part 2

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Construction and operational risks of the Project and their mitigation

Q. HAS STAFF REVIEWED THIRD PARTY ESTIMATES OF CONSTRUCTION AND OPERATING RISK OF OFFSHORE WIND PROJECTS IN THE U.S.?

A. Yes. Staff reviewed a report titled *Strategic owners and robust contractual protections offset US offshore wind power's increased risks*, published by the credit rating company Moody's Investor Service on November 18, 2019 ("Moody's report").[110] The Moody's report describes risks specific to the nascent offshore wind sector in the U.S., compares the risks of offshore wind projects between the U.S. and Europe as well as with onshore peers, and suggests a few risk mitigation avenues for construction and operational risks.

Key risks and challenges listed in the report include:

- The lack of a developed supply chain, including equipment suppliers, specialized installation vessels, and infrastructure to handle the transportation and installation of the equipment. Limited supply chain will require extensive development from the ground up. The U.S. Jones Act requirement for US ship and crew adds further constraints during both construction and operations.
- Construction and operating risk of offshore wind facilities is greater compared with onshore wind facilities due to heightened sensitivity to weather conditions offshore, which can restrict access to a project's site; less proven technology; need for substantially more balance-of-system equipment such as seabed foundations, offshore substations, and subsea export cables; and greater subsurface geophysical risk (e.g., seabed soil conditions, existence of boulders, unexploded military ordnances). During the operational phase, if an export cable failure occurs, it may lead to the revenue loss during the outage period, which could be significant due to the need to replace custom replacement cables, wait time for a specialized cable repair vessel, and the need to address any geotechnical conditions that could have contributed to the damage.

[110] *See* Attachment KK-27 for a copy of relevant pages of the Moody's report.

- Combination of federal, state, and local permits and regulations creates potential for opposition from various stakeholders, which may result in project delays.

The report also lists benefits of offshore wind projects over onshore wind, including less complex topography (no hills or valleys), higher wind speeds offshore, less permitting constraints due to noise or height restrictions, and closer proximity to the densely populated coastal communities reducing curtailment risks.

Q. HOW DID THE COMPANY ADDRESS CONSTRUCTION RISK MITIGATION MEASURES PROPOSED IN THE MOODY'S REPORT FOR OFFSHORE WIND?

A. The Moody's report suggests the following key protective provisions in construction contracts:

- Fixed prices,
- Guaranteed completion dates,
- Minimum performance thresholds, such as capacity or power curve,
- Extended equipment warranties,
- Contractual enhancements for serial defects, and
- Liquidated damage provisions for nonperformance or delays.

At Staff's request, the Company provided a table that illustrates how the Company's construction contracts representing the major CVOW procurement packages are consistent with the six protective provisions listed above.[111]

[111] See Attachment KK-28 for a copy of the Company's response to Staff Interrogatory No. 07-82 (a).

Contractual Provision	Foundations EEW	Transition Pieces Bladt	Offshore Sub Station Bladt/SEMCO	Transportation & Installation DEME/Prysmian	Turbine Supply Agreement SGRE
Fixed Prices	Definition of Contract Price & Article 9 - Compensation and Invoicing	Definition of Contract Price & Article 9 - Compensation and Invoicing	Definition of Contract Price & Article 8 - Compensation and Invoicing	Definition of Contract Price & Article 10 - Compensation and Invoicing	Definition of Contract Price & Article 10 - Compensation and Invoicing
Guaranteed Completion Dates	Definition of Required Milestone Completion Date - Article 8.2 - Delivery Schedule	Definition of Required Milestone Completion Date - Article 6 Delivery Schedule	Definition of Required Milestone Completion Date - Article 7 Delivery Schedule	Definition of Required Milestone Completion Date - Article 8 - Project Schedule and Phases of the Work	Definition of Required Milestone Completion Date - Article 8 - Project Schedule and Phases of the Work
Minimum Performance Thresholds	Exhibit A-1 - Scope of Work	Exhibit A-1 - Scope of Work	Article 10 - Performance Testing and Acceptance - Exhibit A-1 through Exhibit A-7-7 Scope of Work and supporting documents	Exhibit A-1 - A-25 Scope of Work and supporting documents	Exhibit D-07(a) Standard Power Curve TSA, Exhibit D-07(b) - Standard Ct Curve (Cover Page) (Executed Version)
Extended Equipment Warranties	Article 10 - Warranty of the Work and Remedies - 10.4 Warranty Remedy Periods	Article 10 - Warranty of the Work and Remedies - 10.4 Warranty Remedy Periods	Article 9 - Warranty of the Work and Remedies - 9.4 Warranty Remedy Periods	Article 17 - Warranty of the Work and Remedies - 17.6 Warranty Remedy Periods	Article 17 - Warranty of the Work and Remedies - 17.3 Warranty Remedy Periods
Serial Defect Provisions	Article 10.8 - Serial Defects	Article 10.8 - Serial Defects	Article 9.8 - Serial Defects	Article 17.6 - Serial Defects	Article 17.5 - Serial Defects
Liquidated Damages	Article 12 - Liquidated Damages	Article 12 - Liquidated Damages	Article 11 - Liquidated Damages	Article 26 - Liquidated Damages	Article 26 - Liquidated Damages

