COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE BACKUP POWER SUPPLY PLAN OF DUKE ENERGY KENTUCKY, INC.	))	Case No. 2021-00086

RESPONSE TO COMMISSION STAFF'S FINAL ORDER DATED NOVEMBER 30, 2021 REGARDING DUKE ENERGY KENTUCKY, INC.'S BACK-UP POWER SUPPLY PLAN

I. <u>Introduction</u>

Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) submits the following response to the Kentucky Public Service Commission's (Commission) November 30, 2021, Order in Case No. 2020-00086 (Order). Among other things, the Order approved the Company's back-up power supply plan through May 31, 2022, and directed the Company to, "… evaluate whether there is real risk and a need for a back-up power supply plan and provide support whether a back-up power supply plan is necessary. Duke Kentucky should also provide a long-term cost effectiveness analysis of its back-up power supply plans."

In response to the Commission's directives, the Company submits this filing analyzing its historic back-up power supply plans and addressing the need for an ongoing plan. Although this response primarily addresses how the Company manages situations when the amount of customer demand is greater than the amount of generation produced due to a forced outage, the Company additionally briefly outlines a new full hedging construct to limit customer fuel rate volatility and increase price certainty that will be proposed in a future filing.

II. Analysis

A. Overview of Duke Energy Kentucky's Generation Portfolio and Participation in PJM

Duke Energy Kentucky currently owns and operates approximately 1,062 net installed megawatts (MW) of generating capacity, provided by two assets, the East Bend Unit 2 Generating Station (East Bend) and the Woodsdale Generating Station (Woodsdale). East Bend is an approximate 600-megawatt (MW) (net rating)[1] coal-fired base load unit located along the Ohio River in Boone County, Kentucky. The Company's peaking requirements are met with Woodsdale, a six-unit natural gas-fired combustion turbine (CT) with approximately 462 MW (net summer rating) located in Trenton, Ohio. These assets are dispatched into PJM, which maintains functional control of the transmission system within its footprint including the Duke Energy Ohio/Kentucky system.

Duke Energy Kentucky has been a member of PJM since January 1, 2012. PJM's electric market consists of energy, capacity, ancillary services markets (ASM), and a financial transmission rights market. PJM's operation is governed by agreements approved by the Federal Energy Regulatory Commission (FERC), including the Operating Agreement, Open Access Transmission Tariff (OATT), and the Reliability Assurance Agreement (RAA). As a member of PJM, for PJM energy markets, Duke Energy Kentucky is subject to these agreements, which among other things require Duke

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[1] The net ratings represent the amount of power that the Company can dispatch from the plants after some portion of the gross power output is used to power the plant machinery.

Energy Kentucky to offer all of its available generation to PJM and to purchase its customer energy load requirements from the PJM Day-Ahead or Real-Time Energy Markets. Consistent with its PJM membership, the Company meets all energy needs through the PJM Energy Market and does not currently purchase any energy outside of PJM. Through PJM's Day-Ahead Market, market participants can mitigate their exposure to real-time price risk by selling available generation and purchasing forecasted demand in the Day-Ahead Energy Market. Duke Energy Kentucky submits demand bids and supply offers as both a load serving entity (LSE) and a generator owner, respectively. Thus, the Company simultaneously functions as both a buyer and seller to serve its retail electric customers.

As a base load unit, when operating East Bend provides most of the hedge to PJM energy prices, while Woodsdale station provides a hedge against very high energy prices during coincident periods of peak load in the RTO and the Duke Energy Kentucky load zone. Since generation from the Company owned generating units and customer demand are independent of each other, the amount of generation produced and customer demand are almost never equal. Thus, in an hour when the amount of Company generation is greater than customer demand, there is a resulting non-native sale of energy to PJM. When the amount of Company generation is lower than customer demand, there is a resulting energy purchase from PJM to supply customer demand. This energy purchase could be due to a scheduled or forced outage at one of the Companies generating units or could be due to the fact that energy was cheaper to purchase from PJM than the cost to generate energy from one of the Companies generating units, resulting in a savings to the customer. The back-up plan only pertains to the PJM energy market.

For the PJM capacity market, the PJM OATT and RAA specify the obligations and compensation to LSEs for supplying capacity. Consistent with the Commission's Order in Case No. 2010-00203, as a condition of Duke Energy Kentucky becoming a member of PJM, the Commission required the Company to participate in PJM as an FRR entity until such time as it received Commission approval to participate in the PJM capacity auctions. To date, the Company has not requested such permission, but continues to evaluate the merits of exiting the FRR obligation and becoming a full RPM auction participant. Under the FRR construct, an LSE must annually submit a preliminary three-year forward, and a final current year FRR capacity plan that meets a PJM defined customer capacity obligation (FRR Plan). The FRR Plan must identify the unit-specific generating or demand response resources that will be providing the MWs of capacity that will fulfill the LSE's customer obligation. FRR allows the LSE to match its customer reliability requirement to its own generation, demand response, energy efficiency and/or transmission resources, while still being permitted to sell some excess supply into RPM.

As an FRR entity, Duke Energy Kentucky must secure and commit unit-specific generation resources to meet the full load capacity requirements for its customers in advance of the PJM BRA through its FRR Plan. The FRR Plan is forward-looking in that it covers the Delivery Year three years into the future. Presently, the load requirements include both the forecasted load of Duke Energy Kentucky's customers, as well as the reserve requirement mandated by PJM. Duke Energy Kentucky would face severe penalties and limitations on its ability to choose the FRR option if PJM were to deem either its initial or final FRR plans to be insufficient or it's generation otherwise non-compliant with PJM requirements.

B. Prior Supply Plan Analysis

1. Overview of Analysis

As the commission is aware, the Company's back-up power supply plan is to utilize fixed-priced financial swap contracts to lock-in the price of power during scheduled outages and PJM energy market purchases during forced outages. In the two prior back-up power supply plan applications in 2016 and 2020, the Company evaluated but choose not to purchase any of the proposal options received in the Request for Proposals (RFP's). Each of the alternatives evaluated were not anticipated to result in a cost-effective solution, meaning potential benefits did not outweigh the anticipated costs. At the time those evaluations were completed, and conclusions reached, the Company relied upon forecasted data for fuel, power prices, outages, and other inputs.

