EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Application for Review of an Amendment to the Independent Electricity System Operator Market Rules

COMPENDIUM FOR KCLP PANELS

INDEX

TAB A

INTELLIGENT ENERGY FOR A GREENER PLANET

NORTHLAND POWER

Northland Power Investor Presentation

November 2019

TSX: NPI

Forward-Looking Statements Disclaimer

This written and accompanying oral presentation contains certain forward-looking statements which are provided for the purpose of presenting information about management's current expectations and plans. Readers are cautioned that such statements may not be appropriate for other purposes. Northland's actual results could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur. Forward-looking statements are predictive in nature, depend upon or refer to future events or conditions, or include words such as "expects", "anticipates", "plans", "predicts", "believes", "estimates", "intends", "targets", "projects", "forecasts" or negative versions thereof and other similar expressions or future or conditional verbs such as "may", "will", "should", "would" and "could".

These statements may include, without limitation, statements regarding Northland's expectations or ability to complete the Acquisition in the fourth quarter of 2019, or at all, Northland's ability to integrate EBSA if the Acquisition closes, Northland's ability to participate across the energy infrastructure spectrum in Colombia, key members of EBSA continuing to lead EBSA in the future, the sources of proceeds to pay for EBSA, the future growth of EBSA's regulated base rate, expected Adjusted EBITDA and the closing date of the Offering.

These statements may also include, without limitation, statements regarding future adjusted EBITDA, free cash flow, dividend payments and dividend payout ratios; the construction, completion, attainment of commercial operations, cost and output of development projects; litigation claims; plans for raising capital; and the future operations, business, financial condition, financial results, priorities, ongoing objectives, strategies and outlook of Northland and its subsidiaries. These statements are based upon certain material factors or assumptions that were applied in developing the forward-looking statements, including the design specifications of development projects, the provisions of contracts to which Northland or a subsidiary is a party, management's current plans and its perception of historical trends, current conditions and expected future developments, as well as other factors that are believed to be appropriate in the circumstances.

Forward-looking statements are subject to numerous risks and uncertainties, which include, but are not limited to, Northland's ability to satisfy all closing conditions to the Acquisition and the Offering, Northland's ability to integrate EBSA, construction risks, counterparty risks, operational risks, foreign exchange rates, regulatory risks, maritime risks for construction and operation, and the variability of revenues from generating facilities powered by intermittent renewable resources and the other factors described in Northland's 2018 Annual Report and 2018 Annual Information Form, which are both filed electronically at www.sedar.com and Northland's website www.northlandpower.com. Other than as specifically required by law, Northland undertakes no obligation to update any forward-looking statements to reflect events or circumstances after such date or to reflect the occurrence of unanticipated events, whether as a result of new information, future events or results, or otherwise.

All figures are presented in Canadian dollars unless otherwise indicated. All information relating to EBSA contained in this presentation is based solely upon information made publicly available or provided to Northland by the Sellers in connection with the Acquisition. While Northland, after conducting due diligence that it believes to be a prudent and thorough level of investigation, believes it to be accurate in all material respects, an unavoidable level of risk remains regarding the accuracy and completeness of such information.

Northland Overview

- **Global** developer, owner and operator of **sustainable infrastructure assets**
- **Over 30 years of successfully developing**, constructing and operating power projects over full lifecycle
- Well-diversified, **modern fleet** of high-quality assets
- **Power Generating Assets:** 2.4+ GW global fleet
    - **1,400+ MW** of visible renewable power projects pipeline
        - **Offshore Wind**
            - 269 MW Deutsche Bucht – in construction
            - 1,044 MW Hai Long – advanced development
        - **Solar**
            - 130 MW La Lucha – in construction
- **Utility:** Regulated utility servicing 480,000 customers in Latin America
- **Significant development opportunities** across multiple jurisdictions and technologies

Northland's Strategy

1 Creating high-quality projects underpinned by revenue contracts that deliver predictable cash flows

2 Excellence in managing projects and operating facilities, always seeking opportunities to enhance performance and value

3 Actively seeking to invest in jurisdictions where we can apply an early mover advantage to establish a meaningful presence

Northland's business strategy is centered on establishing a significant global presence as a sustainable clean and green energy producer

Focused on Sustainability

- We seek to achieve a sustainable and prosperous future for all of our stakeholders
- We will achieve this through:

Inspired Workforce

- Prioritizing health and safety
- Fostering our values and culture
- Providing meaningful career development opportunities
- Hiring locally and providing international opportunities

Top Clean & Green Developer

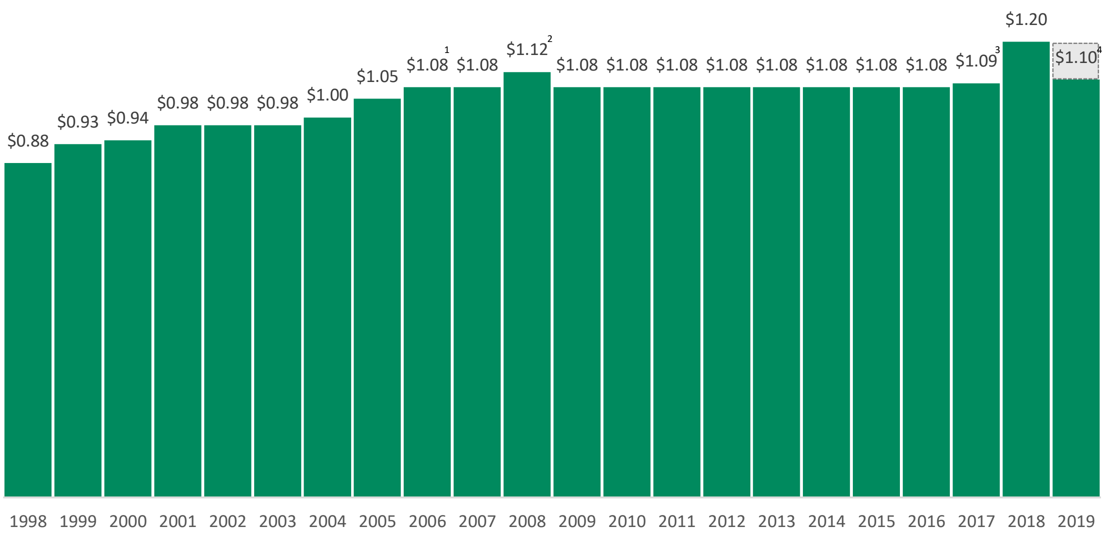
- Focusing on clean and green technologies
- Delivering strong and sustainable financial results
- Generating and distributing economic value
- Capitalizing on revenue generating opportunities through the transition to a low-carbon future

Prosperity for Stakeholders

- Supporting sustainable economies through clean energy and responsible business practices
- Investing in our communities
- Partnering with First Nations and Indigenous groups
- Preserving the natural environment

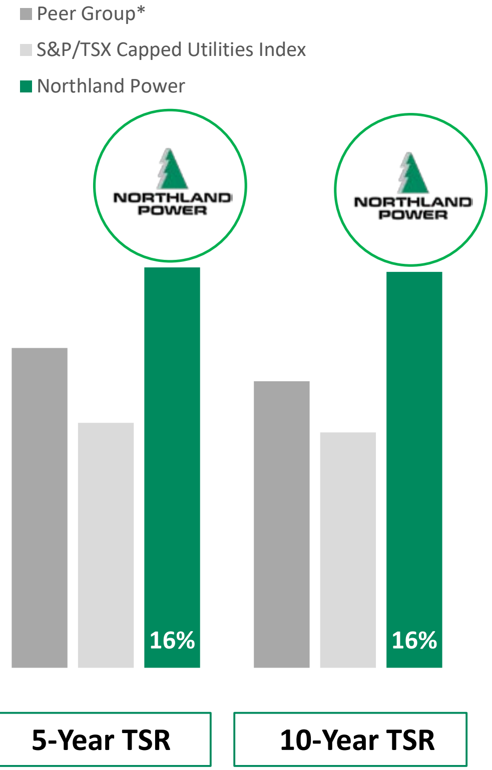
Track Record of Strong Returns to Shareholders

Annual Dividends (Distributions) Per Share (Unit) Since 1997



1. *Includes a special cash dividend of $0.02 per unit declared on December 18, 2006.*
2. *Includes a special cash dividend of $0.04 per unit declared on December 4, 2008.*
3. *Dividend increased from $0.09 to $0.10 for December 2017*
4. *YTD 2019 as at November 15, 2019*

Total Shareholder Return[2]



1. *Canadian IPP Peer Group includes Algonquin Power, Boralex, Brookfield Renewable, Capital Power, Innergex, Pattern Energy, TransAlta.*
2. *As at November 15, 2019.*

Northland Power has consistently delivered strong long-term returns and stable dividends to shareholders

Track Record of Corporate Growth

	2013[1]	2018[2]	Annual Growth	
Assets	$3.0 B	$10.5 B	**28%**	▲
Enterprise Value	$4.1 B	$12.7 B	**25%**	▲
Market Capitalization	$2.2 B	$5.3 B	**19%**	▲
Operating Capacity (Gross)	1,556 MW	2,429 MW	**9%**	▲
Operating Capacity (Net)	1,329 MW	2,014 MW	**9%**	▲
Share Price	$15.48	$27.11	**16%**[3]	▲
# Corporate Offices	1	7		

Building on our success, we continue to deliver on our promises, delivering long-term value for our shareholders

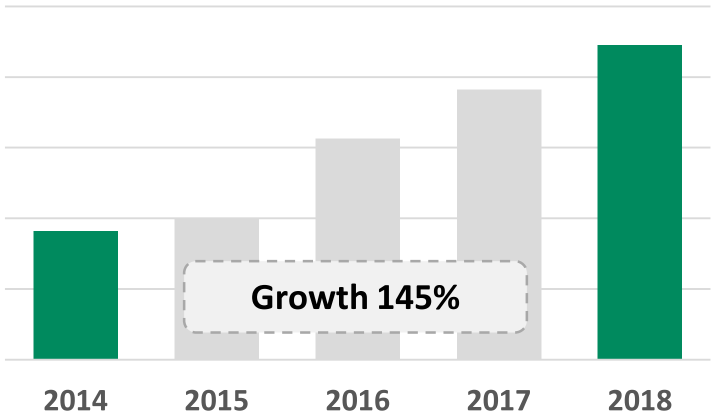
1. *As at December 31, 2013*
2. *As at September 30, 2019, market values as at November 15, 2019*
3. *This number represents the 5-Year Total Shareholder Return (includes capital appreciation and dividend reinvestment)*

