UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-105-000**

COMMENTS AND LIMITED PROTEST OF LS POWER ASSOCIATES, L.P.

Pursuant to the notice[1] issued by the Federal Energy Regulatory Commission (the "Commission") and Rule 211 of the Commission's Rules of Practice and Procedure,[2] LS Power Associates, L.P. ("LS Power") hereby submits these comments on, and a limited protest to, the October 12, 2018 filing[3] by PJM Interconnection, L.L.C. ("PJM") of modifications to its Open Access Transmission Tariff ("Tariff")[4] to revise the Variable Resource Requirement ("VRR") Curve used in PJM"s Reliability Pricing Model ("RPM") auctions.

LS Power is a member of the LS Power Group, which has developed 8,000 MW of new, competitive fossil and renewable generation, and over 500 miles of interstate high-voltage transmission, since its inception in 1990. The LS Power Group, through LS Power Equity Investors, has also acted as the manager and an investor of several private equity and infrastructure funds with total investor commitments of nearly $10 billion since 2005. The LS Power Group has actively invested in the power industry over a period of almost 30 years, and has raised almost $40 billion in bank, debt capital, and private equity capital markets for their projects and asset acquisitions. Overall, LS Power and its affiliates have developed, acquired,

---

1 Combined Notice of Filings #1, Docket Nos. EC19-11-000, *et al.* (Oct. 15, 2018).

2 18 C.F.R. § 285.211 (2018).

3 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER19-105-000 (filed Oct. 12, 2018) (the "October 12 Filing").

4 Capitalized terms not otherwise defined herein have the meaning set forth in the Tariff.

invested in, and managed close to 40,000 MW of competitive power generation. As a result, LS Power is very familiar with the factors that merchant developers must consider in their investment decisions. Importantly, in making those decisions, LS Power and its affiliates have focused on the underlying power assets and the relevant markets, rather than the companies holding such assets. Accordingly, LS Power's experience highlights the importance of ensuring that the VRR Curve, as well as the cost of new entry ("CONE") calculations underlying that curve, properly reflect the conditions that merchant developers commonly expect to face in developing and owning generation facilities.

As described in detail herein, LS Power supports PJM's decision to continue to use a combustion turbine ("CT") in the simple-cycle (peaking) configuration as the Reference Resource that is used to estimate the CONE. Unfortunately, however, certain of the proposed modifications to the VRR Curve and underlying CONE parameters in the October 12 Filing are not just and reasonable because they fail to realistically reflect the costs, concerns, and other factors that developers would face in making the decision to develop new generation in the PJM region. In particular, PJM and its consultant, the Brattle Group ("Brattle"), have used erroneous assumptions regarding tax depreciation and financing terms that will unjustly and unreasonably understate the CONE.

In addition, PJM has chosen to configure its Reference Resource with an unproven turbine technology that is at its nascent stage of commercial application and has not yet been widely used by developers. This turbine has also been shown to have serious design issues in the field, thereby raising concerns regarding the turbine's reliability and making it impossible to accurately determine its development, construction, and going-forward operating costs, which are critical inputs to the CONE.

Finally, PJM erroneously proposes to shift the entire VRR curve to the left, which would only augment the problems resulting from continuing uncertainty in the industry. These errors will jeopardize reliability by producing RPM clearing prices that fail to properly incentivize continued investment in the PJM region.

I.

BACKGROUND

As the October 12 Filing describes, the VRR Curve is the administratively-determined demand curve that is used in PJM's RPM auctions. The Tariff requires PJM to update the shape of the VRR Curve and inputs to that curve every four years.[5] In order to ensure that the RPM auctions result in capacity prices that are adequate to incent new investment when needed, the review process is intended to result in a VRR Curve that will "quantify the ability of the market to invest in new Capacity Resources and . . . meet the applicable reliability requirements on a probabilistic basis."[6]

In the October 12 Filing, PJM proposes various modifications to the parameters underlying the VRR Curve based on the recommendations of Brattle,[7] who worked with Sargent & Lundy, L.L.C., an engineering and consulting company, to calculate an updated CONE. Among other things, PJM has proposed to continue to use a CT to configure the Reference Resource. However, while the Tariff currently uses a CT plant configured with two General

---

5 *See* Tariff, Attachment DD, § 5.10(a)(iii).

6 *Id.*

7 The October 12 Filing includes two affidavits by PJM employees, and three affidavits by Brattle. *See* October 12 Filing, Attachment C, Affidavit of Adam J. Keech (the "Keech Affidavit"); *id.*, Attachment D, Affidavit of M. Gary Helm (the "Helm Affidavit"); *id.*, Attachment E, Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang (the "Newell/Hagerty/Gang Affidavit"); *id.*, Attachment F, Affidavit of Johannes P. Pfeifenberger and Bin Zhou (the "Pfeifenberger/Zhou Affidavit"); *id.*, Attachment G, Affidavit of Samuel A. Newell and David Luke Oates.

Electric ("GE") Frame 7FA turbines, the October 12 Filing proposes instead to use GE's recently released 7HA turbine.[8]

In estimating the CONE, Brattle made a change based on the Tax Cuts and Jobs Act of 2017 ("TCJA"), which provides for bonus depreciation on a temporary basis, where such "[b]onus depreciation is a form of highly accelerated tax depreciation that can be applied immediately upon placing a depreciable asset in service."[9] Specifically, Brattle used the full 100% bonus depreciation permitted by the TCJA in calculating the CONE for a new generation facility entering service in June 1, 2022, and then reduced the CONE values by 2.2% for "each year the bonus depreciation phases down by another 20%."[10]

In addition, Brattle's CONE analysis, which was conducted in April 2018, estimated an after-tax weighted-average cost of capital ("ATWACC") of "8.0%, including debt and . . . equity ratios of 55% and 45%, respectively, a cost of BB-rated debt of 5.5%, and a cost of equity of 13.0%."[11] This analysis was subsequently updated to reflect the fact that "a merchant generator of the type that would sponsor a new entry plant would likely have a credit rating somewhere between B and BB, rather than being rated BB alone,"[12] resulting in a proposed ATWACC of 8.2%.[13]

---

8 *See* October 12 Filing, Transmittal Letter at 17.

9 Newell/Hagerty/Gang Affidavit, ¶ 24. The bonus depreciation is reduced by 20% for each subsequent year. *See id.*

10 *Id.*

11 October 12 Filing, Transmittal Letter at 19.

12 *Id.* (quoting Helm Affidavit, ¶ 9).

13 *See id.*

PJM also proposes to move the entire VRR curve to the left by 1%.[14] PJM states that, in the last VRR Curve review process that was conducted in 2014, it moved the VRR curve to the right by 1% to address uncertainty. The October 12 Filing now claims, however, that "the reasons for right-shifting the VRR curve that PJM cited in 2014 have been resolved or are much less of a concern . . . ."[15]

II.

COMMENTS AND LIMITED PROTEST

A. The October 12 Filing Calculates The CONE Using Unrealistic Assumptions Regarding The Use Of Bonus Depreciation

In the October 12 Filing, PJM states that, "[p]er the 2017 [TCJA], bonus depreciation is allowed for companies not classified as public utilities up to 100% of tax basis."[16] In estimating the CONE, Brattle assumed that this full bonus depreciation would be used to lower the costs of the Reference Resource, and therefore calculated the CONE assuming that "[n]ew units put in service before January 1, 2023 can apply 100% bonus depreciation in the first year of service, which decreases CT CONE on average by $11,700/MW-year. . . ."[17]

As explained in the attached affidavit of Joseph D. Esteves (the "Esteves Affidavit," provided as Attachment A hereto), Brattle's assumptions ignore the fact that the Reference Resource will simply not have adequate tax liabilities to fully utilize the 100% bonus depreciation. Specifically, Mr. Esteves explains that peaking generation assets are normally depreciated over a 15-year period, generally with 5% depreciation in the first year and a

[14] *See id.* at 8-10.

[15] *Id.* at 9.

[16] *Id.* at 21.

[17] Newell/Hagerty/Gang Affidavit, Exh. 2, The Brattle Group, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, at 47 (Apr. 19, 2018) (the "2018 CONE Study").

maximum of 9.5% in year two.[18] Applied to Brattle's CONE estimates,[19] Mr. Esteves shows that this would result in depreciation of $1 million in year one.[20] By contrast, to the extent that the same resource is assumed to use the 100% bonus depreciation permitted under the TCJA, this would result in depreciation of $54 million in the first year.[21]

To be clear, bonus depreciation does not provide any direct payments to the claimant, and instead only provides an income tax deduction. Accordingly, in order to fully use the bonus depreciation, the Reference Resource would have to have at least $54 million in federal tax liability in the first instance. As Mr. Esteves states, this is simply inconceivable for a 320 MW peaking facility, which would not be expected to have even a fraction of the federal tax liability needed.[22]

Although it is clear that the Reference Resource itself would lack the federal tax liability required to take advantage of the 100% bonus depreciation, PJM or Brattle may try to argue that such depreciation can be claimed by the corporate parent of the Reference Resource. As an initial matter, and as discussed in more detail below, Brattle's assumptions that the Reference Resource will be developed by a publicly-traded independent power producer ("IPP") or similarly situated sponsor is contrary to the standalone nature of the Reference Resource.

Equally important, Mr. Esteves further explains that it is highly unlikely that an upstream owner of the Reference Resource would be able to use the full bonus depreciation. As PJM and

---

18 *See* Esteves Affidavit at 4-5 & n.7.

19 As explained in the 2018 CONE Study, depreciable costs consist of "the depreciable overnight capital costs and the accumulated interest during construction (IDC)." 2018 CONE Study at 47. For simplicity, Mr. Esteves's calculations use the "Installed (inc. IDC)" cost of $835/kW-year for a facility in the Rest of RTO. *See* Esteves Affidavit at 6.

20 *See* Esteves Affidavit at 6 & Table 1.

21 *Id.*

22 *Id.* at 7.

Brattle acknowledge, the TCJA expressly bars public utilities from using bonus depreciation.[23] At the same time, Mr. Esteves states that "private equity funds that develop and own new generation capacity are normally pass-through entities for income tax purposes and therefore would not realize any tangible incremental benefit from the bonus depreciation."[24] Critically, Mr. Esteves also explains that even the largest IPPs would struggle to absorb the amount of bonus depreciation used in Brattle's calculations. In particular, Mr. Esteves examined the publicly available tax information of large IPPs, and found that the U.S. federal tax liabilities of these IPPs, which own and operate multiple resources, were minimal and only sufficient to utilize a small portion of the tax benefit associated with 100% bonus depreciation from a new generating project in any given year.[25] Mr. Esteves further explains that this is not surprising, given the nature of investment and revenues in the power generation industry, as well as the large balances of federal net operating loss carryforwards ("NOLs") that are expected to keep IPPs tax efficient and minimize their tax liability in the upcoming years.[26]

There is no basis for imputing substantial tax benefits to the Reference Resource when its owners will only be able to utilize a small fraction of such benefits for the foreseeable future. In fact, this flawed and unrealistic assumption is particularly egregious because of its impact on the CONE: as Brattle itself acknowledges, the bonus depreciation "decreases CT CONE on average by $11,700/MW-year."[27] This significant understatement in the CONE, representing 11% of the proposed CONE value, will have correspondingly large impacts on RPM clearing prices, thereby

---

23 *See* October 12 Filing, Transmittal Letter at 21; Newell/Hagerty/Gang Affidavit, ¶ 24.

24 *See* Esteves Affidavit at 7-8.

25 *See id.* at 8-9 & Table 2.

26 *See id.* at 8-9.

27 2018 CONE Study at 47.

blunting the signals needed to maintain reliability in the region. Accordingly, and as Mr. Esteves states, the Commission should reject the 100% bonus depreciation used in Brattle's calculations and instead direct PJM and Brattle to recalculate the CONE using a 15-year Modified Accelerated Cost Recovery System, which is customary for this industry and will more realistically reflect expected tax deductions.[28]

B. Brattle's ATWACC Calculations Are Based On Inappropriate, Inaccurate And Outdated Assumptions

As explained in detail in the Esteves Affidavit, Brattle used a number of flawed assumptions regarding the terms on which the Reference Resource would be financed in calculating the ATWACC.

1. Financing Assumptions

As the Esteves Affidavit explains, the financing assumptions underlying Brattle's ATWACC analysis are flawed on a fundamental level because Brattle assumed that "the Reference Resource would be developed by a publicly-traded IPP," and that "the publicly-traded IPP would be able to finance the merchant Reference Resource at the same debt to capital ratio and on the same terms as its entire corporate balance sheet."[29] These assumptions are unrealistic and improperly skew the analysis by suggesting that the Reference Resource will be financed on much more favorable terms than would normally be available. As the Esteves Affidavit explains, Brattle's approach is not only inconsistent with "the unit-specific CONE calculation framework," but also with the nature of IPPs and industry practice.[30]

---

[28] *See* Esteves Affidavit at 10.

[29] *Id.* at 11. *See also, e.g.*, Helm Affidavit, ¶ 6; 2018 CONE Study at 7; Pfeifenberger/Zhou Affidavit, ¶ 6.

[30] Esteves Affidavit at 10.

Notably, in its 2014 CONE review, Brattle did not simply use the ATWACC of publicly-traded IPPs, but instead made an upward adjustment based on its "assumption of merchant entry risk that exceeds the average risk of the publicly-traded generation companies . . . ."[31] Similarly, PJM argued that an analysis conducted by intervenors was unreasonably biased because it "considered only the results of a Brattle sub-proxy group, *i.e.*, the three publicly-traded independent power producers, along with an alternative proxy group comprised of these three companies plus an additional independent power producer," which PJM characterized as "limited and insufficient."[32] There is no valid reason for PJM and Brattle to reverse course and now take a narrower approach that focuses on publicly-traded IPPs.

As Mr. Esteves explains, it is inappropriate to assume financing will occur on the publicly-traded IPP level because "typical IPPs have not been nearly as active as other types of sponsors in building new power generation projects in PJM."[33] Moreover, even assuming that a publicly-traded IPP were to seek corporate financing for a single, new merchant facility, this does not mean that it would be able to obtain such financing on the same terms as for its entire corporate balance sheet. In particular, the "Reference Resource is an uncontracted generating unit and therefore depends on rolling RPM capacity revenues, with visibility limited to three years ahead (and really less than 1.5 years accounting for the construction period), and does not

---

[31] The Brattle Group, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM With June 1, 2018 Online Date*, at 37 (May 15, 2014), https://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-cone-study.ashx?la=en.

[32] *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183 at P 74 (2014) (the "2014 VRR Review Order"), *on reh'g*, 153 FERC ¶ 61,035 (2015).

[33] Esteves Affidavit at 11.

benefit from the corporate diversification of an IPP."[34] Accordingly, "using IPP financial metrics as a benchmark for those of a merchant Reference Resource is inappropriate."[35]

Mr. Esteves states that "it would have been more appropriate and realistic for Brattle to assume that the Reference Resource would be developed on a stand-alone basis, using non-recourse financing," because "[p]rivate equity sponsors and infrastructure funds typically access non-recourse project finance markets to fund their investment in new resource additions," while "IPPs also regularly finance generation projects on a non-recourse basis."[36] Under this typical framework, the financing of a generation resource would be "secured by a pledge of the project assets and [would be] based on the cash flows of the project on a standalone basis with no recourse to the sponsor's balance sheet, the rest of the sponsor's fund holdings, or the rest of the owner's corporate portfolio."[37]

2. Debt/Equity Ratio

To properly reflect the financing terms that would be available for the typical standalone, non-recourse financing of a merchant facility like the Reference Resource, Mr. Esteves reviewed information regarding acquisitions of existing merchant peaking facilities in PJM during the 2011 – 2018 period.[38] Based on this review, Mr. Esteves found that Brattle has proposed significantly higher debt ratios than supported by debt quantum levels in such recent transactions. Based on these recent transactions, Mr. Esteves shows that, in fact, a 30% debt

---

34 *Id.* at 11-12.

35 *Id.* at 12.

36 *Id.*

37 *Id.*

38 Mr. Esteves explains that such acquisitions represent a reasonable proxy for the financing of new peaking facilities. *See id.* at 15.

ratio is much more reflective of how the merchant Reference Resource would be financed.[39] Mr. Esteves further states that, as a point of reference, LS Power financed its recent Doswell peaking facility expansion, which is a 340 MW facility in PJM, solely with equity and no debt.[40]

3. Cost of Debt

Mr. Esteves states that "PJM appropriately moved to include IPPs with a B credit rating in determining the cost of debt, which better reflects IPP ratings, as well as the expected credit profile of the Reference Resource."[41] At the same time, Mr. Esteves explains that the cost of debt used by PJM and Brattle is unrealistically low for a number of reasons.

First, while Brattle reviewed the cost of debt over the past three years, the Esteves Affidavit demonstrates that there have been substantial increases in interest rates over the last year, which "strongly suggests that PJM's proposed cost of debt is understated."[42]

Second, Mr. Esteves also states that Brattle assumes that a merchant facility would be financed through the bond market, even though "[a] single unit merchant generating project is typically too small and not sufficiently diversified to be able to tap the bond market for financing efficiently on a standalone basis, and therefore yields on outstanding bonds issued by publicly traded IPPs are not a reliable proxy for the Reference Resource cost of debt."[43] Mr. Esteves explains that, as evidenced by the recent acquisitions of merchant generation facilities, it is more likely that the Reference Resource would be financed through "the traditional project finance

---

39 *See id.* at 13-15 & Table 4.

40 *See id.* at 15 (also explaining that LS Power made this decision, "in part because of the expected limited debt proceeds as a percentage of total installed cost").

41 *Id.* at 16.

42 *Id.* at 16 & Figures 5 & 6.

43 *Id.* at 19.

bank or institutional loan markets, which account for the majority of debt raised for power project financings."[44]

The information reviewed by Mr. Esteves regarding recent acquisitions demonstrates that "acquisitions of portfolios of existing merchant peaking facilities in PJM have been financed in the bank market at a 3.0% to 3.5% margin over the London Interbank Offer Rate ("LIBOR")."[45] Based on these figures, as adjusted to arrive at a fixed-interest term loan, Mr. Esteves states that it is more appropriate to use a 6.75% cost of debt, rather than the 6.0% proposed by Brattle.[46]

4. Cost of Equity

As the 2018 CONE Study explains, Brattle derived the cost of equity using the Capital Asset Pricing Model ("CAPM"), based on "the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's 'beta,'" where the "'beta' describes each company stock's (five-year) historical correlation with the overall market, where the 'market' is taken to be the S&P 500 index."[47]

As described in detail in the affidavit of Tanya L. Bodell of Energyzt (the "Energyzt Affidavit") that is being concurrently filed by the PJM Power Providers Group, Brattle erroneously used the beta of publicly-traded IPPs in order to calculate the cost of equity. The Energyzt Affidavit states that Brattle's sample inappropriately includes U.S. IPPs in the middle of restructuring and consolidation, and Canadian IPPs whose contracted renewable assets,

---

44 *Id.*

45 *See id.*

46 *See id.* at 19-21.

47 2018 CONE Study at 38 (footnote omitted).

regulated distribution, and non-US operations are not representative of the Reference Resource.[48] Mr. Esteves agrees with the Energyzt Affidavit that the beta used by Brattle is too low and understates the asset beta of the Reference Resource.[49] In addition, Mr. Esteves also explains that the beta used by Brattle ignores the fact that risks for a merchant generator operating in PJM have increased since the last VRR Curve review in 2014, "due to structurally lower and more volatile commodity prices, the proliferation of renewables and conservation, significant state subsidies aimed to protect favored uncompetitive resources and threatened similar federal actions, and the emergence of a more demanding Capacity Performance product."[50] Both the Energyzt and Esteves Affidavits state that a beta of 1.0 or close to 1.0 would better reflect the merchant nature of the Reference Resource.[51]

Mr. Esteves also explains that, in comparison to regulated utilities with cost-based ratemaking, or the S&P market as a whole, "the Reference Resource is an investment with one of the highest business risk profiles – it is characterized by a small size, has a high percentage of costs that are fixed (and, therefore, a high operating leverage), and is exposed to construction risk and to highly uncertain RPM revenues set one year at a time – all factors leading to a high unlevered beta asset."[52] Accordingly, in comparison to a recent Commission order finding that the New England Transmission Owners' return on equity ("ROE") should be capped at 13.08%,[53] which the Energyzt Affidavit calculates would translate to a beta of 0.87, as well as

---

48 The Energyzt Affidavit also shows that, as a result of the recent financial distress suffered by the IPPs examined by Brattle, the share prices of those IPPs has diverged from the trend of the S&P 500.

49 Esteves Affidavit at 21-22.

50 *Id.* at 22.

51 *See id.* at 23.

52 *Id.*

53 *See Martha Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 at P 18 (2018).

the S&P 500's implied unlevered beta of 0.91, Mr. Esteves states that "an unlevered beta of 1.0 seems at least appropriate and may potentially be even too conservative for a merchant Reference Resource project."[54] Mr. Esteves also explains that this beta recommendation is consistent with the ROEs observed in the overall equity market, which "had a ROE of 15.82% in 2018, and has remained in the low to mid-teens range since the 2014 Quadrennial Review," and "is at the low end of the range of the ROEs expected by typical sponsors that invest in merchant construction projects in PJM."[55]

5. Overall ATWACC

Based on his analysis, Mr. Esteves explains that "[u]sing an unlevered beta of 1.0 and a comparables-based debt to equity ratio of 30% yields a levered beta of 1.31, a calculated all-in interest cost of debt of 6.75%, and a levered cost of equity of 12.6%."[56] In combination, "[a]djusting the proposed ATWACC to reflect the more realistic assumptions" discussed by Mr. Esteves would result in an ATWACC of 10.2%.[57]

C. The October 12 Filing Reasonably Proposes To Continue Using A CT As The Reference Resource, But Has Erroneously Configured The CT Using An Unproven New Turbine

1. The October 12 Filing Correctly Proposes To Continue Using a CT As The Reference Resource

LS Power strongly supports PJM's finding that it is appropriate and reasonable to continue using a CT in the simple-cycle (peaking) configuration as the Reference Resource. As an initial matter, it bears emphasis that a CT has been the Reference Resource since the inception

54 Esteves Affidavit at 24.

55 *Id.*

56 *Id.*

57 *Id.*

of RPM,[58] and that there is no evidence demonstrating that this is unjust or unreasonable, or that it is necessary to use another plant configuration.

In the past, various stakeholders have argued that PJM should use a combined-cycle plant (a "CC") as the Reference Resource instead of a CT, and it is foreseeable that similar arguments will be advanced in response to the October 12 Filing. However, the Commission correctly rejected such arguments previously, explaining as follows:

> [An intervenor] argues that the Commission erroneously presumed that CONE should be calculated based on the cost of a combustion turbine, when the most frequent new entrant into RPM at this point is not a combustion turbine. [The intervenor] has not explained why the most frequent new entrant should be chosen as the reference technology. Different technologies can efficiently exist within the market and are needed to meet different types of demand. For example, technologies with higher capital costs and lower variable costs typically can meet baseload demand at the lowest cost, while technologies with lower capital costs and higher variable costs can meet peak load at the lowest cost. The most frequent type of entrant is likely to vary over time, in part, because plants of different technologies are likely to retire and need to be replaced at different times and because of the lumpiness in the size of investments.[59]

Critically, the Commission's support for the continued use of a CT was properly based on the recognition that CTs and CCs play a different role in the market. For purposes of the VRR Curve, it is important that the choice of the Reference Resource be consistent with RPM's fundamental goal of ensuring adequate investment in capacity to maintain reliability in the region. In this respect, the testimony of Adam Keech of PJM demonstrates that the continued use of a CT is appropriate because it remains "the cheapest and fastest generation technology

---

[58] *See* Reliability Pricing Model Proposal of PJM Interconnection, L.L.C., Transmittal Letter at 70, Docket Nos. ER05-1410-000, *et al.* (filed Aug. 31, 2005) (proposing the 7FA as the Reference Resource).

[59] August 2009 Order, 128 FERC ¶ 61,157 at P 40.

that could be brought to the market should market signals indicate the need for new capacity."[60] Similarly, the attached affidavit of Carolyne Murff and Andrew Dera of the LS Power Group (the "LS Group Affidavit," provided as Attachment B hereto) explains that a CT is "the simplest, fastest to market resource type that, due to much faster development and shorter construction lead time, can be deployed quickly to address any resource adequacy or reliability concerns."[61] Moreover, a CT is also "the closest to a pure play capacity resource, because it depends primarily on the capacity revenues."[62] This makes a CT the most appropriate choice for the Reference Resource, because it better "reflect[s] the revenue requirement of a resource addition that is underwritten based on capacity revenues,"[63] and, correspondingly, "the cost to bring on line the last increment of capacity needed to satisfy the region's (or Locational Deliverability Area's) reliability needs."[64]

At the same time, Net CONE calculations that are based on a CT are also less vulnerable to errors in the calculation of energy and ancillary services ("EAS") revenues.[65] Indeed, and as Mr. Keech explains, "the reference CC plant would depend on the energy market for about 61% of its revenue requirement, while the reference CT plant would rely on the energy market for only about 27% of its revenue requirement," meaning that "[a] CC Net CONE estimate, therefore, is more likely to be inaccurate . . . than a CT Net CONE estimate."[66] The LS Group

---

60 Keech Affidavit, ¶ 8.

61 LS Group Affidavit at 6.

62 *Id.*

63 *Id.*

64 *PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,090 at P 33 (2009), *reh'g denied*, 131 FERC ¶ 61,168, *reh'g denied*, 132 FERC ¶ 61,222 (2010).

65 *See* October 12 Filing, Transmittal Letter at 11.