The Moody's report also states that "a project that relies on a collection of subcontracts represents a weaker arrangement because it typically would provide contractual protection only at the equipment level such as a turbine's power curve but not the overall plant performance nor overall construction delays."

Notably, one of the cost risk mitigation measures listed in the Company's presentation to the Board of Directors is that the **[BEGIN EXTRAORDINARILY SENSITIVE]** "[redacted] **[END EXTRAORDINARILY SENSITIVE]**

In the Company's response to a Staff discovery request regarding the Moody's report's concerns about multiple subcontracts outlined above, the Company referenced "the lack of entities in the U.S. market capable of providing a fully wrapped engineering, procurement, and construction contract for a first-of-its-kind project of this size within United States federal waters." The Company states, however, that it "has negotiated robust contractual protections within the agreements focused on mitigating overall project risk and simultaneously providing protection for the overall plant's performance and construction delays." Specifically,

[BEGIN EXTRAORDINARILY SENSITIVE]

- [redacted]
- [redacted]

[END EXTRAORDINARILY SENSITIVE]

[112] See Attachment KK-28 for a copy of the Company's response to Staff Interrogatory No. 07-82 (b).

Further, the Moody's report states that **[BEGIN CONFIDENTIAL]** '[redacted] **[END CONFIDENTIAL]**

Relative to that concern, the Company states that it "mitigated interface risk to the CVOW Commercial Project in a twofold manner."

- The Interface Matrix exhibit (below) outlines roles and obligations between contractors as well as the Owner.
- The interface manager on the Project management team will be responsible for ensuring that each of the scope splits outlined in the Interface Matrix is carried out as defined, should any dispute arise.[113]

Contractual Provision	**Foundations** **EEW**	**Transition Pieces** **Bladt**	**Offshore Sub Station** **Bladt/SEMCO**	**Transportation & Installation** **DEME/Prysmian**	**Turbine Supply Agreement** **SGRE**
Interfaces	4.1 Goods and Services	3.11 Interfaces.	3.26 Interfaces.	4.1 General	4.1.1 General
Interface Matrix	Exhibit A-2 Interface Matrix	Exhibit A-2 - Interface Matrix	Exhibit A-2 - Interface Matrix	EXHIBIT A-1 Interface Matrix	Exhibit A-2 Scope and Responsibility Matrix

The Moody's report further suggests that "a robust contingency or completion guarantee ... could reduce or eliminate the risks associated with a weaker construction contract arrangement."

The Company states that "contractual elements such as defined delivery dates, installation dates, and liquidated damages tied to delivery dates ensure contractor

[113] See Attachment KK-28 for a copy of the Company's response to Staff Interrogatory No. 07-82 (c).

performance and timely completion of the Project."[114] The Company has also prepared a table that lists contract provisions addressing project delays.[115]