Track Record of Growth in Financial Results

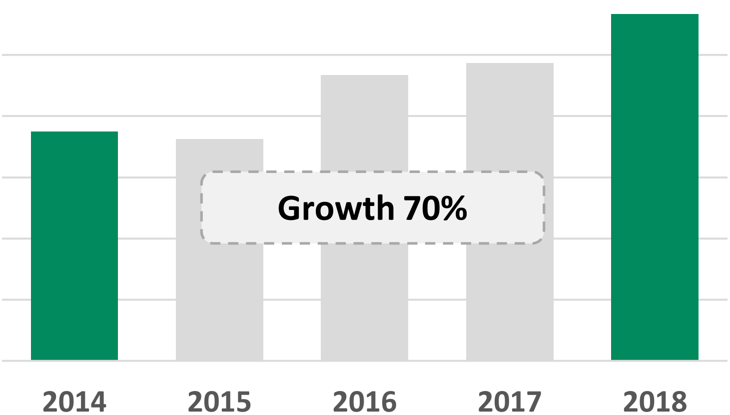
Northland's growth in Adjusted EBITDA and Free Cash Flow Per Share has been substantial

Year-to-date 2019 results building on the momentum and success achieved in 2018

Adjusted EBITDA Growth



Free Cash Flow per Share Growth



	Q3 2019	Q3 2018	Change
Energy Volumes (GWh)	2,058	1,777	16%
Net Income ($MM)	$111	$93	19%
Adjusted EBITDA ($MM)	$224	$197	14%
Free Cash Flow ($MM)	$74	$64	16%
Free Cash Flow per share	$0.41	$0.36	14%

	YTD 2019	YTD 2018	Change
Energy Volumes (GWh)	6,394	5,895	8%
Net Income ($MM)	$391	$340	15%
Adjusted EBITDA ($MM)	$712	$670	6%
Free Cash Flow ($MM)	$251	$249	1%
Free Cash Flow per share	$1.39	$1.40	(1%)

Track Record of Financial Stewardship

- Prudent use of leverage and liquidity
- Northland has a BBB (Stable) investment grade credit rating by S&P
- Strong S&P FFO[1]-to-Debt, well above minimum threshold
- Healthy corporate debt level relative to IPP industry, to support flexibility
- Prudent use of leverage: **95% of $7.2B total debt is non-recourse to Northland**

Corporate Credit Facility	Corporate Debt	Project Debt
$1.0B credit facility to support further development	**$0.2B utilized** Corporate Credit Facility **$0.1B issued** Convertible Debentures	**$6.9B drawn** Non-Recourse Debt

1. FFO represents Funds From Operations.

2019 Financial guidance - Continuing the growth

Expect to continue the growth in Adjusted EBITDA and Free Cash Flow Per Share in 2019

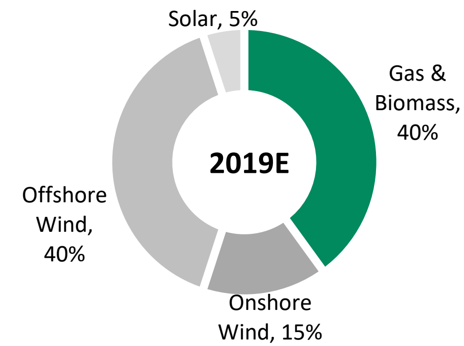
Adjusted EBITDA

$950 to $1,000 Million

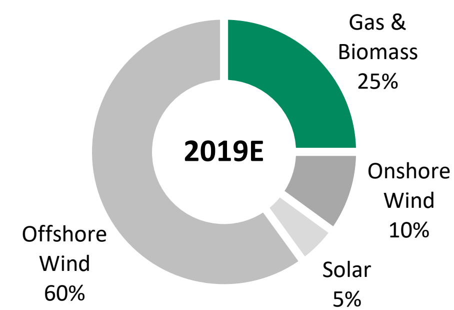
Free Cash Flow

$1.65 to $1.80 Per Share

Operating Capacity by Technology *(Net MW)*



Adjusted EBITDA by Technology *($M)*

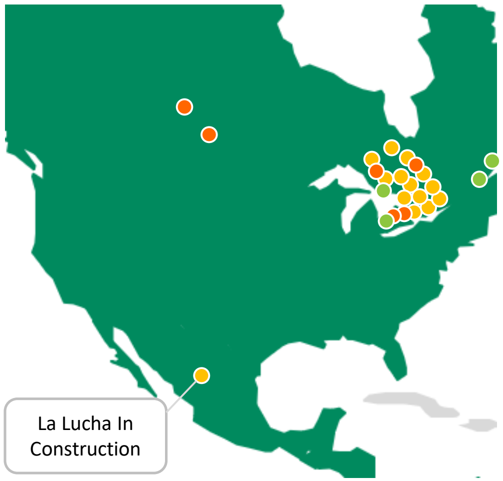


Portfolio Overview

Diversified Asset Portfolio

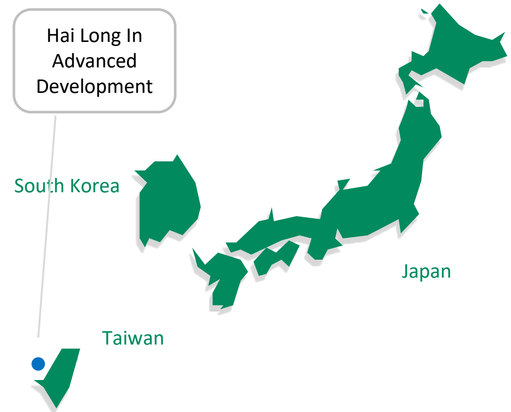
NORTHLAND POWER

North America

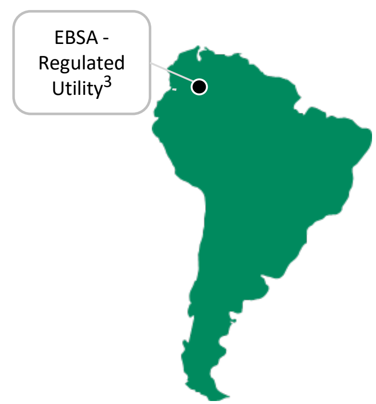


Europe

Asia



South America



Technology:	Operating	Under Construction & Development
Offshore Wind	932 MW	2,093 MW
Onshore Wind	394 MW	-
Solar	130 MW	130 MW
Thermal	973 MW	-
Total Capacity (Gross)[1]	**2,429 MW**	**2,223 MW**

Northland Power owns and operates 2.4 GW of power assets globally

1. *As at November 15, 2019.*
2. *Total Net Capacity: 2,014 MW (Operating) and 1,025 MW (Under Construction & Advanced Development).*
3. *Acquisition of EBSA regulated Utility announced in September 2019. The acquisition is subject to closing conditions with expectation to close by Q4, 2019.*

Optimization of Existing Portfolio

Internalize Expertise

Leverage in-house knowledge to support development and construction

Enhance Profitability

Optimize existing assets and secure new revenue streams

Maximize cash flows from existing assets

- Apply in house expertise to optimize performance of operating assets and enhance value

Utilize Technology

- Leverage “big data” to optimize performance
- Smarter maintenance practices

Secure New Revenue Streams

- New offtake opportunities for post PPA assets

Integrate Energy Marketing

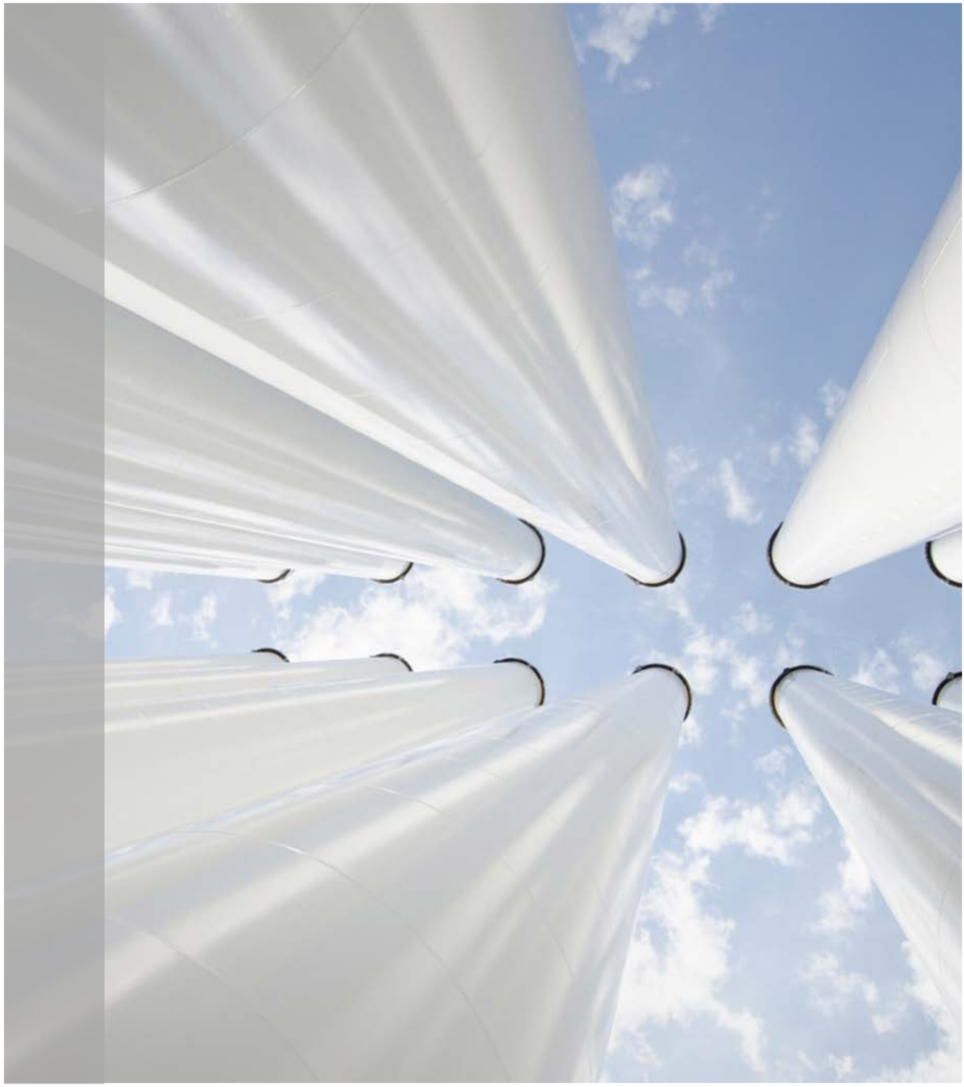
- Greater margins by bringing in-house gas and electricity services
- Manage merchant markets

