London Economics International LLC

ReEnergy Northern Maine Biomass Plants:
Indicative financial analysis

Prepared for Emera Maine

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LEI was retained by Emera to assess the economics of select biomass power plants in Northern Maine

- **LEI was asked by Emera Maine to assess the financial viability of ReEnergy's Ashland and Fort Fairfield plants in the next few years (through 2021) and confirm ReEnergy's assertion that a discount on certain transmission costs is required in order to avoid plant closures**

Plant Name	Ashland	Fort Fairfield
Nameplate Capacity (MW)	39	37
Primary Fuel	Wood Waste Solids	Wood Waste Solids
Generation Technology	Steam Turbine	Steam Turbine
County	Aroostook	Aroostook
Online Date	1993*	1987

** The Ashland facility has been idled for several prolonged periods since coming online*

  - Ashland and Fort Fairfield sell energy and capacity into the ISO New England wholesale power markets and RECs to select New England states' compliance REC programs
  - In order to sell its products into the New England Control Area, ReEnergy is required to purchase transmission service from Emera Maine

- **ReEnergy has stated that it will have to close down these power plants if it does not get a discount on the Schedule 7/8 charges**
  - ReEnergy is requesting Emera Maine to provide relief in the form of a 100% discount on current Schedule 7/8 charges which ranges from total $2 million to $2.1 million a year for each of the biomass power plants (Ashland and Fort Fairfield)

LEI created an indicative financial forecast under varying future wholesale electricity market outcomes

- **LEI's approach involved the creation and estimation of a pro forma income statement to assess whether the select biomass plants are expecting to make positive (or negative) gross profit margin in the next few years, 2018-2021**
  - The financial model presented a range of market revenues that the power plants can earn from the sale of energy, capacity, and RECs in ISO-NE's control area, relative to an estimate of going forward operating costs for two power plants
  - Gross profit margin is approximated using Earnings Before Interest, Taxes, and Depreciation & Amortization ("EBITDA") at a plant level (excluding corporate costs and revenues, as well as capital costs)
  - This is an indicative analysis based on publicly available data, LEI's multi-client market outlook for New England (May 2018) and overall experience and professional judgement
  - LEI created five scenarios, including a "central" case:

Scenarios	Description
Central Case	▪ Assumed a 85% average annual capacity factor and an average energy price from LEI's most recent multi-client study for the New England market; REC prices based on forward quotes; Realized capacity prices based on published ISO-NE FCM results
Lower Energy Prices	▪ Assumed a 85% average annual capacity factor and a low energy price based on the low end of OTC future transactions
Higher Energy Prices	▪ Assumed a 85% average annual capacity factor and a high energy price based on the high end of OTC future transactions
Lower average annual capacity factor	▪ Assumed a 70% average annual capacity factor and the same price from the central case
Lower Capacity Commitment	▪ Assumed a 85% average annual capacity factor, the same price from the central case, and no additional capacity above the cleared capacity in FCA#8-12

- **LEI also prepared a backcast of revenues and costs in 2017 and compared its estimated backcast to actuals provided by ReEnergy; the backcast exercise was done to benchmark LEI's approach for estimating operating costs in relation to market revenues**

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LEI's 2017 estimated plant level EBITDA is aligned with the financial data provided by ReEnergy for these plants

- **In preparing the 2017 backcast, LEI relied on publicly available data and industry standard approximation techniques**
  - Some data is not yet available for 2017 – such as reported fuel costs; other data may never be available publicly – such as bilaterally-negotiated power agreements. Therefore, LEI had to estimate certain revenues and costs
  - ReEnergy's plant level EBITDA used in the comparison excludes consideration of allocated corporate costs or allocated corporate revenues (e.g., hedges)

Values are in thousand USD	Ashland		Fort Fairfield	
	2017 Actual	2017 LEI Estimate	2017 Actual	2017 LEI Estimate
TOTAL Revenues ($)	19,313	18,363	18,483	16,459
(-) TOTAL Opex ($)	(19,252)	(19,262)	(17,611)	(17,507)
(=) Facility Level EBITDA ($)	61	(900)	872	(1,048)
(+) One-time transmission fee rebate*	1,564	1,564	1,484	1,484
(=) Adjusted EBITDA after the one-time rebate ($)	**1,625**	**665**	**2,356**	**436**

** Using LEI's calculation of the one-time rebate of transmission fees is based on capacity pro-rata allocation between the two plants of the FERC approved settlement amount.*

- **The biggest difference between LEI's estimate and ReEnergy's actuals is related to revenues**
  - LEI's estimated 2017 revenues are lower than ReEnergy's actuals due to: (a) additional capacity sold and (b) the timing of ReEnergy's RECs sales in the bilateral market resulted in higher than average REC pricing; such data is not in the public domain
- **Based on this comparison, and after recognizing ReEnergy's bilateral agreement for capacity sales has expired, LEI is confident that it is capturing the market revenues that the power plants can earn from the sale of energy, capacity and RECs in ISO-NE's control area, and an appropriate estimate of facility-level operational costs**

Indicative financial analysis suggests that these two biomass plants would be uneconomic in the next few years