However, to determine the performance of the prior back-up power supply plans as directed by the Commission, the Company performed a hindsight review and re-evaluated several of those prior alternative-solution proposals as initially submitted by bidders, and compared those proposals to the selected plan, but with using actual data. Thus, data such as actual natural gas prices, unit outages, and PJM power prices are now known for those periods previously analyzed with forecasted data. With this actual data, a hypothetical analysis was completed to approximate the results if the Company has selected a different plan. The Company selected several of the lower-cost proposals from the prior RFP to "test" the cost-effectiveness of those potential solutions verses the approved plan. Details of this analysis are included in Attachment 1 to this filing.

2. The Analysis

The hindsight analysis conducted shows that each of the alternative options would not have produced a cost-effective result, meaning each proposal resulted in costs that were greater than the purported benefit of that option. Further, since the options that were selected were the lowest cost options, the options that were not selected would have shown larger losses than those selected. Thus, using this hindsight analysis, the customer was better off in every case with the approved plan, and it was indeed the correct strategy to not pursue any of the alternative options.

It should be acknowledged however, that had any of these alternative solutions analyzed in this hindsight review demonstrated a positive value, it would not necessarily mean the selected plan was imprudent or unreasonable. The Company's initial analysis was made using the best available information at the time. There is no guarantee that the alternative solution would actually have been selected, nor that Duke Energy Kentucky would have exercised the selected contract in the most optimum manner possible in every occurrence. Choosing the most optimum exercise of the available options again assumed perfection, which is typically not possible, since at the time the option would have been exercised the future value of each remaining option would not been known in the case when a limited number of option strikes were available.

Results of the analysis contained in Attachment 1 shows that each of the alternative options analyzed would not have produced a cost-effective result for the customer and are summarized below:

- **2016 RFP Backstand Call Option Analysis Overview**: 4 options were analyzed.

    - The cost of the 4 options would have cost Kentucky customers between $25,331,106 and $42,466,786 each.
- **2016 RFP Daily Call Analysis Overview:** 4 options were analyzed.
    - The cost of the 4 options would have cost Kentucky customers between $24,698,840 and $94,320,098 each.
- **2016 RFP Fixed Strike Call Analysis Overview:** 8 options were analyzed.
    - The cost of the 8 options would have cost Kentucky customers between $8,446,498 and $27,156,012 each.
- **2016 RFP Insurance Analysis Overview:** the best 4 options were analyzed.
    - The cost of the 4 options would have cost Kentucky customers between $2,331,322 and $11,044,891 each.
- **2020 RFP Daily Call Analysis Overview:** the best 7 options were analyzed.
    - The cost of the 7 options would have cost Kentucky customers between $531,498 and $2,214,965 each.
- **2020 RFP Insurance Analysis Overview:** the best 6 options were analyzed.
    - The cost of the 6 options would have cost Kentucky customers between $512,356 and $3,372,954 each.

3. Scheduled Outage Hedging Results and Recommendations

As mentioned, the Company has utilized fixed-priced financial swap contracts to lock-in the price of power during scheduled outages, mainly for East Bend. Although the result of these forward hedges did not always show a positive value, as their purpose is to limit customer fuel rate volatility and increase price certainly during times when East Bend is in a scheduled outage, the margin (profit and loss) of these hedges have realized a positive value to the Customer of $3,659,471 since 2006. Additionally, if only the past 5 years are used (2017-2021), these hedges have realized almost the same positive value to the Customer of $3,673,831. Please refer to Confidential Attachment 2, Scheduled Outage Hedging Gains & Losses 2006-2021.

The benefit of the Company's strategy to lock in energy prices during scheduled outages and to limit fuel rate volatility is apparent. Customers have benefitted from this strategy in real dollars of savings as depicted in Confidential Attachment 2 and avoided higher costs of alternative back-up supply plan alternatives.

III. <u>Recommendations</u>

While the Company does not believe a continued and periodic analysis of back-up power supply plan options is no longer necessary in PJM, the Company does believe that continuing the existing strategy of hedging for scheduled outages to mitigate price volatility is meritorious, beneficial to customers, and should continue. The Company requests, to the extent necessary, that the Commission permit the Company to continue this strategy going forward until the Company can demonstrate the reasonableness of an alternative solution. The Company proposes to continue to utilize fixed-priced financial swap contracts to manage the Company's scheduled outages as it has done since 2006 going forward.

The benefits of the Company's hedging strategy have held true for nearly two decades, which prompts the consideration of whether a more robust hedging program could be beneficial to customers. The primary difference between a full hedging program and what the Company is currently engaging is an additional viewpoint of when there is an expectation to be short energy on a forward basis, either due to potential forced outages or when Company generation is forecasted to be utilized less due to the fact that energy from PJM is the more economic (lower cost) resource to serve customer demand. For example, currently if the Company is "economically short" energy, this energy is purchased at the point this shortfall occurs in the PJM Day-Ahead or Real-Time Energy markets when the amount of generation from cleared generation offers is lower than the amount of customer demand purchased through the demand bid. Under a full hedging program, this expected shortfall of energy could be price hedged further from the point of occurrence, such as months in advance through fixed price financial swap contracts similar to how the Company manages scheduled outages today, or in either the PJM Day-Ahead or Real-Time energy markets.

The Company intends to examine this potential broader hedging strategy further and will report back to the Commission in a future filing. The Company will make a formal filing for approval by the Commission prior to implementing such robust hedging program.