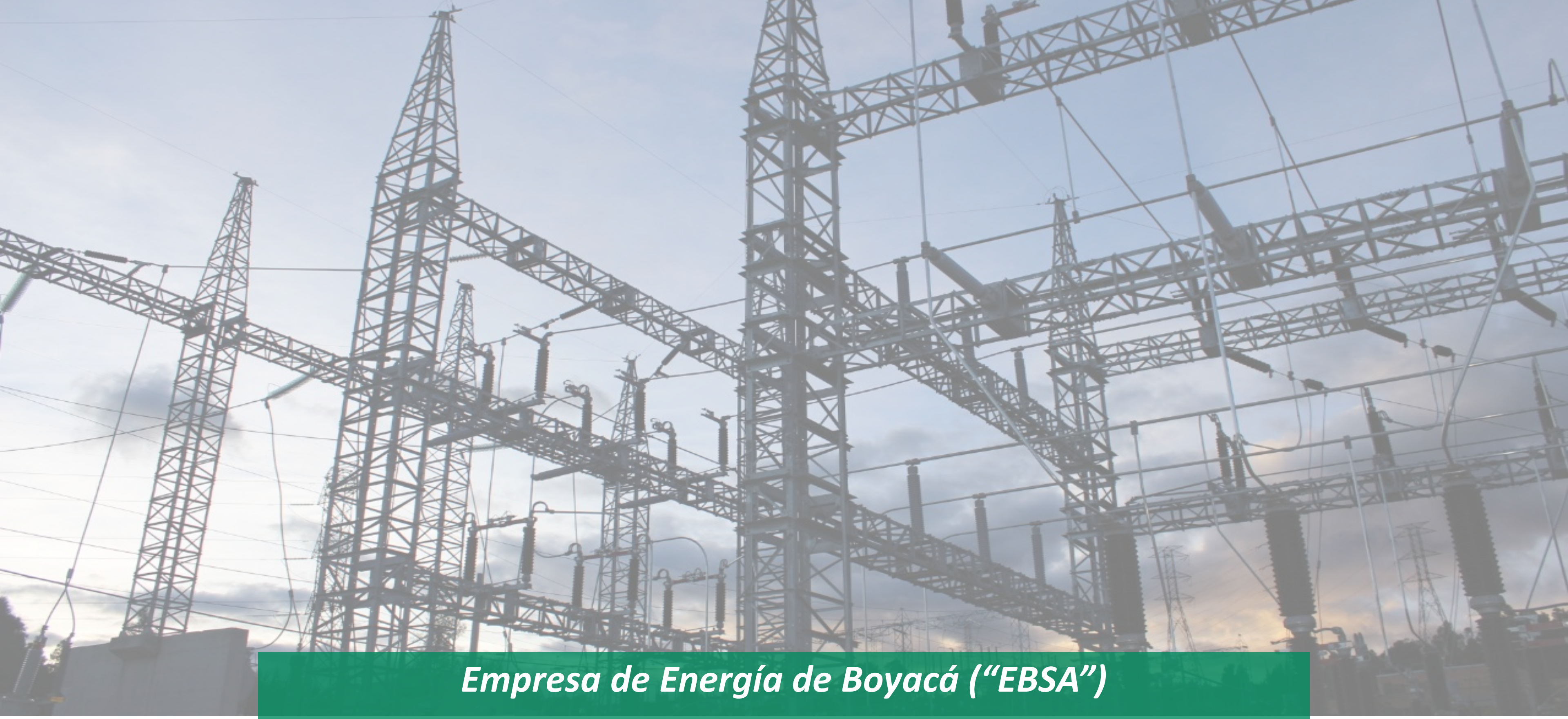
Looking Ahead – Business Objectives

1
- Maintain excellent operating track record
- Maintain excellent health, safety and environmental record
- Continue to optimize operating portfolio

2
- Continue track record of on-time, on-budget execution
- Execute on Deutsche Bucht construction
- Execute on La Lucha project construction

3
- Continue to advance and secure high quality projects
- Continue to diversify across locations and technologies
- Be a leading player in the global transition towards decarbonization





Empresa de Energía de Boyacá (“EBSA”)

Acquisition Highlights & Strategic Rationale

EBSA Acquisition Summary

- Northland announced acquisition of EBSA on September 9, 2019, adding a high quality regulated utility in Colombia
- Acquisition represents a further pivot in Northland's long-term global growth strategy and introduces a new line of business
- EBSA provides strategic value to existing asset portfolio
    - *Provides a measure of stability and predictability to Free Cash Flow*
    - *Diversifies asset base*
    - *Reduces concentration risk as well as exposure to re-contracting and merchant power price risk*
- Provides Northland with a platform to drive future opportunities in Colombia and Latin America
- Closing of the Acquisition is expected in the fourth quarter of 2019

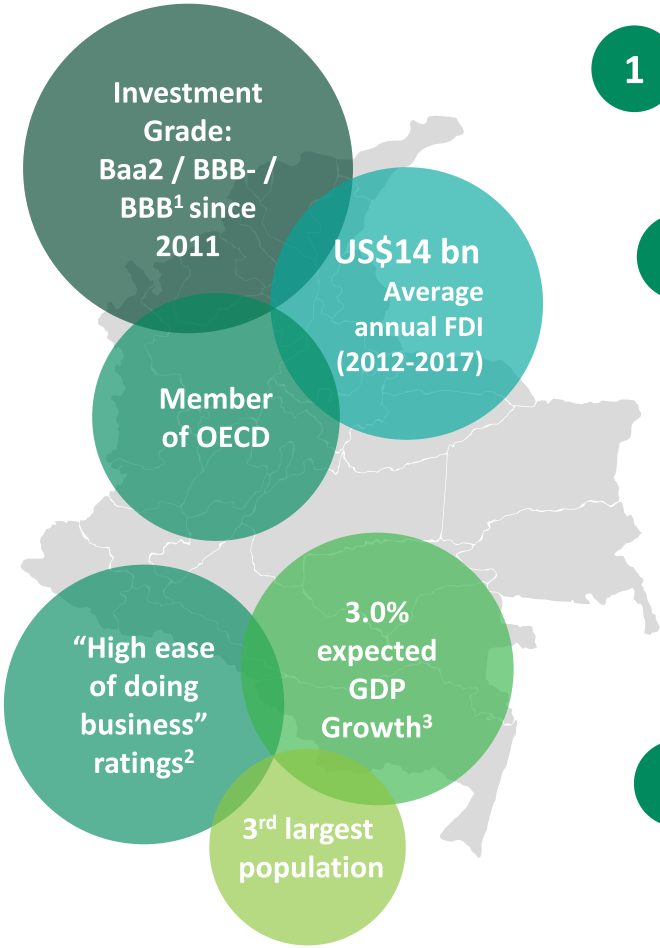
Acquisition Highlights and Investment Thesis

NORTHLAND POWER

1 **Expands Northland's Latin American Energy Infrastructure Business into Colombia**	• 3rd largest population in the region with a growing middle class and attractive GDP growth profile with real GDP growth averaging 3.5% over the past 10 years • Member of the OECD and a creditworthy jurisdiction that has maintained an investment grade credit rating with S&P (BBB-), Moody's (Baa2) and Fitch (BBB) since 2011 • Significant support for infrastructure investments with strong economic and demographic fundamentals and supportive government policies • EBSA is one of a few energy companies in Colombia with favourable grandfathered rights allowing for vertical integration across all segments of the electricity market
2 **Adds a High-Quality Regulated Utility Business**	• Sole distributor to a population of over 1.3 million; proven management team with local expertise • Operates under regulatory framework with an average approved WACC of approximately 11.5% • RAB is expected to grow at an annual average rate of 5% • Other key regulatory features including RAB inflation indexation, a five year planning cycle and limited to no demand risk
3 **Strong Financial Contribution**	• Further diversifies Northland's portfolio by adding a perpetual utility infrastructure business • Adds 2020 Adjusted EBITDA of approximately COP 255 billion (approximately $100 million[1]) • Expected to generate average, mid-single digit accretion to Free Cash Flow per Share during the current regulatory period ending 2023, and increasing accretion over the long-term

1. *Adjusted EBITDA is based on the submitted tariff, the CAD amount assumes COP / CAD rate of 2,540.*

Colombian Market Overview



1 Creditworthy jurisdiction with established legal and regulatory frameworks

- Colombia is a member of the OECD
- Colombia is among the top 3 economies to do business in Latin America[2]

2 Solid macroeconomic fundamentals underpin growth prospects

- One of the most attractive GDP growth profiles in the region[3]
- Single digit inflation since the early 2000s
- 3rd largest population in the region with a growing middle class and GDP per capita

3 Fiscally disciplined jurisdiction

- Strong monetary and fiscal policy, maintaining inflation in single digits since the early 2000's and having a controlled external debt
- Successful economic and political reform and positive long-term investment ratings

4 Thriving investment environment

- Over 400% growth in foreign direct investment since the early 2000s[4]
- Stable exchange rate has supported industrial recovery and non-traditional goods exports

Source: Bloomberg, National Administrative Department of Statistics ("DANE"), World Bank.
1. *Ratings for Moody's, Standard and Poor's and Fitch, respectively.*
2. *World Bank Doing Business 2019 Report.*
3. *BBVA LatAm Economic Outlook Report.*
4. *2017 FDI.*

Premier Regulated Utility

Asset Highlights

Business Overview

- Sole distribution company in Boyacá, operating in 123 municipalities with 1.3 million residents
- Currently serving electricity needs for approximately 480,000 customers