Contractual Provision	Foundations EEW	Transition Pieces Bladt	Offshore Sub Station Bladt/SEMCO	Transportation & Installation DEME/Prysmian	Turbine Supply Agreement SGRE
Guaranteed Completion Dates	Definition of Required Milestone Completion Date - Article 8.2 - Delivery Schedule	Definition of Required Milestone Completion Date - Article 6 Delivery Schedule	Definition of Required Milestone Completion Date - Article 7 Delivery Schedule	Definition of Required Milestone Completion Date - Article 8 - Project Schedule and Phases of the Work	Definition of Required Milestone Completion Date - Article 8 - Project Schedule and Phases of the Work
Progress Behind Schedule LDs	6.1.1 - Progress Behind Schedule 12.2.1 Delay in Delivery of a Foundation Unit 12.2.2 Primary Steel Delivery 12.2.3 Flange Delivery.	6.1.1 - Progress Behind Schedule 12.2.1 – Delay in Delivery of a Batch of Transition Pieces 12.2.2 Primary Steel Delivery 12.2.3 Flange Delivery.	5.1.1 Progress Behind Schedule 11.2 Project Milestones Subject to Liquidated Damages	8.3 - Progress Behind Schedule 26.2 Failure to Timely Achieve Required Milestones	8.2 Progress Behind Schedule 26.2 Failure to Timely Deliver the WTG Type Certificate 26.3 Failure to Achieve the Guaranteed Stage Final Completion Dates 26.4 Failure to Achieve the Guaranteed Unit Ready for Load-Out Dates 26.5 Liquidated Damages for the Installation Vessel Extended Period

Q. DOES SUCCESSFUL CONSTRUCTION OF A GENERATION FACILITY REMOVE OPERATIONAL RISKS?

A. No, not in Staff's opinion. Even if a project is constructed on time and under budget, such project can still face certain risks during operation over its life expectancy. **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted]

[114] See Attachment KK-28 for a copy of the Company's response to Staff Interrogatory No. 07-82 (b).

[115] *Id.*

- [redacted]
- [redacted]
- [redacted] **[END EXTRAORDINARILY SENSITIVE]**

Q. HOW DID THE COMPANY ADDRESS OPERATIONAL RISK MITIGATION MEASURES PROPOSED IN THE MOODY'S REPORT FOR OFFSHORE WIND?

A. The Moody's report suggests implementing the following mitigation measures for operational risks:

- A full-service O&M contractual arrangement, which includes yield guarantees, robust equipment warranties, and fixed prices;
- Training operating staff;
- Internal policies around the US Jones Act; and
- Conservative design elements, such as multiple export cables that are interlinked to provide partial redundancy.

Staff requested that the Company provide a detailed description of mitigation measures for operational risks, which led to the following responses.[117]

The Company's LTSA with Siemens Gamesa Renewable Energy ("SGRE") **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted]

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[116] *See* Filing Schedule 46.b.1.v, Statement 1, at 22 (Slide 21).

[117] *See* Attachment KK-29 for a copy of the Company's response to Staff Interrogatory No. 07-83.

[redacted] **[END EXTRAORDINARILY SENSITIVE]**

The Company's operating personnel will be trained in partnership with SGRE under the provisions of the LTSA, **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted]. **[END EXTRAORDINARILY SENSITIVE]**

Further, the Company stated that the U.S. Jones Act compliance is a requirement for all major construction and procurement agreements on the Project, as listed below.[119]

Contractual Provision	Foundations EEW	Transition Pieces Bladt	Offshore Sub Station Bladt/SEMCO	Transportation & Installation DEME/Prysmian	Turbine Supply Agreement SGRE
U.S. Jones Act	Definitions: Laws and Codes 5.3 Adequate and Competent Labor Force	Definitions: Laws and Codes 5.3 Adequate and Competent Labor Force	Definitions: Laws and Codes 3.23 Maritime Laws and Codes 4.3 Adequate and Competent Labor Force	4.3 Compliance with Laws and Codes 4.27 Maritime Laws and Codes 5.2 Adequate and Competent Labor Force	4.23 U.S. Jones Act

Regarding the export cable risk mitigation, the Company stated that:

> "the CVOW Commercial Project will include three export cables from each offshore substation delivering power to shore for a total of nine export cables for the project. In addition to the reliability from having multiple export cables delivering power to shore, the Company intends to install a state-of-the-art cable condition monitoring system that will provide a condition-based maintenance