IV. **Conclusion**

In summary the Company recommends the following with regards to its back-up power supply plan beyond May 31, 2022:

- Discontinue conducting periodic formalized Request for Proposals
- Continue the use of fixed price financial swap contracts to manage scheduled outages
- Investigate a full hedging proposal with the during the remainder of 2022 with submission of details in a future separate filing.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document being filed in paper medium; that the electronic filing was transmitted to the Commission on March 3rd, 2022; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

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Duke Energy Kentucky
Back-Up Power Supply Plan
RFP Historical Outage Application Analysis

RFP Overview

- Bids received during the 2016 and 2020 DEK Back-Up Power Supply Plan Request for Proposals (RFP) were re-analyzed using historical (actual) PJM Locational Marginal Prices (LMP) data, DEK Generating Unit Outage data, and Natural Gas price data
- 2016 RFP Covered 6/2017-5/2020
- 2020 RFP Covered 6/2021-5/2024
- An extension was granted between the two RFPs, so there is no basis for comparison for the time period 6/2020-5/2021
- In the absence of data, DEK utilized 2-year 2020 RFP bids that cover 6/2021-5/2023 for 6/2020-12/2021

2016 RFP Bid Overview

- Bidder 1
  - Backstand Energy Call Options (4)
  - Daily Call Options (4)
  - Fixed Strike Daily Call Options (Additional) – (8)
- Bidder 2
  - Insurance Bids for 1-2 Years (Less Attractive than Swiss Re)
- Bidder 3
  - Insurance Bids for 2-3 Years (20)

Product Parameters – Backstand Energy Call Options	
Condition Precedent	Unplanned Outage at East Bend Unit 2
Term	2-3 years in the June 1, 2017 – May 31, 2020 timeframe Term 1: June 1, 2017-May 31, 2019 Term 2: June 1, 2017-May 31, 2020
Minimum Size Offering	50 MW per Hour
Maximum Size Offering	600 MW per Hour (50 MW Increments)
Power Price Index (Settlement Point)	PJM AD Hub (Preferred), PJM Western Hub
Gas Price Index	Henry Hub
Coal Price Index	NYMEX Coal
Gas Heat Rate Index	7.0 MMBtu/MWh
	11.0 MMBtu/MWh
Coal Heat Rate Index	10.0 MMBtu/MWh
Fixed Strike Price	$/MWh
Time Period Covered	16 hours weekday on-peak (HE 0800 EPT - 2300 EPT) or (07:00 am EPT through 11:00 PM EPT)
Exercise Notification	10:30 AM EPT Day Ahead (including Sunday notification for Monday)
Strike Limitations	15 Strikes/Year
	25 Strikes/Year
	40 Strikes/Year
	Unlimited Strikes

Product Parameters – Daily Call Options	
Condition Precedent	None
Term	2-3 years in the June 1, 2017 – May 31, 2020 timeframe Term 1: June 1, 2017-May 31, 2019 Term 2: June 1, 2017-May 31, 2020
Minimum Size Offering	50 MW per Hour
Maximum Size Offering	600 MW per Hour (50 MW Increments)
Power Price Index (Settlement Point)	PJM AD Hub (Preferred), PJM Western Hub
Gas Price Index	Henry Hub
Coal Price Index	NYMEX Coal
Gas Heat Rate Index	7.0 MMBtu/MWh
	11.0 MMBtu/MWh
Coal Heat Rate Index	10 MMBtu/MWh
Fixed Strike Price	$/MWh
Time Period Covered	16 hours weekday on-peak (HE 0800 EPT - 2300 EPT) or (07:00 am EPT through 11:00 PM EPT)
Exercise Notification	10:30 AM EPT Day Ahead (including Sunday notification for Monday)
Strike Limitations	15 Strikes/Year
	25 Strikes/Year
	40 Strikes/Year
	Unlimited Strikes

Product Parameters – Insurance Products	
Condition Precedent	Unplanned Outage at East Bend Unit 2
Term	2-3 years in the June 1, 2017 – May 31, 2020 timeframe Term 1: June 1, 2017 – May 31, 2019 Term 2: June 1, 2017 – May 31, 2020
Minimum Size Offering	50 MW per Hour
Maximum Size Offering	600 MW per Hour (50 MW Increments)
Power Price Index (Settlement Point)	PJM AD Hub (Preferred), PJM Western Hub
Fixed Strike Price/Insured Price	$23/MWh
Annual Deductible	$0.5 million
Annual Premiums	Please Provide
Time Period Covered	16 hours weekday on-peak (HE 0800 EPT - 2300 EPT) or (07:00 am EPT through 11:00 PM EPT)
Event Duration Limit	Please provide premium quotes based on consecutive 15-day and consecutive 180-day event duration limits respectively
Annual Insurance Payment Caps/Policy Limit	Please Provide premium quotes based on $10 million and $20 million policy limits respectively
Time Deductible	Please use consecutive 0-hour, 48-hour and 168-hour (only applicable to 180 day event duration limit) time deductible respectively.

2016 RFP Assumptions

- 2016 DEK Backstand RFP Study period was 6/2017 – 5/2020
- Historical Henry Hub gas prices and Historical PJM AD Hub Day-Ahead (DA) LMP's were used for analysis along with historical outages from North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) and historical Henry Hub gas prices
- Products included backstand calls (dependent on actual outage), insurance (dependent on actual outage), daily heat rate calls (independent of outage) and fixed strike calls (independent of outage)
- All Bids covered weekday peaks only (Hours 8 – 23) and had to be utilized for the entire period
- Insurance bids allowed for derates and strikes in 50 MW increments
- Bids were used when:
  - The outage was at least one 16-hour period long
  - The average LMP cost of the 16-hour period was greater than the strike price
- Only forced outages and derates were considered
  - Longest actual forced outage was 8 days
  - Many forced outages converted to scheduled outages after a period of time
  - Outages labeled scheduled or reserve shutdown were not considered