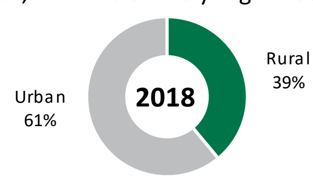
Business Segments

- **Distribution**
  - 2019 RAB of over COP 1,600 billion ($630 million[1])
  - Regulatory mechanism provides for fixed annual income to distributors, limiting demand risk
- **Commercialization**
  - Electricity retailer for 100% of regulated customers in Boyacá
- **Transmission & Others**
  - Owns and operates transmission assets

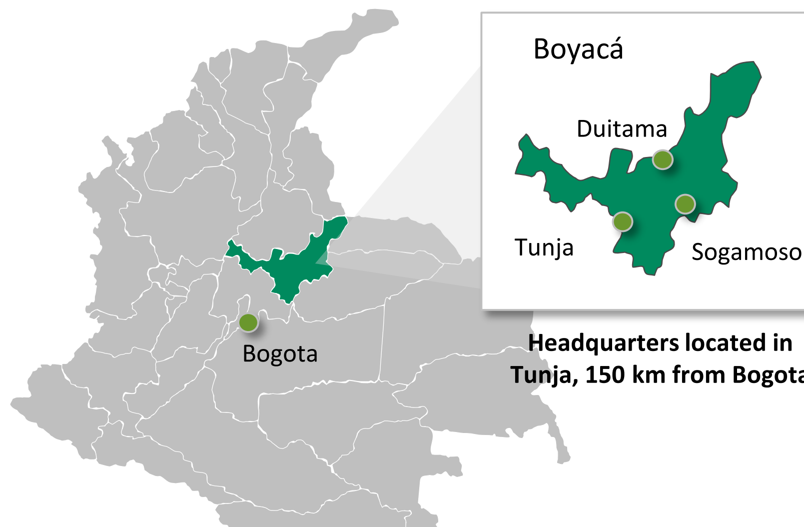
Customer Base

- Customer base is primarily comprised of the residential sector, which is entirely regulated

<u>**Customer Base**</u>



Geographic Location



Headquarters located in Tunja, 150 km from Bogota

The department of Boyacá is a region located near the capital of Bogotá and has abundant natural resources and a growing economy supported by agricultural, mining, and industrial activities

Key Operating Metrics

32,541 km Distribution Lines (SDL + STR)[2]	**104** Substations	**1.8 TWh** Energy Distributed

1. *Assumes COP / CAD rate of 2,540.*
2. *Note: **SDL** = Sistema de Distribución Local. Local distribution system. Includes all assets operating below 57.5kV. **STR** = Sistema de Transmisión Regional. Regional transmission system. Includes all assets operating tension levels between 57.5kV and 220kV.*

Platform for Growth in Latin America

EBSA is one of a few energy companies in Colombia with grandfathered rights which allow for vertical integration and participation in all segments of the electricity supply chain

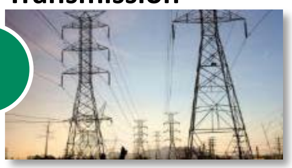
Distribution

1

- In addition to the growth in the distribution segment approved by regulators, EBSA is able to add additional growth projects in Boyacá to its RAB
- Further consolidation in distribution sector is expected nationally

Transmission

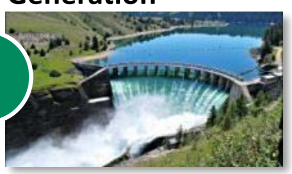
2



- Experienced local team coupled with Northland's greenfield development experience positions EBSA to participate in future growth projects identified in Colombia's electricity and energy national planning agency's expansion plan
- >US$2 billion of transmission projects expected to be tendered in the next 18 months[1]

Generation

3



- EBSA currently has its own development pipeline of generation projects
- Boyacá region has some of Colombia's highest irradiation levels which provides an opportunity to develop solar projects

Ancillary Services

4

- EBSA's unique access to all households in Boyacá provides an opportunity to offer additional services to its customers

1. *UPME 2017-2031 Expansion Plan.*

Construction Overview

Track Record of On-time and On-Budget Project Delivery

Project		Technology	MW (Gross)	COD	On/Ahead of Schedule	Under Budget
Iroquois Falls		Gas	120	1997	✓	✓
Mont Miller		Onshore Wind	54	2005	✓	✓
Jardin d'Éole		Onshore Wind	133	2009	✓	✓
Thorold		Gas	265	2010	✓	✓
Mont Louis		Onshore Wind	101	2011	✓	✓
Spy Hill		Gas	86	2011	✓	✓
North Battleford		Gas	260	2013	✓	✓
Northland Solar		Solar	90	2013 – 15	✓	✓
McLean's Mountain		Onshore Wind	60	2014	✓	✓
Cochrane Solar		Solar	40	2015	✓	✗[1]
Grand Bend		Onshore Wind	100	2016	✓	✓
Gemini		Offshore Wind	600	2017	✓	✓
Nordsee One		Offshore Wind	332	2017	✓	✓
Deutsche Bucht		Offshore Wind	269	2019E	✓[2]	✓[2]
Total			**2,510 MW**			

Northland has a track record of successfully delivering projects on-time and on-budget

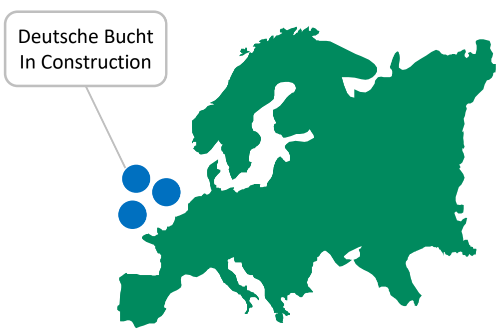
1. *Cochrane Solar was over budget due to the failure, and subsequent commencement of restructuring proceedings of the contractor.*
2. *As at November 15, 2019.*

Global Reach – European Offshore Wind Success

Successfully constructed and operating two offshore wind projects with third project under construction

1.2 GW[1]

European offshore Wind Power



Gemini	**600 MW**

60% Net Northland Interest
COD[2] April 2017
Completed on time and on budget

Nordsee One	**332 MW**

85% Net Northland Interest
COD[2] December 2017
Completed on time and on budget

Deutsche Bucht	**269 MW**

100% Net Northland Interest
Construction ongoing with 31 turbines installed to date

In Construction

1. *Represents total gross operating capacity .*
2. *COD represents Commercial Operations Date.*

Deutsche Bucht – Construction Progressing on Schedule

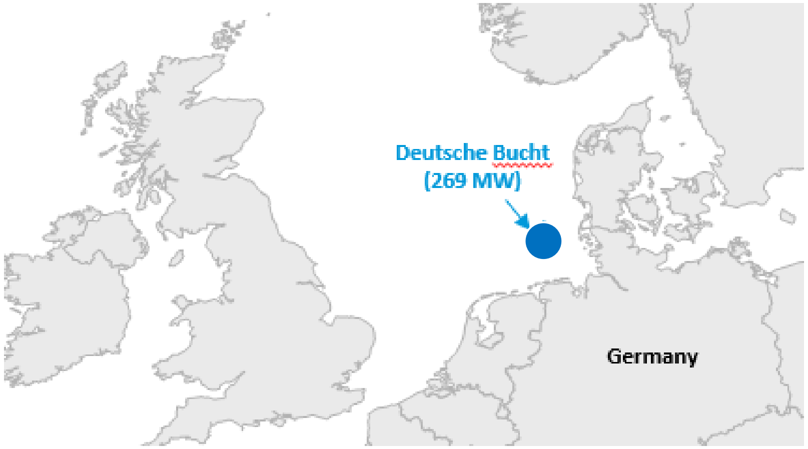
Key Project Highlights

Location:	North Sea, Germany
Model FC/COD:	May 2017 / December 2019
Ownership:	100%
Capacity:	269 MW
Capacity Factor:	49%
PPA Term From COD:	13 years
PPA Strategy:	Feed In Tariff subsidy with German Govt. - €184/MWh (8 years) - €149/MWh (additional 5 years)
Project Status:	Under construction
Estimated Net Capex:	€1.4B

Background Information

- In 2015, Northland acquired 100% interest in offshore development project Deutsche Bucht
- Northland developed, financed and has lead the construction of project through its Hamburg office. Leveraged offshore experience and operations at Nordsee One and Gemini.
- Offshore wind project is located 95 km Northwest of the island of Borkum
- Project will interconnect to the 800 MW BorWin beta offshore substation (TenneT), which was commissioned in January 2015
- Two-contract structure
  - Van Oord (contractor of Gemini) for entire balance of plant
  - MHI Vestas to supply 31 V164 (8.37 MW) wind turbines and provide operations and maintenance service for 15 years

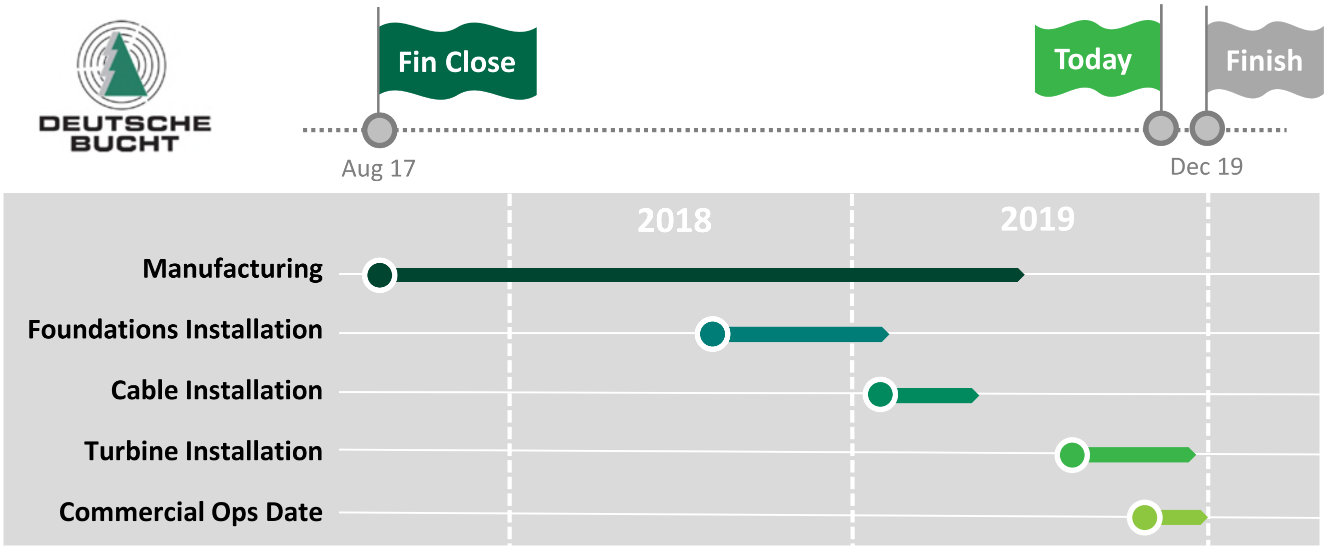
Asset Map



Deutsche Bucht – Project Timeline

Current Project Status

- Project currently under construction
- Installed and commissioned offshore substation and installed 31 turbines with first power realized at the end of July 2019
- The 2 demonstrator projects utilizing mono-bucket foundations are currently being fabricated and installation expected by end of year
- Details:
  - Foundation installation completed
  - Inter Array Cable Package completed last Factory Acceptance Test
  - Offshore Substation fabrication completed
  - Offshore Substation load-out completed
  - Offshore Substation Jacket installation completed