66 Keech Affidavit, ¶ 9.

Affidavit also explains that "a CC project depends significantly more on [EAS] revenues, where the value of the spread between electricity and natural gas commodity prices is inherently uncertain," thereby making it difficult to accurately estimate the Net CONE of a CC.[67] The Commission therefore previously concluded that CCs "have more variable EAS revenues, and . . . present significant estimating uncertainties."[68] Accordingly, the use of a CT as the Reference Resource will help produce more reliable results, and thereby better "ensure that generators receive sufficient total revenue (capacity market payments plus energy and ancillary service revenue) to cover the actual cost of entering the unconstrained region in order to create the proper incentive for new entry."[69]

2. The October 12 Filing Prematurely Proposes To Configure The Reference Resource Using A 7HA Turbine

Based on Brattle's recommendations, the October 12 Filing proposes to change the turbine used in the Reference Resource from the GE 7FA to the GE 7HA. This proposal is premature and not just and reasonable at this time.

As Brattle acknowledges, "[t]he GE 7FA continues to be the turbine with the most capacity added in PJM since 2007."[70] By contrast to the well-established 7FA turbine, the LS Group Affidavit explains in detail that there is considerable uncertainty surrounding the 7HA at this time. Notably, by the time that the 7FA was selected as the Reference Resource, it had already been in the market for nearly a decade and a half, and was backed by extensive

67 LS Group Affidavit at 8-9.

68 *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275 at P 39, *on clarification & reh'g*, 128 FERC ¶ 61,157 (2009).

69 *PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,157 at P 13 (2009) ("August 2009 Order").

70 2018 CONE Study at 16 (footnote omitted).

operational history.[71] Now, however, PJM and Brattle are pushing the 7HA despite that turbine being in its infancy.

The HA turbine is the latest model in GE's H-class. The first facility with an HA turbine was the Bouchain facility owned by Électricité de France S.A. ("EDF"), which uses a 9HA, 50 Hz turbine and commenced operations in June 2016.[72] In the United States, the first HA unit was the Colorado Bend facility owned by Exelon Corporation ("Exelon"), which uses a 7HA, 60 Hz turbine[73] and achieved commercial operation in June 2017.[74] All told, there are currently only a handful of HA facilities operating in the United States.[75] It bears emphasis that, although Brattle states that its recommendation is based on "a recent trend in actual project developments and future orders toward larger turbines,"[76] Brattle's own study shows that there have been ***no*** CT plants built in PJM using the 7HA turbine.[77] Moreover, the LS Group Affidavit explains that, because of the required high firing temperatures, "the HA-class is . . . a poor choice when selective catalytic reduction ("SCR") is required," and that, as a result, "there are currently no simple cycle HAs with a hot SCR/CO catalyst in operation . . . ."[78] Accordingly, "PJM's

---

71 *See* LS Group Affidavit at 3.

72 *See* EDF, *EDF and GE inaugurate Bouchain natural gas combined cycle plant* (June 17, 2016), https://www.edf.fr/en/edf/edf-and-ge-inaugurate-bouchain-natural-gas-combined-cycle-plant.

73 In contrast to the 50 Hz system in Europe, the power grid in the U.S. operates at 60 Hz and therefore requires generating machinery that is designed to run at the 60 Hz frequency.

74 *See* Thomas Gryta and Russell Gold, *GE Discovers Flaw in Latest Power-Plant Turbines* (Wall Street Journal, Sept. 20, 2018), https://www.wsj.com/articles/ge-discovers-flaw-in-latest-power-plant-turbines-1537465093.

75 *See* LS Group Affidavit at 10.

76 2018 CONE Study at v.

77 *See id.* at 17, Table 8. In fact, PJM acknowledges that only one project with a 7HA turbine in simple cycle configuration is currently under development in New England and one was proposed in California, neither of which has any historical operating record. *See* October 12 Filing, Transmittal Letter at 17.

78 LS Group Affidavit at 11.

proposed use of an HA-class unit with a hot SCR is . . . not consistent with industry practice at this time."[79]

In their affidavit, Ms. Murff and Mr. Dera emphasize that, based on their substantial experience developing and operating generation facilities, generation developers will be hesitant to develop new facilities using the 7HA at this time given the nascent installed base of the HA turbine, the lack of experience and related operating data, and, importantly, the early failure of its most critical component that occurred approximately sixty days ago at the site of the inaugural HA unit in the U.S.

The LS Group Affidavit states that, "particularly for competitive power producers that have no guarantee of cost recovery, it is imperative to select proven and reliable technologies rather than being on the cutting edge of new technology."[80] The LS Group Affidavit explains that, as a general matter, merchant generators are unlikely to rush to adopt new technology because of the high capital cost and high capital intensity of power generation, combined with a history in the industry of "costly surprises with advanced new equipment launches, and a significant precedent of challenged market acceptance and unfulfilled market promise of next-generation turbine technology."[81] For example, "ABB's GT24/26 . . . was launched in the mid-1990s and experienced significant technical difficulties in the field in the early 2000s, which caused a fleet-wide retrofit of the 72 units in operation globally, including 51 in the US."[82] Notwithstanding this retrofit, "the GT24 has never lived up to its efficiency targets, the main driver of its development and launch, and more than a decade since the retrofit, its heat rate

79 *Id.*

80 *Id.* at 6.

81 *Id.* at 7.

82 *Id.* at 13.

remains meaningfully behind comparable GE 7FA units."[83] Similarly, GE's 7FB turbine promised significant efficiency, output and lifecycle economics improvements due to its advanced materials, but GE stopped after "ship[ping] only 13 7FB units, which proved unable to run more than 8,000 hours without failing parts."[84] Eventually, GE was forced to "turn down the 7FB firing temperature, the new turbine's main selling point, and to convert its 7FB fleet to modified 7FAs with lower firing temperatures, and at a very significant cost to customers."[85] In addition, Siemens also "stopped making the 501G after just 24 units."[86] In each of these cases, "[a]fter major field problems in the first several years of commercial operation and billions of dollars in redesign and retrofit costs, none of these [new models] are still in production,"[87] and market participants have usually defaulted to one of GE's well-established technologies with a broad installed base, such as the 7FA.[88]

In this case, developers and sponsors will likely be even more hesitant than normal to invest in the new HA technology because of the problems that have been recently experienced in the field. New facilities in Pakistan that use GE's HA-class turbines experienced serious

---

83 *Id.*

84 *Id.*

85 *Id.* at 13-14.

86 *Id.* at 14.

87 *Id.*

88 *See id.*, Exh. 2, *J.P. Morgan, General Electric Co. (GE US), "Voice of the Customer": Turbine Users Feedback Suggests Depth of Technology Issues Worse Than Initially Thought* (Oct. 10, 2018) (the "JP Morgan October 10 Report") (quoting industry journal, which stated that, "[t]o get to today's landscape of F-class machines humming around the world doing what is expected of them, for example, the industry had to get through a tumultuous early to mid-1990s period which deeply affected all five major large-frame [original equipment manufacturers ("OEMs")] at the time. Now there are three.").

performance issues resulting in extended downtimes.[89] A user group also complained about a slew of additional problems with the HA turbines, some of which appear to be fleet-wide.[90] Most troublingly, it has been widely reported that Exelon's Colorado Bend facility had to be shut down following the discovery that there had been a first stage turbine blade failure, despite the fact that the 7HA turbines in that facility had only been installed in the summer of 2017 and had less than 10,000 operating hours.[91] As the LS Group Affidavit states, such a critical failure at such an early point in the turbine's life raises serious concerns, particularly because "the first stage turbine blade is the highest technology component of a turbine that is most critical to achieving guarantees of its output and efficiency, the CT's main key performance indicators ("KPIs")."[92] A report by J.P. Morgan similarly characterized this early failure as "'historic' . . . ."[93]

Moreover, GE acknowledged that the first stage turbine blade failure was not an isolated problem limited to the Colorado Bend facility, but was "likely to affect others."[94] Although GE

---

89 *See, e.g.*, Drazen Jorgic & Henning Gloystein, *In Pakistan, questions raised over GE's flagship power turbines* (Reuters, Dec. 27, 2017), https://www.reuters.com/article/us-generalelectric-pakistan-insight/in-pakistan-questions-raised-over-ges-flagship-power-turbines-idUSKBN1EL0VN.

90 *See* JP Morgan October 10 Report.

91 *See, e.g.*, Peter Maloney, *Trouble in Texas causes shutdown of advanced GE turbine* (UtilityDive, Sept. 21, 2018), https://www.utilitydive.com/news/trouble-in-texas-causes-shutdown-of-advanced-ge-turbine/532901/.

92 LS Group Affidavit at 15.

93 *Id.*, Exh. 1, J.P. Morgan, *General Electric Co., Another Shoe Drops: H Frame Blade Failure Risks Franchise Impairment; Lowering PT* at 1 (Sept. 20, 2018) (the "JP Morgan September 20 Report").

94 Alwyn Scott, *UPDATE 1-GE says four HA turbines in U.S. shut down due to blade problem* (Reuters, Sept. 20, 2018), https://www.reuters.com/article/ge-power-confirmation/update-1-ge-says-four-ha-turbines-in-u-s-shut-down-due-to-blade-problem-idUSL2N1W60VM. *See also* Alwyn Scott, *UPDATE 2-GE says four of its flagship power turbines are shut down in U.S.* (Reuters, Sept. 20, 2018), https://www.cnbc.com/2018/09/20/reuters-america-update-2-ge-says-four-of-its-flagship-power-turbines-are-shut-down-in-u-s.html. EDF's Bouchain plant was also shut down after the problems at Colorado Bend. *See* Alwyn Scott & Geert De Clercq, *France's EDF halts GE turbine at Bouchain, GE shares drop*

has claimed that it has a solution for the first stage blade problems, the JP Morgan September 20 Report raises concerns and questions regarding the viability of the solution.[95] Critically, the LS Group Affidavit points out that, "from a developer's perspective, there is simply no operating data to determine whether GE's 'fix' will be sufficient and effective," and that feedback on the effectiveness of GE's fix would only be available "at the first major inspection, which would normally occur at over 30,000 hours."[96]

Until the problem with the 7HA's first stage turbine blade is properly remedied, facilities with these turbines run the risk of incurring additional costs as a result of lower-than-expected availability. For example, the LS Group Affidavit states that "the owner may bear costs in the form of previously unplanned outages, downtime, foregone revenues, the cost of having to purchase replacement power, and/or incurring penalties that may not be offset by claims damages or against GE."[97] Notably, in the period since PJM's last VRR Curve review, PJM adopted its Capacity Performance framework, which "establishe[d] a new capacity product with a defined performance obligation and enforce[d] that obligation through a robust penalty and bonus payment mechanism,"[98] where resources "can lose as much as Net CONE for complete non-performance in any delivery year that experiences 30 or more Performance Assessment Hours."[99] The threat of onerous penalties for non-performance under the Capacity Performance

---

(Reuters, Sept. 25, 2018), https://www.reuters.com/article/us-ge-power-edf/frances-edf-halts-ge-turbine-at-bouchain-ge-shares-drop-idUSKCN1M5280.

95 *See* JP Morgan September 20 Report at 2-4.

96 LS Group Affidavit at 18.

97 *Id.* at 19-20.

98 *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157 at P 18 (2016).

99 *Id.* at P 72.

framework will make developers particularly cautious about installing a turbine that has not been proven to be reliable.[100]

Moreover, even assuming that GE will manage to address the first stage turbine blade failures and any other problems, it is difficult to accurately ascertain the costs associated with the 7HA turbine at this time. For example, it is common for OEMs to provide aggressive pricing to spur initial sales of a new turbine, and it is therefore not clear that the price of the 7HA will remain consistent in the upcoming years.[101] In addition, the costs of Long-Term Service Agreements ("LTSAs") may increase in the future, particularly because GE will have to recoup the significant unplanned costs of correcting the problems with the first stage turbine blade.[102] Finally, the LS Group Affidavit also explains that the lack of a large installed base limits competition for aftermarket parts, maintenance, and may potentially challenge insurance and financing,[103] while "the investment hurdle associated with investments in the HA technology should [also] rise to reflect these increased risk factors going forward."[104] Accordingly, there are a number of cost factors that remain in flux with respect to the 7HA turbine, making it impossible for Brattle to accurately forecast costs for this technology to, in turn, accurately determine the CONE. By contrast, the installed fleet of the 7FA is orders of magnitude larger, and its costs and performance are well established, which highlights the benefits of continuing to

100 *See* LS Group Affidavit at 20.

101 *See id.* at 18-19. *See also* JP Morgan September 20 Report at 6 ("New GE management themselves have said prior commercial practices in the sales function were focused on market share without regard for profitability let alone longer term risks.").

102 *See* LS Group Affidavit at 19.

103 *See id.* at 20.

104 *Id.*

use the 7FA turbine to configure the Reference Resource until there is additional information on the 7HA.[105]

As the LS Group Affidavit makes clear, LS Power does not view the 7HA turbine to be commercially proven at this point in time. Similarly, the JP Morgan October 10 Report also highlighted concerns by various GE customers regarding the H-class, and pointed out that it may take years to iron out the problems with these turbines.[106] In sum, the Commission should find that PJM's proposal to change the configuration of the Reference Resource to a 7HA turbine is not just and reasonable, without prejudice to PJM re-proposing that change in the future, when the HA-class turbines have demonstrated significantly longer sustained performance history and when costs associated with those turbines can be ascertained with more certainty.

D. PJM Ignores Continued Resource And Market Uncertainty In Proposing To Shift The VRR Curve

In 2014, PJM proposed shifting the VRR Curve to the right by 1%, stating that this was necessary to address "fast changing and uncertain market, policy and legal conditions."[107] PJM now argues, however, that "the 1% rightward shift that was warranted in 2014 as a conservative response to an unusual confluence of events is no longer required,"[108] and therefore proposes to shift the VRR Curve back to the left by 1%. There is no basis for this proposal.

---

105 *See id.* at 20-21.

106 *See generally* JP Morgan October 10 Report.

107 2014 VRR Review Order, 149 FERC ¶ 61,183 at P 25 (quoting PJM witness) (citation omitted). *See also* PJM, *Triennial Review of VRR Curve Shape*, at 4 (stating that the VRR Curve shift was intended to "allow[] RPM to better handle year-to-year volatility in supply and demand conditions that are likely forthcoming given ever increasing RPS targets and the recently promulgated EPA Clean Power Plan under CAA 111(d) and increasing energy efficiency targets that will shift the earning of going forward, avoidable costs from the energy market more toward the capacity market"), https://www.pjm.com/-/media/committees-groups/task-forces/cstf/20140630/20140630-item-04c-vrr-curve-background.ashx.

108 October 12 Filing, Transmittal Letter at 9-10.

In 2014, PJM justified the shifting of the VRR Curve by arguing, in part, that it was anticipating "approximately 26,000 MW of generation retirements from 2009 to 2016 due to the Mercury and Air Toxics Standards [("MATS")] and the emergence of low-cost shale gas . . . ."[109] While Mr. Keech now states that "[t]he wave of MATS-related retirements is essentially complete,"[110] there has been no halt to the tide of retirements. To the contrary, generation retirements have accelerated with over 29,000 MW deactivating or planned to deactivate between 2015-2022.[111]

At the same time, there continues to be significant regulatory and other uncertainty.[112] For example, the implementation of stringent Capacity Performance requirements substantially increases the threat of penalties. In addition, although the greenhouse gas rule was not implemented,[113] states have increasingly begun to pursue initiatives to limit emissions.[114] Furthermore, and as the Commission is well aware, there have been increasing efforts by the states to subsidize large amounts of resources, including nuclear facilities and renewable resources.[115] While the Commission has initiated proceedings to modify the RPM rules to prevent price suppression by subsidized resources, such proceedings are ongoing, and there has

---

109 2014 VRR Review Order, 149 FERC ¶ 61,183 at P 25 (quoting PJM witness) (citation omitted).

110 Keech Affidavit, ¶ 17.

111 *See* PJM, Generation Deactivations, https://pjm.com/planning/services-requests/gen-deactivations.aspx.

112 *See* Esteves Affidavit at 23 (explaining that the risk associated with the Reference Resource has increased since 2014).

113 *See* Keech Affidavit, ¶ 17.

114 *See, e.g.*, Peter Maloney, *New Jersey to rejoin RGGI in new executive order* (UtilityDive, Jan. 29, 2018), https://www.utilitydive.com/news/new-jersey-to-rejoin-rggi-in-new-executive-order/515802/; Robert Walton, *With proposal to join RGGI, Virginia would be first Southern state to cap carbon* (UtilityDive, Jan. 10, 2018), https://www.utilitydive.com/news/with-proposal-to-join-rggi-virginia-would-be-first-southern-state-to-cap-c/514537/.

115 *See generally Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018), *reh'g pending*.

been substantial disagreement about what solution would be effective or sufficient. Finally, structurally lower natural gas prices have also impacted the market and lowered expected revenues.

These types of factors continue to raise doubts on the attractiveness of investments in the industry and the PJM region at this time. Shifting the VRR Curve to the left would only compound this problem and further deter investors from participating in the PJM market. Accordingly, the Commission should reject PJM's proposal to shift the VRR Curve to the left as premature.

III.

CONCLUSION

WHEREFORE, LS Power respectfully requests that the Commission require limited modifications to PJM's proposals in the October 12 Filing as described herein.

Respectfully submitted,

LS POWER ASSOCIATES, L.P.

By: */s/ Neil L. Levy*

Neil L. Levy
Stephanie S. Lim
KING & SPALDING LLP
1700 Pennsylvania Ave., NW
Washington, DC 20006

Jeffrey Wade
Chief Compliance Officer
LS Power Group
1700 Broadway, 35th Floor
New York, NY 10019

Counsel for **LS Power Associates, L.P.**

Dated: November 19, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at Washington, DC, this 19th day of November, 2018.

/s/ Neil L. Levy
Neil L. Levy

Attachment A

The Esteves Affidavit

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER19-105-000

AFFIDAVIT OF JOSEPH D. ESTEVES

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Joseph D. Esteves. My business address is 1700 Broadway, 35th Floor, New York, New York 10019. I am the Chief Financial Officer and Co-Head of Private Equity for LS Power Development, LLC, a member of the LS Power Group ("LS Power"), and the general partner and manager of LS Power Associates, L.P.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

A. I joined LS Power in 2004 and have more than thirty years of experience in the power industry. I serve as the Chief Financial Officer, the Co-Head of the Private Equity business, and a member of the Management Committee. I am responsible for LS Power's financing activity. In the last several years, I have raised over $25 billion in debt and equity capital. Prior to joining LS Power, I served as Executive Vice President at Comverge, Inc., a power technology firm serving electric utilities. Previously, I spent fifteen years with major investment banking firms focused on the energy and power industries. Those roles included Managing Director and Region Head, Project Finance, at UBS; Vice President, Structured Finance at Goldman Sachs & Co.; and Vice President, Corporate Finance at Salomon Brothers Inc. I received an M.B.A. from the Wharton School and a B.EE from the Cooper Union.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This affidavit addresses certain factors used by PJM Interconnection, L.L.C. ("PJM") to calculate the revised cost of new entry ("CONE") in its October 12, 2018 filing in this proceeding.[1] PJM uses a new combustion turbine ("CT") as the Reference Resource to calculate the CONE that is then used in the Variable Resource Requirement ("VRR") curve in PJM's capacity auctions. In determining the CONE, PJM and its consultants, the Brattle Group ("Brattle"), had to make certain assumptions about the After-Tax Weighted-Average Cost of Capital ("ATWACC"), tax rates, and depreciation.

LS Power has been active in the electric power business since 1990 and has significant experience in both developing new electric generation plants as well as acquiring existing power plants throughout the country. With respect to PJM, LS Power developed and built the West Deptford facility in New Jersey and has acquired multiple power facilities. LS Power has been a leader in structuring non-recourse construction and acquisition financings for a large number of power plants in PJM over the last 12 years, particularly with respect to peaking facilities. As the CFO of LS Power, I have personally led the bulk of these financings. The purpose of this affidavit is to address certain assumptions made by PJM and Brattle in calculating the CONE that I believe to be erroneous based on my extensive experience.

[1] Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER19-105-000 (filed Oct. 12, 2018) (the "PJM Filing").

Q. PLEASE SUMMARIZE YOUR CONCERNS REGARDING PJM'S AND BRATTLE'S CONE CALCULATIONS.

A. In calculating the CONE, Brattle applied a year one bonus depreciation rate of 100% based on the Tax Cuts and Jobs Act of 2017 ("TCJA").[2] This assumption has no basis in reality because it is difficult to identify any project owners or project sponsors that will be able to take advantage of the full amount of this bonus depreciation in a single year. In fact, during the initial years, a typical project owner may not be able to absorb the tax benefits available from even the usual and customary 15-year Modified Accelerated Cost Recovery System ("MACRS") depreciation. The presumption that the 100% bonus depreciation can be monetized to add incremental value to the project owner is a critical flaw that significantly understates the actual CONE. I therefore propose that PJM keep the customary 15-year MACRS depreciation when calculating the Reference Resource CONE.

PJM's proposed ATWACC is also based on unrealistic assumptions. PJM proposes an 8.2% ATWACC, which is based on a 55% debt and 45% equity ratio, a cost of debt of 6.0% and a cost of equity of 13.0%.[3] As discussed further below and in the affidavit of Tanya L. Bodell of Energyzt (the "Energyzt Affidavit") that is being provided by the PJM Power Providers Group ("P3"), PJM's proposed ATWACC is unrealistically low. The calculations underlying PJM's ATWACC are based on the assumption that a new generation plant would be financed by a publicly-traded independent power producer

2 *Id.* at 21-22.

3 *See id.* at 19.

("IPP") at its average corporate debt to capital ratio and cost of debt.[4] This ignores the fact that the majority of new-build plants are financed on a standalone, non-recourse basis, and that only such non-recourse financing costs truly provide unit-specific costs consistent with the framework of Reference Resource and CONE calculations. I have therefore proposed an alternative that better reflects the terms and metrics for financing a power plant asset on a standalone basis and is representative of recent transactions involving merchant peaking assets in PJM. PJM's proposed cost of equity also materially understates the underlying business risk of a merchant power generator, which, for a number of reasons highlighted below, is an asset with very high risks. The underlying non-financial business risk of a merchant generator operating in PJM has increased meaningfully since the 2014 Quadrennial Review. Such increase must be reflected by using a more appropriate unlevered cost of equity, as presented in more detail in the Energyzt Affidavit. I therefore propose that PJM use an ATWACC of 10.2%, which is more consistent with the capital structure, the sources of funds, and the underlying operating risks of the Reference Resource, when calculating its CONE.

III. THE PROPOSED USE OF BONUS DEPRECIATION

Q. PLEASE DESCRIBE THE BONUS DEPRECIATION USED BY BRATTLE.

A. Brattle has calculated the CONE assuming that a new plant placed into service prior to January 1, 2023, would apply 100% bonus depreciation in its first year of service. This assumption is without practical merit and had a significant impact on the CONE calculations. For example, Brattle's CONE report states that "[n]ew units put in service

[4] *See id.*, Attachment F, Affidavit of Johannes P. Pfeifenberger and Bin Zhou, ¶ 6 ("Pfeifenberger/Zhou Affidavit").

before January 1, 2023 can apply 100% bonus depreciation in the first year of service, which decreases CT CONE on average by $11,700/MW-year,"[5] which accounts for a significant portion of the total percentage reduction in the CONE.

Q. ARE BRATTLE'S ASSUMPTIONS REGARDING THE USE OF BONUS DEPRECIATION REASONABLE?

A. No. Brattle has not applied the bonus depreciation in a realistic manner and materially overstates the related incremental economic benefit. It is critical to recognize that the 100% bonus depreciation is simply an option, made temporarily available by the TCJA, to allow an entity to reduce its tax liability to the extent such liability is available. The TCJA was not restricted to the power generation industry, and it is possible that in some other industry, where investments are characterized by significantly higher profitability and lower upfront cost than those of a merchant peaking power project, there may be scope for the use of such bonus depreciation. However, it is difficult to imagine any merchant power generator that would have adequate federal taxable income in a typical year necessary to fully absorb the tax deductions associated with 100% bonus depreciation on a standalone basis. Moreover, although a generator could potentially lean on its corporate parent's taxable income, even its consolidated corporate group is unlikely to have sufficient US federal tax liability in any given year to be able to absorb more than a small fraction of the bonus depreciation benefit assumed by Brattle.

I illustrate the problems with Brattle's assumptions in Table 1 below. As a general matter, it is common practice for IPPs to use 15-year MACRS, which would result in a 5

[5] PJM Filing, Attachment E, Exhibit No. 2, PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date at 47 (Apr. 19, 2018) ("Brattle Report").

percent depreciation rate in year 1. For simplicity, I have used Brattle's estimate of the installed costs for a 321 MW CT in PJM's "Rest of RTO."[6] Applied to the $835/kW of installed costs for such a CT, this 15-year MACRS would result in a $13 million deduction in year 1 (5% x $835/kW x 321,000 kW), requiring the IPP to have approximately $1 million of otherwise US federal tax liability, in order to realize the full value of the deduction.[7] By contrast, the 100 percent bonus depreciation would result in a deduction of approximately $268 million, requiring an otherwise tax liability of at least $54 million.

[6] Brattle Report at 51.

[7] 15-yr MACRS accelerated depreciation, traditionally used for peaking projects, generally has a year 1 deduction of 5.0% of the eligible portion of the project cost using a half year depreciation convention. The depreciation in year 2 would increase to 9.5% in year 2 and then subsequently decrease.