Outages for the 2016 RFP Planning Term

Unit	Event No	Event Start	Event End	Event Duration (Hours)	Event Type	Forced, Scheduled, or Other	Cause Code	Event Duration (Hours)	Event Duration (Days)	Equivalent (Hours)	Equivalant Energy Lost (MWh)	Net Maximum Capability (MW)	Net Availability Capability (MW)	Derate (MW)
East Bend Steam-2	26	6/30/17 14:41	7/9/17 1:09	202.00	U1	Forced	4800	202.47	8.44	202.47	121,480	600	0	600
East Bend Steam-2	33	7/22/17 9:49	7/23/17 12:00	26.00	D1	Forced	3199	26.18	1.09	0.04	24	600	599	1
East Bend Steam-2	45	9/15/17 13:50	9/18/17 10:30	68.00	U1	Forced	1050	68.67	2.86	68.67	41,200	600	0	600
East Bend Steam-2	48	9/19/17 7:30	9/22/17 11:00	75.00	D1	Forced	3199	75.50	3.15	8.22	4,932	600	535	65
East Bend Steam-2	51	9/25/17 13:00	9/27/17 19:00	54.00	D1	Forced	3199	54.00	2.25	1.10	659	600	588	12
East Bend Steam-2	58	11/8/17 9:00	11/10/17 1:00	40.00	D1	Forced	1040	40.00	1.67	0.60	360	600	591	9
East Bend Steam-2	62	12/6/17 20:34	12/9/17 11:40	63.00	U1	Forced	1050	63.10	2.63	63.10	37,860	600	0	600
East Bend Steam-2	8	2/3/18 1:37	2/5/18 6:40	53.00	U1	Forced	1040	53.05	2.21	53.05	31,830	600	0	600
East Bend Steam-2	20	6/21/18 4:36	6/29/18 7:20	194.00	D1	Forced	1850	194.73	8.11	37.74	22,644	600	484	116
East Bend Steam-2	32	8/16/18 10:15	8/22/18 17:26	151.00	D1	Forced	3220	151.18	6.30	6.47	3,882	600	574	26
East Bend Steam-2	33	8/25/18 5:00	8/26/18 19:26	38.00	D1	Forced	3220	38.43	1.60	2.15	1,291	600	566	34
East Bend Steam-2	36	9/2/18 20:18	9/6/18 21:00	96.00	D1	Forced	1455	96.70	4.03	6.45	3,868	600	560	40
East Bend Steam-2	35	9/12/18 14:56	9/13/18 21:00	30.00	U1	Forced	3619	30.07	1.25	30.07	18,040	600	0	600
East Bend Steam-2	40	10/3/18 0:45	10/6/18 8:08	79.00	U1	Forced	1060	79.38	3.31	79.38	47,630	600	0	600
East Bend Steam-2	43	11/21/18 13:52	11/23/18 5:08	39.00	U1	Forced	3110	39.27	1.64	39.27	23,560	600	0	600
East Bend Steam-2	50	12/3/18 14:04	12/5/18 13:04	47.00	U1	Forced	1020	47.00	1.96	47.00	28,200	600	0	600
East Bend Steam-2	6	1/21/19 2:25	1/22/19 15:43	37.00	D1	Forced	0340	37.30	1.55	1.60	962	600	574	26
East Bend Steam-2	8	3/30/19 11:00	4/3/19 0:00	85.00	U1	Forced	3110	85.00	3.54	85.00	51,000	600	0	600
East Bend Steam-2	18	5/5/19 20:00	5/7/19 20:00	48.00	D1	Forced	8250	48.00	2.00	17.44	10,463	600	382	218
East Bend Steam-2	15	5/28/19 0:00	5/30/19 19:48	67.00	D4	Forced	8230	67.80	2.83	22.60	13,560	600	400	200
East Bend Steam-2	25	10/1/19 15:10	10/3/19 22:00	54.00	U1	Forced	3110	54.83	2.28	54.83	32,900	600	0	600
East Bend Steam-2	34	12/16/19 12:00	12/18/19 20:20	56.00	D4	Forced	0344	56.33	2.35	1.88	1,127	600	580	20

- 2017-2018 planning year only had 8 conforming outages
- 2018-2019 planning year only had 12 conforming outages
- 2019-2020 planning year only had 2 conforming outages

2016 RFP Backstand Call Analysis Overview

- Backstand Calls were dependent on outages; four options were offered; 600 MW per strike
- Options included two and three year bids with both 7 and 11 Heat rates and a limit of 25 strikes

Bid	Term (Years)	Heat Rate (Thousands of Btu/kWh)	Strikes	Demand Charge ($/kW-Mo)
1	2	7	25	$2.15
2	2	11	25	$1.95
3	3	7	25	$2.25
4	3	11	25	$2.05

- Bids were called when
  - The outage was at least one 16-hour period long (8-23)
  - The average LMP cost of the 16-hour period was greater than the strike price
  - Results are seen in the table below
    - Market = Market Cost During Strike, Backstand Call Premium = Cost of Contract, & Strike Cost = Cost of Strike
    - Value to DEK: Positive = benefit to DEK, negative = cost to DEK

Bid	Term (Years)	Heat Rate (Thousands of Btu/kWh)	Strikes	Market Cost	Backstand Call Premium	Strike Cost	Value to DEK (Mkt+Prem+ Strike)
1	2	7	25	$12,792,624	-$30,960,000	-$7,163,730	-$25,331,106
2	2	11	25	$10,396,461	-$28,080,000	-$8,621,151	-$26,304,690
3	3	7	25	$13,610,432	-$48,600,000	-$7,477,218	-$42,466,786
4	3	11	25	$10,980,928	-$44,280,000	-$8,866,671	-$42,165,743

2016 RFP Daily Call Analysis Overview

- Daily Calls were not dependent on outages; four options were offered; 600 MW per strike
- Options included two and three year bids with both 7 and 11 Heat rates and a limit of 25 strikes

Bid	Term (Years)	Heat Rate (Thousands of Btu/kWh)	Strikes	Demand Charge ($/kW-Mo)
1	2	7	25	$5.40
2	2	11	25	$2.50
3	3	7	25	$5.45
4	3	11	25	$2.60

- Bids were called upon when:
  - Bids were allowed 25 strikes, so the top 25 highest LMP weekday 8-23 hour averages used for analysis
  - The average LMP cost of the 16-hour period was greater than the strike price
  - Results are seen in the table below
    - Market = Market Cost During Strike, Backstand Call Premium = Cost of Contract, & Strike = Cost of Strike
    - Value to DEK: Positive = benefit to DEK, negative = cost to DEK