On-Time, On-Budget

Project Completion[1]:

Manufacturing:	100%
Found. Install.:	100%
Cable Install.:	100%
Turbine Install.:	94%

1. *Metrics exclude 17MW Demonstrator Project*

Global Reach – Latin American Development

Initial investment into Mexico with La Lucha Solar project; opportunities for potential developments across countries and technologies

130 MW[1]

Mexico Solar

La Lucha	130 MW

First investment in Mexico targeting commercial and industrial offtake

In Construction

EBSA

Regulated Utility

Latin America

Potential opportunities for on-shore renewables, transmission and hydro across multiple countries

1. *Represents total gross operating capacity .*

La Lucha – Mexican Solar

Key Project Highlights

Location:	Durango, Mexico
Model FID/COD:	May 2019 / H2 2020
Ownership:	100%
Capacity:	130 MW
Technology:	Solar
Contract Strategy:	Bilateral Contracts /Merchant Mix
Project Status:	Under construction
Estimated Net Capex:	$0.2B

Background Information

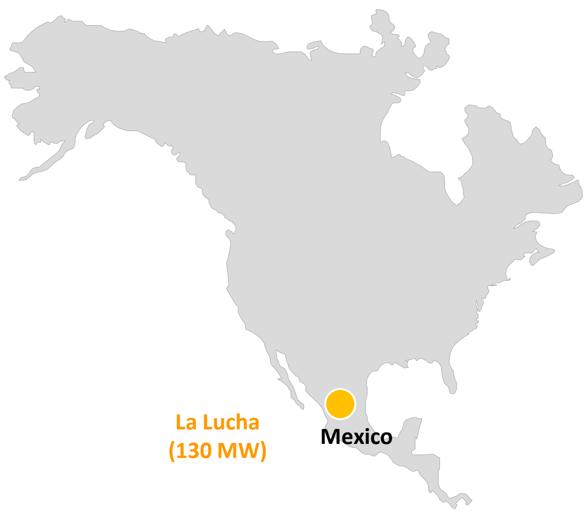
- Develop, construct and operate 130 MW solar project in the state of Durango, Mexico
- First step in Mexico strategy that will focus on commercial and industrial market with a diversified generation portfolio
- All major permitting for the project has been obtained as well access to required lands
- Commercial and Industrial offtake contracts to be secured during construction with full 130 MW expected to be contracted by commercial operations date (COD)
- Non-recourse project financing to be secured at COD

Northland announces FID and start of construction

May 2019 | **Second half 2020**

Completion of construction and commencement of Commercial operations

Asset Map



Development Overview

Power Markets are Changing

Our industry has evolved over the past 10 years

- **Supportive Government Policies** – *Governments have taken real action to reduce carbon footprint*
- **Industry Evolution & Technological Advancement** – *Renewables are now a cost-effective and feasible alternative to add new power*
- **Market Liberalization and Competition** – *Increased demand has attracted new players ready to deploy capital in competition with traditional IPPs*

Opportunities:

- Global shift towards renewable power
- Offshore wind expansion to new markets
- Large volume of power and infrastructure assets to be constructed globally

Challenges:

- Significant volume of capital chasing late stage projects
- Long-term PPAs less prevalent
- Global growth creates new exposures

Adapting to Change - Enhancing our Development Pipeline

Focus on current projects under advanced development, while increasing pipeline of future development opportunities

Global Development Offices

Decentralize development to increase project pipeline

Strategic Partnerships

Establish strategic partnerships in target markets to enhance marketing and development efforts

Opportunity Set

- Offshore wind opportunities in multiple regions
- Decarbonization and denuclearization of electricity grids

Higher value early stage development

- Leverage early mover advantage to establish presence in new markets

Explore infrastructure and non-power opportunities

- Storage and transmission opportunities
- Bulk storage
- Water desalination

Global Reach – Additional Development Opportunities

Multiple renewable power opportunities across jurisdictions and technologies

The Opportunity Set

- Renewable power opportunities in multiple regions
- Decarbonization and denuclearization of electricity grids
- Storage and transmission opportunities

North America

Mature markets for renewable and thermal power projects
Opportunity for bulk storage

Europe

Significant offshore wind presence
Further potential for additional offshore and on-shore development opportunities across continent

Latin America

Markets for renewable and thermal power projects
Qualified supplier/power marketing
Transmission and storage

Asia

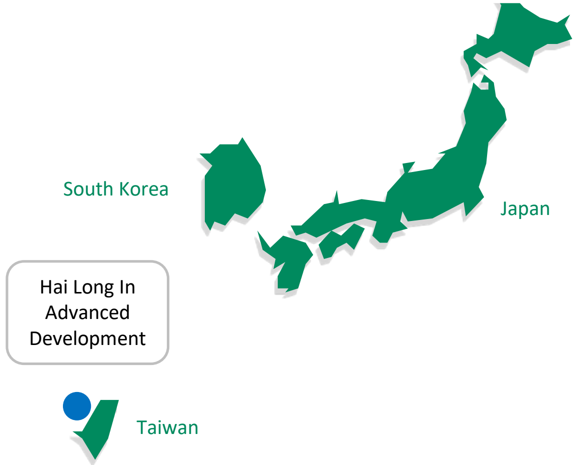
Significant potential for renewables across region
Offshore wind industry in its infancy but has substantial potential

Global Reach – Asian Offshore Wind Development

Successfully secured 1,044 MW of grid allocation offshore wind in Taiwan
Looking for additional opportunities in Japan and South Korea

1.0 GW[1]

Asia
Offshore Wind Power



Hai Long **1,044 MW**

60% Net Northland Interest
Construction expected to be completed by end of 2025

South Korea

Established local office to source development opportunities

Japan

Potential opportunities for offshore wind and other developments

1. *Represents total gross operating capacity.*

Taiwan – Hai Long Offshore Wind

NORTHLAND POWER

Project Overview

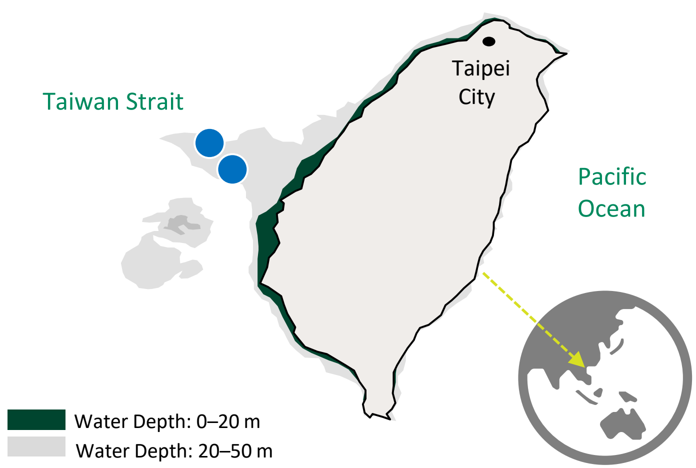
- Northland and its partner Yushan Energy continue to advance development and work to execute PPAs[1] for two remaining projects
- Hai Long awarded 1,044 MW grid allocation for 2025E COD[2]
- Major Milestones:
  - **April 2018** – FIT[3] allocation (Hai Long 2A: 300 MW)
  - **June 2018** – Competitive auction (Hai Long 2B and 3: 744 MW)
  - **February 2019** – Executed PPA for 300 MW FIT[3] allocation
    - 20 year tiered FIT[3] price structure

Key Project Highlights

Status:	Advanced Development
Location:	• 40-50 km off the west coast of Taiwan, in Taiwan Straits, located in Changhua County • Water depth between 35 and 50 meters • 10 m/s average wind speed
Capacity:	1,044 MW (gross)
Contract:	Signed 20-year PPA[1] under FIT[3] (300 MW); pursuing 20-year PPA[1] for remaining (744 MW) with Taipower
Technology:	Offshore wind
Ownership:	Northland Power: 60% Yushan Energy: 40%

Project Name	Capacity	PPA[1] Rate (NTD[4]/kWh)
Hai Long 2A	300MW	• Yrs 1-10[4]: 6.2795 • Yrs 11-20[4]: 4.1422
Hai Long 2B	232MW	
Hai Long 3	512MW	