- **Based on an indicative forward-looking financial analysis, both Ashland and Fort Fairfield biomass plants have negative plant level EBITDAs in all scenarios tested by LEI for the 2018 to 2021 timeframe**
  - Under the Central Case, gross margin losses range from $610 thousand (2021) to $1.8 million (2019) for Ashland plant and $1.7 million (2021) to $2.8 million (2019) for Fort Fairfield
  - LEI tested four other scenarios involving variations in projected market prices and quantity of energy and capacity sold (which affects revenues and variable operating costs)
- **Under the Central Case, the plants could achieve a break-even EBITDA ($0) with the following levels (in percentage terms) of relief from the Schedule 7/8 transmission charges:**

Plant	4Q2018	2019	2020	2021
Ashland	100%*	~90%	~50%	~30%
Fort Fairfield	100%*	100%*	~98%	~85%
Portfolio composite	**100%***	**100%***	**~75%**	**~55%**

A full relief on the Schedule 7/8 transmission charges improves EBITDA, but the EBITDA remains slightly negative

Portfolio composite = percentage of transmission relief needed at a portfolio level EBITDA (Ashland + Fort Fairfield) to break-even

- **In addition to the Central Case, a 100% discount (relief) of the Schedule 7/8 transmission charges can turn the projected EBITDA to positive values under some scenarios**
  - Ashland: central case scenario and low energy prices scenario (years 2019, 2020, and 2021); high energy prices scenario (all years); lower average annual capacity factor scenario (years 2020 and 2021); and lower capacity commitment scenario (2021).
  - Fort Fairfield: central case scenario (years 2020 and 2021); high energy prices scenario (all years); lower capacity commitment scenario (2020)

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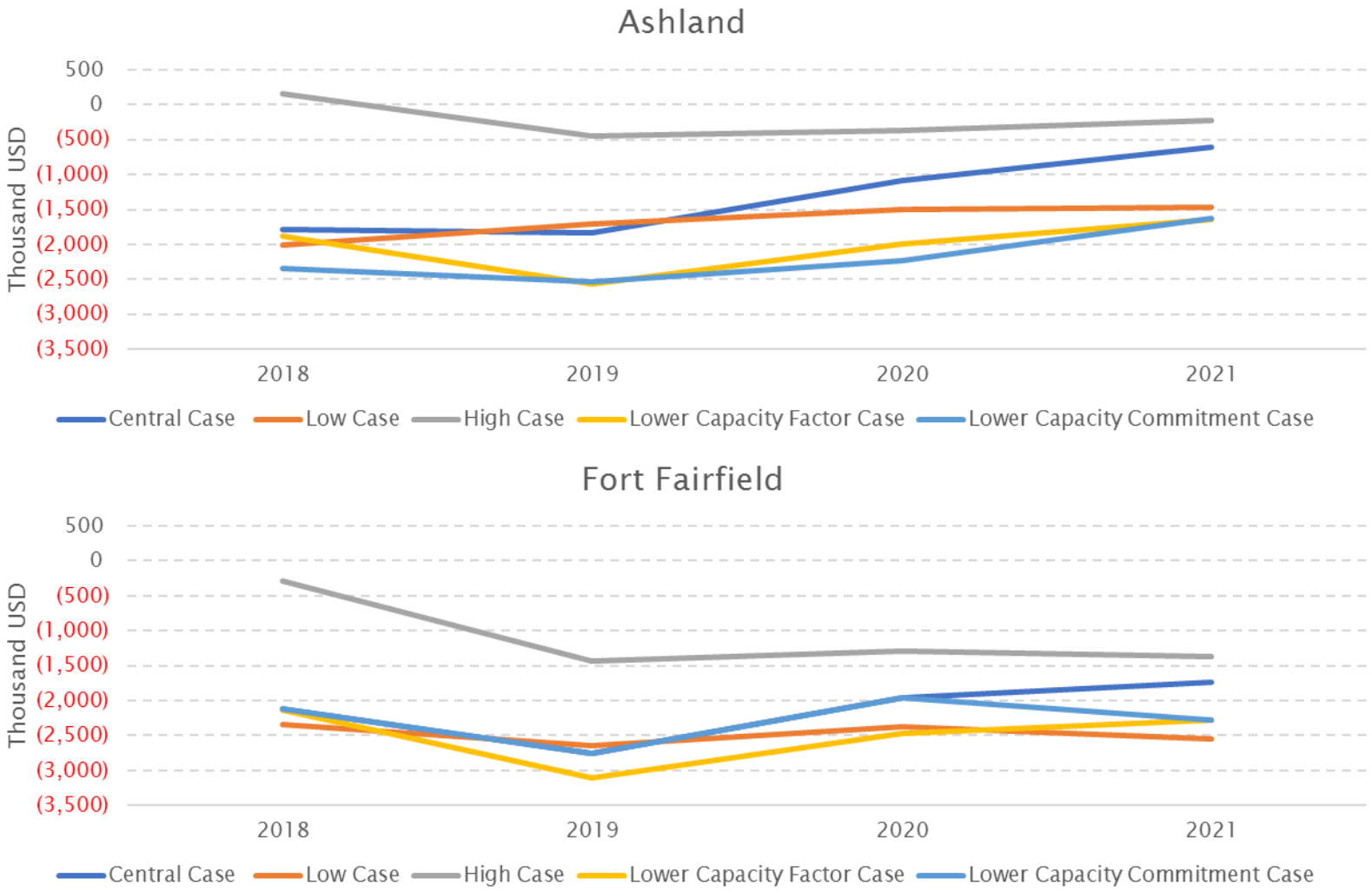
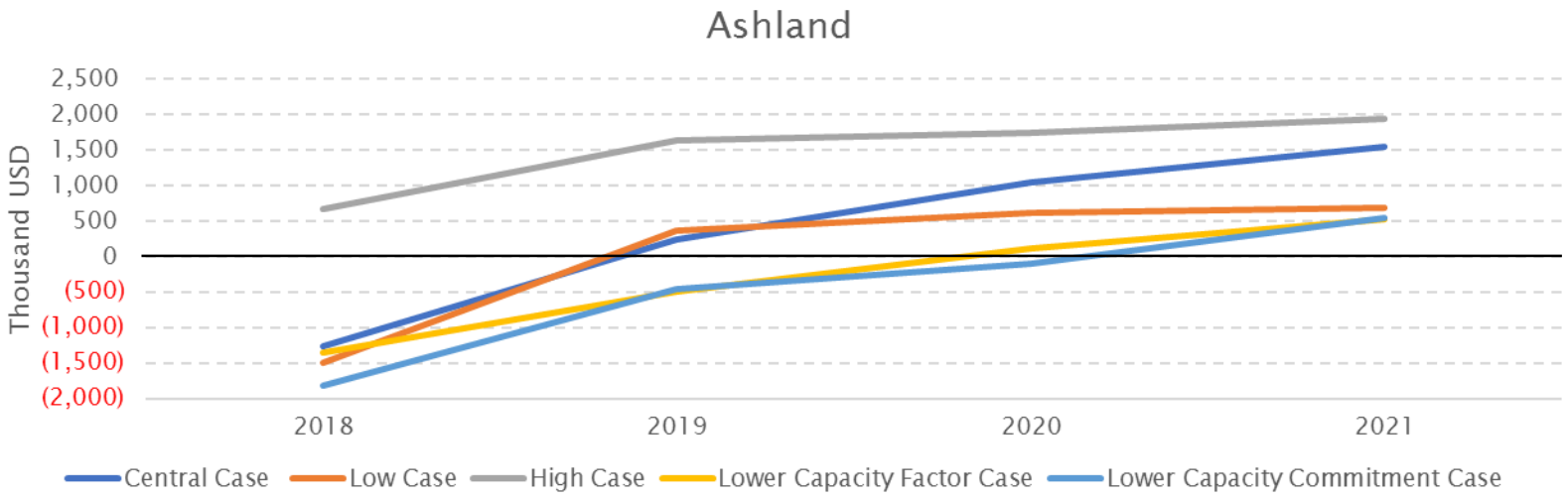
All scenarios modeled by LEI suggest that both power plants will earn a negative EBITDA* in the next few years