Bid	Term (Years)	Heat Rate (Thousands of Btu/kWh)	Strikes	Market Cost	Daily Call Premium	Strike Cost	Value to DEK (Mkt+Prem+ Strike)
1	2	7	25	$29,288,683	-$77,760,000	-$11,482,464	-$59,953,781
2	2	11	25	$28,399,912	-$36,000,000	-$17,098,752	-$24,698,840
3	3	7	25	$38,961,742	-$117,720,000	-$15,561,840	-$94,320,098
4	3	11	25	$38,072,971	-$56,160,000	-$23,509,200	-$41,596,229

2016 RFP Fixed Strike Call Analysis Overview

- Daily Calls were not dependent on outages; 600 MW strike
- Options included 2 and 3 year bids with $50, $60, $80 and $100 strike price and $/MWh premiums
- MWh premiums are for the entire period, so used 52 weeks * 5 days * 16 hours

Bid	Term (Years)	Strike Price ($/MWh)	Strikes	Demand Charge ($/MWh)
1	2	$50	25	$4.26
2	2	$60	25	$3.36
3	2	$80	25	$2.4
4	2	$100	25	$1.82
5	3	$50	25	$4.4
6	3	$60	25	$3.46
7	3	$80	25	$2.46
8	3	$100	25	$1.89

2016 RFP Fixed Strike Call Analysis Overview

- Bids were called when
  - Bids were allowed 25 strikes, so the top 25 highest LMP weekday 8-23 hour averages were used for analysis
  - The average LMP cost of the 16 hour period was greater than the strike price
    - Market = Market Cost During Strike, Backstand Call Premium = Cost of Contract, & Strike = Cost of Strike
    - Value to DEK: Positive = benefit to DEK, negative = cost to DEK

Bid	Term	Strike Price ($/MWh)	Strikes	Market Cost	Fixed Call Premium	Strike Cost	Value to DEK (Mkt+Prem+ Strike)
1	2	$50	25	$21,496,720	-$21,265,920	-$15,810,000	-$15,579,200
2	2	$60	25	$14,287,880	-$16,773,120	-$10,908,000	-$13,393,240
3	2	$80	25	$6,087,774	-$11,980,800	-$4,608,000	-$10,501,026
4	2	$100	25	$2,558,942	-$9,085,440	-$1,920,000	-$8,446,498
5	3	$50	25	$22,081,188	-$32,947,200	-$16,290,000	-$27,156,012
6	3	$60	25	$14,872,347	-$25,908,480	-$11,484,000	-$22,520,133
7	3	$80	25	$6,087,774	-$18,420,480	-$4,608,000	-$16,940,706
8	3	$100	25	$2,558,942	-$14,152,320	-$1,920,000	-$13,513,378

2016 RFP Insurance Analysis Overview

- Insurance options are seen below; only 4 options were analyzed

	Term	Policy Limit	Event Days	Time Deduct	Prem ($M)
1	2	$10	15	0	$3.50
2	2	$10	15	48	$1.70
~~3~~	~~2~~	~~$10~~	~~180~~	~~0~~	~~$3.90~~
~~4~~	~~2~~	~~$10~~	~~180~~	~~48~~	~~$2.20~~
~~5~~	~~2~~	~~$10~~	~~180~~	~~168~~	~~$1.30~~
~~6~~	~~2~~	~~$20~~	~~15~~	~~0~~	~~$3.60~~
~~7~~	~~2~~	~~$20~~	~~15~~	~~48~~	~~$1.70~~
~~8~~	~~2~~	~~$20~~	~~180~~	~~0~~	~~$4.60~~
~~9~~	~~2~~	~~$20~~	~~180~~	~~48~~	~~$2.80~~
~~10~~	~~2~~	~~$20~~	~~180~~	~~168~~	~~$1.80~~
11	3	$10	15	0	$4.60
12	3	$10	15	48	$2.20
~~13~~	~~3~~	~~$10~~	~~180~~	~~0~~	~~$5.00~~
~~14~~	~~3~~	~~$10~~	~~180~~	~~48~~	~~$2.80~~
~~15~~	~~3~~	~~$10~~	~~180~~	~~168~~	~~$1.60~~
~~16~~	~~3~~	~~$20~~	~~15~~	~~0~~	~~$5.20~~
~~17~~	~~3~~	~~$20~~	~~15~~	~~48~~	~~$2.50~~
~~18~~	~~3~~	~~$20~~	~~180~~	~~0~~	~~$6.30~~
~~19~~	~~3~~	~~$20~~	~~180~~	~~48~~	~~$3.60~~
~~20~~	~~3~~	~~$20~~	~~180~~	~~168~~	~~$2.20~~

2016 RFP Insurance Analysis Overview

- Two insurance bidders bid into the RFP but only one with more attractive bids was reanalyzed
- Modeled 0 and 2 day deduction only since all forced outages were less than 8 days; did not model the 7 day time deduction
- Only used $10M policy limit cases since $20M policy limits were more expensive and we never exceeded $10M per year
- Only used 15 day limits and not 180 day limits since all outages were short and 180 day limit options were more expensive
- Bids were tied to outages, so they were utilized when:
  - The outage was at least one 16-hour period long
  - The average LMP cost of the 16-hour period was greater than the strike price
- MW in 50 MW increments were used for each strike
- Weekends were included as part of time deductible
    - Market Cost = Market Cost During Strike, Insurance Premium = Cost of Contract, & Strike Cost = Cost of Strike
    - Value to DEK: Positive = benefit to DEK, negative = cost to DEK

BId	Term	Policy Limit	Event Days	Time Deduct (Hours)	Market Cost	Insurance Premium	Strike Cost	Value to DEK (Mkt+Prem+ Strike)
1	2	$10M	15	0	$6,327,997	-$7,000,000	-$3,937,600	-$4,609,603
2	2	$10M	15	48	$3,388,228	-$3,400,000	-$2,319,550	-$2,331,322
11	3	$10M	15	0	$6,931,909	-$13,800,000	-$4,176,800	-$11,044,891
12	3	$10M	15	48	$3,388,228	-$6,600,000	-$2,319,550	-$5,531,322