Table 1 – The Effect of 100% Bonus Depreciation for the Reference Resource Project

	Tax Depreciation Schedule Comparison		15 yr MACRS	100% Expensing
	(ignores interest deduction)		yr 1	yr 1
a	Depreciation deduction, half-year convention	%	5.0%	100%
b	**Reference Resource project cost***	**$/kW**	**835**	**835**
c=a*b	Depreciation expense	$/kW-yr	$42	$835
	RPM revenue, RTO, BRA 2021/22	$/MW-d	140	140
d	RPM revenue, RTO	$/kW-yr	$51	$51
e	FOM*	$/kW-yr	$17	$17
f=d-e	**Reference Resource NOI or EBITDA****	**$/kW-yr**	**$34**	**$34**
g=f-c	Taxable income (losses)	$/kW-yr	($8)	($801)
h	Federal tax rate	%	21%	21%
i=g*h	Reference Resource tax (benefit)	$/kW-yr	($2)	($168)
j	Project nameplate capacity	MW	321	321
k=c*j/1000	Depreciation expense	$MM	$13	$268
l=g*j/1000	Taxable income (losses)	$MM	($2)	($257)
l=i*j/1000	Reference Resource tax (benefit)	$MM	($1)	($54)
	Corporate parent tax liability needed***	**$MM**	**$1**	**$54**
	* Brattle's "H" class RTO cost unchanged			
	** ignores E&AS and VOM			
	*** to offset Reference Resource tax benefit			

A few points are noteworthy here. First, in order to take full advantage of the bonus depreciation, the CT would need $257 million, or approximately $801/kW, of taxable income. It should be obvious that no CT of this size would have high enough revenues necessary to produce such taxable income.

Second, even if the bonus depreciation were included on the consolidated return of the generator's corporate parent, it is highly unlikely that the full deduction would be used on a consolidated basis. Under the TCJA, public utilities are not eligible to use the 100% bonus depreciation deduction.[8] In addition, private equity funds that develop and own

[8] *See* Brattle Report at vi, footnote 8.

new generation capacity are normally pass-through entities for income tax purposes and therefore would not realize any tangible incremental benefit from the bonus depreciation. Finally, even assuming that the CT is included in the consolidated return of a large corporate IPP (which appears to be the implicit Brattle assumption), it is still highly unlikely that utilization of the 100% bonus depreciation could be justified. As a general matter, corporate IPPs have relatively low US federal income tax liability because these are normally tax efficient entities with large balances of US federal net operating loss carryforwards ("NOLs").

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE TAX LIABILITY INFORMATION OF CORPORATE IPPS.

A. I reviewed information regarding NRG Energy, Inc. ("NRG") and Calpine Corporation ("Calpine") as reported in their respective 10-K reports. Until Calpine was acquired by a private equity firm in 2017, NRG and Calpine were the two largest, publicly traded IPPs. Nonetheless, as shown in Table 2, based on the reported financials for 2015, 2016, and 2017, neither NRG nor Calpine would have been able to absorb the full bonus depreciation of a single merchant project as assumed in Brattle's calculations.

Table 2 – Reported US taxable income, current taxes and cash taxes paid by NRG and Calpine ($ millions, Source: Company 10-K Reports)

NRG	2017	2016	2015	Source, 2017 10-K
taxable income (loss)	($1,540)	($978)	($4,986)	IS, p.69
income tax (benefit) - incl US, foregn, current, and deferred	$8	$5	$1,345	IS, p.69
US taxable income (loss)	($1,557)	($989)	($4,997)	Note 19
income tax (benefit) - US current taxes	**$19**	**$6**	**$9**	Note 19
cash taxes paid during the period	**$9**	**$14**	**$12**	Note 25

Calpine	2017	2016	2015	Source, 2017 10-K
taxable income (loss)	($313)	$159	$173	IS, p.37
income tax (benefit) - incl US, foregn, current, and deferred	$8	$48	($76)	IS, p.37
US taxable income (loss)	($358)	$116	$133	Note 11
income tax (benefit) - US federal current taxes	**($10)**	**($10)**	**($1)**	Note 11
cash taxes paid during the period	**$12**	**$12**	**$21**	p.118

As shown in Table 2, NRG's and Calpine's US federal tax liability from 2015 through 2017 was a fraction of the amount required to benefit from the full bonus depreciation deduction on a Reference Resource. This is not a surprise given challenged commodity prices, high operating costs, NOLs, capital losses, and other activities unrelated to the Reference Resource. I would also point out that, although this reflects historical data, this condition of insignificant level of tax liability is unlikely to materially change in the near future. NRG and Calpine have very large US federal NOLs, expected to materially mitigate future tax liability, keeping these companies essentially as non-taxpayers for the next decade or longer. As of December 2017, NRG and Calpine had reported federal NOLs of $2.8 billion and $6.6 billion, respectively.

It therefore appears highly unlikely that any entity active in power generation would be able to use the 100% bonus depreciation deduction as implied by Brattle in the coming years.

Q. HOW SHOULD THE CONE CALCULATIONS BE MODIFIED TO REFLECT YOUR FINDINGS?

A. As I explained, Brattle's presumed use of 100% bonus depreciation deduction does not reflect reasonable expectations regarding the taxable income of CT projects, or the tax liability of their corporate parents. Brattle's assumption is overly simplistic, ignores the tax reality of the industry, and is unwarranted. The effect of this assumption is to arbitrarily lower CONE by a material percentage to reflect a non-existent additional benefit, potentially artificially suppressing RPM clearing prices. I therefore propose that PJM remove the 100% bonus depreciation benefit proposed by Brattle and instead calculate the Reference Resource CONE based on the 15-year MACRS that is customarily used in the industry, which would result in a 5% depreciation rate in year 1.

IV. INACCURACIES IN THE PROPOSED ATWACC

Q. PLEASE EXPLAIN THE BASIS FOR THE ATWACC RECOMMENDED BY PJM AND BRATTLE.

A. In their testimony, Mr. Johannes P. Pfeifenberger and Dr. Bin Zhou of Brattle state that they developed the proposed ATWACC based on their independent estimation of the ATWACC for publicly-traded IPPs and market evidence of recent M&A transactions.[9]

Q. DO YOU HAVE ANY CONCERNS REGARDING THE APPROACH TO FINANCING ASSUMPTIONS USED BY BRATTLE?

A. Yes. Most critically, Brattle erroneously assumes that project financing would occur on the same terms as if a publicly-traded IPP were the borrower. This is inconsistent with the unit-specific CONE calculation framework. It also ignores the fact that the vast

[9] Pfeifenberger/Zhou Affidavit, ¶ 6.

majority of new peaking power plants in PJM have been built by entities that are not publicly-traded IPPs. Standalone, unit-specific financing assumptions are more internally consistent with the CONE framework and more appropriately reflect investment decisions by competitive generators based on marginal investment costs and benefits associated with the addition of a new resource. This unit-specific approach applies not only to upfront construction costs and fixed operating costs of the Reference Resource but also to its financing costs. Therefore, basing the capital structure and financing costs for a merchant Reference Resource CONE project on an IPP balance sheet is an inappropriate and unrealistic assumption.

Q. PLEASE EXPLAIN WHY BRATTLE'S ASSUMPTIONS ARE NOT REALISTIC.

A. Brattle's proposed 55%/45% debt/equity ratio is based on IPP corporate balance sheet leverage levels – *i.e.*, Brattle assumes that the Reference Resource would be developed by a publicly-traded IPP. In addition, Brattle also assumes that the publicly-traded IPP would be able to finance the merchant Reference Resource at the same debt to capital ratio and on the same terms as its entire corporate balance sheet.

These estimates are simply not achievable by the stand-alone entities actually building new power plants in PJM today.

Assuming a corporate financing of the Reference Resource ignores the fact that typical IPPs have not been nearly as active as other types of sponsors in building new power generation projects in PJM. As such, Brattle's approach of using the IPP balance sheet when assessing the sources of debt funds is fundamentally flawed. It ignores the actual credit risk taken by actual lenders to new-build power plants. The Reference Resource is an uncontracted generating unit and therefore depends on rolling RPM capacity revenues,

with visibility limited to three years ahead (and really less than 1.5 years accounting for the construction period), and does not benefit from the corporate diversification of an IPP. For these reasons, using IPP financial metrics as a benchmark for those of a merchant Reference Resource is inappropriate.

Q. WHAT FINANCING ASSUMPTIONS SHOULD BRATTLE HAVE USED INSTEAD?

A. Rather than assuming that the Reference Resource would be developed by a publicly-traded IPP with corporate level financing, it would have been more appropriate and realistic for Brattle to assume that the Reference Resource would be developed on a stand-alone basis, using non-recourse financing.

Such an approach is more consistent with industry practice. Private equity sponsors and infrastructure funds typically access non-recourse project finance markets to fund their investment in new resource additions. Given that the CONE of the Reference Resource is intended to represent the costs of a potential new entrant, it would be overly limiting to assume that the Reference Resource is backed by a publicly-traded IPP. Furthermore, IPPs also regularly finance generation projects on a non-recourse basis. Such project financings are secured by a pledge of the project assets and are based on the cash flows of the project on a standalone basis with no recourse to the sponsor's balance sheet, the rest of the sponsor's fund holdings, or the rest of the owner's corporate portfolio.

Non-recourse project financings offer the best representation of the borrowing capacity, capital structure, and cost of debt to be used for the CONE of the Reference Resource. Non-recourse project finance markets (*i.e.*, traditional bank and institutional loan markets) have been a major and consistent source of financing for power generation

resource additions throughout the U.S. and within PJM's footprint. Based on public sources, LS Power estimates that in the last five years alone, nearly $8 billion of non-recourse project financing has been raised for new power plant construction in PJM. A listing of representative projects are in Table 3 below.

Table 3 – Recent non-recourse project financings of power generating facilities in PJM

Institutional Loan market		**$MM**
Liberty		$585
Patriot		$585
Stonewall		$500
Hummel		$460
Total Institutional Loan market		**$2,130**
Bank Loan Market		**$MM**
Newark		$590
CPV Saint Charles		$400
Oregon Clean Energy		$500
Carroll County		$480
Lordstown		$430
Middletown		$400
Westmoreland		$650
Lackawanna		$900
Birdsboro		$300
Hickory Run		$460
CPV Fairview		$700
Total Bank Loan Market		**$5,810**
Sources: Spark Spread, ESAI Power Capacity Watch, Company press releases, LS Power estimates		

Q. HOW WOULD CHANGING THESE FINANCING ASSUMPTIONS AFFECT THE ATWACC CALCULATIONS?

A. The financing terms for standalone, merchant financing would obviously be more restrictive than for corporate borrowing by a diversified IPP. Table 4 summarizes some publicly available information regarding recent merchant peaker transactions in PJM.

As shown in the Table, recent acquisitions of merchant peaking units (a number of them located in constrained, premium priced LDAs), have been financed at debt levels averaging $212/kW over the period since 2012, and at debt levels averaging $252/kW in the shorter period since 2015.

Table 4 – Reference Resource Debt to Capital Ratio and Debt Interest Margin based on PJM Merchant Peaker Financings since 2012

	Reported Acquisition Transactions involving Merchant Peaking Projects												
		Average	Average										
	Name	2012-18	2015-18	Lee County	Kimura Power	RA Generation	Lincoln Power	Spruce Generation	RA Generation	Elgin Energy	Zephyr	Tenaska Capital	Riverside
	Sponsor/ Acquirer			Rockland Capital	Rockland Capital	LS Power	Carlyle Group	LS Power	LS Power	Rockland	Rockland	Tenaska	LS Power
	Seller			refi	AES OH Generation	refi	Rockland Capital	Dynegy		refi	LS Power	refi	
	Closing Date			8/2/18	3/27/18	9/28/17	6/23/17	7/1/17	2/7/17	4/28/16	2/18/15	8/22/2013	12/17/12
	Portfolio			Lee County Total	Kimura Power Total	RA Generation Total	Lincoln Power Total	Spruce Generation	RA Generation	Elgin Energy	Zephyr	Tenaska Capital	Riverside
	Individual Projects												
(a)	Individual Plants, Capacity, MW	1,032	989	640	973	1,453	1,063	1,279	1,453	484	563	1,834	925
	Individual Plants, Number of Units	10	10	8	12	13	12	8	13	4	8	12	5
	Project Location - State, PJM LDA			ComEd	RTO	ComEd	ComEd	RTO	ComEd	ComEd	ComEd, RTO	Il, OH	RTO
(b)	Reported Acquisition Term Loan Amount, $MM	219	249	200	200	400	297	365	300	107.5	120	350	200
(d)	Reported Interest Cost (spread over LIBOR, bps)	L+355 bps	L+321 bps	L+300 bps	L+300 bps	L+325 bps	L+325 bps	L+325 bps	L+325 bps	L+350 bps		L+592 bps	
(c)=(b)/(a)*1000	Implied Acquisition Debt Quantum, $/kW	$212	$252	$313	$206	$275	$279	$285	$206	$222	$213	$191	$216
835 $/kW	Implied Debt:Capital Ratio - RTO*	25%	30%	37%	25%	33%	33%	34%	25%	27%	26%	23%	26%
874 $/kW	Implied Debt:Capital Ratio - SWMAAC*	24%	29%	36%	24%	31%	32%	33%	24%	25%	24%	22%	25%
925 $/kW	Implied Debt:Capital Ratio - WMAAC*	23%	27%	34%	22%	30%	30%	31%	22%	24%	23%	21%	23%
938 $/kW	Implied Debt:Capital Ratio - EMAAC*	23%	27%	33%	22%	29%	30%	30%	22%	24%	23%	20%	23%
	Source: Spark Spread, Company press releases												
	* based on Brattle's upfront cost for GE 7HA.02 CT												
	** Tilton is physically in MISO but has a pseudo tie into PJM												

The transactions listed in Table 4 represent acquisitions of existing, multi-unit peaking facilities, each comprising from 4 to 18 CT units. We have used acquisitions of merchant peaker portfolios as a proxy because there has been a dearth of new-build peaker financings in recent years. The level of debt in these recent acquisitions suggests that a debt to capital ratio of approximately 30% would be appropriate, based on Brattle's understated projected costs for the 7HA Reference Resource, which range from $835/kW in the RTO, to $938/kW in EMAAC.[10]

This level of debt is more consistent with my experience bringing merchant peaker capacity to PJM, rather than the 55/45 ratio used by Brattle.

It is important to note that project lenders determine the debt capacity of a facility not necessarily by some standard debt to capital ratio but rather by the cash flow projected to be earned by the project, primarily from RPM's capacity market revenues, with little to zero credit given to any energy revenue. While the cash flow could be expected to be somewhat better than that of an existing peaker, such difference does not generally lead to a material increase in debt capacity, especially given the reduced period of known RPM capacity revenues for a project in construction (*i.e.*, 1.5 years vs. 3 years). Finally, I note that LS Power's Doswell facility is the only competitive merchant peaker project developed in PJM in recent years. In developing that facility, LS Power ultimately decided to proceed on an all-equity funding basis, in part because of the limited expected debt proceeds as a percentage of total installed cost.

[10] I would note that my colleagues are separately addressing in another affidavit the flaws in PJM's proposal to use the General Electric 7HA turbine as the Reference Resource.

Q. PLEASE EXPLAIN IF THE COST OF DEBT PROPOSED BY PJM IS CONSISTENT WITH CURRENT MARKET CONDITIONS.

A. It is not. PJM appropriately moved to include IPPs with a B credit rating in determining the cost of debt, which better reflects IPP ratings, as well as the expected credit profile of the Reference Resource. However, PJM and Brattle used a debt benchmark that does not accurately reflect the underlying Reference Resource financing metrics. Moreover, as I stated previously, PJM and Brattle unrealistically assumed that the Reference Resource would be financed by a publicly-traded IPP on its balance sheet, which results in an unrealistically low cost of debt.

Q. HOW IS PJM'S PROPOSED 6.0% COST OF DEBT UNREALISTICALLY LOW?

A. In determining the cost of debt of 5.5%, Brattle used ratings-based index interest rates over the last three years. PJM's proposed cost of debt of 6.0% is closer but is also understated.

As shown in Figure 5 below, over the last 12 months alone, the forward 5-yr interest "risk-free" rate has increased by nearly 110 basis points ("bps"), and the 10-yr risk-free rate has risen by over 90 bps during the same period. Similarly, Figure 6 below shows that a broad index of BB- and especially B- rated corporate bond yields has widened materially in the past month and past 12 months. This strongly suggests that PJM's proposed cost of debt is understated.

Figure 5 – The 5-yr and 10-yr US Treasury Yields Have Risen 110bps (53%), and 92bps (37%), respectively, over last 12 months

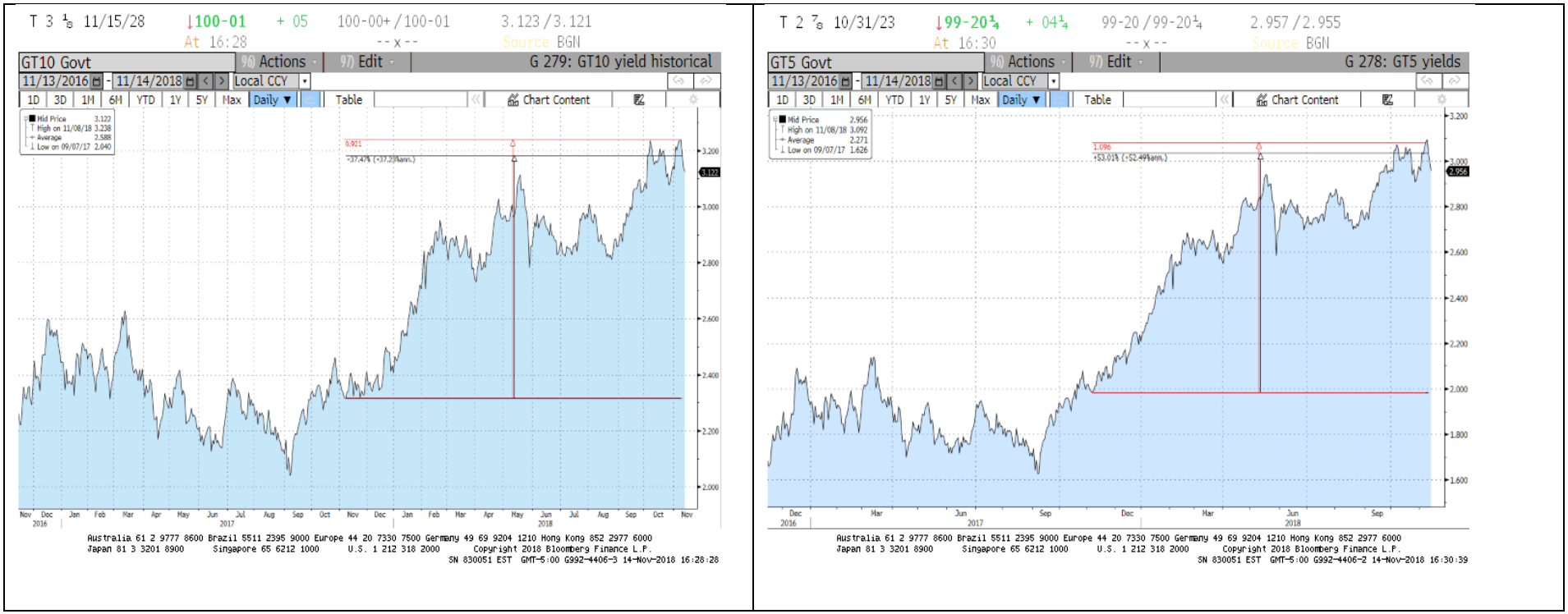
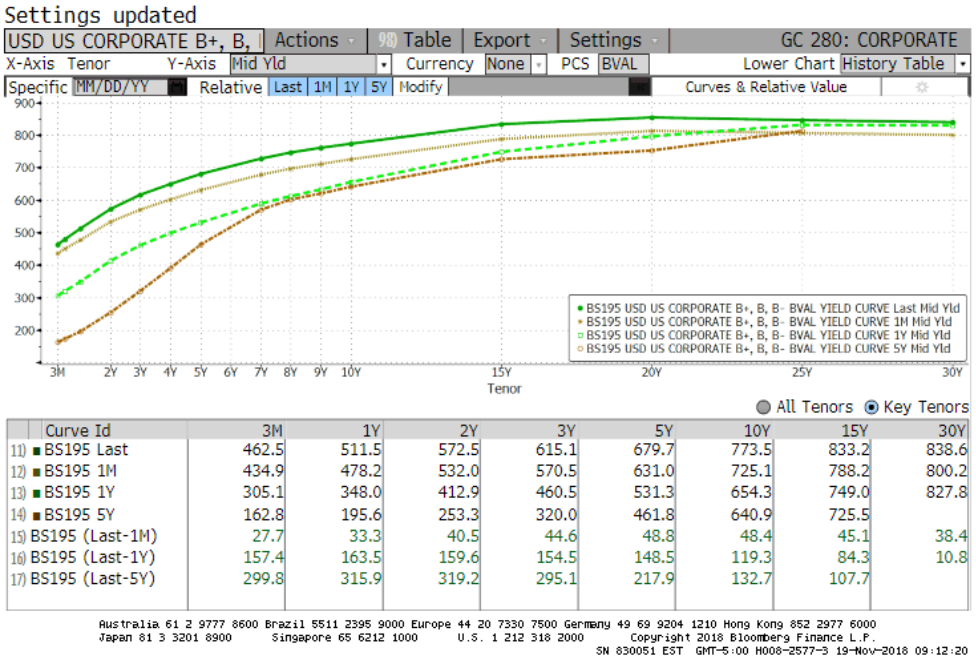
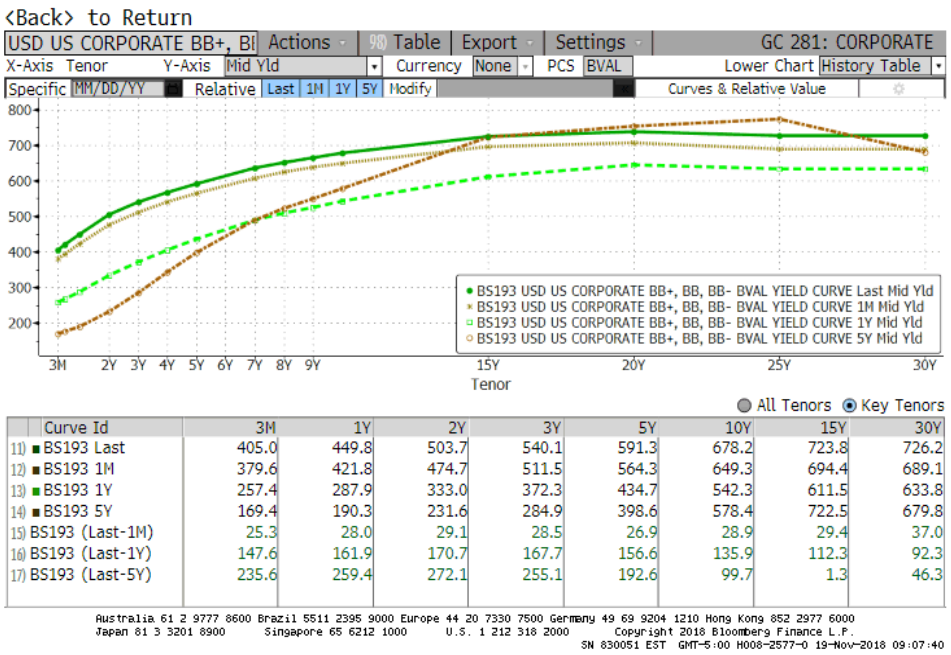


Figure 6 – Changes in Yield Curves for US Corporate Credits Rated in the B and BB Range over 1 mo, 1 yr, and 5 yrs





Q. IN YOUR OPINION, WHAT REPRESENTS A REASONABLE COST OF DEBT FOR PURPOSES OF CALCULATING THE CONE OF THE REFERENCE RESOURCE?

A. As I explained previously, the Reference Resource would more realistically be financed on a standalone, non-recourse basis. The bond market is not the best source to use for cost of debt estimates for this type of project. A single unit merchant generating project is typically too small and not sufficiently diversified to be able to tap the bond market for financing efficiently on a standalone basis, and therefore yields on outstanding bonds issued by publicly traded IPPs are not a reliable proxy for the Reference Resource cost of debt. A single project is likely to get better terms and higher certainty of financing from the traditional project finance bank or institutional loan markets, which account for the majority of debt raised for power project financings.

As shown in Table 4, acquisitions of portfolios of existing merchant peaking facilities in PJM have been financed in the bank market at a 3.0% to 3.5% margin over the London Interbank Offer Rate ("LIBOR").[11] To account for the higher risk associated with a single unit and with new construction of the Reference Resource, it is reasonable to use the average interest margin of 3.21% over LIBOR, observed during the period since 2015, as the initial credit spread. Importantly, the initial interest margin, captured in Table 4, typically steps up by 25 bps after 3 years, further increasing the levelized cost of debt. I believe it would therefore be appropriate to use a total credit spread of 3.31% (the "Credit Spread"), which includes a small upward adjustment (of 10 bps, which is only a

[11] Merchant peaking facilities have been also financed in the B loan market albeit less frequently and at higher interest spreads. I focused on the lower cost debt available in the traditional project finance bank market.

portion of the typical 25 bps increase) to partially account for a portion of this future step up in the interest. In both the bank and the institutional loan markets, pricing is typically expressed as a spread over the LIBOR benchmark, which is floating. It is customary, and lenders typically require the project sponsor, to hedge the floating rate exposure as part of the financing, by swapping the floating benchmark interest rate into a fixed rate equivalent (the "Swap Rate") that is based on the tenor of the financing. The swap replaces the typically rising LIBOR forward curve with a single fixed Swap Rate. The all-in interest rate on the financing is obtained as the sum total of the Swap Rate, a small swap credit spread payable to the swap bank, and the Credit Spread.