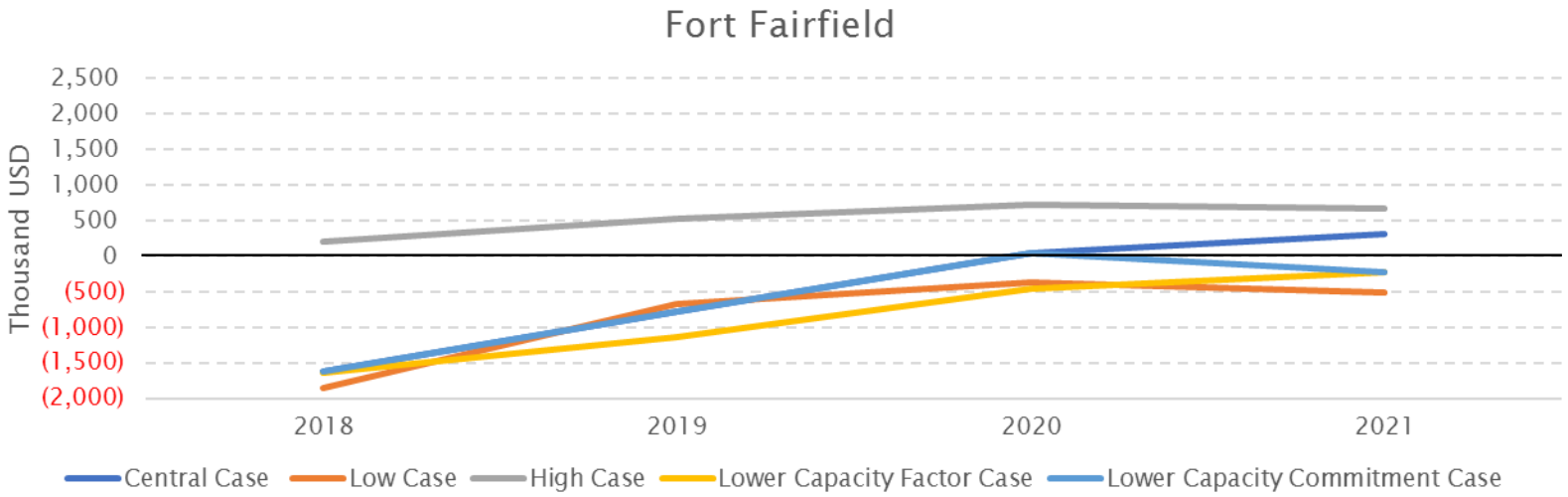


*This is a plant-level EBITDA, before any allocated corporate costs and before taking into account any capital costs, depreciation or taxes

Detailed numbers are provided in Appendix 1

With a 100% discount on Schedule 7/8 transmission charges, Ashland and Fort Fairfield may earn a positive EBITDA* in some scenarios and some years