2020 DEK RFP Overview

- Insurance Options
  - Bidder 1 (20)
  - Bidder 2 (31)
- Daily Call Options
  - Bidder 3 (36)
  - Bidder 4 (14+)

Product Parameters – Daily Call Options	
Condition Precedent	None
Term	2-3 years in the June 1, 2021 – May 31, 2024 timeframe Term 1: June 1, 2021-May 31, 2023 Term 2: June 1, 2021-May 31, 2024
Minimum Size Offering	50 MW per Hour
Maximum Size Offering	600 MW per Hour (50 MW Increments)
Power Price Index (Settlement Point)	PJM AD Hub (Preferred), PJM Western Hub
Gas Price Index	Chicago Citygate Gas Daily index
Coal Price Index	NYMEX Coal
Gas Heat Rate Index	7.0 MMBtu/MWh
	11.0 MMBtu/MWh
	14.0 MMBtu/MWh or higher
Coal Heat Rate Index	10 MMBtu/MWh
Fixed Strike Price	$/MWh
Time Period Covered	16 hours weekday on-peak (HE 0800 EPT - 2300 EPT) or (07:00 am EPT through 11:00 PM EPT)
Exercise Notification	10:30 AM EPT Day Ahead (including Sunday notification for Monday)
Strike Limitations	15 Strikes/Year
	25 Strikes/Year
	40 Strikes/Year
	Unlimited Strikes

Product Parameters – Insurance Products	
Condition Precedent	Unplanned Outage at East Bend Unit 2
Term	2-3 years in the June 1, 2021 – May 31, 2024 timeframe Term 1: June 1, 2021 – May 31, 2023 Term 2: June 1, 2021 – May 31, 2024
Minimum Size Offering	50 MW per Hour
Maximum Size Offering	600 MW per Hour (50 MW Increments)
Power Price Index (Settlement Point)	PJM AD Hub (Preferred), PJM Western Hub
Fixed Strike Price/Insured Price	$25/MWh
Annual Deductible	$3 million
Annual Premiums	Please Provide
Time Period Covered	16 hours weekday on-peak (HE 0800 EPT - 2300 EPT) or (07:00 am EPT through 11:00 PM EPT)
Event Duration Limit	Please provide premium quotes based on consecutive 21-calendar-day and consecutive 180-calendar-day event duration limits respectively
Annual Insurance Payment Caps/Policy Limit	Please Provide premium quotes based on $10 million and $20 million policy limits respectively
Time Deductible	Please use consecutive 0-hour, 48-hour and 168-hour (only applicable to 180-day event duration limit) time deductible respectively.

2020 RFP Assumptions

- 2020 DEK Backstand RFP Study period was 6/2021 – 5/2024
- Although there were no proposals for 6/2020-5/2021, we applied the two year bids for 6/2021-5/2022
- Historical Henry Hub gas prices and Historical AD Hub DA LMPs were used for analysis along with historical outages from GADs
- Products included, insurance (dependent on outage) and daily heat rate calls (independent of outage)
- All Bids covered weekday peaks only (Hrs 8 – 23) and had to be utilized for the entire period
- Insurance bids do not allow for derates
- Bids were used when:
  - The outage was at least one 16-hour period long
  - The average LMP cost of the 16-hour period was greater than the strike price
- Only forced outages and derates were considered
  - Longest forced outage was 8 days
  - Many forced outages converted to scheduled outages
  - Outages labeled scheduled or reserve shutdown were not considered

Outages for the 2020 RFP planning term

- No derates are allowed in 2020 RFP
- Outages had to be > 16-hour peak period to strike
- Under these definitions, there were only 2 outages in 2020-2021 and 4 outages in 2021-2022 (6 months only)

Unit	Event No	Event Start	Event End	Event Type	Forced, Scheduled, or Other	Cause Code	Event Duration (Hours)	Event Duration (Days)	Equivalent (Hours)	Equivalant Energy Lost (MWh)	Net Maximum Capability (MW)	Net Availability Capability (MW)
East Bend Steam-2	18	6/1/20 17:45	6/2/20 21:00	U1	Forced	8261	27.25	1.14	27.25	16,350	600	0
East Bend Steam-2	4	1/27/21 3:20	1/29/21 11:44	U1	Forced	3110	56.40	2.35	56.40	33,840	600	0
East Bend Steam-2	43	7/29/21 3:14	7/30/21 19:50	U1	Forced	0890	40.60	1.69	40.60	24,360	600	0
East Bend Steam-2	54	8/2/21 19:06	8/5/21 10:14	U1	Forced	3416	63.13	2.63	63.13	37,880	600	0
East Bend Steam-2	55	8/28/21 19:00	9/5/21 10:30	U1	Forced	4520	183.50	7.65	183.50	110,100	600	0
East Bend Steam-2	77	12/18/21 21:28	12/25/21 21:40	U1	Forced	4609	168.20	7.01	168.20	100,920	600	0

2020 RFP Daily Call Options

- Daily Calls were not dependent on outages
- No three year term bids analyzed
- Top 15 and 25 highest average LMP costs were pulled in 2020/2021 and 2021/2022 (7 months) for analysis
- Bidder 3 daily call bids are in 100 MW increments with hourly strikes limits with payment is in $/MWh for half a year – three bids analyzed at 100 MW
- Bidder 4 daily call bids are in 50 MW increments with limited strikes – four bids are analyzed at 50 MW