Typically, a new-build project financing obtained in the bank market allows for construction draws before project completion and converts into term financing after the project reaches commercial operation. The fixed interest cost of the term financing can be locked in with certainty at financial close using a forward starting interest rate swap, which offers the project sponsor an opportunity to lock into a fixed interest rate at financial close, prior to the start of construction. As shown in Table 7 below, a 3.34% Swap Rate is representative of the fixed interest rate at financial close for a project with a 12 month construction period. Adding together the 3.31% Credit Spread from (d) in Table 4, the 3.34% Swap Rate[12] and a swap credit spread of 10 bps to reflect a margin to

[12] This swap rate is based on a 24 month forward starting swap, reflecting construction lead time at financial closing, and a 7 year debt maturity, shorter than the 20 year levelization period used for the Reference Resource. Extending the maturity of debt and the swap would result in higher, all-in interest cost of debt.

the swap bank[13] results in an all-in fixed interest cost of debt of 6.75%. This all-in interest rate can be viewed as conservative given the rising interest rate environment.

Table 7 – Calculating the Cost of Reference Resource Debt into Fixed, Spot, 6-mo, 12-mo forward starting swapped LIBOR curves. (Source: Bloomberg)

All-In Interest Cost of Debt			
	interest cost of debt	%	comment
(d) Table 5	LIBOR Spread	**3.31%**	2015-18 average
(a)	Forward Starting Swap Rate lookup (see below)	**3.34%**	based on lookup
(b)	Swap Credit Spread	0.10%	BB- to B credit
(c)=(d)+(a)+(b)	**All-in Interest Cost of Debt**	**6.75%**	

Forward Curve Matrix, US 6 Mo LIBOR Swap Rates										
Forwards	4YR	5YR	6YR	7YR	8YR	9YR	10YR	12YR	15YR	20YR
Coupon	3.2246	3.2309	3.2445	3.261	3.2827	3.3047	3.3253	3.3634	3.3995	3.4201
11/7/2018	3.2199	3.2289	3.2421	3.2587	3.2798	3.3011	3.3227	3.3625	3.3970	3.4140
6Mo	3.28	3.2823	3.2912	3.3071	3.3267	3.3466	3.3664	3.3975	3.427	3.44
1Yr	3.2847	3.2912	3.3036	3.3235	3.3442	3.3637	3.3858	3.4125	3.438	3.4463
2Yr	3.2779	3.2954	3.3201	3.3446	3.3667	3.3915	3.4068	3.4322	3.4505	3.4514
Source: Bloomberg FWCM (Forward Curve Matrix) screen, 10/31/18										

Q. DO YOU AGREE WITH THE COST OF EQUITY PROPOSED BY PJM?

A. No. As detailed in the Energyzt Affidavit, Brattle has calculated the ATWACC using a severely understated beta. As explained in the Energyzt Affidavit, Brattle simply based its calculation of the beta of the Reference Resource on a sample of supposedly "comparable" publicly-traded IPPs, which included several Canadian IPPs with significant Canadian and European operations, and business mix heavily dependent on

[13] This 10 bps adder is based on a generally accepted practice.

very low-risk long-term contracted renewables and regulated distribution assets,[14] which are not representative of the Reference Resource. Brattle's sample also included US IPPs affected by significant company-specific factors since 2014 (such as restructurings and forced asset sales), which, as Energyzt notes, resulted in the abnormally low betas of such IPPs, thereby masking their underlying risks. Brattle's approach ignores the fact that none of such company-specific factors should apply to the Reference Resource itself. This unmitigated error, in turn, carries through to Brattle's cost of equity and ATWACC calculations.

I would also note that the Energyzt Affidavit finds that PJM is proposing a lower asset beta for the Reference Resource than in the 2014 Quadrennial Review. As Energyzt points out, asset beta, by definition, is a measure of the underlying risk of the investment and reflects the required return on equity without any debt, and, as such, should reflect the underlying operational, business risks of the asset. Such risks have increased considerably since 2014, due to structurally lower and more volatile commodity prices, the proliferation of renewables and conservation, significant state subsidies aimed to protect favored uncompetitive resources and threatened similar federal actions, and the emergence of a more demanding Capacity Performance product. This increase in the underlying fundamental business risk a Reference Resource is exposed to should be reflected in an increase in the asset beta used to calculate the cost of equity and the ATWACC component of the CONE.

[14] As an example, Brattle's list of "comparable" IPPs (Brattle Report, footnote 69) includes TransAlta, a Canadian power company with highly contracted, rate base-like revenues based on long-term power sales contracts that were administratively set at the time of the Alberta power market deregulation to emulate the company's legacy cost of service utility model.

Q. DO YOU RECOMMEND ANY ADJUSTMENTS TO THE ASSET BETA OR COST OF EQUITY PROPOSED BY PJM?

A. Yes. As stated in the Energyzt Affidavit, an asset beta of 1.0 is more representative of the expected beta of the Reference Resource.

As the Energyzt Affidavit explains, FERC's October 16, 2018 order involving New England Transmission Owners found a 13.08% ROE to be the top of a range of reasonable ROEs for regulated transmission companies,[15] which would translate to an asset beta of 0.87. As the Energyzt Affidavit also notes, the observed beta of the public overall equity market of 1.0 implies an unlevered beta for the S&P 500 of 0.91 (0.9 to 0.92 range since January 2014).

The appropriate asset beta reflecting the underlying business risk of the Reference Resource should be above the top of the range FERC found to be reasonable for regulated transmission owners, and above the unlevered beta of the S&P 500. As the Energyzt Affidavit points out, in comparison to regulated transmission operations and the S&P 500, the Reference Resource is an investment with one of the highest business risk profiles – it is characterized by a small size, has a high percentage of costs that are fixed (and, therefore, a high operating leverage), and is exposed to construction risk and to highly uncertain RPM revenues set one year at a time – all factors leading to a high unlevered beta asset. The high operational risk of merchant generation is also corroborated by the relatively more modest financial leverage creditors allow for such assets. A strong inverse relationship between business risk and acceptable financial risk

[15] *See Martha Coakley, Attorney General of the Commonwealth of Massachusetts v. Bangor Hydro-Electric Co., et al.*, 165 FERC ¶ 61,030 at P 56 (2018).

is at the core of the well-established common framework for credit ratings methodology, published and applied by credit rating agencies, which requires financial risk to be more limited for assets with a higher operational risk, everything else being equal.[16] In this context, an unlevered beta of 1.0 seems at least appropriate and may potentially be even too conservative for a merchant Reference Resource project.

Finally, the overall equity market had a ROE of 15.82% in 2018, and has remained in the low to mid-teens range since the 2014 Quadrennial Review.[17] In my experience, this is at the low end of the range of the ROEs expected by typical sponsors that invest in merchant construction projects in PJM.

Based on these factors, I recommend that PJM use an asset beta of 1.0 for the purposes of calculating the cost of equity and the ATWACC of the Reference Resource. Using an unlevered beta of 1.0 and a comparables-based debt to equity ratio of 30% yields a levered beta of 1.31, a calculated all-in interest cost of debt of 6.75%, and a levered cost of equity of 12.6%, as shown in Table 8 below.

Q. HOW WOULD THE ATWACC BE AFFECTED BY THESE CHANGES?

A. Adjusting the proposed ATWACC to reflect the more realistic assumptions described above, would result in an ATWACC of 10.2%, as shown in Table 9 below.

16 *See, e.g.*, "Methodology: Business Risk/Financial Risk Matrix Expanded," RatingsDirect, Standard & Poor's Ratings Services, September 18, 2012.

17 Source: Bloomberg.

Table 8 – The Calculation of the Reference Resource Cost of Equity

(a)	unlevered beta	1.00
(b)	project debt	30%
(c)	project equity	70%
(d)=(b)/(c)	debt/equity	43%
(e)	tax rate	27.72%
(f)=(a)*[1+(1-(e))*d]	levered beta	1.31
(g)	MRP	6.9%
(h)	Risk-Free Rate	3.5%
(k)=(h)+(g)*(f)	**cost of equity**	**12.6%**

Table 9 – Rolling It All Up, the Calculation of the Reference Resource ATWACC

	merchant CT		tax rate*	weight
comps	project debt	6.75%	27.72%	30%
(k)	project equity	12.6%		70%
	ATWACC	**10.2%**		100%
	* federal and state			

* *

Q. DOES THIS CONCLUDE YOUR AFFIDAVIT?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-105-000**

AFFIDAVIT

Joseph Esteves, being duly sworn, deposes and states that the statements contained in the foregoing Affidavit of **Joseph Esteves** are true and correct to the best of his knowledge and belief.

Joseph Esteves

Subscribed and sworn to before me
this 15 day of November, 2018

Notary Public for the State of **New York**

My Commission expires: 09/15/2020

ALEXANDRA LINARES-PENA MEJIA
NOTARY PUBLIC, STATE OF NEW YORK
NO. 01LI6192833
QUALIFIED IN QUEENS COUNTY
COMMISSION EXPIRES 09/15/2020

Attachment B

The LS Group Affidavit

Document Accession #: 20181119-5279 Filed Date: 11/19/2018

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER19-105-000

AFFIDAVIT OF CAROLYNE MURFF AND ANDREW DERA

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAMES, OCCUPATIONS AND BUSINESS ADDRESS.

A. We are both employed by the LS Power Group. Carolyne Murff is the Senior Vice President, Head of Asset Management, and Andrew Dera is the Vice President, Engineering & Construction. Our business address is 1700 Broadway, 35th Floor, New York, NY 10019.

Q. PLEASE DESCRIBE EACH OF YOUR QUALIFICATIONS.

A. Carolyne Murff joined LS Power in 2005 and has more than twenty-seven years of experience in the power industry. Ms. Murff holds responsibility for the asset management of LS Power's operating portfolio, for which she oversees the operations and commercial activities of more than 15,000 MW of power generation. Ms. Murff also supports LS Power's acquisition and divestiture activities. Prior to joining LS Power, Ms. Murff held various positions in acquisition/divesture, development, construction, asset management, and the operation of power generation facilities in domestic and international power markets. Ms. Murff received a B.S. in Mechanical Engineering from Texas A&M University.

Andrew Dera joined LS Power in 1999 and has twenty-one years of industry experience. Mr. Dera is responsible for the engineering, procurement, and construction of several of

LS Power's greenfield power generation and transmission projects. Additionally, Mr. Dera provides technical support for ongoing development projects. Prior to joining LS Power, Mr. Dera was employed by Sargent & Lundy, LLC. Mr. Dera received a B.S. in Mechanical Engineering from Rensselaer Polytechnic Institute and an M.B.A. from Rutgers University. Mr. Dera is also a licensed professional engineer.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. We are submitting this affidavit to respond to the proposal of PJM Interconnection, L.L.C. ("PJM") to replace the existing Reference Resource used to set the cost of new entry ("CONE") for the Reliability Pricing Model ("RPM") market. The existing Reference Resource is a simple cycle plant consisting of two General Electric ("GE") 7FA combustion turbines ("CTs"), representing a well-established, widely deployed, and successfully operating technology. PJM proposes to replace the GE 7FA and adopt instead a single unit of GE's next-generation advanced 7HA CT as the Reference Resource to calculate the CONE.[1]

It is our understanding that the CONE is intended to represent the lifecycle costs that a developer would reasonably expect to face in developing a new generation resource in the PJM region. Similarly, the configuration of the Reference Resource is intended to be consistent with the choices that a typical competitive generation developer would make in deciding to invest in the PJM region at present. Importantly, because the CONE is used to set the demand curve that is used in the RPM auctions, selection of the wrong

[1] *See* Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters at 17, Docket No. ER19-105-000 (filed Oct. 12, 2018) (the "PJM Filing").

Reference Resource could adversely affect prices in the RPM market, thereby deterring investment and jeopardizing reliability.

While we are not experts on turbine design, we have extensive experience with the development of new generation facilities, including, in particular, with the factors that competitive generators will consider in selecting turbines. We are therefore providing this affidavit to discuss the feasibility of the 7HA turbine for new CTs at this time.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. We agree with PJM's continued use of a CT unit for its Reference Resource. However, PJM's proposal to move to a 7HA turbine is premature at this time and should be postponed until GE's HA technology has been established as a proven, reliable technology. In this respect, when we refer to a proven technology, we mean a technology that has a sufficiently large installed base, and an average unit that is able to demonstrate a successful performance record over a significantly greater number of operating hours.

The advanced HA turbine is relatively new, as it was introduced by GE only a few years ago, and has been in service in the US for less than 18 months. As a result, its installed fleet is nascent at best, and nonexistent in the Reference Resource simple cycle configuration. At the time its predecessor, the GE 7FA, was initially recommended to PJM as a Reference Resource in 2005, the CT already had one of the largest installed fleets, was present in PJM, including in simple cycle operation, and had accumulated a very significant number of successful operating hours over a decade and a half in service.

In contrast, the 7HA employs new, proprietary materials that are not yet fully proven operationally, its critical components operate at some of the industry's most extreme firing temperatures to achieve its design specifications, and information related to the

operations and maintenance of the 7HA at this time remains highly limited and mixed at best. Troublingly, the row 1 blades of this particular turbine, its most critical components, experienced serious problems at its inaugural site at Exelon Corporation's ("Exelon") Colorado Bend facility, despite the fact that the turbine had less than 10,000 hours of operations since it was placed in service, a fraction of the component's intended service life and barely one-third still of its first maintenance interval. A failure of the most critical component of the most advanced CT on the market, a component that experiences the highest firing temperatures and is manufactured using new metallurgy, so early in its service life is alarming, even by the standards of the CT industry, where new design launches have historically been fraught with technology related problems. GE later acknowledged that there is a widespread problem that affects the first stage turbine blade that would involve a fleet-wide retrofit, the effectiveness of which may not be truly known for the next several years. Although GE has claimed that it has a solution for this problem, there is no operating data available to ensure that the solution will be effective or that there will not be new problems in the future. Given the next generation, proprietary materials and design used in this critical component of the GE HA turbine, we will only be able to tell whether this "fix" is in fact effective and permanent by reviewing operating data from the upcoming years.

In the meantime, merchant generators that must commit long term investment capital to construct new facilities are likely to avoid installing these turbines until there is substantially more operating and maintenance data available, including as it relates to the ongoing fleet-wide retrofit to address the failure. As a result, it does not appear reasonable for PJM to use the 7HA turbine in the Reference Resource at this time. In

addition, it is clear that the recently-discovered problems will affect the lifecycle cost for this class of turbines, making it difficult to obtain reasonably accurate upfront or operating cost estimates for such a CT. Importantly, it is impossible to determine lifecycle costs due to the HA turbine at this time because of its commercial immaturity. The limited and issue-prone operating history and the early life-cycle fleet-wide retrofit to address a serious and unexpected field failure demonstrate that selection of the GE HA technology is not appropriate at this time. PJM should therefore keep the current GE 7FA Reference Resource for the next four year period until the next Quadrennial Review in 2022 while continuing to monitor 7HA operating and maintenance history and its acceptance in simple cycle configuration by PJM market participants.

Q. DO YOU AGREE WITH PJM'S PROPOSED REFERENCE RESOURCE CONFIGURATION?

A. Yes. We agree with PJM's choice of a simple cycle CT rather than combined cycle ("CC") plant as the appropriate configuration for the Reference Resource. In particular, we agree with PJM that a CC project depends significantly more on energy and ancillary services ("E&AS") revenues, where the value of the spread between electricity and natural gas commodity prices is inherently uncertain. This makes the risk of a mistake with an estimate of Net CONE much greater for a CC than for a CT and a CC based Net CONE more prone to greater reliability risk than that based on a CT as the Reference Resource.[2] PJM further correctly points out that CT resources have the lowest absolute project cost, have been economically viable in PJM, and can be added faster than CC resources. We would note that LS Power recently added 2 GE 7FA CTs (340 MW) at the

[2] Affidavit of Adam Keech on behalf of PJM, paragraphs 9-12.

Doswell CT, which accounts for the majority of the new merchant peaking capacity in PJM since 2014.

A CT is the resource that is best suited to the Reference Resource for the capacity market because it is the simplest, fastest to market resource type that, due to much faster development and shorter construction lead time, can be deployed quickly to address any resource adequacy or reliability concerns. A Reference Resource for PJM's RPM capacity market requires quick and reliable provision of resource adequacy and reliability, which makes time to market one of the most important considerations in deciding on the Reference Resource configuration.

A CT is also the closest to a pure play capacity resource, because it depends primarily on the capacity revenues. This makes a CT appropriate for the Reference Resource, which should reflect the revenue requirement of a resource addition that is underwritten based on capacity revenues. A CC, in contrast, mainly relies E&AS revenues, is deployed after a longer development and construction lead time, to take advantage of an expected increase in the energy margin, and represents an investment that is fundamentally underwritten based on the energy margin.

III. FLAWS IN PJM'S PROPOSAL

Q. PJM STATES THAT IT IS APPROPRIATE TO USE THE 7HA BECAUSE IT IS THE LATEST AND MOST COST EFFECTIVE TECHNOLOGY. DO YOU AGREE?

A. It is important to recognize that, particularly for competitive power producers that have no guarantee of cost recovery, it is imperative to select proven and reliable technologies rather than being on the cutting edge of new technology. This industry is characterized by high capital intensity and long-term investment commitments. In addition, this

industry involves long project development lead times and slow equipment deployment cycles, from order booking to delivery to field installation to first major inspection. Major introductions of advanced, next-generation turbomachinery are made every couple of decades, not years, and are rarely a smooth process. Accordingly, PJM must recognize that the choice of a technology as a benchmark for the industry requires demonstrated operational success over a sustained period.

Although it is understandable that PJM would want to track general trends and improvements in technology, it should be recognized that not all new technology will wind up being generally acceptable over the longer term. As we explain below, this industry has the potential for costly surprises with advanced new equipment launches, and a significant precedent of challenged market acceptance and unfulfilled market promise of next-generation turbine technology. Prudent investment decisions by competitive generators involving major equipment choices require a thorough, data driven analysis of risk and reward over the plant life cycle. When next generation technology is involved, this analysis is primarily based on *history* not *theory*: it requires a look-back at a statistically significant sample of actual operating field data rather than an aspirational look forward based on original equipment manufacturer ("OEM") specifications, promotional materials, or order bookings.

Q. PJM'S FILING IN THIS PROCEEDING STATES THAT ITS PROPOSAL TO MOVE TO A 7HA TURBINE AS THE REFERENCE RESOURCE IS CONSISTENT WITH GENERAL TRENDS IN THE INDUSTRY. DO YOU AGREE?

A. As an initial matter, while PJM and its consultants at the Brattle Group ("Brattle") state that a number of combined-cycle plants ("CCs") have recently been developed using GE's H-class turbines,[3] it is important to recognize that it is not the "trend" in orders booked or units shipped but the size of the installed fleet of CTs of particular technology and the fleet's operating hours in the field that should matter when selecting the technology for the Reference Resource.

In this respect, PJM currently uses two 7FA turbines in the Reference Resource, and has done so since the implementation of the RPM market in 2007, reaffirmed in the three prior PJM reviews in 2008, 2011, and 2014 when Brattle recommended keeping the 7FA technology as the Reference Resource based on the fact that it was the predominant turbine type specified for CT plants built within PJM's footprint. GE's F-class turbines have accumulated close to three decades of proven performance, the industry's leading installed base of 1,600 CTs globally and 700 units in North America, and 64 million of operating hours,[4] and are still being actively deployed. In fact, LS Power's Doswell peaking addition, which went into operation in June 2018, uses 7FA turbines.

---

[3] PJM Filing, Attachment E, Exhibit No. 2, The Brattle Group, PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date at 14 (Apr. 19, 2018) (the "2018 CONE Study").

[4] *See* https://content.gepower.com/pw-hq/2018PSCatalog/html/index.html?page=110&origin=reader.

Notably, GE's F-class was introduced in the mid- to late 1980s, while the 7FA had been in commercial operation since the early 1990s, meaning that the fleet was more advanced in its deployment and more mature in its lifecycle before it was adopted by PJM. At the time the 7FA was initially recommended to PJM in August 2005 for consideration as the Reference Resource, the 7FA CT already had a history of technically and commercially successful operation and field service for close to a decade and a half, including in PJM, in both combined cycle and simple cycle configuration. PJM reaffirmed the use of the 7FA in the three subsequent reviews in 2008, 2011, and 2014, even though new turbine technologies were introduced in the intervening years that promised improved efficiency and output. PJM's decision to stick with the established 7FA has proven to be the right one, given that such other turbines never became commercially viable.[5]

By contrast to the broadly used 7FA, the HA-class turbine, recommended by PJM, is very new, has not reached the same point in its adoption or technology lifecycle, and falls materially short of the proven performance record of its predecessor GE frame technology at the time of its adoption by PJM as the Reference Resource.[6] The first HA unit, the Bouchain plant owned by Electricite de France SA that uses 9HA turbines, was put into service in June 2016. However, even this short operating history of just over 2 years is of limited relevance in predicting the performance of the 7HA since due to its slower speed at 50Hz it may not exhibit the same failure modes as the HA machines that

[5] ABB's GT24/26 and the G-class both showed early promise as the next generation equipment of choice in aeroderivative and heavy duty frame machines, respectively. Both promises, however, failed to materialize for a number of technical, commercial, and competitive reasons.

[6] The HA-class history also pales in comparison with other CT technologies deployed in PJM, including LM6000, a market leading peaking technology with 1,200 units installed and 33 million combined operating hours, a significant history despite their intermittent and infrequent dispatch.

run at 60Hz speed. The first HA units in the United States were Exelon's Colorado Bend and Wolf Hollow facilities, which achieved commercial operation in June 2017. All told, there are only a handful of operating units in the United States that use the HA turbines, and of those, only two are in PJM, and none in the proposed simple cycle configuration. Moreover, GE's H-class turbines have not been the preferred choice for combustion turbines ("CTs"). There are currently no CTs in PJM that use or are being developed with H-class turbines to date. Brattle itself acknowledges that there are only two CTs in the country that are being developed with H-class turbines.[7]

Q. WHY HAVE GE'S H-CLASS TURBINES NOT BEEN THE TECHNOLOGY OF CHOICE FOR CTS?

A. The H-class turbine is better suited for CC, rather than peaking, facilities. The H-class technology was developed to maximize the benefits in baseload, rather than peaking, operating mode. As a general matter, frame machines are better suited for baseload duties in a CC facility, while aeroderivative machines are better suited for peaking facilities because they are faster to install, and outperform frame machines in terms of start times, cycling performance, and flexibility.

Notably, recent additions of the H-class in CC configurations have been brought to the PJM system as baseload energy resources to replace retiring coal-fired plants in PJM, made possible by low-cost Marcellus shale gas. Larger nameplate capacity and higher combined cycle efficiency of the HA machine are important for baseload operation in CC but are not helpful in peaking duty and are not key drivers of CT selection for a simple cycle plant. In fact, the HA unit's CC advantages do not translate into simple cycle

[7] *See* 2018 CONE Study at 17.

operation, relevant for the Reference Resource proposed by PJM: the HA unit with a 8,200 Btu/kWh heat rate in simple cycle configuration slightly underperforms GE's LM6000, the industry's leading aeroderivative CT.

Of course, we understand that peakers in PJM and elsewhere have been developed using GE's 7FA turbines, which are also frame machines. In fact, and as we stated previously, LS Power's recent 340 MW Doswell addition to the PJM system uses two GE 7FA turbines. However, this choice is due to the F-class turbines' combination of relatively low upfront cost, mature and proven technology, and known lifecycle cost owing to its significant operating history and the largest installed fleet in the industry. However, as we explained already, the H-class has a nascent installed base with highly limited and troubled operating history, and would not provide the same benefits of reliability and predictability to offset the traditional shortcomings of a frame machine.

In addition, due to the higher firing temperatures than a 7FA, the HA-class is also a poor choice when selective catalytic reduction ("SCR") is required, which is the case for peaking units throughout PJM.[8] To our knowledge, there are currently no simple cycle HAs with a hot SCR/CO catalyst in operation; instead, H-class units operating today have only been used in a CC configuration where the catalyst is not exposed to the same operating conditions as the CT exhaust gas flow is significantly cooled as it passes through the heat recovery steam generator sections before reaching the SCR. PJM's proposed use of an HA-class unit with a hot SCR is therefore not consistent with industry practice at this time.

[8] *See* PJM Filing at 18.

IV. CONCERNS REGARDING GE'S H-CLASS TURBINES

Q. PLEASE EXPLAIN WHY THE SMALL INSTALLED FLEET SIZE OF ADVANCED HA UNITS AND THE RELATIVE SCARCITY OF OPERATING HOURS IS A MATTER OF CONCERN.

A. As a general matter, it may be difficult for developers to justify a long-term capital investment in new facilities that utilize new and unproven technology. In this respect, we would note that, in combination, we have assisted the LS Power Group with the development of numerous new generation facilities in PJM and elsewhere in the United States. In our experience, sponsors will generally chose proven technology that is supported by substantial operating data in developing new generation facilities. This is not surprising, because large combustion turbines are among the most complex examples of rotating machinery where an unreliable technology could lead to operating risks and unanticipated costs. Moreover, sponsors will oftentimes prefer proven technology that has predictable risks and known lifecycle costs over new technology that promises greater efficiency but is unproven and involves a quantum leap in its design or materials employed.

Q. PLEASE EXPLAIN WHY INTRODUCTIONS OF NEXT GENERATION CT TECHNOLOGY MAY GIVE POTENTIAL GENERATION OWNERS CAUSE FOR CONCERN.

A. The past two decades have been fraught with tradeoffs between the CTs' higher firing temperatures, larger output sizes, and advanced materials on the one hand and loss of reliability on the other. Not every advanced combustion turbine class launched with great promise has survived past the development and technology related performance problems encountered during the initial years after their introduction. There is precedent with

introductions of cutting edge CT technology that promised record breaking performance specifications but were abandoned after a relatively short period as market participants pivoted to a more commercially established technology, usually GE's LM6000 or GE's 7FA.