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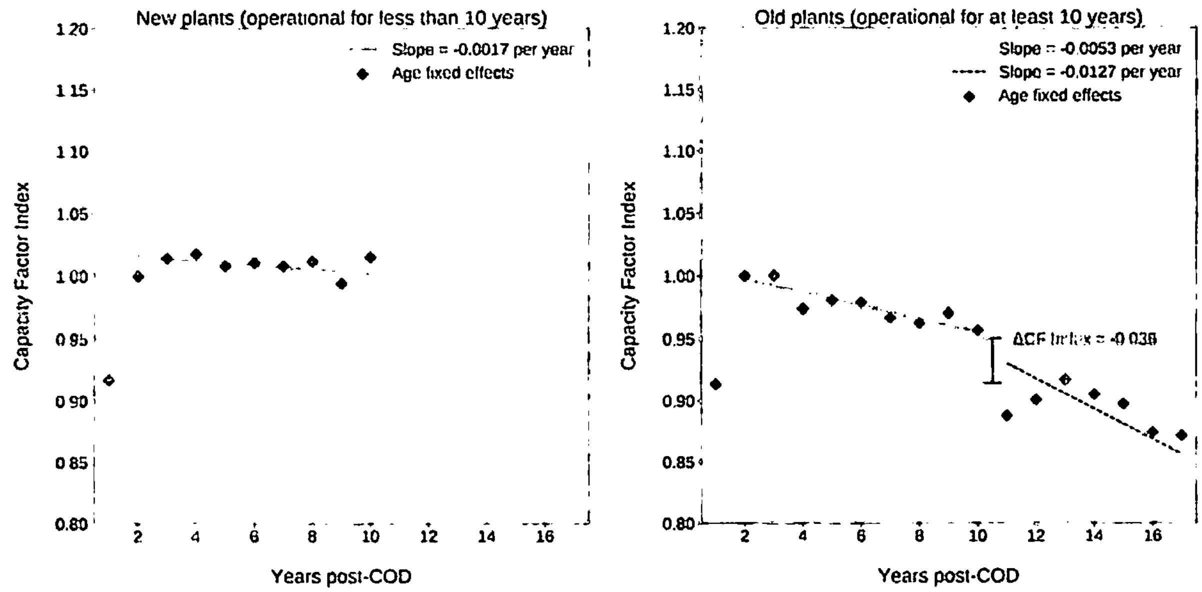
[118] Bennett Direct, at 16-17.

[119] *Id.* part (c).

program for the offshore cable systems. This system will be able to monitor and provide information such as fiber-optic temperatures, detect hot spots, provide thermal statistics, provide real-time thermal ratings, depth of burial, enhanced GPS map for DAS/DTS, cable fault location, and vessel anchoring detection."[120]

Q. ARE ADDITIONAL OPERATIONAL RISK MITIGATION MEASURES DESIRABLE?

A. Yes, in Staff's view, based on certain research findings. Specifically, in May 2020, the Berkeley Lab published a study of the performance degradation of 917 onshore wind facilities in the U.S., titled *How Does Wind Project Performance Change with Age in the United States?*[121] The study found "a significant drop in performance by 3.6% after 10 years, as plants lose eligibility for the production tax credit." This is a single year drop, not a cumulative effect, as shown in the chart below copied from the study. Further, after this single year drop, plants' performance continued to decline at a higher rate (1.27% per year) than in the first ten years of the plants' commercial operations (0.53% per year).



[120] *Id.* part (d).

[121] https://www.cell.com/joule/pdfExtended/S2542-4351(20)30174-4

The authors of the study concluded that "[t]he tax-credit sensitivity shows that performance decline is not only a physical process, but is also influenced by maintenance cost-benefit tradeoffs. Thus, performance decline can be partially managed and influenced by policy." As will be discussed later in detail, Staff recommends that the Commission consider a performance guarantee for the CVOW Commercial Project.

Q. HAS STAFF IDENTIFIED ADDITIONAL OPERATIONAL RISKS?

A. Yes. In its 2020 IRP, the Company described challenges related to the solar production profile. First, the Company states that, "[i]n the spring and fall ... as increasing amount of solar generation is added to the system, solar can produce more energy than is needed to meet customer demand during the daytime."[122]