2020 RFP Daily Call Options – Bidder 3

	Term	Size	Index	Strike	HR	Gas Index	Hours	Hours	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6
									100 MW	100 MW	100 MW	100 MW	100 MW	100 MW
1	6/1/21-5/31/23	100	PJM AD	$ 35.00	N/A	N/A	16	8192	$4.99	$5.12	$5.39	$5.64	$5.89	$6.14
~~2~~	~~6/1/21-5/31/24~~	~~100~~	~~PJM AD~~	~~$ 35.00~~	~~N/A~~	~~N/A~~	~~16~~	~~12288~~	~~$5.12~~	~~$5.37~~	~~$5.62~~	~~$5.87~~	~~$6.12~~	~~$6.37~~
3	6/1/21-5/31/23	100	PJM AD	N/A	11	CCG	16	8192	$5.48	$5.73	$5.98	$6.23	$6.48	$6.73
4	~~6/1/21-5/31/24~~	~~100~~	~~PJM AD~~	~~N/A~~	~~11~~	~~CCG~~	~~16~~	~~12288~~	~~$6.00~~	~~$6.25~~	~~$6.50~~	~~$6.75~~	~~$7.00~~	~~$7.25~~
5	6/1/21-5/31/23	100	PJM AD	N/A	14	CCG	16	8192	$2.45	$2.70	$2.95	$3.20	$3.45	$3.70
~~6~~	~~6/1/21-5/31/24~~	~~100~~	~~PJM AD~~	~~N/A~~	~~14~~	~~CCG~~	~~16~~	~~12288~~	~~$2.87~~	~~$3.12~~	~~$3.37~~	~~$3.62~~	~~$3.87~~	~~$4.12~~

- Bidder 3’s offer is structured in 100 MW tranches with increasing pricing for each tranche
- Bidder 3’s bid is priced in $/MWh with annual cost of at 4096 MWh * 100 MW Tranche Cost

2020 RFP Daily Call Options – Bidder 4

	Term	Size	Index	Strikes	HR	Gas Index	Hours	Premium
1	6/1/21-5/31/23	50	PJM AD	15.00	11.00	CCG	16	$741,667 Per 50 MW
2	6/1/21-5/31/23	50	PJM AD	25.00	11.00	CCG	16	$1,020,833 Per 50 MW
~~3~~	~~6/1/21-5/31/23~~	~~50~~	~~PJM AD~~	~~40.00~~	~~11.00~~	~~CCG~~	~~16~~	~~$1,345,833 Per 50 MW~~
~~4~~	~~6/1/21-5/31/23~~	~~50~~	~~PJM AD~~	~~Unlimited~~	~~11.00~~	~~CCG~~	~~16~~	~~$2,500,000 Per 50 MW~~
~~5~~	~~6/1/21-5/31/24~~	~~50~~	~~PJM AD~~	~~15.00~~	~~11.00~~	~~CCG~~	~~16~~	~~$1,154,167 Per 50 MW~~
~~6~~	~~6/1/21-5/31/24~~	~~50~~	~~PJM AD~~	~~25.00~~	~~11.00~~	~~CCG~~	~~16~~	~~$1570833 Per 50 MW~~
~~7~~	~~6/1/21-5/31/24~~	~~50~~	~~PJM AD~~	~~40.00~~	~~11.00~~	~~CCG~~	~~16~~	~~$2,058,333 Per 50 MW~~
~~8~~	~~6/1/21-5/31/24~~	~~50~~	~~PJM AD~~	~~Unlimited~~	~~11.00~~	~~CCG~~	~~16~~	~~$4,038,333 Per 50 MW~~
9	6/1/21-5/31/23	50	PJM AD	15.00	14.00	CCG	16	$516,667 Per 50 MW
10	6/1/21-5/31/23	50	PJM AD	25.00	14.00	CCG	16	$675,000 Per 50 MW
~~11~~	~~6/1/21-5/31/23~~	~~50~~	~~PJM AD~~	~~40.00~~	~~14.00~~	~~CCG~~	~~16~~	~~$829,167 Per 50 MW~~
~~12~~	~~6/1/21-5/31/24~~	~~50~~	~~PJM AD~~	~~15.00~~	~~14.00~~	~~CCG~~	~~16~~	~~$825,000 Per 50 MW~~
~~13~~	~~6/1/21-5/31/24~~	~~50~~	~~PJM AD~~	~~25.00~~	~~14.00~~	~~CCG~~	~~16~~	~~$1,041,667 Per 50 MW~~
~~14~~	~~6/1/21-5/31/24~~	~~50~~	~~PJM AD~~	~~40.00~~	~~14.00~~	~~CCG~~	~~16~~	~~$1,275,000 Per 50 MW~~

Bidder 4 is offering 50 MW blocks at an annual fixed cost per 50 MW

2020 RFP Daily Call Results w/Historical Data

- Market Cost = Market Cost During Strike, Daily Call Premium = Cost of Contract, & Strike Cost = Cost of Strike
- Value to DEK: Positive = benefit to DEK, negative = cost to DEK

	Term (Years)	Policy Limit	Heat Rat (Thousands of Btu/kWh)	Strikes	Market Cost	Daily Call Premium	Strike Cost	Value to DEK (Mkt + Prem+Strike)
Bid 4, Opt 1	2	10	11	15	$1,611,140	-$1,483,334	-$871,596	-$743,790
Bid 4, Opt 2	2	10	11	25	$2,585,958	-$2,041,666	-$1,448,832	-$904,540
Bid 4, Opt 9	2	10	14	15	$1,611,140	-$1,033,334	-$1,109,304	-$531,498
Bid 4, Opt 10	2	10	14	25	$2,585,958	-$1,350,000	-$1,843,968	-$608,010
Bid 3, Opt 1	2	10	35	N/A	$5,171,915	-$4,005,888	-$2,576,000	-$1,409,973
Bid 3, Opt 3	2	10	11	N/A	$5,171,915	-$4,489,216	-$2,897,664	-$2,214,965
Bid 3, Opt 5	2	10	14	N/A	$5,171,915	-$2,351,104	-$3,687,936	-$867,125

2020 RFP Insurance Bid Assumptions

- Modeled 0 and 2 day deduction only since all forced outages were less than 8 days; did not model the 7 day time deduction
- Only used $10M policy limit cases since $20M policy limits were more expensive and we never exceeded $10M per year
- Only used 15 day limits and not 180 day limits since all outages were short and 180 day limit options were more expensive
- Bids were tied to outages, so they were utilized when:
  - The outage was at least one 16-hour period long
  - The average LMP cost of the 16-hour period was greater than the strike price
- 600 MW were used regardless of derate or total outage
- Weekends were included as part of time deductible