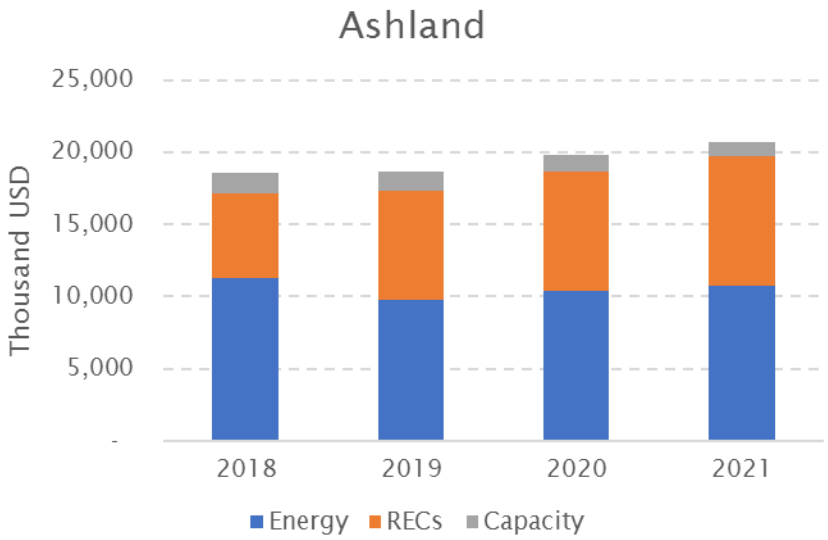


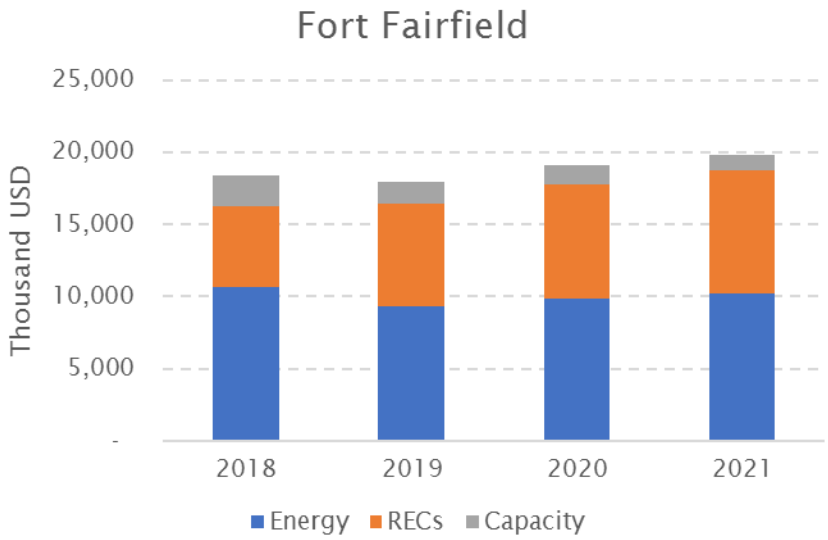
**2018 EBITDA only considers a transmission relief in 4Q2018.*
This is a plant-level EBITDA, before any allocated corporate costs and before taking into account any capital costs, depreciation or taxes

Detailed numbers are provided in Appendix 1

Under the Central Case, LEI estimates total revenues between $18 million and $21 million per year for each plant

- **Although Ashland didn't clear the FCA#10-12, LEI assumed that any unsold capacity would be sold in future Reconfiguration Auctions and both plants would be able to monetize their CSOs of 32 MW and 31 MW (Ashland and Fort Fairfield, respectively) each year through the end of 2021**
  - LEI did not assess any expected capacity performance penalty risk to these capacity sales given the expected average annual capacity factor of these resources in the pro forma and the low likelihood of a system stress event given the general level of supply in the New England region
- **Expected higher CT Class I REC prices from 2019 onwards offset the lower energy revenues (after PPA expires after Q3 2018) leading to a small upward trend in the overall revenue forecast over time under the Central Case**