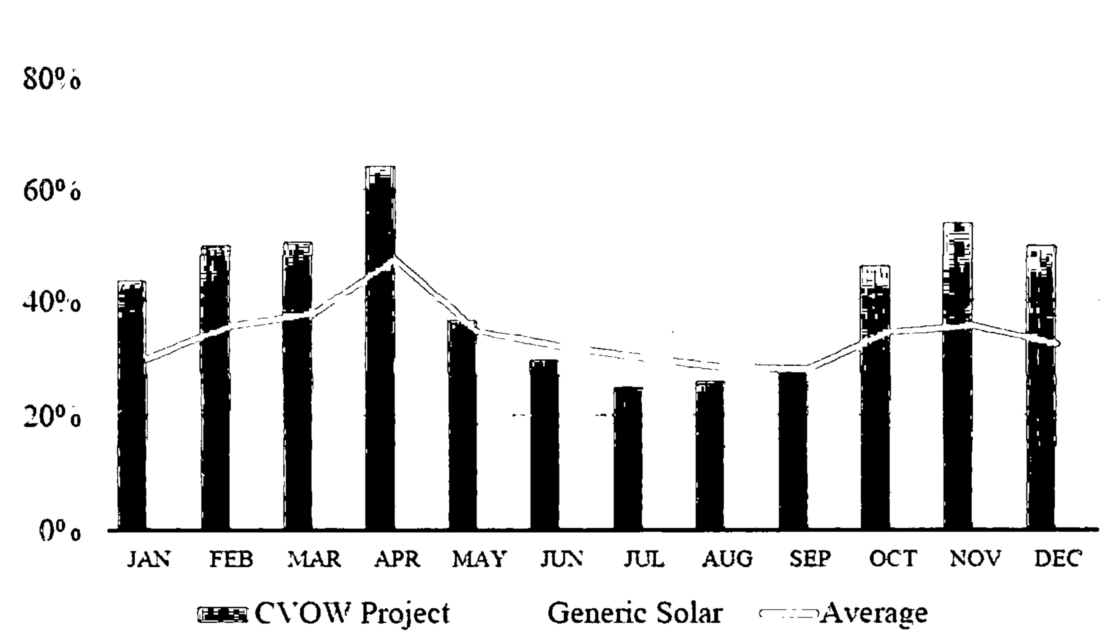
In Staff's view, this description is equally applicable to offshore wind resources.

The chart below is Figure 6 from Company witness Kelly's direct testimony in the instant case.[123] It shows that the CVOW Project is expected to have a much higher capacity factor in the spring and fall than solar facilities.

[122] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code sections 56-597 et seq.*, Case No. PUR-2020-00035, Doc. Con. Ctr. No. 210210007, Final Order (Feb. 1, 2021)("2020 IRP Order") at 99. In its 2021 IRP Update, the Company reassessed these concerns as "less impactful" but conceded that "this concern potentially occurs beyond 2035." *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2021 Update to its Integrated Resource Plan pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2021-00201, Application at 48.

[123] Staff copied Figures 4, 5, and 6 from Company witness Kelly's testimony from Attachment Staff Set 01-07, which the Company provided in response to Staff Interrogatory No. 01-07.