One example of state of the art CT technology that was rushed to market with support from technical experts but without sufficient field testing include ABB's GT24/26, which was launched in the mid-1990s and experienced significant technical difficulties in the field in the early 2000s, which caused a fleet-wide retrofit of the 72 units in operation globally, including 51 in the US. This development, after unexpected delays with validation of the retrofit components and EUR 4 billion in costs and liabilities, ultimately led to the demise, bailout, and exit from the industry of one of the few major CT OEMs. Despite this historic fleet-wide redesign and retrofit, financially ruinous to the CT OEM, the GT24 has never lived up to its efficiency targets, the main driver of its development and launch, and more than a decade since the retrofit, its heat rate remains meaningfully behind comparable GE 7FA units.

Other, more recent, examples include GE's 7FB, and the advanced frame G-class. The 7FB turbine, launched in 1999 as a successor to the 7FA and placed in service in 2003, promised to leverage GE's advanced blade materials development to enable higher firing temperature, which would in turn deliver improvements in efficiency, output, and lifecycle economics over the 7FA turbine. However, GE shipped only 13 7FB units, which proved unable to run more than 8,000 hours without failing parts. This development, reminiscent of the recent HA class failure at Colorado Bend, forced GE to eventually turn down the 7FB firing temperature, the new turbine's main selling point,

and to convert its 7FB fleet to modified 7FAs with lower firing temperatures, and at a very significant cost to customers. In a similar pivot away from a leap in technology, Siemens stopped making the 501G after just 24 units.

After major field problems in the first several years of commercial operation and billions of dollars in redesign and retrofit costs, none of these units are still in production. In each of these cases, the push to higher firing temperatures, next generation efficiency levels, and larger output left behind a stranded CT fleet with no further growth prospects and insufficient in size to attract the attention of third party aftermarket providers. In each of these programs, early adopters of faulty cutting edge technology were left captive to CT OEMs for the rest of the units' service life, with no alternatives for aftermarket parts, and higher operating uncertainty and lifecycle costs, hardly a desirable situation for the project sponsor. Ultimately, these turbines were not commercially viable even though a number of them were placed into operation.

The HA-class turbine raises similar concerns as those prior failed CT designs. As the blade failure at Colorado Bend demonstrates, limited testing on a test stand on the factory floor is often insufficient to identify major technical issues, particularly when a leap in stated performance is enabled by new advanced designs and proprietary materials. A test of time in field operation is the only true indicator of the potential performance of an advanced CT. The novelty of the HA technology suggests that we may be at a similar point to ABB's GT24 in the early 2000s, and the substantial uncertainty with this technology and the proposed "fix" remain high. For these reasons, adoption of the 7HA technology at present is premature and should be postponed until these units are

determined to be reliable, proven technology choices with visible lifecycle costs. The earliest evaluation of this technology should be at the next Quadrennial Review.

Q. WHY IS THE RECENT FIRST BLADE FAILURE AT EXELON'S COLORADO BEND FACILITY A MAJOR CONCERN FOR THIS TECHNOLOGY GOING FORWARD?

A. The recent failure of GE's inaugural US HA.02 unit is unusual and raises significant additional concerns regarding PJM's proposal to use the 7HA turbine. It was widely reported that there was a failure in a first stage turbine blade at Exelon's Colorado Bend facility just two months ago, in September 2018, despite the fact that the facility had less than 10,000 hours of operations. This unusual early failure has broad repercussions for this technology since the average HA machine had less than 6,000 operating hours as of early September 2018, and most of the operating 7HA CTs are yet to pass this number of operating hours where the Colorado Bend blade failure took place. A September 20, 2018 report by J.P. Morgan ("September 20 Report," provided here as Exhibit 1) points out that a serious failure with such limited operating hours is highly unusual and raises broad, fundamental concerns regarding the CT performance.[9]

The Colorado Bend blade failure was particularly problematic for various reasons. First, and as J.P. Morgan's report correctly points out, the first stage turbine blade is the highest technology component of a turbine that is most critical to achieving guarantees of its output and efficiency, the CT's main key performance indicators ("KPIs"). Second, GE has expressly acknowledged that this is a widespread problem that affects other installed and shipped turbines, thereby requiring GE to put a fleet-wide replacement program in

[9] *See* September 20 Report at 1.

place. Third, the 7HA failure was caused by oxidation of the new, proprietary material used in the first blade, a material that was fundamental in helping GE accelerate its entry into advanced class heavy duty CT market, and making the introduction of the 7HA possible. Such failure could not have been predicted by the limited testing GE employs on the test stand at the factory floor before bringing new technology to market. Likewise, it is impossible to determine whether the "fix" GE is putting in place will work or not.

We would also point out that concerns regarding the HA turbine are not limited to the problems at Colorado Bend. For example, it was widely reported that there were serious performance shortfalls in new facilities with this technology in Pakistan.[10] In addition, a myriad of technology related problems with the HA machines were recently highlighted by the Combined Cycle Journal, an industry publication that covered the recent, inaugural HA technology user group meeting,[11] and were also summarized in J.P. Morgan's October 10, 2018 report ("October 10 Report," provided as Exhibit 2). Some of the HA technology related problems reported had an unknown root cause and either already have, or could become, significant fleet-wide issues. One of the biggest issues reported was a failure of a key component of the HA turbine's unique combustion system, which damaged the fuel nozzles, causing the unit to trip offline. Another major reported problem that has plagued some HA sites is the persistent problem of excessive vibration levels, which appear in HA units at only 3,700 operating hours and increase over time, which appear to be caused by thermal changes in the unit, and lead to a number of secondary issues, including more frequent replacement of other hardware. This has

[10] *See, e.g.*, September 20 Report at 3.

[11] *See* Combined Cycle Journal, *7HA users wrestle with emergent issues at inaugural meeting* (Oct. 8, 2018), http://www.ccj-online.com/7ha-users-wrestle-with-emergent-issues-at-inaugural-meeting/.

already been acknowledged as a fleet-wide issue that GE has repeatedly tried but been unable to correct. Other reported issues included significant delays in critical spare part deliveries straining the supply chain.

These factors will add to general concerns over the small size and insufficient operating history of the nascent HA installed base and will make it particularly difficult for a developer to justify selection of the HA technology at this time.

Q. ARE YOUR CONCERNS ADDRESSED BY GE'S STATEMENT THAT IT HAS ALREADY IDENTIFIED A FIX FOR THE FIRST STAGE TURBINE BLADE FAILURES?

A. No, the fix is far from proven. As J.P. Morgan's September 20 Report stated, the critical nature of the first stage turbine blade indicates that it will be difficult and expensive to come up with a permanent and effective fix, and that similar issues with new technology have taken years, rather than months, to remedy, and at a cost of billions of dollars to the CT OEM.[12] We agree that this critical component failure will likely take extensive troubleshooting and analysis to isolate the root cause of the problem, redesign the blade, and develop the tooling for the manufacturing of a new blade. It is therefore not surprising that J.P. Morgan stated that "we struggle to believe that the fix is permanent or to just to keep the turbine running in the near term."[13]

Most importantly, from a developer's perspective, there is simply no operating data to determine whether GE's "fix" will be sufficient and effective. GE's choice of proprietary design and new, advanced materials, and its go-to-market approach based on testing

12 *See id.* at 7.

13 *Id.*

limited to 400 hours on a test stand effectively shift the burden of proof of this new technology to field operations. The early adopter HA customers will serve as real-time test stands for any fleet-wide "fix" GE proposes to address the first blade issue. As a general matter, we would expect feedback on the effectiveness of the fix at the first major inspection, which would normally occur at over 30,000 hours.

We would also note that despite GE's comment that it has a "fix", the maintenance interval of the HA-class CT will most likely not be maintained as the oxidation of the blade alloy has been reported to shorten its life. The supposed "fix" also does not guarantee that the cost of the turbines with this technology will not be affected. Finally, as we stated previously, even aside from the Colorado Bend failure, there have already been other technology-related problems raised by the HA customers regarding the performance of these units in normal operation,[14] and other major issues with the HA technology may still surface.

Q. PLEASE EXPLAIN HOW THE COSTS OF THE TURBINE COULD BE IMPACTED IN THE NEXT FOUR YEARS.

A. There are a variety of ways in which the problems with the first stage turbine blade, which have demonstrated that the HA CT would be unable to meet its contractual obligations under Long-Term Service Agreements ("LTSAs"), could affect costs going forward. First, there are reasons to believe, as is often the case with major new design launches, that that GE relied on aggressive pricing in order to drive early sales of its HA turbine.[15] It is also reasonably expected that GE will seek to become more financially

[14] *See* October 10 Report at 1-2.

[15] *See* September 20 Report at 6.

disciplined going forward. It is therefore not clear if these discounted prices will continue.

Second, it is reasonable to expect that the costs of LTSAs may also increase because GE will need to recoup the costs of making the necessary fixes to existing and new turbines, likely including spares and units in backlog, in order to address the first stage turbine blade problems and the costs of making necessary fixes to the HA turbines. The initial impact to GE of this retrofit is estimated at several hundred million dollars, putting the cost to serve the technology at a multiple of the initially expected level.[16] CT OEMs traditionally rely on LTSAs to serve as the principal driver of profitability as the original equipment sales are priced aggressively to secure future installed base for the lucrative aftermarket business. Given the burden of unforeseen retrofit costs and liabilities that GE is absorbing in connection with the blade failure, the initial LTSAs for the early HA units appear clearly underpriced, and may see upward pricing pressure during the next four year period, above levels assumed by Brattle in their report to PJM. Brattle's cost assumptions appear questionable based on our expertise as a developer.

Third, and as explained above, there is no operating data available to demonstrate that GE's identified solution will in fact be effective, putting the project owner at risk of incurring additional costs if the turbines do not prove reliable in the long run. Although the costs of the blade replacements would be covered by GE, the project owner could also incur the immediate costs of lower availability in the short run as well as the outage related costs not covered by the OEM. For example, the owner may bear costs in the form of previously unplanned outages, downtime, foregone revenues, the cost of having

16 *Id.* at 2.

to purchase replacement power, and/or incurring penalties that may not be offset by claims damages or against GE. The possibility of lowered availability is particularly troubling because of heavy penalties under PJM's recent Capacity Performance rules, which would further deter developers from choosing unproven new technology. In this respect, some of the costs associated with establishing the viability of the new technology is effectively shifted to early adopters of this technology, rather than being borne by GE. The limited installation of the HA turbines will also make it prohibitive for third parties' to compete in providing aftermarket parts and maintenance for these turbines, which would otherwise help control costs. Accordingly, any HA CT customer would likely remain captive to GE for the entire service life of the CT with respect to aftermarket parts and service, a costly and inflexible proposition. A lack of competition for aftermarket parts and service raises potential questions as to the quality of service. Additionally, the availability and pricing of insurance and financing, two markets that are sensitive to increased underlying risk, may also be impacted. And finally, the investment hurdle associated with investments in the HA technology should rise to reflect these increased risk factors going forward. No such uncertainty exists with respect to the lifecycle costs and aftermarket options of GE's mature 7FA technology, the single largest CT fleet in the world, making the 7FA a more logical CT choice for competitive generators.

Q. PLEASE PROVIDE YOUR VIEW ON WHETHER IT IS REASONABLE FOR PJM TO USE THE 7HA TURBINE IN THE REFERENCE RESOURCE AT THIS TIME.

A. As stated above, our understanding is that the Reference Resource is intended to represent a new generation facility that could reasonably be expected to be developed in

the PJM region to serve in a peaking application. In our opinion, the 7HA turbine does not appear to be a feasible choice for merchant generators at this time. As we stated above, the nascent installed base, the lack of a proven track record, and the recent problems at Colorado Bend and other plants will make it difficult for competitive generators to commit investment capital for a plant using this technology until longer operating history is available, until more units are deployed, including in PJM and in simple cycle configuration, and until the effectiveness of the upcoming fleet-wide fix to the recent blade failure are known, and the lifecycle costs and risk reward of the technology can be assessed with reasonable certainty. There should be a higher cost of equity and there may be a higher cost of debt, insurance, and major maintenance to account for the operational risk associated with these turbines. Over the course of the next four years, the price of the turbines could also rise to account for the necessary changes to address the oxidization problems, and the cost of operating and maintaining the plant could also increase. It is therefore very difficult to accurately determine the costs and assess the risk reward of such a plant since the uncertainty associated with the 7HA simply does not provide adequate data to determine the viability of the HA turbine and associated costs. By contrast, there is a high degree of certainty surrounding the 7FA turbine and associated costs because it has been so widely installed and has accumulated such an undeniable track record over the past three decades.

Accordingly, it appears premature for PJM to switch to the 7HA turbine at this time.

* *

Q. DOES THIS CONCLUDE YOUR AFFIDAVIT?

A. Yes.

Document Accession #: 20181119-5279 Filed Date: 11/19/2018

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-105-000**

AFFIDAVIT

Carolyne Murff, being duly sworn, deposes and states that the statements contained in the foregoing Affidavit of **Carolyne Murff** are true and correct to the best of her knowledge and belief.

Carolyne Murff

Subscribed and sworn to before me
this 15 day of November, 2018

Notary Public for the State of **New York**

My Commission expires: 09/15/2020

ALEXANDRA LINARES-PENA MEJIA
NOTARY PUBLIC, STATE OF NEW YORK
NO. 01LI6192833
QUALIFIED IN QUEENS COUNTY
COMMISSION EXPIRES 09/15/2020

Document Accession #: 20181119-5279 Filed Date: 11/19/2018

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER19-105-000**

AFFIDAVIT

Andrew Dera, being duly sworn, deposes and states that the statements contained in the foregoing Affidavit of **Andrew Dera** are true and correct to the best of his knowledge and belief.

Andrew Dera
Andrew Dera

Subscribed and sworn to before me
this 15th day of November, 2018

Alexandra
Notary Public for the State of **New York**

My Commission expires: 09/15/2020

ALEXANDRA LINARES-PENA MEJIA
NOTARY PUBLIC, STATE OF NEW YORK
NO. 01LI6192833
QUALIFIED IN QUEENS COUNTY
COMMISSION EXPIRES 09/15/2020

Exhibit 1

General Electric Co.

Another Shoe Drops: H Frame Blade Failure Risks Franchise Impairment; Lowering PT

Underweight

GE, GE US
Price: $12.86

Price Target: $10.00
Previous: $11.00

The impact on "asset value" from a failure at GE's US H-frame launch customer, while tough to estimate, represents a negative development for a company that has little wiggle room for more "shoes to drop", counting on equity markets and V-shape recoveries in long cycle businesses to reduce leverage that is already well above levels that support the standing rating. Namely, our channel checks, confirmed now by GE Power CEO, GE investor relations and the customer, suggest GE has experienced a failure in a 1st stage blade (rotating part, GE refers to as a "bucket") on an H-frame in one of its two initial marquee installations in the US, Colorado Bend. GE is minimizing the issue, referring to the problem in general as an "oxidation issue"; they are working with customers to maintain the machines with the same type blade, though with extra maintenance runs, while planning to replace the older blades with updated in-production technology planned to be used in the next generation of turbine. On the flip side, one channel participant we talked to spoke of the break at <10,000 hours as "historic", and the problem is material enough for Exelon to have shut the plant down, along with the award winning Wolf Hollow plant (for precautionary measures), suggesting it's worse than GE says. While the debate can rage around the structural versus cyclical nature of the power industry downturn (we believe structural), **if as bad as it seems, we believe there should no longer be any doubt that GE Power has company-specific issues, not only due to the decline in the profit pool from its large installed base of services (see note), but now around the H-frame technology, and, potentially on the profitability of the related future services stream that is key to replacing the one currently running down, some of which sits on the balance sheet in $9 B of contract assets.**

Bottom line, while we give GE some benefit of the doubt in its comments, we think the mere occurrence is significant in the context of the state of the story. **We have said time and again how orders at GE do not ultimately equal cash flow, but here the story could be how orders may equal losses and liabilities with a mosaic that confirms our concerns around the on-the-ground impact of everything that has transpired in the past**

Electrical Equipment & Multi-Industry

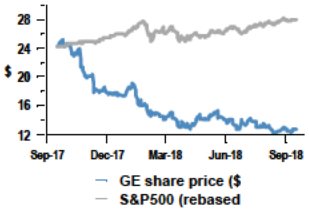
C. Stephen Tusa, Jr CFA AC
(1-212) 622-6623
stephen.tusa@jpmorgan.com
Bloomberg JPMA TUSA <GO>

Rajat Gupta
(1-212) 622-6382
rajat.gupta@jpmorgan.com

Patrick M. Baumann, CFA
(1-212) 622-0160
patrick.m.baumann@jpmchase.com

J.P. Morgan Securities LLC

Price Performance



	YTD	1m	3m	12m
Abs	-26.3%	4.6%	-0.7%	-46.9%
Rel	-35.1%	2.6%	-6.0%	-62.9%

General Electric Co. (GE;GE US)

FYE Dec	2017A	2018E	2019E (Prev)	2019E (Curr)	2020E (Prev)	2020E (Curr)
EPS - Recurring ($)						
Q1 (Mar)	0.14	0.16A	-	-	-	-
Q2 (Jun)	0.21	0.19A	-	-	-	-
Q3 (Sep)	0.21	0.20	-	-	-	-
Q4 (Dec)	0.43	0.27	-	-	-	-
FY	1.00	0.82	0.80	0.75	0.92	0.82
Bloomberg EPS FY ($)	1.05	0.93	-	1.04	-	1.17

Source: Company data, Bloomberg, J.P. Morgan estimates.

Company Data	
Price ($)	12.86
Date Of Price	19-Sep-18
52-week Range ($)	25.21-11.94
Market Cap ($ mn)	112,653.60
Fiscal Year End	Dec
Shares O/S (mn)	8,760
Price Target ($)	10.00
Price Target End Date	31-Dec-19

See page 11 for analyst certification and important disclosures.

C. Stephen Tusa, JI CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

decade. We are now assuming weaker results at power and some franchise value impact and as such we are moving to a $10 Dec-19 end PT with this note. GE remains our top UW.

To clearly present GE's side of the story, on Monday, they confirmed a first stage blade failed, not part of the combustion chamber, and they did not think there was a containment issue. They said they are still working through the specifics of the root cause. They noted that they had similar issues with the F-frame. GE has dispatched engineers who are working to keep the machines running with blades out of inventory to replace the current type earlier than initially estimated to avoid another failure. Yesterday morning just before market open, Power CEO Russel Stokes, on a LinkedIn post entitled "Making The Best Turbines Is Hard Enough. At GE, We Never Stop Making Them Better", in the 8th and 9th paragraphs, further opined on the Pakistan issue, as well as noted identifying "an oxidation issue that affects the lifespan of a single blade component" and they have "identified a fix and have been working proactively with HA operators to address impacted turbines". He called the fixes "minor adjustments". Updated messaging from GE post the Stokes commentary is that a next gen blade is ready and in production as part of the next gen turbine product, and that will be used to replace this older, less robust blade. The incident at the current customer happened on September 4 so it's still early in being able to evaluate the ultimate financial outcome, but whatever comes will likely be through either warranty, or part of the CSA as negative productivity, timing of which depends on contract structure, among other things.

We understand why GE would minimize the issue, and we are not turbine experts, but **the mosaic here raises red flags around risks that are both financial and fundamental for franchise value that bear watching**. First, calling out the "oxidation issue" factually identifies what happened within the blade, but not necessarily the root cause and while GE says they have new blades ready, which implies knowing how to fix the root cause, we wonder why they would have let this incident get this far if so. If it's heat tolerance, as MHI had experienced in testing some of their larger turbines, then it's an issue that takes more than a minor adjustment to fix, potentially requiring more cooling, which would challenge the ability to get to promised efficiencies. On this front, the term "fix" is somewhat vague, and means that they are indeed taking care of the customers, replacing blades earlier than planned, something we don't doubt, but it would seem to be too early to have a bankable long term technology plan.

Financially, near term costs include warranty and LTSA productivity (i.e., services margin as the cost of unexpected maintenance well above the projection which GE will pay for), but also costs for guarantees around lost production, which if they had been extended in the initial negotiations to get the order, can be larger than the LDs highlighted last year (which totaled ~$300mm). **If not remedied expeditiously, this could be a balance sheet issue as well, as per GE Power's $9 B in contract assets that sit on the balance sheet** to reflect cash profits expected from

C. Stephen Tusa, Jr CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

projected contract performance. GECS has also taken on some risk by investing beside some customers to enable installations. At a high level, if we go back in history, **recall Alstom, when it acquired ABB's turbine technology that had been failing to meet performance requirements with customers, incurred €4 B of related costs to deal with liabilities and a fix of the situation, though they did not have a finco enabler. GE Power is already losing money including restructuring.**

Fundamentally, when thinking about the time and attention to remedy the problem, this presents an unusual challenge for an organization with little power generation experience at the top, trying to cut cost while at the same time driving "transactional services" market share, all at a time when the related supply chain for casting/forgings is extremely tight. There is risk around management taking its eye off of what is already a hard to see ball. From a franchise perspective, this is the not the first time the H frame, introduced in 2013 and touted by GE as "the best new product launch in the last 20 years", has had issues. The press has written at length about the problems in Pakistan, where GE was well behind in its guarantees to the government there for critical projects, characterized as a "combustor issue", acknowledged by Stokes in his post. This will likely be **reflected in market share, which has already collapsed to #3 in 1H18.**

For GE, widening the lens, **this is not only an earnings issue for Power with a potentially significant tail that is not one-time in nature if not remedied expeditiously, but also impacts the franchise value—and emblematic of the more systemic problems that come when a management team running a long cycle business focuses too much on short term results and market share statistics based on orders**. They end up behind the curve on a major technology type (even 10 years), they rush their copy to market to maintain leading market share, with commercial teams prioritized over engineering, over-promising on technology specifications with guarantees so make customers feel better about related risk. **Keep in mind turbine material science technology is the secret sauce that is the tie that binds Aviation and Power.** The challenge there is to make a turbine that fires at a higher temperature, but, unlike a HDGT, needs to weigh less. To be clear, the big difference is that while engines run at similar rate of heat, they are only firing that high for takeoff and landing so the read on that is not direct; however, this needs to be watched and considered as delays continue on the new engine. Recall that while GE and SAF share revenues, they do not share costs, and the hot section is GE Aviation's responsibility. Further details are below.

C. Stephen Tusa, JI CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

J.P.Morgan

Table 1: Possible Implications/Outcomes

Market share/Franchise	After suffering initial launch issues in Pakistan and LD claims from customers, this brings reputational risk. Committing to a fix could also impact the services franchise and as cutting costs at the same time management is committing required resources will likely take away from the initiative to drive transactional volumes, and potentially lead to weaker levels of service
Cost	Servicing at a much higher rate than expected at inception of these contracts has negative implications for "service productivity" (cum-catch gains). Damages/claims for missed operating hours which could be multiples of the LDs highlighted last year (which totaled ~$300 mm). For reference ALO had to incur costs of ~€4 B in early 2000s due to issues with ABB's turbines
Write-downs	If not quickly remedied, complex, long term nature of contracts could drive material impairments of assets including contract assets (~$9.2B in Power, ~45% of total GE), ~$5.1B of receivables factored at GECS, $8.9B in EFS assets (~20% of which are Power) and risks to the $17B Alstom goodwill
Aircraft engine technology read through	Turbine material science technology is the secret sauce that is the tie that binds Aviation and Power. This needs to be watched and considered as delays continue on the new engine.

Source: Company reports and J P. Morgan estimates.

- **What we know about the turbines in question.** Our channel checks alerted us to a failure in Exelon's Colorado Bend plant, and GE's 7H.02 turbine operating there since November 2017, namely a failure of a 1st stage blade. Exelon investor relations confirmed that there was a failure to J.P. Morgan utility analyst Chris Turnure. They noted it was one turbine and one incident, but they also shut down Wolf Hollow as a precaution, but also noting an immaterial financial impact as the failure is under warranty and they will not be paying for the fix out of their pocket. **GE has confirmed that it was a failure in the first stage turbine blades, which GE refers to as "buckets".** GE notes that this is an "oxidation" issue that affects the lifespan of a single blade component. They acknowledge that this was a frustrating development for them and their customers and have identified a fix, and that they have been working proactively with HA operators to address impacted turbines. The noted that this 'minor' adjustment that they need to make does not make the HA any less of a "record setting turbine" and that they are meeting and in many cases exceeding their performance goals at every customer site today. There is likely a financial impact coming through either warranty, or part of the CSA as negative productivity. They also noted that they had similar issues with the F-frame and that this is "not a technology issue". **As background, GE has sold 82 H-frames, 51 of which have been shipped and 30 of which are in the field operating.**

- **Why, if it's a first stage blade failure, this could be a challenging technical problem…**According to our checks, the failure of a "row 1 bucket" is material as the most expensive, highest tech component in a gas turbine, the most critical component for achieving output and efficiency guarantees. GE's side of the story is that this is not a "technology" issue, considered normal for a new turbine, and CEO Stokes talked to a fix that has been identified and minimal adjustments though we do not know why the oxidation happened (cooling air that is too hot, too little air flow, etc.). **However, after speaking to more than one channel participant, our understanding is that this is the most**

C. Stephen Tusa, JI CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

J.P.Morgan

difficult part to design, manufacture and repair, made from proprietary nickel based single crystal alloys requiring close to perfection at a microscopic level. These parts have a hollow core that has complex internal cooling passageways (requiring cooling air circuits), complex coatings and a blade root that is ground to one ten-thousandth of an inch tolerance. This part also faces the most severe operating atmosphere than any other part, heated (3000 degree gasses) and cooled rapidly. GE has said that they have a next gen blade ready and in production with their next gen turbine, which has orders in backlog, and this will be used to replace the older one in the older version. MHI claims to have had some problems on 1st stage blades during test and claims to have taken a period measured in years to remedy it.