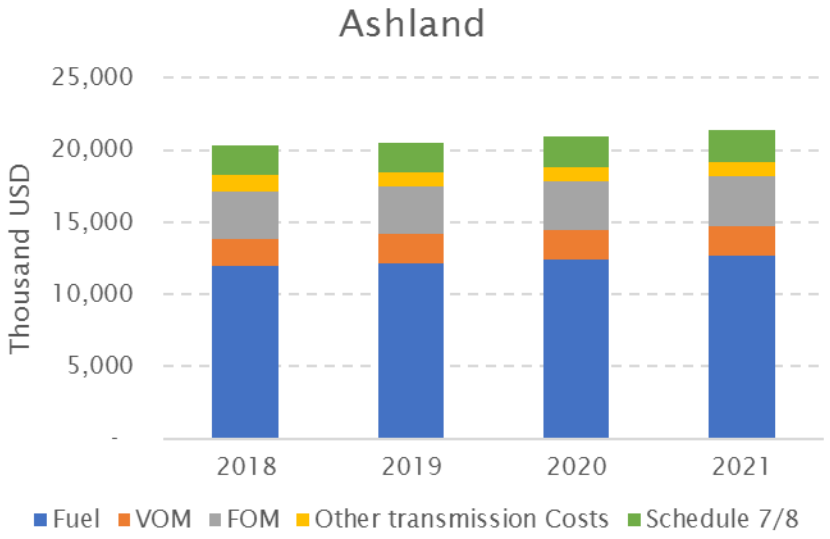


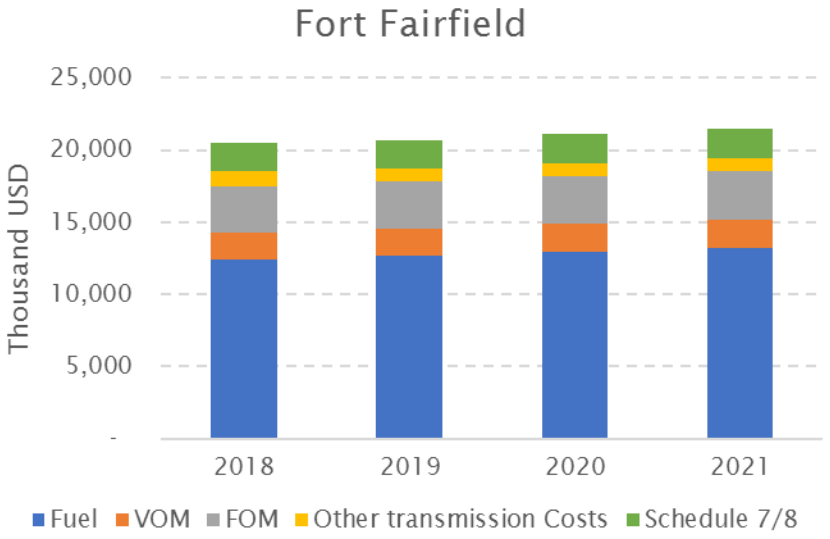


Detailed numbers are provided in Appendix 1

Operating cost estimates range between $20 million and $22 million per year for each plant under the Central Case

- **Costs are based on publicly available data from various sources (see next section of slide deck) and are generally aligned with costs of similar power plants in the Northeast**
  - Fuel costs represent the largest share of total operating costs (~60%) and typically is the most site-specific
  - Transmission costs consist of New Brunswick Power and Emera Maine published tariffs and are the second largest cost item, at about 15% of total operating costs
  - Labor is the largest component of fixed costs (headcount is based on publicly available data) and 11% of total operating costs





VOM = variable O&M costs
FOM = fixed O&M costs
Other transmission costs = New Brunswick Power point-to-point charges and Emera Maine Schedules 1/2 charges

Detailed numbers are provided in Appendix 1

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Revenues and costs estimates are based on publicly available data and LEI's professional judgement

Inputs		Sources
Estimated Revenues	Energy	▪ January 2017 to May 2018: day ahead spot prices reported by ISO-NE for the Salisbury node ▪ June 2018 to December 2018: forwards prices for Z.MAINE* as reported by OTC Global Holdings (3-month average, March-May 2018) ▪ 2019 onwards: based on LEI's most recent multi-client study for the New England market for the Maine zone* (CMI, May 2018) ** Z.MAINE prices are on average 6% higher than prices at Salisbury node (2015-2017). LEI adjusted the price by reducing forwards and CMI by 6%*
	Renewable Energy Credits	▪ 2017 and 2018: CT Class I REC historical price based on the average traded price for the REC vintage (up to May 2018) ▪ 2019 onwards: CT Class I REC prices for future compliance periods, sourced from Karbone broker as of May 2018. Both plants are eligible.
	Capacity	▪ ISO-NE FCA clearing prices for New Brunswick imports (each calendar year, an annualized value across two capability periods is being used) ▪ For the reconfiguration auctions, LEI assumed a 80% price discount to the ISO-NE FCA clearing prices for New Brunswick imports
	PPA	▪ MPUC Biomass procurement (Docket No. 2016-00084): 2-year term contract for differences, starting in March 2017 (or until funding is exhausted) at a $46.50/MWh price (energy only)
Estimated Costs	Fuel	▪ Same base* fuel cost estimate for the two plants based on data from third party data provider **Base fuel cost was adjusted, based on information and historical data provided by ReEnergy, to reflect the differences in fuel composition between the two power plants*
	Variable O&M	▪ Same variable O&M estimate for the two plants based on data from third party data provider
	Fixed O&M	▪ Labor based on LEI professional judgment using data from Bureau of Labor Statistics ▪ Other fixed O&M based on plant specific cost estimate from third party data provider
	Transmission	▪ Maine: Emera Maine Public District OATT. Attachment J Formula Rates Exhibit 1a. Rate year June 1, 2017 to May 31, 2018. ▪ New Brunswick: NB Power OATT. Schedules 7 and 8. May 6, 2016.
Operations	Average annual capacity factor	▪ 85% average annual capacity factor assumption reflecting the best operations pattern observed in recent years

Revenues are projected on the basis of wholesale energy market sales (PPA agreement that is ending this year), capacity sales, and REC sales

Assumptions on Revenues

Input	2018	2019	2020	2021
Energy	Wholesale energy sales from any excess generation above PPA	100% wholesale energy sales		
Capacity[1]	32 MW of capacity supply obligation for Ashland and 31 MW for Fort Fairfield (FCA prices and Annual Reconfiguration Auction prices)			
Renewable Energy Credits[2]	CT Class 1 sales (RECs generated for each MWh of generation)			
PPA	Energy from 40 MW through Q3 (total across both plants)	No PPA		