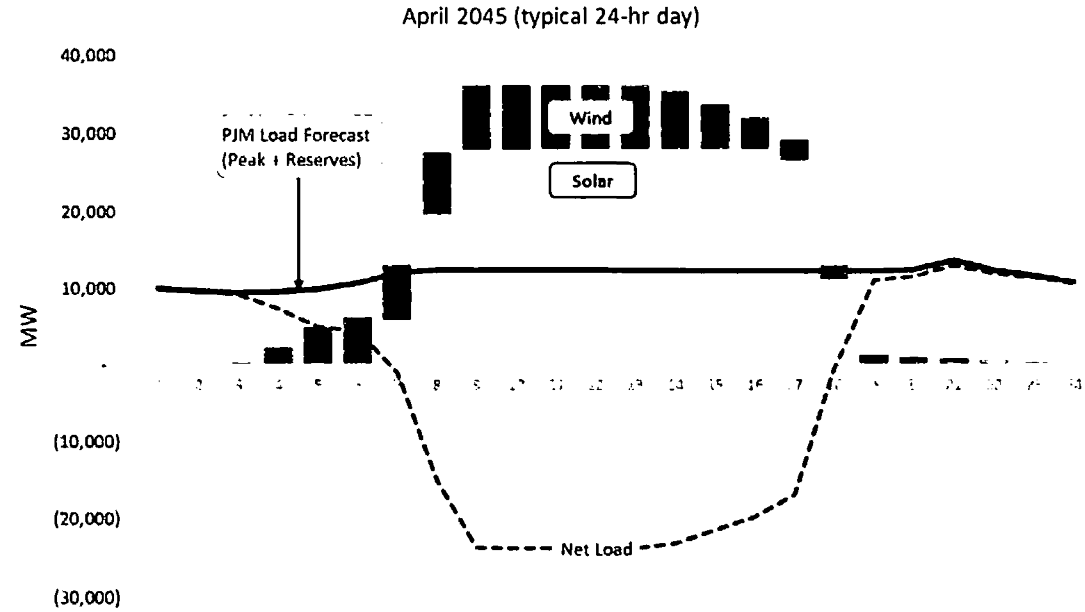
Figure 6 - Monthly Capacity Factor



Further, the Company stated that "the inclusion of large amounts of solar and wind generation significantly alters the shape of the net load profile (i.e., forecasted load less the non-dispatchable solar and wind energy) causing a dip in the middle of the day. ... The Company would need additional energy at dawn and dusk, but would have excess energy during the daytime."[124] This is illustrated in Figure 5.6.3.1 of the Company's 2020 IRP, which is copied below for convenience.

[124] 2020 IRP Order at 99-100.

Figure 5.6.3.1 Solar and Wind Capacity Compared to Load Forecast



To analyze the impact of the CVOW Commercial Project on the load during the spring and fall, Staff prepared the table below, based on the forecasted hourly energy production factors of the CVOW Commercial Project.[125] The table shows that the CVOW Commercial Project's forecasted capacity factors are especially high in daytime hours in the spring and fall, which may exacerbate the excess energy problem.

The Company proposed the following solutions to this problem in its 2020 IRP. "The Company could address this challenge with additional energy storage resources, though some energy would be lost when storage resources are used. The Company could also increase the amount of energy it exports subject to system need, though this volume would be limited by transmission export capacity. The Company may also be limited in its ability to export excess energy in the spring and fall to the extent neighboring states

[125] Staff used the data from Attachment AG Set 03-43, which the Company provided in response to Consumer Counsel's Interrogatory No. 03-43.

elect to develop significant volumes of solar resources similar to Virginia and also have excess energy. In some instances, it would become more economic to "dump" this excess energy when compared to the costs of building additional energy storage resources, increasing transmission export capacity, or facing negative market energy prices."[126]

Staff notes that all the solutions proposed above may result in higher costs (if additional storage resources are introduced) or in lower revenues (if energy sales are lost).

Table. The forecasted hourly energy production factors of the CVOW Project

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Hourly average
0:00	43%	46%	44%	60%	41%	33%	29%	33%	36%	43%	56%	50%	43%
1:00	44%	44%	46%	62%	43%	35%	31%	34%	36%	43%	57%	50%	44%
2:00	46%	44%	48%	64%	44%	36%	33%	33%	36%	43%	57%	50%	44%
3:00	47%	45%	50%	65%	44%	36%	34%	32%	34%	43%	56%	49%	44%
4:00	47%	47%	51%	67%	43%	36%	34%	30%	33%	44%	55%	49%	45%
5:00	47%	50%	52%	70%	41%	36%	33%	**24%**	31%	45%	54%	49%	44%
6:00	47%	52%	52%	70%	39%	34%	31%	**23%**	29%	47%	53%	49%	44%
7:00	47%	52%	52%	71%	36%	33%	30%	**21%**	27%	49%	51%	48%	43%
8:00	46%	51%	53%	70%	34%	31%	29%	**20%**	27%	50%	51%	49%	43%
9:00	46%	51%	55%	69%	33%	30%	27%	**19%**	26%	51%	52%	51%	42%
10:00	45%	51%	57%	68%	31%	30%	25%	**22%**	25%	50%	53%	53%	43%
11:00	44%	51%	59%	67%	30%	29%	**23%**	**22%**	25%	50%	52%	53%	42%
12:00	43%	51%	61%	66%	29%	28%	**21%**	23%	24%	50%	53%	52%	42%
13:00	41%	51%	59%	66%	30%	27%	**19%**	**21%**	24%	50%	53%	52%	41%
14:00	41%	51%	56%	62%	32%	26%	**18%**	23%	24%	49%	54%	53%	41%
15:00	42%	52%	53%	62%	32%	**23%**	[illegible]	23%	23%	46%	53%	52%	40%
16:00	41%	53%	50%	60%	32%	**20%**	[illegible]	24%	24%	44%	52%	51%	39%
17:00	39%	53%	48%	58%	33%	**20%**	[illegible]	24%	25%	43%	52%	49%	38%
18:00	38%	53%	46%	57%	35%	**22%**	[illegible]	25%	26%	42%	51%	48%	38%
19:00	38%	51%	45%	57%	36%	24%	**18%**	26%	27%	41%	51%	46%	38%
20:00	38%	49%	43%	57%	37%	26%	**20%**	26%	28%	41%	52%	43%	38%
21:00	40%	48%	41%	59%	38%	28%	23%	27%	29%	42%	54%	44%	39%
22:00	42%	48%	41%	59%	39%	29%	25%	31%	31%	43%	55%	45%	40%
23:00	44%	44%	41%	59%	39%	31%	27%	32%	34%	44%	56%	48%	42%
Monthly average	43%	49%	50%	64%	36%	29%	25%	26%	28%	46%	53%	49%	41%