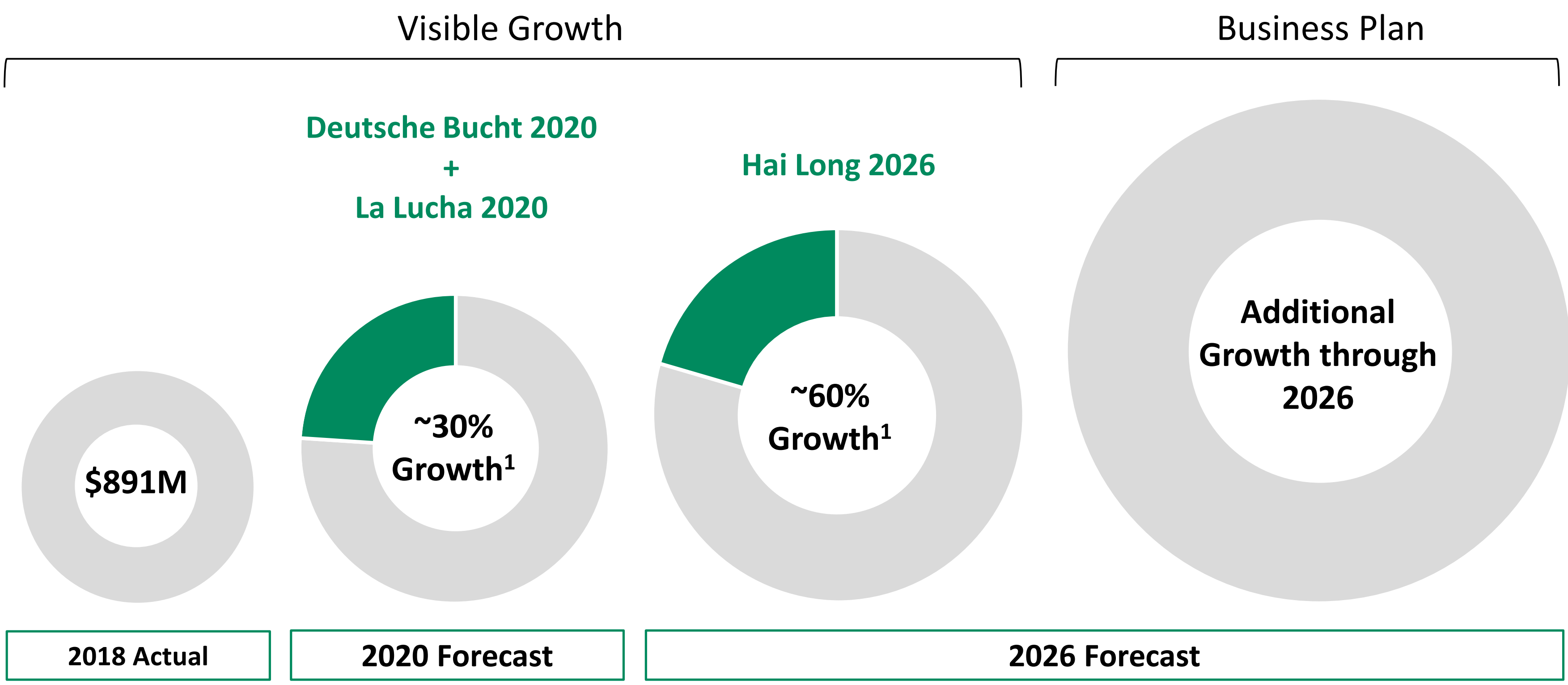
Asset Location



1. *PPA represents Power Purchase Agreement.*
2. *COD represents Commercial Operations Date.*
3. *FIT represents Feed In Tariff.*
4. *NTD represents New Taiwan Dollar.*

Northland's Visible Pipeline of Growth Opportunities

Business Plan provides platform for significant Adjusted EBITDA growth



1. *The growth % is based on 2018 Adjusted EBITDA and excludes potential impacts from EBSA acquisition until deal closes in Q4, 2019.*

The above graphic/chart is an illustration of management's business plan. They are based upon Northland's operating facilities continuing to perform in a manner consistent with operations in 2018, with additions to Adjusted EBITDA from projects in development, construction, and management business plan, and other adjustments resulting from power contract renewals as described in our MD&A and 2018 AIF. The illustrations do not constitute a financial forecast, projection or guidance and are based upon assumptions that are subject to change.

Northland - A Compelling Investment

1 *High quality globally diversified asset portfolio offering exposure across multiple technologies*

2 *Experienced management team with a track record of delivering on commitments*

3 *Track record of strong consistent growth and strong consistent returns for shareholders*

4 *Disciplined approach to business execution and sourcing of development opportunities ensures maximum realized value*

Northland's business strategy is centered on establishing a significant global presence as a sustainable clean and green energy producer

Appendix

Reporting of Non-IFRS Financial Measures

This investor presentation includes references to Northland's adjusted EBITDA and free cash flow, measures not prescribed by International Financial Reporting Standards (**IFRS**). Adjusted EBITDA and free cash flow, as presented, may not be comparable to other similarly-titled measures presented by other publicly-traded companies, as these measures do not have a standardized meaning under IFRS. These measures should not be considered in isolation or as alternatives to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with IFRS. These measures are also not necessarily indicative of operating income or cash flows from operating activities as determined under IFRS. Rather, these measures are provided to complement IFRS measures in the analysis of Northland's results of operations, and are used by management to evaluate the performance of the company for internal assessment purposes. Management believes that adjusted EBITDA and free cash flow are widely-accepted financial indicators used by investors to assess the performance of a company. These measures provide investors with additional information to assist them in understanding these critical components of the company's financial performance, including its ability to generate cash through its current operations. These measures have been applied consistently for all periods presented in this document.

Adjusted EBITDA

Adjusted EBITDA provides investors with an indication of Northland's capacity to generate income from operations and investments before taking into account management's financing decisions and the costs of consuming tangible and intangible capital assets, which vary according to asset type and management's estimate of their useful lives.

Adjusted EBITDA is calculated as income (loss) before income taxes adjusted for depreciation of property, plant and equipment, amortization of contracts and other intangible assets, net finance costs, Gemini subordinated debt earned by Northland, fair value losses (gains) on derivative contracts, unrealized foreign exchange losses (gains), elimination of non-controlling interests and finance lease and equity accounting.

Free cash flow

Free cash flow is calculated as cash flow provided by operating activities adjusted for net change in non-cash working capital balances, capital expenditures, interest paid, scheduled principal repayments on term loans, funds set aside for scheduled principal repayments and for asset purchases, restricted cash (funding) for major maintenance, write-off of deferred development costs, consolidation of managed facilities, income from equity accounted investments, proceeds from sale of assets, and preferred share dividends. This measure, along with cash flow provided by operating activities, is considered to be a key indicator for investors to understand Northland's ability to generate cash flow from its current operations.

Readers should refer to our MD&As accompanying our financial statements for an explanation of adjusted EBITDA and free cash flow, and for a reconciliation of Northland's reported adjusted EBITDA to its consolidated income (loss) before taxes and a reconciliation of Northland's free cash flow to its cash provided by operating activities. These are filed from time to time on our company's website www.northlandpower.ca.

Market Summary

Key Metrics[1]	
Recent Share Price (TSX: NPI)	$27.11
Shares (Common + Subscription Receipts + Class A)	195 million
Annual Dividend	$1.20
2019 EBITDA Guidance	$950 – $1,000 million
2019 FCF/sh Guidance	$1.65 – $1.80 /sh
Total Debt, Net of Cash[2]	$6.0 billion
Convertible Debentures (NPI.DB.C)	$191 million
Preferred Shares (NPI.PR.A, NPI.PR.B, NPI.PR.C)	$177 million
Market Capitalization (Common + Class A)	$5.3 billion
Enterprise Value	$12.7 billion
Credit Rating (S&P)	BBB Stable

1. *As at November 15, 2019 unless stated otherwise.*
2. *As at September 30, 2019.*

European Offshore Wind Facility Details

	Gemini	Nordsee One	Deutsche Bucht
Capacity	600 MW	332 MW	269 MW
Distance to Shore	85km	40km	95km
Wind Turbines	150 x Siemens 4 MW	54 Senvion x 6.15 MW	33 x MHI Vestas 8MW
Turbine Foundation	Monopile	Monopile	Monopile[1]
Water Depth	28m to 36m	26m to 29m	39m to 41m
Total Project Costs	€2.8 Billion	€1.2 Billion	€1.4 Billion
Revenue Contract Type	Contract for Differences (CFD) (FiT-Type)	Feed in tariff	Feed in tariff
Revenue Contract Term	15 years	~10 years	~13 years
Revenue Contract Price	~€169/MWh [No escalation]	€194/MWh for 8 years, €154/MWh for 1.5 years [No escalation]	€184/MWh for 8 years, €149/MWh for 4.7 years [No escalation]
Grid Connection Responsibility	Gemini responsible for connection to shore	Tennet responsible for connection to shore	Tennet responsible for connection to shore
NPI Ownership	60%	85%	100%

1. *Deutsche Bucht is implementing the development of two additional demonstration turbines utilizing suction bucket foundations*

Operating Facilities

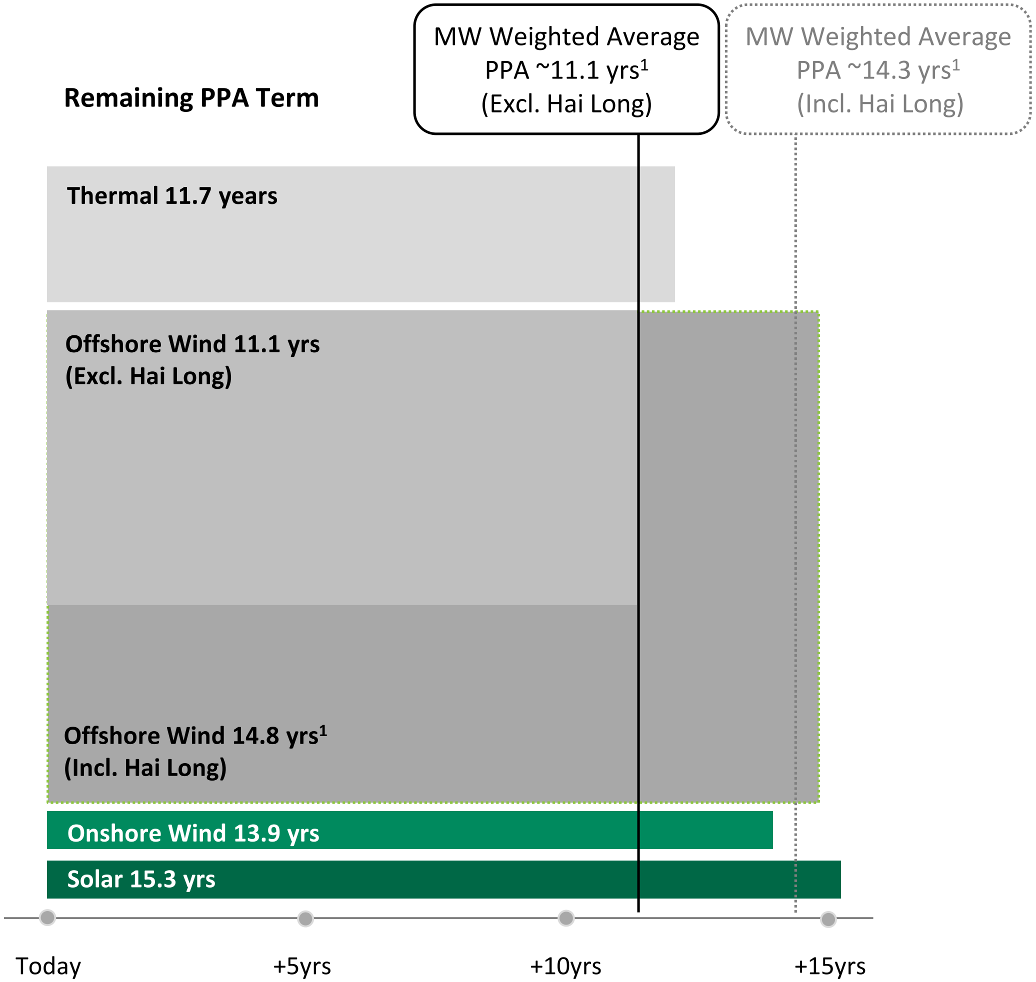
Project	Location	Gross Capacity	Northland Ownership	Technology	PPA Term
Thorold	ON, CA	265 MW	100%	Natural gas combined cycle	2030
Iroquois Falls	ON, CA	120 MW	100%	Natural gas combined cycle	2021
Spy Hill	SK, CA	86 MW	100%	Natural gas peaking plant	2036
Kirkland Lake	ON, CA	132 MW	68%[1]	Biomass and natural gas combined cycle and peaking	2030
Mont Louis	QC, CA	100 MW	100%	Onshore Wind	2031
Jardin d'Éole	QC, CA	134 MW	100%	Onshore Wind	2029
Loblaws (Roof-top)	Various	1 MW	100%	Roof-top Solar	2031
North Battleford	SK, CA	260 MW	100%	Natural gas combined cycle	2033
Ground-Mount Solar	ON, CA	130 MW	100% (90 MW) 62.5% (40 MW)	Solar	2033-2035
McLean's Mountain	ON, CA	60 MW	50%	Onshore Wind	2034
Grand Bend	ON, CA	100 MW	50%	Onshore Wind	2036
Gemini	Netherlands	600 MW	60%	Offshore Wind	2032
Nordsee One	Germany	332 MW	85%	Offshore Wind	2027