- **…with potentially material repercussions...** The company has accumulated 175k operating hours on the machines, up from 55K in December, 88K in March, and 118K in June versus the leading competitor at over 500,000+. This would suggest many of the machines have yet to surpass the key 8,000-10,000 hour interval. It's our understanding that these parts should last for 32,000-72,000 hours with repairs at 24,000 and 48,000, historically, though for AGPs the company had touted interval extensions to 32,000 hours for newer technology similar to the H-frame. **A blade failure at less than 8,000-10,000 hours typically means a warranty claim (confirmed in this case), loss of LTSA profitability (significant unplanned expense, negative productivity), drain on service personnel to do fleet-wide campaign at a time when Bulls are talking about taking share in transactional services.** This will be a massive undertaking to establish the cause of failure, redesign the turbine blade, develop hard tooling at casting vendors, learn to cast, machine and apply coatings to the new blade, schedule customer outages and send service crews to sites around the world. Keep in mind that in December, GE said in a release they had targeted 300,000 operating hours by year-end 2018, which looks like a stretch now.

Table 2: GE Commentary/Statistics on H-Frame operating hours

Dec'17	20 units in commercial operation, first fire for first unit at EDF was in 2016, and since that time 19 other units came online, with the fleet hitting 55,000+ operating hours, and Bouchain over 10,000. They expected to exceed 300,000 hours by the end of 2018
June'18	76 units ordered, 118,000 operating hours
Current	82 orders, 51 shipments, 30 units in the field (all expected to be operational by year-end), ~174,000 operating hours

Source: Company reports and J P. Morgan estimates.

- **...for franchise: this issue comes after Pakistan and reinforces the trend on market share, which was evident in 1H18…** We have been arguing consistently that GE has used every tool in its kit financially to drive orders, and here GE had claimed that HA.02 was "the fastest new product introduction in company history", required owing to its late introduction versus competitors. It's reasonable to believe that in order to

C. Stephen Tusa, JI CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

get to performance levels required to sell the turbine, commercial teams made big promises around which engineering teams likely took on bigger risks, given that less cooling air means more output and heat rate. GE is also known to have offered "care packages" to early-adopter HA.02 customers (we had highlighted this initially last year), which provided extended warranty coverage, insurance against production loss, and other non-standard offerings to win installations. Recall GE has already suffered initial launch issues with key customers, particularly in Pakistan, related to combustion hardware and "fuel delivery", all of which had been played down by management as normal. New GE management themselves have said prior commercial practices in the sales function were focused on market share without regard for profitability let alone longer term risks. What's notable is that Exelon and GE both touted the deals for the integrated nature of the equipment and "Predix" technology, suggesting that even customer communications can be a bit heavier on marketing than a validation of robust technology, let alone considering the financial terms that ultimately got the deal across the finish line. With new management not that steeped in power industry experience we wonder if they will be able to handle this complex situation, especially at the same time they are trying to cut costs and grow transactional services. When it comes to services, as per the above, we believe cutting costs at the same time management is committing required resources will at the very least take away from the initiative to drive transactional volumes, and potentially lead to weaker levels of service.

Below we show how the competitor is touting its durability statistics and how they relate to this issue for reference.

Table 3: MHI's Pitch On Reliability Of Its Technology For Comparison Purposes

The MHPS J-series now has 30 turbines in commercial operation with all delivered on time. 25 of the 30 J-series have exceeded 8,000 hours of operation. The fleet leader has over 40,000 hours of operation, and the fleet has 99.3% reliability. This is a new industry record per MHI.
MHI's fleet leader in the US is GRDA. Per MHPS, this is has passed 8,000 hours of reliable commercial operation.
MHPS's fleet leading JAC turbine has >17,000 hours of operation. MHPS' use of an external air cooler that cools the cooling air before it enters the turbine section allows the turbine to avoid an internal oxidation problem per MHPS. MHPS notes that they discovered a problem during 8,000 hour endurance testing at T-Point, and used this learning to develop the external air cooler before increasing their firing temperature to current levels.

Source: Company reports and J P. Morgan estimates.

- **…and financials: taking care of customers, and fixing the issues both temporarily and longer term, is expensive.** Financially, GE has noted that they are actively working with customers to change out blades. The average machine has been running for about ~5,800 hours as of 9/3/18, click here for the latest HA fleet status, so this likely well below the interval they initially expected, especially given the average turbine runs about 8,000 hours per year (Exelon's started late last year). **While CEO**

C. Stephen Tusa, JI CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

Stokes noted that they have a fix that requires a "modest adjustments", with our conversations with management implying that the new blade is already in production, we wonder why the new blades were not being used to prevent such a situation. In other words, we struggle to believe that the fix is permanent or to just to keep the turbine running in the near term. Keep in mind that assuming it's an issue around cooling, which, factually confirmed by an industry consultant, competitors had challenges with in their test runs in actual plants, which they engineered around, fixing an issue around heat means adding more cooling mechanisms and likely impact efficiency (ability to run hotter). As for the cost to serve, there are heavy burdens associated with servicing at multiples the level expected at inception of these contracts, with negative implications for what GE defines as "service productivity" that had been showing in positive cumulative catch up gains on servicing of turbines that was outperforming expectations at inception of the contracts – these could be substantially negative. Outside of the cost to serve, however, are make goods on missed operating hours, which is hard to calculate, but represents the difference between cost to produce and cost to buy power in the spot market. Here, the fact that both turbines for Exelon are shut down within the range of summer months is a further cause for concern (we were recently in Houston and happy the power is on). **We believe ultimate charges here could be larger than the LDs highlighted last year (which totaled ~$300 mm)**. GE's situation to us looks somewhat similar to the problems Alstom experienced with ABB's turbines back in early 2000s, though the reference is just a starting point. **Here, Alstom took €4 B in costs and liabilities for a remedy and make goods to customer, the single largest driver of its bail out request in 2004.**

- **…and substantial balance sheet exposure including $9.2 B in contract assets, $5.1 B in receivables, $8.9 B in EFS assets.** This all also plays into the balance sheet and the value of these complex, long term contracts, and we would expect material impairments of assets including contract assets, which in Power represents $9.2B (~45% of total GE). Also keep in mind the ~$5.1B of receivables sold to GECS (as of 2017 end) over time (already monetized as FCF for GE Industrial), as well as $8.9B in remaining EFS assets, ~20% of which are Power related as per our understanding, and the $17 B in Alstom, goodwill which is already close to levels that would trigger an impairment.

- **Taking it a step further: materials technology, and aggressive risky commercial promises cut across the company.** If GE is indeed underselling the risk, known to happen before, this would appear to be emblematic of the types of problems that arise when a management team running a long cycle business focuses too much on short term results and market share statistics based on orders. They end up behind the curve on a major technology type (like even 10 years), they rush their copy to market to maintain leading market share, over-promising on technology specifications with guarantees so customers feel less risk. **Keep in mind**

C. Stephen Tusa, JI CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

turbine material science technology is the secret sauce that is the tie that binds Aviation and Power. The challenge there is to make a turbine that fires at a higher temperature, but, unlike a HDGT, needs to weigh less. To be clear, the big difference is that while engines run at similar rate of heat, they are only firing that high for takeoff and landing so the read on that basis should make Bulls feel better, but this still needs to be watched as engines are delayed. Recall that while GE and SAF share revenues, they do not share costs, and the hot section is GE Aviation's responsibility.

- **Reducing PT to reflect higher costs and "asset value" impairment.** The mosaic here continues to reinforce our view that the "asset value" of GE's business is overstated by a simplified use of standing GE Industrial financials. While the proxy filings at BHGE and GET/WAB underscore how GE businesses many times look different/worse when separated from the GE umbrella, the issue at Power is much more fundamental and suggests something more systemic: the use of financial engineering to provide air cover for aggressive commercial behavior for which ultimately orders do not equal profits which do not equal FCF. The difference is that here orders are actually leading to losses and liabilities, all at a time when the company has almost no wiggle room to spare in a balance sheet that we believe looks nothing like its rating. Even the ratings agencies have said a lack of progress in power profit improvement or a major write down of contract assets could drive a downgrade. **We are cutting our estimates for Power and moving to a Dec'19 PT of $10 on a lower multiple on a clearly impaired franchise that is set to deliver fundamentally weaker FCF. Our estimates are based on a 16.7x implied EV/FCF multiple (~10% discount to the group and implied parity to the group taking into account pending unresolved liabilities) on our 2020 FCF estimates. We remain UW.**

C. Stephen Tusa, Jr CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

Investment Thesis, Valuation and Risks

General Electric Co. *(Underweight; Price Target: $10.00)*

Investment Thesis

GE has transformed significantly, with major portfolio change including $20B in divestitures, upcoming spin-off of Healthcare, asset sales on the GECS side, the Alstom acquisition, various financial frameworks, an activist, and IOT/3-D printing emphasis. Despite these moves, earnings still are far from reset as we still see structural concerns in the key Power markets, minimal margin for error on leverage, numerous tail liabilities at both GE and GECS, all hurdles to the multiple and forward trajectory of numbers, while on a FCF basis the stock continues to screen as expensive, given the continued disconnect with reported EPS. We stick to what the numbers and related valuation say, which underpins our UW rating.

Valuation

Maintain UW; establish a Dec-19 PT of $10 (vs Dec-18 $11 prior). On our 2019 EPS estimate, GE shares now trade at ~17x, a 10-15% discount to the group. Our Dec 2019 price target of $10 is based on a 16.7x FCF multiple. Our $10 price target would imply a ~10% discount to our sector target multiple on EV/FCF (~30% discount on P/E), because of asset value impairment, on our 2020 FCF estimates and a parity when accounting for other potential liabilities. Our group target multiple of 18x is at a ~5-10% premium to the standing average S&P FY1/FY2 multiples, in line with its historical premium.

Risks to Rating and Price Target

Upside risks include: 1) Power fundamentals do not deteriorate as expected, 2) significant improvement in FCF generation, 3) stronger than expected uptick in Digital revenues, which also helps profitability, 4) fundamentals in Oil & Gas recover faster than expected, and 5) better than expected execution on product transition in Aviation.

C. Stephen Tusa, Jr CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

J.P.Morgan

General Electric Co.: Summary of Financials

Income Statement - Annual	FY16A	FY17A	FY18E	FY19E	FY20E
Revenue	**123,783**	**118,240**	**120,431**	**116,657**	**121,213**
COGS	-	-	-	-	-
Gross profit	**-**	**-**	**-**	**-**	**-**
SG&A	-	-	-	-	-
Adj. EBITDA	**20,005**	**6,728**	**13,484**	**13,308**	**14,590**
D&A	(2,597)	(2,857)	(3,115)	(2,880)	(2,875)
Adj. EBIT	**15,262**	**222**	**9,955**	**9,430**	**11,328**
Net Interest	(2,026)	(2,753)	(3,007)	(2,900)	(2,850)
Adj. PBT	**13,236**	**10,886**	**11,587**	**10,274**	**11,147**
Tax	(967)	(3,691)	(143)	(642)	(1,201)
Minority Interest	-	-	-	-	-
Adj. Net Income	**13,602**	**8,657**	**7,094**	**6,063**	**6,652**
Reported EPS	1.34	1.00	0.82	0.75	0.82
Adj. EPS	**1.49**	**1.00**	**0.82**	**0.75**	**0.82**
DPS	**0.93**		**-**	**-**	**-**
Payout ratio	69.1%	-	-	-	-
Shares outstanding	9,130	8,687	8,704	8,109	8,149

Income Statement - Quarterly	1Q18A	2Q18A	3Q18E	4Q18E
Revenue	**28,660A**	**30,103A**	**29,773**	**31,895**
COGS	-	-	-	-
Gross profit	**-**	**-**	**-**	**-**
SG&A	-	-	-	-
Adj. EBITDA	**2,936A**	**3,098A**	**3,225**	**4,225**
D&A	(758)A	(837)A	(760)	(760)
Adj. EBIT	**1,852A**	**2,639A**	**2,326**	**3,137**
Net Interest	(642)A	(690)A	(800)	(875)
Adj. PBT	**2,787A**	**2,916A**	**2,731**	**3,152**
Tax	(112)A	(525)A	(137)	631
Minority Interest	-	-	-	-
Adj. Net Income	**1,418A**	**1,626A**	**1,735**	**2,315**
Reported EPS	0.16A	0.19A	0.20	0.27
Adj. EPS	**0.16A**	**0.19A**	**0.20**	**0.27**
DPS	**-**	**-**	**-**	**-**
Payout ratio	-	-	-	-
Shares outstanding	8,696A	8,699A	8,705	8,715

Balance Sheet & Cash Flow Statement	FY16A	FY17A	FY18E	FY19E	FY20E
Cash and cash equivalents	10,525	18,822	22,702	18,163	16,893
Accounts receivable	12,715	14,638	15,558	15,981	16,794
Inventories	22,263	19,344	17,631	17,732	18,828
Other current assets	137	569	2,928	2,928	2,928
Current assets	**45,640**	**53,373**	**58,819**	**54,804**	**55,443**
PP&E	19,103	23,963	16,625	17,005	17,930
LT investments	-	-	-	-	-
Other non current assets	213,131	201,933	188,108	184,799	181,385
Total assets	**277,874**	**279,269**	**263,552**	**256,608**	**254,759**
Short term borrowings	20,482	14,548	8,319	8,319	8,319
Payables	20,876	21,851	20,787	20,666	20,579
Other short term liabilities	36,509	40,192	37,024	36,242	35,984
Current liabilities	**77,867**	**76,591**	**66,130**	**65,228**	**64,882**
Long-term debt	58,810	67,040	68,640	65,140	63,640
Other long term liabilities	63,992	62,356	54,757	53,457	53,157
Total liabilities	**200,669**	**205,987**	**189,527**	**183,825**	**181,679**
Shareholders' equity	75,828	56,030	57,531	56,291	56,587
Minority interests	1,378	17,252	16,493	16,493	16,493
Total liabilities & equity	**277,874**	**279,269**	**263,552**	**256,608**	**254,759**
BVPS	**8.31**	**6.45**	**6.61**	**6.94**	**6.94**
y/y Growth	*(15.4%)*	*(22.3%)*	*2.5%*	*5.0%*	*0.0%*
Net debt/(cash)	68,767	62,766	54,257	55,296	55,066
Cash flow from operating activities	**29,870**	**11,039**	**2,501**	**7,227**	**8,886**
o/w Depreciation & amortization	2,597	2,857	3,115	2,880	2,875
o/w Changes in working capital	3,221	2,040	126	(776)	(1,606)
Cash flow from investing activities	**(1,894)**	**(8,327)**	**2,234**	**(3,910)**	**(4,450)**
o/w Capital expenditure	(4,498)	(4,650)	(3,400)	(3,700)	(3,800)
as % of sales	*3.6%*	*3.9%*	*2.8%*	*3.2%*	*3.1%*
Cash flow from financing activities	**(27,430)**	**5,141**	**(649)**	**(7,855)**	**(5,706)**
o/w Dividends paid	(8,474)	(8,355)	(4,178)	(3,892)	(3,912)
o/w Net debt issued/(repaid)	2,746	15,963	4,808	(3,500)	(1,500)
Net change in cash	**153**	**8,297**	**3,880**	**(4,538)**	**(1,270)**
Adj. Free cash flow to firm	**5,277**	**2,373**	**(899)**	**3,527**	**5,086**
y/y Growth	*(29.8%)*	*(55.0%)*	*(137.9%)*	*(492.2%)*	*44.2%*

Ratio Analysis	FY16A	FY17A	FY18E	FY19E	FY20E
Gross margin	-	-	-	-	-
EBITDA margin	16.2%	5.7%	11.2%	11.4%	12.0%
EBIT margin	12.3%	0.2%	8 3%	8.1%	9 3%
Net profit margin	11.0%	7.3%	5 9%	5.2%	5 5%
ROE	15.6%	13.1%	12.5%	10.7%	11.8%
ROA	4.5%	3.1%	2.6%	2.3%	2.6%
ROCE	7.9%	0.1%	7 2%	6.7%	7.8%
SG&A/Sales	-	-	-	-	-
Net debt/equity	89.1%	85.6%	73.3%	76.0%	75.3%
P/E (x)	8.6	12.9	15.8	17.2	15.8
P/BV (x)	1.5	2.0	1 9	1.9	1 9
EV/EBITDA (x)	9.1	28.4	13 5	13.8	12 5
Dividend Yield	7.2%	-	-	-	-
Sales/Assets (x)	0.4	0.4	0.4	0.4	0 5
Interest cover (x)	9.9	2.4	4 5	4.6	5.1
Operating leverage	93.2%	2200.7%	236807.5%	168.0%	515.2%
Revenue y/y Growth	5.4%	(4.5%)	1 9%	(3.1%)	3 9%
EBITDA y/y Growth	(5.9%)	(66.4%)	100.4%	(1.3%)	9.6%
Tax rate	7.3%	33.9%	1 2%	6.2%	10.8%
Adj. Net Income y/y Growth	3.8%	(36.4%)	(18.1%)	(14.5%)	9.7%
EPS y/y Growth	13.8%	(33.1%)	(18.2%)	(8.3%)	9 2%
DPS y/y Growth	0.1%	-	-	-	-

Source: Company reports and J.P. Morgan estimates.
Note: $ in millions (except per-share data) Fiscal year ends Dec. o/w - out of which

C. Stephen Tusa, Jr CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

Analyst Certification: The research analyst(s) denoted by an "AC" on the cover of this report certifies (or, where multiple research analysts are primarily responsible for this report, the research analyst denoted by an "AC" on the cover or within the document individually certifies, with respect to each security or issuer that the research analyst covers in this research) that: (1) all of the views expressed in this report accurately reflect his or her personal views about any and all of the subject securities or issuers; and (2) no part of any of the research analyst's compensation was, is, or will be directly or indirectly related to the specific recommendations or views expressed by the research analyst(s) in this report. For all Korea-based research analysts listed on the front cover, they also certify, as per KOFIA requirements, that their analysis was made in good faith and that the views reflect their own opinion, without undue influence or intervention.

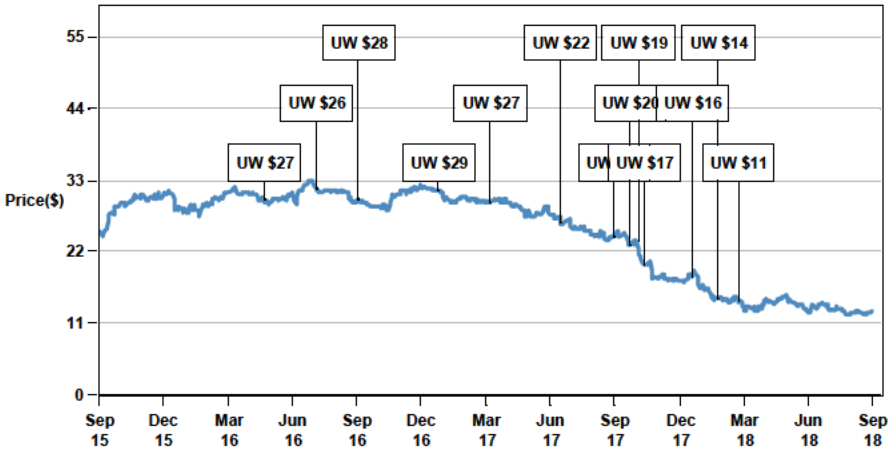
Important Disclosures

- **Market Maker/ Liquidity Provider:** J.P. Morgan Securities plc and/or an affiliate is a market maker and/or liquidity provider in securities issued by General Electric Co..
- **Lead or Co-manager:** J.P. Morgan acted as lead or co-manager in a public offering of equity and/or debt securities for General Electric Co. within the past 12 months.
- **Client:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as clients: General Electric Co..
- **Client/Investment Banking:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as investment banking clients: General Electric Co..
- **Client/Non-Investment Banking, Securities-Related:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as clients, and the services provided were non-investment-banking, securities-related: General Electric Co..
- **Client/Non-Securities-Related:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as clients, and the services provided were non-securities-related: General Electric Co..
- **Investment Banking (past 12 months):** J.P. Morgan received in the past 12 months compensation for investment banking services from General Electric Co..
- **Investment Banking (next 3 months):** J.P. Morgan expects to receive, or intends to seek, compensation for investment banking services in the next three months from General Electric Co..
- **Non-Investment Banking Compensation:** J.P. Morgan has received compensation in the past 12 months for products or services other than investment banking from General Electric Co..
- **Other Significant Financial Interests:** J.P. Morgan owns a position of 1 million USD or more in the debt securities of General Electric Co..

Company-Specific Disclosures: Important disclosures, including price charts and credit opinion history tables, are available for compendium reports and all J.P. Morgan–covered companies by visiting https://www.jpmm.com/research/disclosures, calling 1-800-477-0406, or e-mailing research.disclosure.inquiries@jpmorgan.com with your request. J.P. Morgan's Strategy, Technical, and Quantitative Research teams may screen companies not covered by J.P. Morgan. For important disclosures for these companies, please call 1-800-477-0406 or e-mail research.disclosure.inquiries@jpmorgan.com.

C. Stephen Tusa, Jr CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

General Electric Co. (GE, GE US) Price Chart



Date	Rating	Share Price ($)	Price Target ($)
12-May-16	UW	30 09	27.00
25-Jul-16	UW	31.64	26.00
23-Sep-16	UW	30 04	28.00
13-Jan-17	UW	31 39	29.00
28-Mar-17	UW	29.44	27.00
06-Jul-17	UW	26 31	22.00
20-Sep-17	UW	24 32	22.00
11-Oct-17	UW	23 07	20.00
23-Oct-17	UW	23 83	19.00
01-Nov-17	UW	20 02	17.00
08-Jan-18	UW	18 28	16.00
12-Feb-18	UW	14 82	14.00
13-Mar-18	UW	14.43	11.00

Source: Bloomberg and J.P. Morgan; price data adjusted for stock splits and dividends.
Initiated coverage Sep 07, 2001.

The chart(s) show J.P. Morgan's continuing coverage of the stocks; the current analysts may or may not have covered it over the entire period.
J.P. Morgan ratings or designations: OW = Overweight, N= Neutral, UW = Underweight, NR = Not Rated

Explanation of Equity Research Ratings, Designations and Analyst(s) Coverage Universe:
J.P. Morgan uses the following rating system: Overweight [Over the next six to twelve months, we expect this stock will outperform the average total return of the stocks in the analyst's (or the analyst's team's) coverage universe.] Neutral [Over the next six to twelve months, we expect this stock will perform in line with the average total return of the stocks in the analyst's (or the analyst's team's) coverage universe.] Underweight [Over the next six to twelve months, we expect this stock will underperform the average total return of the stocks in the analyst's (or the analyst's team's) coverage universe.] Not Rated (NR): J.P. Morgan has removed the rating and, if applicable, the price target, for this stock because of either a lack of a sufficient fundamental basis or for legal, regulatory or policy reasons. The previous rating and, if applicable, the price target, no longer should be relied upon. An NR designation is not a recommendation or a rating. In our Asia (ex-Australia and ex-India) and U.K. small- and mid-cap equity research, each stock's expected total return is compared to the expected total return of a benchmark country market index, not to those analysts' coverage universe. If it does not appear in the Important Disclosures section of this report, the certifying analyst's coverage universe can be found on J.P. Morgan's research website, www.jpmorganmarkets.com.

Coverage Universe: Tusa, Jr, Stephen: 3M (MMM), Atkore (ATKR), Dover (DOV), Emerson Electric Co. (EMR), Evoqua Water Technologies (AQUA), Fortive Corp. (FTV), General Electric Co. (GE), HD Supply (HDS), Honeywell (HON), Hubbell Inc. (HUBB), Ingersoll Rand (IR), John Bean Technologies (JBT), Johnson Controls (JCI), Lennox International (LII), Pentair PLC (PNR), Rockwell Automation (ROK), Roper Technologies (ROP), TriMas (TRS), United Technologies (UTX), Watsco (WSO), Wesco International (WCC)

J.P. Morgan Equity Research Ratings Distribution, as of July 02, 2018

	Overweight (buy)	Neutral (hold)	Underweight (sell)
J.P. Morgan Global Equity Research Coverage	47%	41%	13%
IB clients*	54%	48%	40%
JPMS Equity Research Coverage	45%	42%	13%
IB clients*	74%	66%	58%

*Percentage of investment banking clients in each rating category.
For purposes only of FINRA/NYSE ratings distribution rules, our Overweight rating falls into a buy rating category; our Neutral rating falls into a hold rating category; and our Underweight rating falls into a sell rating category. Please note that stocks with an NR designation are not included in the table above.

Equity Valuation and Risks: For valuation methodology and risks associated with covered companies or price targets for covered companies, please see the most recent company-specific research report at http://www.jpmorganmarkets.com, contact the primary analyst or your J.P. Morgan representative, or email research.disclosure.inquiries@jpmorgan.com. For material information about the proprietary models used, please see the Summary of Financials in company-specific research reports and the Company Tearsheets, which are

C. Stephen Tusa, Jr CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

available to download on the company pages of our client website, http://www.jpmorganmarkets.com. This report also sets out within it the material underlying assumptions used.

Equity Analysts' Compensation: The equity research analysts responsible for the preparation of this report receive compensation based upon various factors, including the quality and accuracy of research, client feedback, competitive factors, and overall firm revenues.

Other Disclosures

J.P. Morgan ("JPM") is the global brand name for J.P. Morgan Securities LLC ("JPMS") and its affiliates worldwide. J.P. Morgan Cazenove is a marketing name for the U.K. investment banking businesses and EMEA cash equities and equity research businesses of JPMorgan Chase & Co. and its subsidiaries.

All research reports made available to clients are simultaneously available on our client website, J.P. Morgan Markets. Not all research content is redistributed, e-mailed or made available to third-party aggregators. For all research reports available on a particular stock, please contact your sales representative.