[1)] For capacity revenues, LEI is aware that both plants cleared in the FCA #9 (2018/2019), but only Fort Fairfield cleared in the FCA #10-11 (2019/2020 - 2020/2021). Neither plant cleared in the FCA #12 (2021/2022)

- For Central Case and three other sensitivities, LEI is assuming Ashland could enter the reconfiguration auctions and be awarded a CSO at 80% of the price that cleared in FCA#10-12; Fort Fairfield would do the same for FCA#12
- LEI did not adjust for capacity performance penalty risk

[2)] For RECs revenues, there is also the risk of regulatory changes, which LEI is not considering at the moment

Assumptions on Costs

- **Costs were estimated for the year of 2018 and inflated annually based on a 2% inflation rate, including transmission tariffs; where appropriate, costs varied with output across different scenarios**

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2017 estimate captures all market revenue opportunities and associated operating costs, based on publicly available data

ReEnergy Northern ME Biomass Economics	Ashland 2017	Fort Fairfield 2017
Estimated Revenues		
Energy Revenues ($)	$10,736,955	$8,758,683
Energy revenue from spot market ($)	*$8,274,029*	*$6,807,661*
Energy revenue from PPA ($)	*$2,462,925*	*$1,951,022*
(+) Renewable Energy Credits ($)	$7,625,750	$6,274,274
(+) Capacity Revenues ($)	$0	$1,426,075
(=) TOTAL Revenues ($)	**$18,362,705**	**$16,459,032**
Estimated Operating Expenses		
Fuel Cost ($)	$10,799,212	$9,764,085
(+) Variable O&M ($)	$1,753,306	$1,442,575
(+) Fixed O&M ($)	$3,195,476	$3,139,655
Labor ($)	*$2,106,970*	*$2,106,970*
Other fixed O&M ($)	*$1,088,506*	*$1,032,685*
(+) Transmission Costs ($)	$3,514,425	$3,160,467
Emera Maine	*$2,761,590*	*$2,619,970*
NBPower	*$752,835*	*$540,497*
(=) TOTAL Opex ($)	**$19,262,419**	**$17,506,783**
EBITDA ($)	**($899,714)**	**($1,047,751)**
(+) One-time transmission fee rebate ($)	$1,564,416	$1,484,189
(=) Adjusted EBITDA after the one-time rebate ($)	**$664,702**	**$436,439**

This is a plant-level EBITDA, before any allocated corporate costs and before taking into account any capital costs, depreciation or taxes

Financial results for all scenarios (without transmission relief)

Values are in thousand USD	Ashland				Fort Fairfield			
	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Scenario 1 – Central case (both plants sell capacity; 85% load factor)								
TOTAL Revenues ($)	18,577	18,679	19,841	20,728	18,391	17,923	19,125	19,778
TOTAL Opex ($) - w/o transmission relief	20,356	20,510	20,920	21,338	20,508	20,678	21,091	21,513
EBITDA ($) - w/o transmission relief	(1,779)	(1,831)	(1,079)	(610)	(2,118)	(2,755)	(1,966)	(1,735)
Scenario 2 – Low case (lower energy prices)								
TOTAL Revenues ($)	18,341	18,801	19,413	19,864	18,167	18,039	18,720	18,959
TOTAL Opex ($) - w/o transmission relief	20,356	20,510	20,920	21,338	20,508	20,678	21,091	21,513
EBITDA ($) - w/o transmission relief	(2,015)	(1,709)	(1,507)	(1,474)	(2,341)	(2,639)	(2,372)	(2,555)
Scenario 3 – High case (higher energy prices)								
TOTAL Revenues ($)	20,513	20,065	20,551	21,108	20,227	19,238	19,799	20,138
TOTAL Opex ($) - w/o transmission relief	20,356	20,510	20,920	21,338	20,508	20,678	21,091	21,513
EBITDA ($) - w/o transmission relief	157	(445)	(369)	(230)	(281)	(1,440)	(1,292)	(1,375)
Scenario 4 – Lower average annual capacity factor (70%)								
TOTAL Revenues ($)	16,030	15,440	16,373	17,100	15,623	14,778	15,767	16,322
TOTAL Opex ($) - w/o transmission relief	17,909	18,013	18,374	18,741	17,763	17,878	18,236	18,600
EBITDA ($) - w/o transmission relief	(1,879)	(2,573)	(2,000)	(1,641)	(2,140)	(3,100)	(2,469)	(2,278)
Scenario 5 – Lower capacity committed (only 1 plant clears ISO-NE's FCM)								
TOTAL Revenues ($)	18,017	17,967	18,692	19,717	18,391	17,923	19,125	19,230
TOTAL Opex ($) - w/o transmission relief	20,356	20,510	20,920	21,338	20,508	20,678	21,091	21,513
EBITDA ($) - w/o transmission relief	(2,339)	(2,542)	(2,228)	(1,621)	(2,118)	(2,755)	(1,966)	(2,283)

This is a plant-level EBITDA, before any allocated corporate costs and before taking into account any capital costs, depreciation or taxes

Financial results for all scenarios with 100% discount on Schedule 7/8 (transmission relief)