1. *Northland has an effective 77% residual economic interest*

Producing and Maintaining Stable Cash Flows

Remaining PPA Term for Each Facility

- Stable long-term cash flows from contracted revenues
- MW weighted average PPA life ~11.1 years[1]
- Hai Long projects will add 626 MW (net) and 20-year PPA life when operational
- Re-contracting opportunities for expiring PPAs (Iroquois Falls)
- Robust European power market mechanisms



1. *The weighted average PPA life is weighted by respective MW capacity. The thickness of each bar represents each facilities respective overall contribution to 2018 Adjusted EBITDA*

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TAB B

KCLP-APPrO-2

INTERROGATORY

Ref: Affidavit of John Windsor at paras. 22-23

Ref: AMPCO Reply to Submissions on Motion for Stay, paras. 56(j), 58(g), and 74(b)

Preamble:

At paragraphs 22-23 of its Affidavit, KCLP states (emphasis added):

> *"If the stay is granted, and the auction is delayed from its planned December 2019 auction date, then KCLP would lose out on the opportunity to compete for capacity for both the summer and winter periods. This would result in a lost opportunity cost for KCLP, which could cost KCLP millions of dollars and potentially force KCLP to shut down.*
>
> …
>
> *The impact would be similar to if the OEB grants the stay, as discussed above. Ultimately, if KCLP is unable to compete in a TCA, and otherwise secure an adequate revenue stream, this will place more pressure to shut down the facility permanently, as it continues to lose millions of dollars annually in the absence of a contract."*

At paragraph 56(j) of its Reply Submission on Motion for Stay, AMPCO, referring to KCLP, states:

> "*4 off-contract generators have registered to participate in the December 4th TCA. One of these has evidenced an expectation for 'millions of dollars' of benefit from that auction."*

And at paragraph 58(g), AMPCO states:

> "*The public interest and the interests of consumers are served by preserving, and not undermining, competition in the IAM. There are undisputed facts that…one of these generators anticipates the potential for 'millions of dollars' of benefits from successful participation in the December 4th TCA, obviously at the expense of its competitors in the auction."*

At paragraph 74(b), AMPCO reiterates:

> "*Facts indicating the possibility of irreparable harm are…the indication from the one of these generators who has offered evidence is that they stand to gain 'millions of dollars'*

> *in benefits in this auction, which by definition would be at the expense of their competitors"*

Question:

Please confirm whether KCLP stands to gain "millions of dollars" should it successfully clear the December 4, 2019 TCA.

RESPONSE:

This is not correct. KCLP requires the December TCA to maintain its KCLP generation facility as a going concern in the near term. Based on the most recent historical DR auction price, KCLP may only break-even in the near term. The true value of the KCLP capacity will likely only be realized when the forecasted capacity gap arises in 2023.

WITNESS: John Windsor

TAB C

134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-17-000; Order No. 745]

Demand Response Compensation in Organized Wholesale Energy Markets

(Issued March 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP). This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

EFFECTIVE DATE: This Final Rule will become effective on **[**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER**]**. Dates for compliance and other required filings are provided in the Final Rule.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets — Docket No. RM10-17-000

ORDER NO. 745

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(Issued March 15, 2011)

Paragraph Numbers

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Demand Response Compensation in Organized Wholesale Energy Markets — Docket No. RM10-17-000

FINAL RULE

ORDER NO. 745

(Issued March 15, 2011)

I. Introduction

1. This Final Rule addresses compensation for demand response in Regional Transmission Organization (RTO) and Independent System Operator (ISO) organized wholesale energy markets, i.e., the day-ahead and real-time energy markets. As the Commission has previously recognized, a market functions effectively only when both supply and demand can meaningfully participate. The Commission, in the Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010, proposed a remedy to concerns that current compensation levels inhibited meaningful demand-side participation.[1] After nearly 3,800 pages of comments, a subsequent technical conference, and the opportunity for additional comment, we now take final action.

[1] Demand Response Compensation in Organized Wholesale Energy Markets, Notice of Proposed Rulemaking, 75 FR 15362 (Mar. 29, 2010), FERC Stats. & Regs. ¶ 32,656 (2010) (NOPR).

2. We conclude that when a demand response[2] resource[3] participating in an organized wholesale energy market[4] administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described herein, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP).[5] The Commission finds that this approach to compensation for

---

[2] Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy. 18 CFR 35.28(b)(4) (2010).

[3] Demand response resource means a resource capable of providing demand response. 18 CFR 35.28(b)(5).

[4]The requirements of this final rule apply only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO. Thus, this Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions, such as, for instance, Midwest ISO's Emergency Demand Response, NYISO's Emergency Demand Response Program, and PJM's Emergency Load Response Program. This Final Rule also does not apply to compensation in ancillary services markets, which the Commission has addressed elsewhere. See, e.g., Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719).

[5] LMP refers to the price calculated by the ISO or RTO at particular locations or electrical nodes or zones within the ISO or RTO footprint and is used as the market price to compensate generators. There are variations in the way that RTOs and ISOs calculate LMP; however, each method establishes the marginal value of resources in that market. Nothing in this Final Rule is intended to change RTO and ISO methods for calculating LMP.

demand response resources is necessary to ensure that rates are just and reasonable in the organized wholesale energy markets. Consistent with this finding, this Final Rule adds section 35.28(g)(1)(v) to the Commission's regulations to establish a specific compensation approach for demand response resources participating in the organized wholesale energy markets administered by RTOs and ISOs. The Commission is not requiring the use of this compensation approach when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.[6]

3. This cost-effectiveness condition, as determined by the net benefits test described herein, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill. This is the case because customers are billed for energy based on the units, MWh, of electricity consumed. We refer to this potential result as the billing unit effect of dispatching demand response. By contrast, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load. To address this billing unit effect, the Commission in this Final Rule requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced

[6] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. When the net benefits test described herein is satisfied and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.

4. To implement the net benefits test described herein, we direct each RTO and ISO to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective. The RTO or ISO should determine, based on historical data as a starting point and updated for changes in relevant supply conditions such as changes in fuel prices and generator unit availability, the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. This price level is to be updated monthly, by each ISO or RTO, as the historic data and relevant supply conditions change.[7]

[7] In its compliance filing an RTO or ISO may attempt to show, in whole or in part, how its proposed or existing practices are consistent with or superior to the requirements of this Final Rule.

5. This Final Rule also sets forth a method for allocating the costs of demand response payments among all customers who benefit from the lower LMP resulting from the demand response.

6. The tariff changes needed to implement the compensation approach required in this Final Rule, including the net benefits test, measurement and verification explanation and proposed changes, and the cost allocation mechanism must be made on or before July 22, 2011. All tariff changes directed herein should be submitted as compliance filings pursuant to this Final Rule, not pursuant to section 205 of the Federal Power Act (FPA).[8] Accordingly, each RTO's or ISO's compliance filing to this Final Rule will become effective prospectively from the date of the Commission order addressing that filing, and not within 60 days of submission.

7. In addition, we believe that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of the ISOs and RTOs may be more precise than the monthly price threshold and, therefore, provide the greatest opportunity for load to benefit from participation of demand response in the organized wholesale energy market administered by an RTO or ISO. However, we acknowledge the position of several of the RTOs and ISOs that modification of their dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term. In

[8] 16 U.S.C. 824d (2006).

light of those concerns, we require each RTO and ISO to undertake a study examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when paying demand response resources the LMP results in net benefits to customers in both the day-ahead and real-time energy markets. The Commission directs each RTO and ISO to file the results of this study with the Commission on or before September 21, 2012.[9]

II. Background

8. Effective wholesale competition protects customers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new technologies.[10] Improving the competitiveness of organized wholesale energy markets is therefore integral to the Commission fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[11]

---

[9] We note that this report is for informational purposes only and will neither be noticed nor require Commission action.

[10] See, e.g., Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, at P 1 (2008) (Order No. 719); see also Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at P 1 (1999), order on reh'g, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607, 348 U.S. App. D.C. 205 (D.C. Cir. 2001).

