,576	2.39	6.5	1400.0	2.5	1.5	4.0	20.0	25.0

Activity	Duration	Unit
Preparation of Tender Docs	3	Months
Invitation to Tender	6	Months
Tender Evaluation, Approval and Selection	6	Months
PPA Negotiation	6	Months
Project Agreements	12	Months
Financial Close	6	Months
Consruction Period	12	Months
Project Schedule Summary		
Total Planning & Development Time	**30**	**Months**
Total Construction Time	**12**	**Months**
Total Lead Time for Thermal Projects	**42**	**Months**

Thermal Projects Lead Time Computation

Activity	Duration	Unit
Preparation of Tender Docs	3	Months
Invitation to Tender	6	Months
Tender Evaluation, Approval and Selection	6	Months
PPA Negotiation	6	Months
Project Agreements	12	Months
Financial Close	6	Months
Consruction Period	24	Months
Project Schedule Summary		
Total Planning & Development Time	**30**	**Months**
Total Construction Time	**24**	**Months**
Total Lead Time for Thermal Projects	**54**	**Months**

Hydro Projects Lead Time Computation

Activity	Duration	Unit
Preparation of Tender Docs	3	Months
Invitation to Tender	6	Months
Tender Evaluation, Approval and Selection	6	Months
PPA Negotiation	6	Months
Project Agreements	12	Months
Financial Close	6	Months
Consruction Period	36	Months
Project Schedule Summary		
Total Planning & Development Time	**30**	**Months**
Total Construction Time	**36**	**Months**
Total Lead Time for Thermal Projects	**66**	**Months**

Appendix D: JPS (Generation) Plant Retirement Schedule

JPS Generation Asset Retirement Schedule (Summary)

Generator Units		Capacity (MW)	Commercial Operations Date (COD)	JPS Licence 2016 Retirement Schedule	Minister's Retirement Schedule 2018
Old Harbour 1	OH 1	30	1967	1992	2008
Old Harbour 2	OH 2	60	1968	1993	2019
Old Harbour 3	OH 3	65	1971	1996	2019
Old Harbour 4	OH 4	68.5	1972	1997	2019
Hunts Bay 6	HB 6	68.5	1976	2001	2020
Gas Turbine 3	GT 3	21.5	1972	1996	2030
Gas Turbine 5	GT5	21.5	1973	1997	2019
Gas Turbine 6	GT 6	14	1990	2014	2023
Gas Turbine 7	GT7	18	1990	2014	2023
Gas Turbine 8	GT8	14	1992	2017	2014
Gas Turbine 9	GT 9	20	1992	2016	2023
Gas Turbine 10	GT 10	32.5	1993	2017	2021
Gas Turbine 11	GT 11	20	2001	2025	2046
Gas Turbine 12	GT 12	38	2003	2027	2048
Gas Turbine 13	GT 13	38	2003	2027	2048
Gas Turbine ST 14	ST14	38	2003	2027	2048
Rockfort 1	RF 1	20	1985	2010	2032
Rockfort 2	RF 2	20	1985	2010	2032
		607.5			