Options related research: If the information contained herein regards options related research, such information is available only to persons who have received the proper option risk disclosure documents. For a copy of the Option Clearing Corporation's Characteristics and Risks of Standardized Options, please contact your J.P. Morgan Representative or visit the OCC's website at https://www.theocc.com/components/docs/riskstoc.pdf

Private Bank Clients: Where you are a client of the private banking businesses offered by JPMorgan Chase & Co. and its subsidiaries ("J.P. Morgan Private Bank"), research is issued to you by J.P. Morgan Private Bank and not by any other division of J.P. Morgan, including but not limited to the J.P. Morgan corporate and investment bank and its research division.

Legal Entities Disclosures
U.S.: JPMS is a member of NYSE, FINRA, SIPC and the NFA. JPMorgan Chase Bank, N.A. is a member of FDIC. **U.K**.: JPMorgan Chase N.A., London Branch, is authorised by the Prudential Regulation Authority and is subject to regulation by the Financial Conduct Authority and to limited regulation by the Prudential Regulation Authority. Details about the extent of our regulation by the Prudential Regulation Authority are available from J.P. Morgan on request. J.P. Morgan Securities plc (JPMS plc) is a member of the London Stock Exchange and is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. Registered in England & Wales No. 2711006. Registered Office 25 Bank Street, London, E14 5JP. **South Africa**: J.P. Morgan Equities South Africa Proprietary Limited is a member of the Johannesburg Securities Exchange and is regulated by the Financial Services Board. **Hong Kong**: J.P. Morgan Securities (Asia Pacific) Limited (CE number AAJ321) is regulated by the Hong Kong Monetary Authority and the Securities and Futures Commission in Hong Kong and/or J.P. Morgan Broking (Hong Kong) Limited (CE number AAB027) is regulated by the Securities and Futures Commission in Hong Kong. **Korea**: This material is issued and distributed in Korea by or through J.P. Morgan Securities (Far East) Limited, Seoul Branch, which is a member of the Korea Exchange(KRX) and is regulated by the Financial Services Commission (FSC) and the Financial Supervisory Service (FSS). **Australia**: J.P. Morgan Securities Australia Limited (JPMSAL) (ABN 61 003 245 234/AFS Licence No: 238066) is regulated by ASIC and is a Market, Clearing and Settlement Participant of ASX Limited and CHI-X. **Taiwan**: J.P. Morgan Securities (Taiwan) Limited is a participant of the Taiwan Stock Exchange (company-type) and regulated by the Taiwan Securities and Futures Bureau. **India:** J.P. Morgan India Private Limited (Corporate Identity Number - U67120MH1992FTC068724), having its registered office at J.P. Morgan Tower, Off. C.S.T. Road, Kalina, Santacruz - East, Mumbai – 400098, is registered with Securities and Exchange Board of India (SEBI) as a 'Research Analyst' having registration number INH000001873. J.P. Morgan India Private Limited is also registered with SEBI as a member of the National Stock Exchange of India Limited (SEBI Registration Number - INB 230675231/INF 230675231/INE 230675231), the Bombay Stock Exchange Limited (SEBI Registration Number - INB 010675237/INF 010675237) and as a Merchant Banker (SEBI Registration Number - MB/INM000002970). Telephone: 91-22-6157 3000, Facsimile: 91-22-6157 3990 and Website: www.jpmipl.com. For non local research reports, this material is not distributed in India by J.P. Morgan India Private Limited. **Thailand**: This material is issued and distributed in Thailand by JPMorgan Securities (Thailand) Ltd., which is a member of the Stock Exchange of Thailand and is regulated by the Ministry of Finance and the Securities and Exchange Commission and its registered address is 3rd Floor, 20 North Sathorn Road, Silom, Bangrak, Bangkok 10500. **Indonesia**: PT J.P. Morgan Securities Indonesia is a member of the Indonesia Stock Exchange and is regulated by the OJK a.k.a. BAPEPAM LK. **Philippines**: J.P. Morgan Securities Philippines Inc. is a Trading Participant of the Philippine Stock Exchange and a member of the Securities Clearing Corporation of the Philippines and the Securities Investor Protection Fund. It is regulated by the Securities and Exchange Commission. **Brazil**: Banco J.P. Morgan S.A. is regulated by the Comissao de Valores Mobiliarios (CVM) and by the Central Bank of Brazil. **Mexico**: J.P. Morgan Casa de Bolsa, S.A. de C.V., J.P. Morgan Grupo Financiero is a member of the Mexican Stock Exchange and authorized to act as a broker dealer by the National Banking and Securities Exchange Commission. **Singapore:** This material is issued and distributed in Singapore by or through J.P. Morgan Securities Singapore Private Limited (JPMSS) [MCI (P) 099/04/2018 and Co. Reg. No.: 199405335R], which is a member of the Singapore Exchange Securities Trading Limited and/or JPMorgan Chase Bank, N.A., Singapore branch (JPMCB Singapore) [MCI (P) 046/09/2018], both of which are regulated by the Monetary Authority of Singapore. This material is issued and distributed in Singapore only to accredited investors, expert investors and institutional investors, as defined in Section 4A of the Securities and Futures Act, Cap. 289 (SFA). This material is not intended to be issued or distributed to any retail investors or any other investors that do not fall into the classes of "accredited investors," "expert investors" or "institutional investors," as defined under Section 4A of the SFA. Recipients of this document are to contact JPMSS or JPMCB Singapore in respect of any matters arising from, or in connection with, the document. **Japan**: JPMorgan Securities Japan Co., Ltd. and JPMorgan Chase Bank, N.A., Tokyo Branch are regulated by the Financial Services Agency in Japan. **Malaysia**: This material is issued and distributed in Malaysia by JPMorgan Securities (Malaysia) Sdn Bhd (18146-X) which is a Participating Organization of Bursa Malaysia Berhad and a holder of Capital Markets Services License issued by the Securities Commission in Malaysia. **Pakistan**: J. P. Morgan Pakistan Broking (Pvt.) Ltd is a member of the Karachi Stock Exchange and regulated by the Securities and Exchange Commission of Pakistan. **Saudi Arabia**: J.P. Morgan Saudi Arabia Ltd. is authorized by the Capital Market Authority of the Kingdom of Saudi Arabia (CMA) to carry out dealing as an agent, arranging, advising and custody, with respect to securities business under licence number 35-07079 and its registered address is at 8th Floor, Al-Faisaliyah Tower, King Fahad Road, P.O. Box 51907, Riyadh 11553, Kingdom of Saudi Arabia. **Dubai**: JPMorgan Chase Bank, N.A., Dubai Branch is regulated by the Dubai Financial Services Authority (DFSA) and its registered address is Dubai International Financial Centre - Building 3, Level 7, PO Box 506551, Dubai, UAE.

Country and Region Specific Disclosures
U.K. and European Economic Area (EEA): Unless specified to the contrary, issued and approved for distribution in the U.K. and the EEA by JPMS plc. Investment research issued by JPMS plc has been prepared in accordance with JPMS plc's policies for managing conflicts of interest arising as a result of publication and distribution of investment research. Many European regulators require a firm to establish, implement and maintain such a policy. Further

C. Stephen Tusa, Jr CFA
(1-212) 622-6623
stephen.tusa@jpmorgan.com

information about J.P. Morgan's conflict of interest policy and a description of the effective internal organisations and administrative arrangements set up for the prevention and avoidance of conflicts of interest is set out at the following link https://www.jpmorgan.com/jpmpdf/1320742677360.pdf. This report has been issued in the U.K. only to persons of a kind described in Article 19 (5), 38, 47 and 49 of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (all such persons being referred to as "relevant persons"). This document must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this document relates is only available to relevant persons and will be engaged in only with relevant persons. In other EEA countries, the report has been issued to persons regarded as professional investors (or equivalent) in their home jurisdiction. **Australia:** This material is issued and distributed by JPMSAL in Australia to "wholesale clients" only. This material does not take into account the specific investment objectives, financial situation or particular needs of the recipient. The recipient of this material must not distribute it to any third party or outside Australia without the prior written consent of JPMSAL. For the purposes of this paragraph the term "wholesale client" has the meaning given in section 761G of the Corporations Act 2001. J.P. Morgan's research coverage universe spans listed securities across the ASX All Ordinaries index, securities listed on offshore markets, unlisted issuers and investment products which Research management deem to be relevant to the investor base from time to time. J.P. Morgan seeks to cover companies of relevance to the domestic and international investor base across all GIC sectors, as well as across a range of market capitalisation sizes. **Germany:** This material is distributed in Germany by J.P. Morgan Securities plc, Frankfurt Branch which is regulated by the Bundesanstalt für Finanzdienstleistungsaufsicht. **Hong Kong:** The 1% ownership disclosure as of the previous month end satisfies the requirements under Paragraph 16.5(a) of the Hong Kong Code of Conduct for Persons Licensed by or Registered with the Securities and Futures Commission. (For research published within the first ten days of the month, the disclosure may be based on the month end data from two months prior.) J.P. Morgan Broking (Hong Kong) Limited is the liquidity provider/market maker for derivative warrants, callable bull bear contracts and stock options listed on the Stock Exchange of Hong Kong Limited. An updated list can be found on HKEx website: http://www.hkex.com.hk. **Korea:** This report may have been edited or contributed to from time to time by affiliates of J.P. Morgan Securities (Far East) Limited, Seoul Branch. **Singapore:** As at the date of this report, JPMSS is a designated market maker for certain structured warrants listed on the Singapore Exchange where the underlying securities may be the securities discussed in this report. Arising from its role as designated market maker for such structured warrants, JPMSS may conduct hedging activities in respect of such underlying securities and hold or have an interest in such underlying securities as a result. The updated list of structured warrants for which JPMSS acts as designated market maker may be found on the website of the Singapore Exchange Limited: http://www.sgx.com. In addition, JPMSS and/or its affiliates may also have an interest or holding in any of the securities discussed in this report – please see the Important Disclosures section above. For securities where the holding is 1% or greater, the holding may be found in the Important Disclosures section above. For all other securities mentioned in this report, JPMSS and/or its affiliates may have a holding of less than 1% in such securities and may trade them in ways different from those discussed in this report. Employees of JPMSS and/or its affiliates not involved in the preparation of this report may have investments in the securities (or derivatives of such securities) mentioned in this report and may trade them in ways different from those discussed in this report. **Taiwan**: Research relating to equity securities is issued and distributed in Taiwan by J.P. Morgan Securities (Taiwan) Limited, subject to the license scope and the applicable laws and the regulations in Taiwan. According to Paragraph 2, Article 7-1 of Operational Regulations Governing Securities Firms Recommending Trades in Securities to Customers (as amended or supplemented) and/or other applicable laws or regulations, please note that the recipient of this material is not permitted to engage in any activities in connection with the material which may give rise to conflicts of interests, unless otherwise disclosed in the "Important Disclosures" in this material. **India:** For private circulation only, not for sale. **Pakistan:** For private circulation only, not for sale. **New Zealand:** This material is issued and distributed by JPMSAL in New Zealand only to persons whose principal business is the investment of money or who, in the course of and for the purposes of their business, habitually invest money. JPMSAL does not issue or distribute this material to members of "the public" as determined in accordance with section 3 of the Securities Act 1978. The recipient of this material must not distribute it to any third party or outside New Zealand without the prior written consent of JPMSAL. **Canada:** The information contained herein is not, and under no circumstances is to be construed as, a prospectus, an advertisement, a public offering, an offer to sell securities described herein, or solicitation of an offer to buy securities described herein, in Canada or any province or territory thereof. Any offer or sale of the securities described herein in Canada will be made only under an exemption from the requirements to file a prospectus with the relevant Canadian securities regulators and only by a dealer properly registered under applicable securities laws or, alternatively, pursuant to an exemption from the dealer registration requirement in the relevant province or territory of Canada in which such offer or sale is made. The information contained herein is under no circumstances to be construed as investment advice in any province or territory of Canada and is not tailored to the needs of the recipient. To the extent that the information contained herein references securities of an issuer incorporated, formed or created under the laws of Canada or a province or territory of Canada, any trades in such securities must be conducted through a dealer registered in Canada. No securities commission or similar regulatory authority in Canada has reviewed or in any way passed judgment upon these materials, the information contained herein or the merits of the securities described herein, and any representation to the contrary is an offence. **Dubai:** This report has been issued to persons regarded as professional clients as defined under the DFSA rules. **Brazil**: Ombudsman J.P. Morgan: 0800-7700847 / ouvidoria.jp.morgan@jpmorgan.com.

General: Additional information is available upon request. Information has been obtained from sources believed to be reliable but JPMorgan Chase & Co. or its affiliates and/or subsidiaries (collectively J.P. Morgan) do not warrant its completeness or accuracy except with respect to any disclosures relative to JPMS and/or its affiliates and the analyst's involvement with the issuer that is the subject of the research. All pricing is indicative as of the close of market for the securities discussed, unless otherwise stated. Opinions and estimates constitute our judgment as of the date of this material and are subject to change without notice. Past performance is not indicative of future results. This material is not intended as an offer or solicitation for the purchase or sale of any financial instrument. The opinions and recommendations herein do not take into account individual client circumstances, objectives, or needs and are not intended as recommendations of particular securities, financial instruments or strategies to particular clients. The recipient of this report must make its own independent decisions regarding any securities or financial instruments mentioned herein. JPMS distributes in the U.S. research published by non-U.S. affiliates and accepts responsibility for its contents. Periodic updates may be provided on companies/industries based on company specific developments or announcements, market conditions or any other publicly available information. Clients should contact analysts and execute transactions through a J.P. Morgan subsidiary or affiliate in their home jurisdiction unless governing law permits otherwise.

"Other Disclosures" last revised August 18, 2018.

Exhibit 2

J.P.Morgan

North America Equity Research

10 October 2018

General Electric Co. (GE US)

Underweight

Price: $13.55
09 Oct 2018

"Voice of the Customer": Turbine Users Feedback Suggests Depth of Technology Issues WorseThan Initially Thought

While consensus seemingly continues to ignore on-the-ground realities in exchange for hope around a new CEO, if the $23B goodwill charge, guide down, and CEO change were not enough, **recently published feedback from a GE H-frame Users Group event (described below) suggests more serious technology issues with the new flagship product.** While most of the focus has been on the technology around the blades, which GE has more or less admitted to with a reference to a fix (see below), details below indicate a myriad of shortfalls in other parts of the turbine that we find hard not to consider "technology flaws". Namely, detailed below is commentary from the Users Group that was coincidentally hosted by Exelon a week after they shut down their plants due to problems. Comments below highlight issues ranging from the blades, which are driving inconsistent levels of service and delayed OE deliveries, to axial fuel staging failure ("AFS"), to excessive vibration, along with a list of 11 other things the author of the article published on CCJ Online refers to as "teething" issues (which implies the other items are beyond teething).

Figure 1: Voice of the H-frame Customer Shows Myriad Technology Issues

Punch-list items	
Digital valve positioners	"Instantaneous" failure of digital valve positioner that leads to GT trip after about 3000 operating hours.
	Temperature-control issues with DVP led to 3 trips.
Water intrusion	Fan/blowers in GT housing reduce heat levels but also create a differential pressure which sucks water in when it rains, which a site in arid climate didn't experience until the first heavy rain. Blowers are redundant and both need to be in service to maintain internal temperature so electrical and digital electronics don't burn up.
	After a lost bearing in motor of a fan, one site had to replace the entire motor
Air-filter cleaning system	After experiencing leaks in some valves, one plant decided to replace all 400 of them, and the communication-system bus connecting to the individual valves failed.
Online washing	Several plants do online washing everyday and had to make modifications to "make sure the pump logic was properly integrated." One user cautioned that the drains are sized for "zero margin," and had to replace a few bad valves and fix loose flanges.
Water carryover	More than one plant has experienced water carryover from evap cooler into gas turbine.
Generator	Flashover event with collector brushes, OEMrecommended reduced number of brushes from 24 (based on nameplate rating) to 12. Generator end windings "required lots of money and work", which the OEMcalls "normal wear and tear". One user cautioned on negotiating with OEM as they could accuse of "improper maintenance"
ST/G bearing leak	A site with a single-shaft combined cycle reported that the No.1 bearing in low-pressure steam turbine/generator sprung a "major leak" and plant had to "limp through the summer".
Miscellaneous heaters	One site experienced "lots of issues with air-cooled condenser" and "lots of workarounds" with startup natural-gas auxiliary heat exchanges, natural-gas performance heat exchanger, air inlet heating system (upstream of the inlet air filters).
Cap effusion plate	An overseas site reported minor cracks detected in combustor-cap effusion plate, following borescope inspection after 8,500 operating hours.
Igniters	Packing leakage and overheated igniter wiring discovered during first inspection. Presented noted an igniter had liberated at another site.
Lift-oil pumps	Failures with lift-oil pumps, tightly designed lube-oil skids. The site found a breaker off of one pump while another wouldn't start.

Stage 1 blade failures	Bucket issue has impacted schedules of machine delivery to US customers. One said that the buckets destined for their machine (first "Gen II" S1Bs) were now being diverted as replacements in the failed units, postponing commercial operating dates (COD). With no commercial operating experience with Gen II hardware, users wonder whether this "fix" would be the right one. The next opportunity to "look at them" in the first machine incorporating it was not expected until a scheduled outage many months out. An operating site cited 9-10 months delay on spare parts while "desperate" for stage 1 blades Another was expecting S1B replacements in 2019, now coming earlier than expected Another got a mix of Gen I and II hardware. Site with several thousand hours on HA.01 machines reported that dampening pins for stage 1 buckets had already been replaced twice.
AFS failure	Axial Fuel staging (AFS) is part of the DLN 2.6+ combustion system. Fuel enters the GT compartment, passes into a ring manifold and is delivered to each combustion chamber via "pig tails". Fuel is then equally distributed to 4 1/2-inch tubes attached on the outside of the "Unibody" (but internal to the combustor), and injected into the hot gas path through four nozzles. This flow path introduces fuel gas downstream of the flame zone and upstream of the turbine first-stage nozzle. The fuel gas auto-ignites, increasing the energy available for the power turbine but with no increase in NOx emissions, allowing for extended turndown while maintaining emissions compliance Failure of key component of HA combustor feature, axial fuel staging (AFS), when the GT was operating at 298 MW. The failure caused internal damage to the combustion system, and damage to the site as AFS breached a combustor can into the turbine compartment, triggering the fire protection system and tripping the unit. 40 of the 48 components on the machine with AFS were replaced. At least two other plants had AFS components replaced as well AFS tube failure during normal operations caused disintegration of two fuel nozzles, damage to Unibody assembly within the combustor, some splatter impinging on first-stage nozzles and buckets within the quadrant of the failed combustor. The failure also caused a breach to combustor wall as hot gases entered the turbine compartment, triggering fire-protection-system heat detectors and protective action of unit trip. Root cause still unknown, pending completion of the analysis by the OEM. A data review revealed an instant spike in NOx, exhaust spreads and low-band combustion dynamics about 45 minutes before unit trip
Vibration	Cold-start transient vibration and start-to-start vibration issues associated with bearing No.3 appeared around 3700 operating hours on HA.02 machines, OEM recently acknowledged these were fleet-wide issues, with half a dozen other machines experiencing the same problems. Increasing vibration levels are associated with thermal changes in the unit, which low-load operations aggravate. OEMdidn't attempt to solve the problem nor corrected the balance with strategically placed weights. Excessive vibration leads to secondary issues such as oil leakage at the defector plate from generator rotor bearings, loose terminal trips, and failures of exhaust-thermocouple attachments, many of which are being replaced Sites correct the issues themselves: one site is testing a prototype thermocouple that may be more robust, while another changed out the seals on leaking generator bearing, added a row of labyrinths and made some adjustments which appear to have corrected the problem.
Complex controls	Several attendees commented on the complexity of H-class control system and shortage of OEMcontrol-system engineers familiar. An attendee said "whenever we do a logic change, GE doesn't have enough controls engineers to support us." Concerns that "digital intelligence is not 100% developed" for these systems. One site blamed a trip on fieldbus error in control system and requested that GT controls be hard-wired Complaint that original GT/G controls had no redundant vibration configuration, cautioning to "be aware of primary-frequency response logic for performance tests" and urged colleagues to "be familiar with foundation Fieldbus and Profibus for controls as applicable to the Mark VIe GT control platform." Incorrect digital valve position (DVP) firmware settings resulted in miscommunication between OEM and sub-vendor.

Source: www.ccj-online.com

The **commentary is a reminder of the hurdles to a "fix" for a Power business that is already set to lose money on a GAAP basis, with pronounced free cash outflows, facing not only macro headwinds, but more competition/overcapacity, and now company specific technology issues. We are not sure what is left to determine "asset value" here as issues like this are not solved by a simple recall and re-ship. These are engineering feats that need to be validated, typically taking time measured in years not months, and in long cycle technology businesses where a new product gets introduced every couple of decades, missing a cycle has long term implications.**

Fundamentally, on the "fix" thesis, we continue to find quite an interesting motivational juxtaposition between the "all hands on deck" commentary from Power management two Fridays ago, with investor calls for dramatic headcount reductions, and the hole many employees and retirees see in their holdings on the back of strategic missteps of former senior management. The other juxtaposition is that GE has highlighted that the "Fieldcore and APM teams are ready to execute" on this fix, while at the same time Bulls continue to claim market share in

the transactional part of services is key to better days. Said differently, **for a company in this position, there is no room for error to deal with these issues while trying to take out costs and fix service levels.** Yes, there have been issues like this in the past (see below) but mostly when the waters were calmer, when there were well equipped experienced teams to deal with something like this and plenty of resources, mostly financial, to cover the losses, with less penetration of guaranteed CSAs, versus the backdrop today which in our view is seemingly the opposite on almost all fronts. Furthermore, Bulls say Power does not matter on the one hand while still pitching $1 in EPS as the valuation anchor, an argument that we think lacks credibility considering the ~$0.40 of Power related earnings explicitly embedded in this number ("normalized" profit and no restructuring), or ~40% of the total. In other words, it matters. In the end, **we continue to believe the news was a legitimate driver of the related stock decline, with enough uncertainty and downside implications for a highly levered company with no available cash flow, and little room for error, to justify further downside, especially from current levels.**

H-frame Users Group held coincidentally a week after blade related shutdown at Exelon. As background, Users Group events are scheduled and organized by utility turbine customers to provide members with an open forum for dialogue and exchange of information to improve operational and maintenance practices around particular products. In Danaher speak, this is "Voice of the Customer" (VOC). For example, there is a Users Group for GE's F-frame technology, as well as others. The GE 7HA Users Conference was held in Fort Worth on September 12-13, and included representatives from over a dozen facilities and five countries, operators of 30+ turbines. Given limited operating experience for the fleet thus far, this appeared to be the inaugural event. This was coincidentally **hosted by Exelon, the US launch customer, a little over one week after the blade issue they had, which is how and why the news was broken within the industry.**

The information recently published is sourced from CCJ Online, an industry journal which noted: *"The scene was reminiscent of the early 1990s when the F-class technology emerged in commercial settings, dozens of units were sold worldwide, engines began operating before any appreciable operating experience had been gained with the fleet leaders, and before long, units were being air-lifted from around the world to have serious deficiencies addressed...We don't preface this article this way to create ill will among users and OEMs, but to remind the community that the evolution of high-energy, highly engineered, cutting-edge power systems is rarely a smooth process. To get to today's landscape of F-class machines humming around the world doing what is expected of them, for example, the industry had to get through a tumultuous early to mid-1990s period which deeply affected all five major large-frame OEMs at the time. Now there are three."* In other words, these types of issues were enough last time around to permanently change the balance of power and structure of the industry, though we don't recall hearing about this volume of technology shortfalls with MHI and/or Siemens.

Meanwhile, Sell Side analysis attaches a somewhat large enough expense number to the fix to acknowledge it as an issue, but not enough to make it "material to the thesis", and then say it's "ring fenced". This misses the point. As per the above, the "fix" likely means they will work to maintain customer plant operations, and then install new blades as they are available. The issue as we see it is that with an unprecedented use of LTSAs, as reflected in their $71B services backlog (ironically viewed by everyone as a positive), they have guaranteed a fixed rate for the customer, and GE has based their margin on their expected productivity which is based on a few major outages and overhauls. Interestingly, despite attrition, and flat to down unit sales, this backlog is UP from 2015, showing how important in "value" these new H-frame deliveries are, typically a 100% capture rate for GE, running against the argument that less than 1% of units makes the problem immaterial. **We view this backlog more as a measure of exposure now versus the positive moat Bulls believe it to be. Indeed, the issue here means likely multiple more overhauls, at GE's expense. Additionally, on the OE side, with the rapid decline in F-frame demand, the future is owned by advanced class turbines like H, and we think higher insurance premiums and customer hesitancy, without the past crutch of GE Capital, means impaired share position and an installed base that will fade.**

Key questions that require more color

What is the total service backlog for the H-frames delivered and on order? This is the first step towards evaluating the ultimate profit impact.

What is the actual "solution" and how do you validate it? Our checks with specialists in the industry, confirmed by comments above, make it hard for us to believe that a true "technology fix" is in place. Indeed, the

entire problem being faced here is about a lack of validation, which takes a commitment to spending and, more so, time, which for competitors is measured in years, not months. As per the above, it's unclear that if the test stand did not catch these items, how, other than running the machines for one year, can customers trust the technology? Our view is that the fix referred to here is temporary and we look forward to more color from management on what the current "solution" actually is, and to which problem exactly. If ultimately the solution results in reduced inspection intervals, then this change will flow through the CSAs, and impair the expected profitability.

What is the cycle time to produce new blades? Typically 12 months from order to delivery, and as per the above, customers are being put into the queue for replacements, as well as OE shipments.

How will you prioritize customers' needs for turbines to be delivered that are in backlog versus the installed base that needs blades? Clearly there are delays, we are curious as to how the line is prioritized.

What experience does current leadership have in dealing with issues like this? The average tenure in charge for GE's Power leadership in OE, Services and the current head of the business is <10 years.