[11] 16 U.S.C. 824d (2006); Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 1.

organized wholesale energy markets. We find, based on the record here that, when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers.[115] As stated in the NOPR, we believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.[116]

48. The Commission emphasizes that these findings reflect a recognition that it is appropriate to require compensation at the LMP for the service provided by demand response resources participating in the organized wholesale energy markets only when two conditions are met:

- The first condition is that the demand response resource has the capability to provide the service , i.e., the demand response resource must be able to displace a

---

[115] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

[116] NOPR at P 12.

generation resource in a manner that serves the RTO or ISO in balancing supply and demand.

- The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

49. With respect to the first, capability-related condition, we note that a power system must be operated so that there is real-time balance of generation and load, supply and demand. An RTO or ISO dispatches just the amount of generation needed to match expected load at any given moment in time. The system can also be balanced through the reduction of demand.[117] Both can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand.

50. With respect to the second cost-effectiveness condition, the record leads us to alter the proposal set forth in the NOPR in this proceeding. As various commenters explain, dispatching demand response resources may result in an increased cost per unit to load

---

[117] Andrew L. Ott Sept. 13, 2010 Statement at 1.

> Economic and Capacity-based demand response clearly provides benefits to regional grid operation and the wholesale market operation. . . . These demand resources provide benefits by providing valuable alternatives to PJM in maintaining operational reliability and in promoting efficient market operations.

Id. at 1; see also CDRI May 13, 2010 Comments at 10; CDWR May 13, 2010 Comments at 5; NJPBU May 13, 2010 Comments at 2.

TAB D

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**

VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

the otherwise DRA, demand response auction, when it becomes a transitional capacity auction.

That is the whole issue at play here today, is the issue of the discriminatory nature of the amendments. That is why I included it in my affidavit. That is why I understood that the IESO would understand it. And I hope that clarifies what it was that I was trying to state.

MR. MONDROW: Thank you, Mr. Anderson. I am going to just identify for you, again, Exhibit K1.1, which was the letter dated November 22nd, 2019, the CV which you have already spoken to, and a one-page witness statement which we provided, Madam Chair, to parties in advance just so they would have an indication of two issues connected to Dr. Rivard's evidence that Mr. Anderson wished to address in his direct testimony. And so that is why I identify that and filed it.

Mr. Anderson, just to those two issues, in his evidence Dr. Rivard goes through a number of scenarios involving a demand response resource consisting of a behind-the-meter generation facility which allows the load customer to displace a portion of its own demand for energy from the market, and Dr. Rivard compares that facility to a load customer who is also a directly connected generator, market participant.

And you wanted to address the aptness of that comparison in Dr. Rivard's evidence.

MR. ANDERSON: I did, thank you. Dr. Rivard's example is very specific. He uses an example of a demand response resource with a behind-the-meter generator, so in that case when activated the demand response resource simply ramps up its generator.

This is, by far, the minority example of what actually happens in a demand response activation. Typical demand resources don't have behind-the-meter generators. The majority of them do not.

And what they do, in terms of responding to activation notices, is they dial back their processes. They shut down equipment. They stop making whatever widgets that they would rather be making.

These operations incur real costs to do this, beyond the cost of lost production, as highlighted by Dr. Rivard. And I will give you some examples of this. I will take the steel industry as an example, because it is probably easier to understand than some of the others.

In a situation where demand response is activated, typically steel manufacturing entities would take out of service called an electric arc furnace. If that electric arc furnace happens to still have molten steel inside it, you're no longer putting electricity to it to keep it that way. It will eventually harden up. That is a very bad thing. So they do fire on gas.

In addition to that, there's a downstream process where billets are loaded into a furnace for further processing. Those furnaces are full of refractory, which is basically industrial grade insulation, for lack of a better term.

That refractory, if it is subjected to temperature fluctuations, will crack, break, and fall off. It is very expensive. So they also have to fire that furnace with natural gas, which they otherwise would not have to do. These are costs that are avoidable in a situation where they have been told to activate.

Another example -- and again it is a gas-firing example -- steel melts at somewhere around 2,500 degrees Fahrenheit. Generally speaking, the facilities that make steel don't have building heating. They don't need it. But in a situation in the middle of winter where you have shut down and stopped your process, it starts to get cold, and things inside that facility can freeze up, and they do have to bring in gas-fired heaters to keep that facility warm. Again, another situation where, but for the activation, you wouldn't be burning that gas and you wouldn't be incurring that cost.

So for those customers there is a much broader range of costs beyond the value of the lost load and a broader range of risks to consider.

And I think one final point that Dr. Rivard makes is an implication based on -- I think it is based on some of his other studies from other jurisdictions that you can simply shift that production, you can make those widgets later. And some DR resources can actually do that. Many cannot. When you lose the production of those widgets, you lose it for good. You don't just shift it into the off-shift, because you don't have that spare capacity. And I think that is something that needs to be mentioned in respect of Dr. Rivard's examples. Thank you.

MR. MONDROW: Thank you, Mr. Anderson.

And one final topic from Dr. Rivard's evidence. He discusses the industrial conservation incentive program. I think that is referred to commonly as the ICI program. And I would like you to, if you could, open Dr. Rivard's evidence and turn to paragraph 52, and Madam Chair, this is Dr. Rivard's report. It is dated November 8th, 2019. It was revised and refiled on November 21st, 2019, and obviously Dr. Rivard will speak to that. That may be the appropriate time to give it an exhibit number, but Mr. Anderson did want to comment on one passage from that evidence. It is page 29, paragraph 52.

MR. ANDERSON: Yes, thank you for that. I believe --

MR. MONDROW: Sorry, it is actually over at the top -- just for the record, Mr. Anderson, it is -- paragraph 52 continues on page 29, and I just want to orient us with the passage.

The passage reads, at the top of page 29 -- it is the third -- second full sentence, and it reads:

> "In effect, the ICI rewards DR resources that are also class A consumers by compensating them twice for making their generator available, once through the avoidance of the global adjustment, which recovers the capacity cost of the committed generator, and once through the availability payment."

And you believe there is something missing from that statement.

MR. ANDERSON: I believe there is something incorrect with that statement, yes.

My understanding of this goes to Dr. Rivard's example of DR Corp. versus, I think it is Gen Corp. And my understanding is DR Corp. can't simply drop load for ICI, which is the Industrial Conservation Initiative, if you're not there to provide the capacity that you are obligated to provide. You can only drop it once.

So at ICI times demand response resources will not have the capacity available and will typically pull their offers. In fact, in January and February, July and August, which are the prime ICI months, payments get clogged back on a two-to-one basis. The IESO will claw back availability payments if you are not there to provide the capacity that you are obligated to provide.

And during those months, the prime ICI months, they will claw them back on a two-to-one basis in terms of number of hours.

So the availability and non-performance charge information is set out in the introduction to demand response auction, which is an IESO document dated May 2017, at page 32, and then on performance factors, this is the two-to-one, is set out in market manual 12, section 7.1.

So the key piece being if you are already bound for ICI you're not getting those available payments any more. They're going to be clawed back. You can only drop your capacity once. If it's not there, you can't drop it again. And I think that is a key distinction from Dr. Rivard's evidence.

MR. MONDROW: Thank you, Mr. Anderson.

Madam Chair, Mr. Anderson is now available for cross-examination.

MS. SPOEL: Thank you, Mr. Mondrow. Ms. Krajewska, I think you are going first on our list.

MS. KRAJEWSKA: I believe it is Mr. Barz.

MS. SPOEL: Oh, Mr. Barz, okay, sorry.

CROSS-EXAMINATION BY MR. BARZ:

MR. BARZ: Good morning. If I may approach the Panel, I have dropped off two copies of the compendium, but I have a third for -- I'm not sure -- but if I might approach and just give you it.

MS. DJURDJEVIC: We will make that Exhibit K1.4.

EXHIBIT NO. K1.4: ASSOCIATION OF POWER PRODUCERS OF ONTARIO COMPENDIUM FOR AMPCO PANEL 1.

MR. BARZ: I may refer to some of the exhibits throughout the cross, but not all of them. Were all of the Panel members able to locate their copies?

MS. FRANK: No.

MR. BARZ: It should just say Association of Power Producers of Ontario at the bottom, on the top -- on the first page, the cover page.

MS. SPOEL: We have it.

MR. BARZ: You have got it?

MS. SPOEL: Yes.

Ontario context.

But, yes, I think that would be an appropriate place to start.

MS. KRAJEWSKA: Mr. Anderson, I am going to take you back to tab F of your cross-examination compendium, which is your response to the interrogatories from Staff.

The list of factors, do they represent the variable costs of your membership? Do they represent the marginal cost of your membership in putting in the offer price? I mean, what do they represent in economic terms?

MR. ANDERSON: Yes, I am going to put my hand up right now and say I am not an economist. But what we're looking at here in terms of the cost per curtailment, there is a large category of lost opportunity cost. And then what it is framed as is semi-variable cost recovery. I would say that is variable costs, and that includes labour costs, other overhead, and really other costs for the production facility -- the gas firing that I talked about, for example, in the electric arc furnace or in the reheat furnace would fit in that category.

MS. KRAJEWSKA: And if you --

MR. ANDERSON: Sorry, I just want to finish and give a complete answer.

If you turn the page to number 3, I guess it is, the other consideration, it talks about administrative costs and that's administrative costs of actually doing the DR business.

It also talks about shut down and start up risk and there are costs associated with that. Wear and tear on equipment is a very real cost, and the other thing to think about is in a number of these process-oriented facilities, when start up and shut down, you've gone outside your quality boundaries for a period of time.

So you are wasting, whether it is pulp and paper or whether it is steel, or whatever the widget is that comes out the back end of that facility, you have wasted a chunk of it. So those are very real costs.

MS. KRAJEWSKA: But in each of those circumstances, the DR resource would factor that cost into their bid price, correct?

MR. ANDERSON: Each resource would factor it in in the way it saw as appropriate.

MS. KRAJEWSKA: Mr. Anderson, I would like to -- in your witness statement, you take issue with Mr. Rivard's evidence with respect to his models that look at DR resources that have a behind-the-meter generator. That's correct?

MR. ANDERSON: Yes, that's correct.

MS. KRAJEWSKA: And, Mr. Anderson, you have not filed any evidence with respect to how many of your members have behind-the-meter generators.

MR. ANDERSON: I have not, no. But as I said in my -- I believe in my direct, those who have behind-the-meter generation are in the far minority to those who do not.

MS. KRAJEWSKA: But that information is also - how many, or which demand response resources or consumers of