Values are in thousand USD	Ashland				Fort Fairfield			
	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast
Scenario 1 – Central case (both plants sell capacity; 85% load factor)								
TOTAL Revenues ($)	18,577	18,679	19,841	20,728	18,391	17,923	19,125	19,778
TOTAL Opex ($) - with transmission relief	19,836	18,432	18,800	19,176	20,015	18,707	19,081	19,462
EBITDA ($) - with transmission relief	(1,260)	247	1,041	1,552	(1,625)	(784)	45	316
Scenario 2 – Low case (lower energy prices)								
TOTAL Revenues ($)	18,341	18,801	19,413	19,864	18,167	18,039	18,720	18,959
TOTAL Opex ($) - with transmission relief	19,836	18,432	18,800	19,176	20,015	18,707	19,081	19,462
EBITDA ($) - with transmission relief	(1,495)	369	613	688	(1,848)	(668)	(361)	(504)
Scenario 3 – High case (higher energy prices)								
TOTAL Revenues ($)	20,513	20,065	20,551	21,108	20,227	19,238	19,799	20,138
TOTAL Opex ($) - with transmission relief	19,836	18,432	18,800	19,176	20,015	18,707	19,081	19,462
EBITDA ($) - with transmission relief	676	1,633	1,751	1,932	212	531	719	676
Scenario 4 – Lower average annual capacity factor (70%)								
TOTAL Revenues ($)	16,030	15,440	16,373	17,100	15,623	14,778	15,767	16,322
TOTAL Opex ($) - with transmission relief	17,389	15,936	16,254	16,579	17,270	15,907	16,225	16,549
EBITDA ($) - with transmission relief	(1,359)	(495)	119	521	(1,647)	(1,129)	(458)	(227)
Scenario 5 – Lower capacity committed (only 1 plant clears ISO-NE's FCM)								
TOTAL Revenues ($)	18,017	17,967	18,692	19,717	18,391	17,923	19,125	19,230
TOTAL Opex ($) - with transmission relief	19,836	18,432	18,800	19,176	20,015	18,707	19,081	19,462
EBITDA ($) - with transmission relief	(1,820)	(464)	(108)	541	(1,625)	(784)	45	(232)

**2018 EBITDA only considers a transmission relief in 4Q2018.*
This is a plant-level EBITDA, before any allocated corporate costs and before taking into account any capital costs, depreciation or taxes

Detailed breakdown of plant level revenues and costs under the Central Case

	Ashland				Fort Fairfield			
ReEnergy Northern ME Biomass Economics	2018	2019	2020	2021	2018	2019	2020	2021
Estimated Revenues								
Energy Revenues ($)	$11,233,399	$9,786,685	$10,415,654	$10,715,032	$10,657,327	$9,284,803	$9,881,518	$10,165,544
Energy revenue from spot market ($)	*$10,104,152*	*$9,786,685*	*$10,415,654*	*$10,715,032*	*$9,585,990*	*$9,284,803*	*$9,881,518*	*$10,165,544*
Energy revenue from PPA ($)	*$1,129,247*	*$0*	*$0*	*$0*	*$1,071,337*	*$0*	*$0*	*$0*
(+) Renewable Energy Credits ($)	$5,900,806	$7,550,244	$8,276,229	$9,002,214	$5,598,201	$7,163,052	$7,851,807	$8,540,562
(+) Capacity Revenues ($)	$1,442,560	$1,341,824	$1,148,928	$1,010,688	$2,135,125	$1,474,980	$1,392,055	$1,071,763
(=) TOTAL Revenues ($)	**$18,576,765**	**$18,678,753**	**$19,840,811**	**$20,727,934**	**$18,390,653**	**$17,922,835**	**$19,125,380**	**$19,777,869**
Estimated Operating Expenses								
Fuel Cost ($)	$11,930,205	$12,168,809	$12,412,186	$12,660,429	$12,437,802	$12,686,558	$12,940,289	$13,199,095
(+) Variable O&M ($)	$1,936,928	$1,975,667	$2,015,180	$2,055,483	$1,837,598	$1,874,350	$1,911,837	$1,950,074
(+) Fixed O&M ($)	$3,259,830	$3,325,026	$3,391,527	$3,459,357	$3,202,870	$3,266,927	$3,332,266	$3,398,911
Labor ($)	*$2,149,110*	*$2,192,092*	*$2,235,934*	*$2,280,652*	*$2,149,110*	*$2,192,092*	*$2,235,934*	*$2,280,652*
Other fixed O&M ($)	*$1,110,720*	*$1,132,934*	*$1,155,593*	*$1,178,705*	*$1,053,760*	*$1,074,835*	*$1,096,332*	*$1,118,259*
(+) Transmission Costs ($)	$3,228,913	$3,040,032	$3,100,833	$3,162,849	$3,029,920	$2,850,057	$2,907,058	$2,965,200
Emera Maine	*$2,476,078*	*$2,272,140*	*$2,317,583*	*$2,363,934*	*$2,349,099*	*$2,155,620*	*$2,198,732*	*$2,242,707*
NBPower	*$752,835*	*$767,892*	*$783,250*	*$798,915*	*$680,821*	*$694,437*	*$708,326*	*$722,493*
(=) TOTAL Opex ($)	**$20,355,876**	**$20,509,534**	**$20,919,725**	**$21,338,119**	**$20,508,190**	**$20,677,893**	**$21,091,451**	**$21,513,280**
(-) Transmission relief ($)	$519,480	$2,077,920	$2,119,478	$2,161,868	$492,840	$1,971,360	$2,010,787	$2,051,003
(=) TOTAL Opex ($) - with transmission relief	**$19,836,396**	**$18,431,614**	**$18,800,246**	**$19,176,251**	**$20,015,350**	**$18,706,533**	**$19,080,663**	**$19,462,277**
EBITDA ($)	**($1,779,111)**	**($1,830,782)**	**($1,078,913)**	**($610,185)**	**($2,117,537)**	**($2,755,057)**	**($1,966,070)**	**($1,735,411)**
EBITDA - with transmission relief	**($1,259,631)**	**$247,138**	**$1,040,565**	**$1,551,683**	**($1,624,697)**	**($783,697)**	**$44,717**	**$315,592**