The AGP question. Management made a clear statement in the most recent press release that the issue does not impact AGPs. On AGPs, in sales literature for the 9FB, the company notes clearly that the model has "Advanced Gas Path Features and improved materials provide cooling and longer parts durability." Additionally, a big aspect of the AGP pitch is improved materials to increase output and extend maintenance intervals to 32k hours. Our discussions with technology experts suggest that while there may be some similar materials, the upgraded F frames run at lower temperatures, and this is the reason as to why they are not impacted. We have reached out to two utilities and they have said they do not believe their AGPs are affected.

The Aviation question. As for Aviation, clearly a very serious scenario if diseased, we have reasons to believe this is not a direct read through. While we believe LEAP still has its own challenges and is behind plan (interestingly they had a coating issue as well last year), key differences between HDGTs and aircraft engines are smaller blades and less time at a high temperature (only firing that hot during takeoff and landings). There should be more questions asked, but for now, we don't see a "smoking gun" here.

The mosaic and why it has gotten to this point: catching up in a long cycle technology business rarely works. We continue to get questions as to how GE got to this point. As the news unfolds, and we speak to channel players such as competitors and evaluate the different design approaches here, this outcome becomes less of a surprise to us. Notably, it's not news that GE built a dominant F-frame, and that installed base and the service revenue it generated was the core of the franchise for 15 years. Given that others like MHI have limited F-frame positions, along with less of a cultural mandate for near term returns, which for GE was perpetuated by the need for cash in the downturn, they took a long term view that advanced class machines like their J-class would see a wave of demand as the world turned to gas for baseload, unafraid of cannibalizing the legacy. The validation of their technology is detailed in a recent article in Power Engineering. GE stuck with F-frame technology through the downturn and right up until 2012 when the company announced an initiative called Fastworks, which promised, through the use of a test stand, among other measures, to develop and deliver a new H frame turbine in two years. In fact, management pitched this approach as a revelation with many Sell Side Bulls highlighting it as evidence of cultural change at GE. However, with MHI and Siemens gaining a big advantage on validation with tangible fired hours, we see this as GE making an attempt to catch up. They claimed they could use new materials to make a quantum leap from F-class efficiency to the new H. MHI, for one, uses new materials and extra cooling equipment to get their machine to work, and many competitors were questioning how GE could have made this work. Keep in mind that the 7H machine has established new industry records for power output, efficiency, emissions, and turndown flexibility. These achievements were reported in an earlier article. What would drive GE to take this risk? We know how focused this company was on market share (for optics and for returns), and with coal retirements accelerating and baseload applications driving advanced class demand, they made the push to maintain the 40-50% they felt was their entitlement. It now seems to us that GE overpromised, and likely took on risk for customers to win deals, and these recent developments indicate that the competitors' approach, while coming with a lower near term ROI, was the right approach. We hope for the Bull case that the same types of promises were not made to maintain share in LEAP, another product that promised higher efficiency driven by materials system technology.

Electrical Equipment & Multi-Industry
C. Stephen Tusa, Jr CFA AC
(1-212) 622-6623
stephen.tusa@jpmorgan.com
Bloomberg JPMA TUSA <GO>
Patrick M. Baumann, CFA
(1-212) 622-0160
patrick.m.baumann@jpmchase.com
J.P. Morgan Securities LLC

www.jpmorganmarkets.com

Analyst Certification: The research analyst(s) denoted by an "AC" on the cover of this report certifies (or, where multiple research analysts are primarily responsible for this report, the research analyst denoted by an "AC" on the cover or within the document individually certifies, with respect to each security or issuer that the research analyst covers in this research) that: (1) all of the views expressed in this report accurately reflect his or her personal views about any and all of the subject securities or issuers; and (2) no part of any of the research analyst's compensation was, is, or will be directly or indirectly related to the specific recommendations or views expressed by the research analyst(s) in this report. For all Korea-based research analysts listed on the front cover, they also certify, as per KOFIA requirements, that their analysis was made in good faith and that the views reflect their own opinion, without undue influence or intervention.

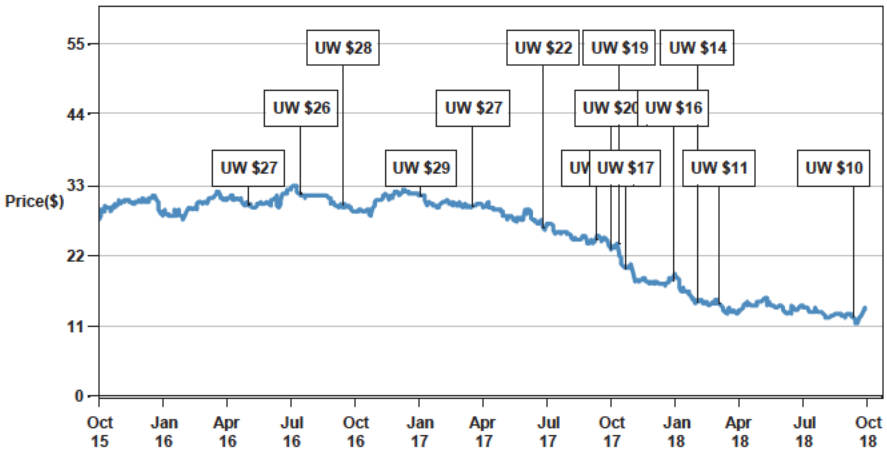
J.P. Morgan does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision.

Important Disclosures

- **Market Maker/ Liquidity Provider:** J.P. Morgan Securities plc and/or an affiliate is a market maker and/or liquidity provider in securities issued by General Electric Co..
- **Lead or Co-manager:** J.P. Morgan acted as lead or co-manager in a public offering of equity and/or debt securities for General Electric Co. within the past 12 months.
- **Client:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as clients: General Electric Co..
- **Client/Investment Banking:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as investment banking clients: General Electric Co..
- **Client/Non-Investment Banking, Securities-Related:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as clients, and the services provided were non-investment-banking, securities-related: General Electric Co..
- **Client/Non-Securities-Related:** J.P. Morgan currently has, or had within the past 12 months, the following entity(ies) as clients, and the services provided were non-securities-related: General Electric Co..
- **Investment Banking (past 12 months):** J.P. Morgan received in the past 12 months compensation for investment banking services from General Electric Co..
- **Investment Banking (next 3 months):** J.P. Morgan expects to receive, or intends to seek, compensation for investment banking services in the next three months from General Electric Co..
- **Non-Investment Banking Compensation:** J.P. Morgan has received compensation in the past 12 months for products or services other than investment banking from General Electric Co..
- **Other Significant Financial Interests:** J.P. Morgan owns a position of 1 million USD or more in the debt securities of General Electric Co..

Company-Specific Disclosures: Important disclosures, including price charts and credit opinion history tables, are available for compendium reports and all J.P. Morgan–covered companies by visiting https://www.jpmm.com/research/disclosures, calling 1-800-477-0406, or e-mailing research.disclosure.inquiries@jpmorgan.com with your request. J.P. Morgan's Strategy, Technical, and Quantitative Research teams may screen companies not covered by J.P. Morgan. For important disclosures for these companies, please call 1-800-477-0406 or e-mail research.disclosure.inquiries@jpmorgan.com.

General Electric Co. (GE, GE US) Price Chart



Date	Rating	Share Price ($)	Price Target ($)
12-May-16	UW	30.09	27.00
25-Jul-16	UW	31.64	26.00
23-Sep-16	UW	30.04	28.00
13-Jan-17	UW	31.39	29.00
28-Mar-17	UW	29.62	27.00
06-Jul-17	UW	26.31	22.00
20-Sep-17	UW	24.32	22.00
11-Oct-17	UW	23.07	20.00
23-Oct-17	UW	23.83	19.00
01-Nov-17	UW	20.02	17.00
08-Jan-18	UW	18.28	16.00
12-Feb-18	UW	14.82	14.00
13-Mar-18	UW	14.43	11.00
20-Sep-18	UW	12.46	10.00

Source: Bloomberg and J.P. Morgan; price data adjusted for stock splits and dividends.
Initiated coverage Sep 07, 2001.

The chart(s) show J.P. Morgan's continuing coverage of the stocks; the current analysts may or may not have covered it over the entire period.
J.P. Morgan ratings or designations: OW = Overweight, N= Neutral, UW = Underweight, NR = Not Rated

Explanation of Equity Research Ratings, Designations and Analyst(s) Coverage Universe:
J.P. Morgan uses the following rating system: Overweight [Over the next six to twelve months, we expect this stock will outperform the average total return of the stocks in the analyst's (or the analyst's team's) coverage universe.] Neutral [Over the next six to twelve months, we expect this stock will perform in line with the average total return of the stocks in the analyst's (or the analyst's team's) coverage universe.] Underweight [Over the next six to twelve months, we expect this stock will underperform the average total return of the stocks in the analyst's (or the analyst's team's) coverage universe.] Not Rated (NR): J.P. Morgan has removed the rating and, if applicable, the price target, for this stock because of either a lack of a sufficient fundamental basis or for legal, regulatory or policy reasons. The previous rating and, if applicable, the price target, no longer should be relied upon. An NR designation is not a recommendation or a rating. In our Asia (ex-Australia and ex-India) and U.K. small- and mid-cap equity research, each stock's expected total return is compared to the expected total return of a benchmark country market index, not to those analysts' coverage universe. If it does not appear in the Important Disclosures section of this report, the certifying analyst's coverage universe can be found on J.P. Morgan's research website, www.jpmorganmarkets.com.

Coverage Universe: Tusa, Jr, Stephen: 3M (MMM), Atkore (ATKR), Dover (DOV), Emerson Electric Co. (EMR), Evoqua Water Technologies (AQUA), Fortive Corp. (FTV), General Electric Co. (GE), HD Supply (HDS), Honeywell (HON), Hubbell Inc. (HUBB), Ingersoll Rand (IR), John Bean Technologies (JBT), Johnson Controls (JCI), Lennox International (LII), Pentair PLC (PNR), Rockwell Automation (ROK), Roper Technologies (ROP), TriMas (TRS), United Technologies (UTX), Watsco (WSO), Wesco International (WCC)

J.P. Morgan Equity Research Ratings Distribution, as of October 01, 2018

	Overweight (buy)	Neutral (hold)	Underweight (sell)
J.P. Morgan Global Equity Research Coverage	47%	40%	13%
IB clients*	54%	49%	37%
JPMS Equity Research Coverage	45%	42%	13%
IB clients*	75%	66%	53%

*Percentage of investment banking clients in each rating category.
For purposes only of FINRA/NYSE ratings distribution rules, our Overweight rating falls into a buy rating category; our Neutral rating falls into a hold rating category; and our Underweight rating falls into a sell rating category. Please note that stocks with an NR designation are not included in the table above.

Equity Valuation and Risks: For valuation methodology and risks associated with covered companies or price targets for covered companies, please see the most recent company-specific research report at http://www.jpmorganmarkets.com, contact the primary analyst or your J.P. Morgan representative, or email research.disclosure.inquiries@jpmorgan.com. For material information about the proprietary models used, please see the Summary of Financials in company-specific research reports and the Company Tearsheets, which are available to download on the company pages of our client website, http://www.jpmorganmarkets.com. This report also sets out within it the material underlying assumptions used.

Equity Analysts' Compensation: The equity research analysts responsible for the preparation of this report receive compensation based upon various factors, including the quality and accuracy of research, client feedback, competitive factors, and overall firm revenues.

Other Disclosures

J.P. Morgan ("JPM") is the global brand name for J.P. Morgan Securities LLC ("JPMS") and its affiliates worldwide. J.P. Morgan Cazenove is a marketing name for the U.K. investment banking businesses and EMEA cash equities and equity research businesses of JPMorgan Chase & Co. and its subsidiaries.

All research reports made available to clients are simultaneously available on our client website, J.P. Morgan Markets. Not all research content is redistributed, e-mailed or made available to third-party aggregators. For all research reports available on a particular stock, please contact your sales representative.

Options related research: If the information contained herein regards options related research, such information is available only to persons who have received the proper option risk disclosure documents. For a copy of the Option Clearing Corporation's Characteristics and Risks of Standardized Options, please contact your J.P. Morgan Representative or visit the OCC's website at https://www.theocc.com/components/docs/riskstoc.pdf

Private Bank Clients: Where you are a client of the private banking businesses offered by JPMorgan Chase & Co. and its subsidiaries ("J.P. Morgan Private Bank"), research is issued to you by J.P. Morgan Private Bank and not by any other division of J.P. Morgan, including but not limited to the J.P. Morgan corporate and investment bank and its research division.

Legal Entities Disclosures
U.S.: JPMS is a member of NYSE, FINRA, SIPC and the NFA. JPMorgan Chase Bank, N.A. is a member of FDIC. **Canada**: J.P. Morgan Securities Canada Inc. is a registered investment dealer, regulated by the Investment Industry Regulatory Organization of Canada and the Ontario Securities Commission and is the participating member on Canadian exchanges. **U.K.**: JPMorgan Chase N.A., London Branch, is authorised by the Prudential Regulation Authority and is subject to regulation by the Financial Conduct Authority and to limited regulation by the Prudential Regulation Authority. Details about the extent of our regulation by the Prudential Regulation Authority are available from J.P. Morgan on request. J.P. Morgan Securities plc (JPMS plc) is a member of the London Stock Exchange and is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. Registered in England & Wales No. 2711006. Registered Office 25 Bank Street, London, E14 5JP. **Germany**: This material is distributed in Germany by J.P. Morgan Securities plc, Frankfurt Branch which is regulated by the Bundesanstalt für Finanzdienstleistungsaufsich and also by J.P. Morgan AG (JPM AG) which is a member of the Frankfurt stock exchange and is regulated by the Federal Financial Supervisory Authority (BaFin), JPM AG is a company incorporated in the Federal Republic of Germany with registered office at Taunustor 1,

60310 Frankfurt am Main, the Federal Republic of Germany. **South Africa**: J.P. Morgan Equities South Africa Proprietary Limited is a member of the Johannesburg Securities Exchange and is regulated by the Financial Services Board. **Hong Kong**: J.P. Morgan Securities (Asia Pacific) Limited (CE number AAJ321) is regulated by the Hong Kong Monetary Authority and the Securities and Futures Commission in Hong Kong and/or J.P. Morgan Broking (Hong Kong) Limited (CE number AAB027) is regulated by the Securities and Futures Commission in Hong Kong. **Korea**: This material is issued and distributed in Korea by or through J.P. Morgan Securities (Far East) Limited, Seoul Branch, which is a member of the Korea Exchange(KRX) and is regulated by the Financial Services Commission (FSC) and the Financial Supervisory Service (FSS). **Australia**: J.P. Morgan Securities Australia Limited (JPMSAL) (ABN 61 003 245 234/AFS Licence No: 238066) is regulated by ASIC and is a Market, Clearing and Settlement Participant of ASX Limited and CHI-X. **Taiwan**: J.P. Morgan Securities (Taiwan) Limited is a participant of the Taiwan Stock Exchange (company-type) and regulated by the Taiwan Securities and Futures Bureau. **India:** J.P. Morgan India Private Limited (Corporate Identity Number - U67120MH1992FTC068724), having its registered office at J.P. Morgan Tower, Off. C.S.T. Road, Kalina, Santacruz - East, Mumbai – 400098, is registered with Securities and Exchange Board of India (SEBI) as a 'Research Analyst' having registration number INH000001873. J.P. Morgan India Private Limited is also registered with SEBI as a member of the National Stock Exchange of India Limited (SEBI Registration Number - INB 230675231/INF 230675231/INE 230675231), the Bombay Stock Exchange Limited (SEBI Registration Number - INB 010675237/INF 010675237) and as a Merchant Banker (SEBI Registration Number - MB/INM000002970). Telephone: 91-22-6157 3000, Facsimile: 91-22-6157 3990 and Website: www.jpmipl.com. For non local research reports, this material is not distributed in India by J.P. Morgan India Private Limited. **Thailand**: This material is issued and distributed in Thailand by JPMorgan Securities (Thailand) Ltd., which is a member of the Stock Exchange of Thailand and is regulated by the Ministry of Finance and the Securities and Exchange Commission and its registered address is 3rd Floor, 20 North Sathorn Road, Silom, Bangrak, Bangkok 10500. **Indonesia**: PT J.P. Morgan Securities Indonesia is a member of the Indonesia Stock Exchange and is regulated by the OJK a.k.a. BAPEPAM LK. **Philippines**: J.P. Morgan Securities Philippines Inc. is a Trading Participant of the Philippine Stock Exchange and a member of the Securities Clearing Corporation of the Philippines and the Securities Investor Protection Fund. It is regulated by the Securities and Exchange Commission. **Brazil**: Banco J.P. Morgan S.A. is regulated by the Comissao de Valores Mobiliarios (CVM) and by the Central Bank of Brazil. **Mexico**: J.P. Morgan Casa de Bolsa, S.A. de C.V., J.P. Morgan Grupo Financiero is a member of the Mexican Stock Exchange and authorized to act as a broker dealer by the National Banking and Securities Exchange Commission. **Singapore:** This material is issued and distributed in Singapore by or through J.P. Morgan Securities Singapore Private Limited (JPMSS) [MCI (P) 099/04/2018 and Co. Reg. No.: 199405335R], which is a member of the Singapore Exchange Securities Trading Limited and/or JPMorgan Chase Bank, N.A., Singapore branch (JPMCB Singapore) [MCI (P) 046/09/2018], both of which are regulated by the Monetary Authority of Singapore. This material is issued and distributed in Singapore only to accredited investors, expert investors and institutional investors, as defined in Section 4A of the Securities and Futures Act, Cap. 289 (SFA). This material is not intended to be issued or distributed to any retail investors or any other investors that do not fall into the classes of "accredited investors," "expert investors" or "institutional investors," as defined under Section 4A of the SFA. Recipients of this document are to contact JPMSS or JPMCB Singapore in respect of any matters arising from, or in connection with, the document. **Japan**: JPMorgan Securities Japan Co., Ltd. and JPMorgan Chase Bank, N.A., Tokyo Branch are regulated by the Financial Services Agency in Japan. **Malaysia**: This material is issued and distributed in Malaysia by JPMorgan Securities (Malaysia) Sdn Bhd (18146-X) which is a Participating Organization of Bursa Malaysia Berhad and a holder of Capital Markets Services License issued by the Securities Commission in Malaysia. **Pakistan**: J. P. Morgan Pakistan Broking (Pvt.) Ltd is a member of the Karachi Stock Exchange and regulated by the Securities and Exchange Commission of Pakistan. **Saudi Arabia**: J.P. Morgan Saudi Arabia Ltd. is authorized by the Capital Market Authority of the Kingdom of Saudi Arabia (CMA) to carry out dealing as an agent, arranging, advising and custody, with respect to securities business under licence number 35-07079 and its registered address is at 8th Floor, Al-Faisaliyah Tower, King Fahad Road, P.O. Box 51907, Riyadh 11553, Kingdom of Saudi Arabia. **Dubai**: JPMorgan Chase Bank, N.A., Dubai Branch is regulated by the Dubai Financial Services Authority (DFSA) and its registered address is Dubai International Financial Centre - Building 3, Level 7, PO Box 506551, Dubai, UAE.

Country and Region Specific Disclosures

U.K. and European Economic Area (EEA): Unless specified to the contrary, issued and approved for distribution in the U.K. and the EEA by JPMS plc. Investment research issued by JPMS plc has been prepared in accordance with JPMS plc's policies for managing conflicts of interest arising as a result of publication and distribution of investment research. Many European regulators require a firm to establish, implement and maintain such a policy. Further information about J.P. Morgan's conflict of interest policy and a description of the effective internal organisations and administrative arrangements set up for the prevention and avoidance of conflicts of interest is set out at the following link https://www.jpmorgan.com/jpmpdf/1320742677360.pdf. This report has been issued in the U.K. only to persons of a kind described in Article 19 (5), 38, 47 and 49 of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (all such persons being referred to as "relevant persons"). This document must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this document relates is only available to relevant persons and will be engaged in only with relevant persons. In other EEA countries, the report has been issued to persons regarded as professional investors (or equivalent) in their home jurisdiction. **Australia:** This material is issued and distributed by JPMSAL in Australia to "wholesale clients" only. This material does not take into account the specific investment objectives, financial situation or particular needs of the recipient. The recipient of this material must not distribute it to any third party or outside Australia without the prior written consent of JPMSAL. For the purposes of this paragraph the term "wholesale client" has the meaning given in section 761G of the Corporations Act 2001. J.P. Morgan's research coverage universe spans listed securities across the ASX All Ordinaries index, securities listed on offshore markets, unlisted issuers and investment products which Research management deem to be relevant to the investor base from time to time. J.P. Morgan seeks to cover companies of relevance to the domestic and international investor base across all GIC sectors, as well as across a range of market capitalisation sizes. **Germany:** This material is distributed in Germany by J.P. Morgan Securities plc, Frankfurt Branch which is regulated by the Bundesanstalt für Finanzdienstleistungsaufsicht. **Hong Kong:** The 1% ownership disclosure as of the previous month end satisfies the requirements under Paragraph 16.5(a) of the Hong Kong Code of Conduct for Persons Licensed by or Registered with the Securities and Futures Commission. (For research published within the first ten days of the month, the disclosure may be based on the month end data from two months prior.) J.P. Morgan Broking (Hong Kong) Limited is the liquidity provider/market maker for derivative warrants, callable bull bear contracts and stock options listed on the Stock Exchange of Hong Kong Limited. An updated list can be found on HKEx website: http://www.hkex.com.hk. **Korea:** This report may have been edited or contributed to from time to time by affiliates of J.P. Morgan Securities (Far East) Limited, Seoul Branch. **Singapore:** As at the date of this report, JPMSS is a designated market maker for certain structured warrants listed on the Singapore Exchange where the underlying securities may be the securities discussed in this report. Arising from its role as designated market maker for such structured warrants, JPMSS may conduct hedging activities in respect of such underlying securities and hold or have an interest in such underlying securities as a result. The updated list of structured warrants for which JPMSS acts as designated market maker may be found on the website of the Singapore Exchange Limited: http://www.sgx.com. In addition, JPMSS and/or its affiliates may also have an interest or holding in any of the securities discussed in this report – please see the Important Disclosures section above. For securities where the holding is 1% or greater, the holding may be found in the Important Disclosures section above. For all other securities mentioned in this report, JPMSS and/or its affiliates may have a holding of less than 1% in such securities and may trade them in ways different from those discussed in this report. Employees of JPMSS and/or its affiliates not involved in the preparation of this report may have investments in the securities (or derivatives of such securities) mentioned in this report and may trade them in ways different from those discussed in this report. **Taiwan**: Research relating to equity securities is issued and distributed in Taiwan by J.P. Morgan Securities (Taiwan) Limited, subject to the license scope and the applicable laws and the regulations in Taiwan. According to Paragraph 2, Article 7-1 of Operational Regulations Governing Securities Firms Recommending Trades in Securities to Customers (as amended or supplemented) and/or other applicable laws or regulations, please note that the recipient of this material is not permitted to engage in any activities in connection with the material which may give rise to conflicts of interests, unless otherwise disclosed in the "Important Disclosures" in this material. **India:** For private circulation only, not for sale. **Pakistan:** For private circulation only, not for sale. **New Zealand:** This material is issued and distributed by JPMSAL in New Zealand only to persons whose principal business is the investment of money or who, in the course of and for the purposes of their business, habitually invest money. JPMSAL does not issue or distribute

this material to members of "the public" as determined in accordance with section 3 of the Securities Act 1978. The recipient of this material must not distribute it to any third party or outside New Zealand without the prior written consent of JPMSAL. **Canada:** The information contained herein is not, and under no circumstances is to be construed as, a prospectus, an advertisement, a public offering, an offer to sell securities described herein, or solicitation of an offer to buy securities described herein, in Canada or any province or territory thereof. Any offer or sale of the securities described herein in Canada will be made only under an exemption from the requirements to file a prospectus with the relevant Canadian securities regulators and only by a dealer properly registered under applicable securities laws or, alternatively, pursuant to an exemption from the dealer registration requirement in the relevant province or territory of Canada in which such offer or sale is made. The information contained herein is under no circumstances to be construed as investment advice in any province or territory of Canada and is not tailored to the needs of the recipient. To the extent that the information contained herein references securities of an issuer incorporated, formed or created under the laws of Canada or a province or territory of Canada, any trades in such securities must be conducted through a dealer registered in Canada. No securities commission or similar regulatory authority in Canada has reviewed or in any way passed judgment upon these materials, the information contained herein or the merits of the securities described herein, and any representation to the contrary is an offence. **Dubai:** This report has been issued to persons regarded as professional clients as defined under the DFSA rules. **Brazil**: Ombudsman J.P. Morgan: 0800-7700847 / ouvidoria.jp.morgan@jpmorgan.com.

General: Additional information is available upon request. Information has been obtained from sources believed to be reliable but JPMorgan Chase & Co. or its affiliates and/or subsidiaries (collectively J.P. Morgan) do not warrant its completeness or accuracy except with respect to any disclosures relative to JPMS and/or its affiliates and the analyst's involvement with the issuer that is the subject of the research. All pricing is indicative as of the close of market for the securities discussed, unless otherwise stated. Opinions and estimates constitute our judgment as of the date of this material and are subject to change without notice. Past performance is not indicative of future results. This material is not intended as an offer or solicitation for the purchase or sale of any financial instrument. The opinions and recommendations herein do not take into account individual client circumstances, objectives, or needs and are not intended as recommendations of particular securities, financial instruments or strategies to particular clients. The recipient of this report must make its own independent decisions regarding any securities or financial instruments mentioned herein. JPMS distributes in the U.S. research published by non-U.S. affiliates and accepts responsibility for its contents. Periodic updates may be provided on companies/industries based on company specific developments or announcements, market conditions or any other publicly available information. Clients should contact analysts and execute transactions through a J.P. Morgan subsidiary or affiliate in their home jurisdiction unless governing law permits otherwise.

"Other Disclosures" last revised October 06, 2018.

Document Content(s)