2020 RFP Insurance Options – Bidder 1

	Term	Size	Index	Strike	Deductible	Premium	Time Period	Duration	Policy Cap	Time Deduct
1	6/1/21-5/31/23	600	AEP Hub	25	$3,000,000	$1,686,477	16	Consect 21	$10,000,000	0
~~2~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 21~~	~~$10,000,000~~	~~0~~
3	6/1/21-5/31/23	600	AEP Hub	25	$3,000,000	$936,932	16	Consect 21	$10,000,000	48
~~4~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 21~~	~~$10,000,000~~	~~48~~
~~5~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$1,967,556~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~0~~
~~6~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~0~~
~~7~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$1,124,318~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~8~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~9~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$2,389,176~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~0~~
~~10~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~0~~
~~11~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$1,873,863~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~48~~
~~12~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~48~~
~~13~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$1,218,011~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~168~~
~~14~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~168~~
~~15~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$2,998,181~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~0~~
~~16~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~0~~
~~17~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$2,342,329~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~48~~
~~18~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~48~~
~~19~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$1,639,630~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~168~~
~~20~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~NBD~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~168~~

Bidder 1 provided 10 Viable Options – no 3 year options were available

2020 RFP Insurance Options – Bidder 2

	Term	Size	Index	Strike	Deductible	Premium	Time Period	Duration	Policy Cap	Time Deduct
1	6/1/21-5/31/23	600	AEP Hub	25	$3,000,000	$617,156	16	Consect 21	$10,000,000	0
~~2~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$617,156~~	~~16~~	~~Consect 21~~	~~$10,000,000~~	~~0~~
3	6/1/21-5/31/23	600	AEP Hub	25	$3,000,000	$256,178	16	Consect 21	$10,000,000	48
4	6/1/21-5/31/24	600	AEP Hub	25	$3,000,000	$256,178	16	Consect 21	$10,000,000	48
5	6/1/21-5/31/23	600	AEP Hub	25	$1,000,000	$535,644	16	Consect 21	$10,000,000	48
~~6~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$1,000,000~~	~~$535,644~~	~~16~~	~~Consect 21~~	~~$10,000,000~~	~~48~~
~~7~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~0~~
~~8~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~0~~
~~9~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~48~~
~~10~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~48~~
~~11~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$407,555~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~168~~
~~12~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$407,555~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~168~~
~~13~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$733,600~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~0~~
~~14~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$733,600~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~0~~
~~15~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$465,777~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~16~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$465,777~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~17~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$1,000,000~~	~~$652,088~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~18~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$1,000,000~~	~~$652,088~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~19~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~0~~
~~20~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~0~~
~~21~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~48~~
~~22~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~48~~
~~23~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$524,000~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~168~~
~~24~~	~~6/1/21-5/31/24~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$524,000~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~168~~
25	6/1/21-5/31/23	600	AEP Hub	25	$3,000,000	$1,071,289	16	Consect 21	$10,000,000	0
~~26~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 21~~	~~$10,000,000~~	~~48~~
~~26~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$1,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 21~~	~~$10,000,000~~	~~48~~
~~27~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$660,822~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~0~~
~~27~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~48~~
~~28~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$10,000,000~~	~~168~~
~~28~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$669,556~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~0~~
~~29~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~29~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$1,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 21~~	~~$20,000,000~~	~~48~~
~~30~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~$855,867~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~0~~
~~30~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~48~~
~~31~~	~~6/1/21-5/31/23~~	~~600~~	~~AEP Hub~~	~~25~~	~~$3,000,000~~	~~Not Quoted~~	~~16~~	~~Consect 180~~	~~$20,000,000~~	~~168~~

Bidder 2 Provided 21 Bid Options

2020 RFP Insurance Results w/Historical Outages

- Market Cost = Market Cost During Strike, Insurance Premium = Cost of Contract, Insurance Deductible = Value Deducted Before Benefits Accrue & Strike Cost = Cost of Strike
- Value to DEK:
  - If (Market Cost + Strike Cost) > Insurance Deductible, Value to DEK equates to: Market Cost + Strike Cost – Insurance Deductible + Insurance Premium
  - If (Market Cost + Strike Cost) < Insurance Deductible, value to DEK equates to Insurance Premium
  - Positive = benefit to DEK, negative = cost to DEK

	Term	Policy Limit	Event Days	Time Deduct (Hours)	Market Cost	Insurance Premium	Insurance Deductible	Strike Cost	Value to DEK (Mkt+Prm+Ded)
Bid1, Opt 1	2	$10M	21	0	$5,818,499	-$3,372,954	$6,000,000	-$3,312,000	-$3,372,954
Bid1, Opt 3	2	$10M	21	48	$4,417,796	-$1,873,864	$6,000,000	-$2,428,800	-$1,873,864
Bid2, Opt 1	3	$10M	15	0	$5,818,499	-$1,234,312	$6,000,000	-$3,312,000	-$1,234,312
Bid2, Opt 3	2	$10M	21	48	$4,417,796	-$512,356	$6,000,000	-$2,428,800	-$512,356
Bid2, Opt 5	2	$10M	21	48	$4,417,796	-$1,071,288	$2,000,000	-$2,428,800	-$1,071,288
Bid2, Opt 25	2	$10M	21	0	$5,818,499	-$2,142,578	$6,000,000	-$3,312,000	-$2,142,578

CONFIDENTIAL PROPRIETARY TRADE SECRET

Risk Year	Total	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
DEK Scheduled Outage Hedging Gains and Losses 2006-2021 (Realized Results: Positive Value is a credit to customers, Negative Value is a cost to customers)													
2006	[redacted]												
2007	[redacted]												
2008	[redacted]												
2009	[redacted]												
2010	[redacted]												
2011	[redacted]												
2012	[redacted]												
2013	[redacted]												
2014	[redacted]												
2015	[redacted]												
2016	[redacted]												
2017	[redacted]												
2018	[redacted]												
2019	[redacted]												
2020	[redacted]												
2021	[redacted]												
	[redacted]												