**2018 EBITDA only considers a transmission relief in 4Q2018.*
This is a plant-level EBITDA, before any allocated corporate costs and before taking into account any capital costs, depreciation or taxes

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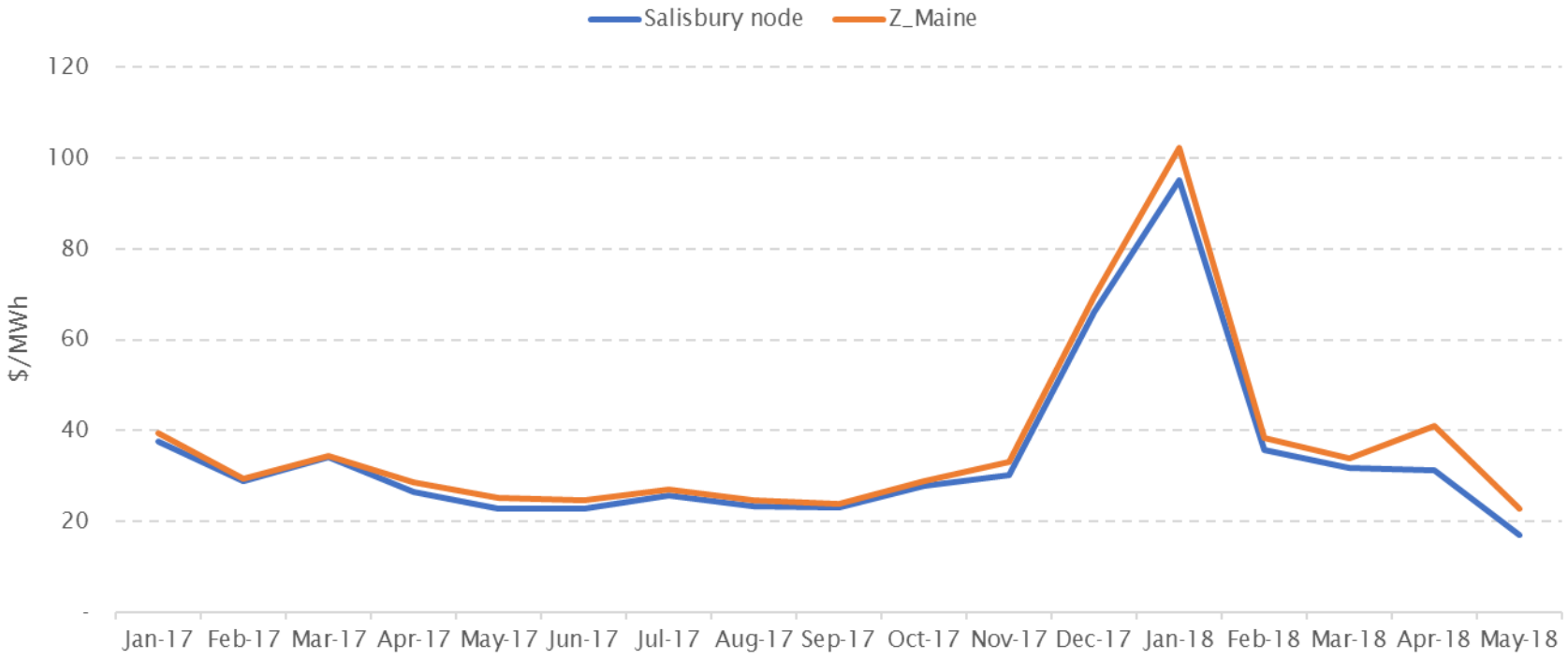
Salisbury node is priced at a small discount from the Z.MAINE prices

- Average price at Salisbury node in 2017 was $30.85 per MWh, while Maine zone average price was recorded around $32.50 per MWh for this same period
- In late 2017 and early 2018, there was an overall surge in energy prices in New England

Day-Ahead Around the clock monthly prices



Agenda

LEI is a global economic, financial and strategic advisory professional services firm

London Economics International LLC ("LEI") combines detailed understanding of specific network and commodity industries, such as electricity generation and transmission, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

LEI has extensive experience in several areas, including:

GENERATION:

- **Working with generation owners to forecast market conditions and evaluate future revenues**
- **Assessing the impact of new generation resources on capacity and energy prices**

TRANSMISSION:

- **Advising on tariff design and other business issues for regulated & merchant transmission**
- **Conducting cost-benefit analysis around proposed transmission projects**

RENEWABLES:

- **Working with developers to value potential revenue streams from Renewable Energy Credits ("RECs") and/or emissions offsets**
- **Counseling governments and regulators on creating policies which efficiently incentivize investment in renewable energy**

NATURAL GAS:

- **Assessing the synergies between the natural gas and electric power industries**
- **Examining performance-based ratemaking and total factor productivity for natural gas distribution companies**

ASSET VALUATION, PRICE FORECASTING & MARKET ANALYSIS

REGULATORY ECONOMICS, PBR & MARKET DESIGN

TRANSMISSION

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