[126] 2020 IRP Order at 100.

Figures 4 and 5 in Company's witness Kelly's testimony demonstrate, however, that the CVOW Commercial Project would help alleviate the need for additional energy from dusk till dawn in winter and summer, although it would still exacerbate the problem of excess energy during daytime. For convenience, these figures are copied below.

Figure 4 - Average Capacity Factor in January

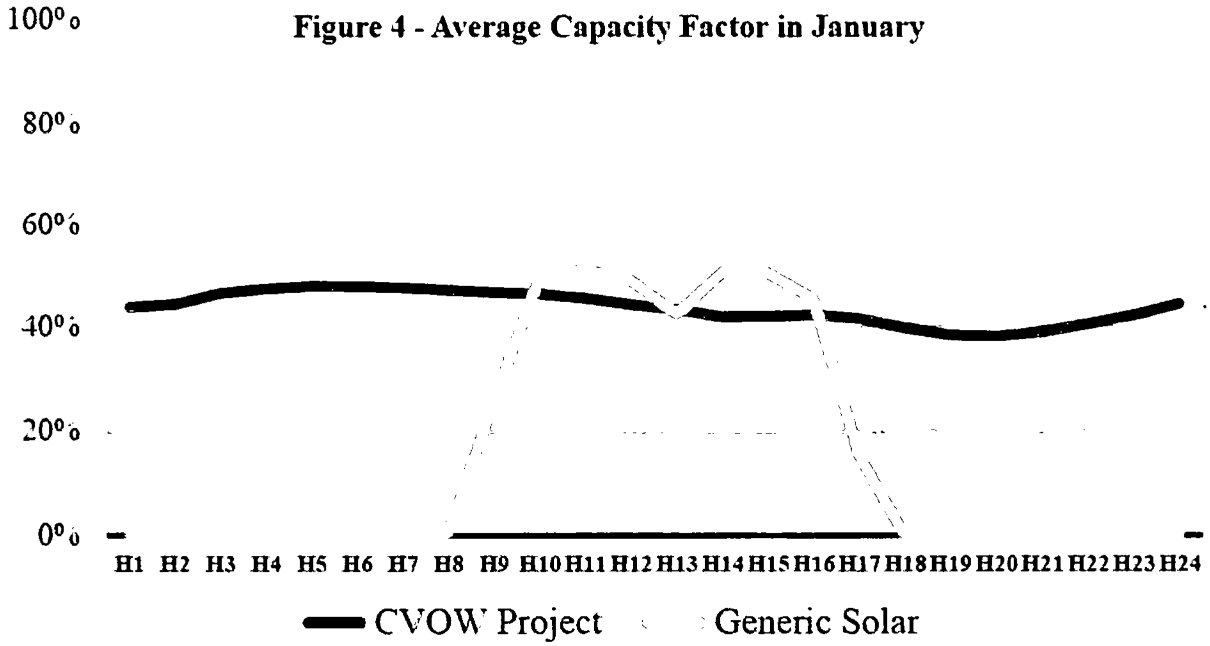
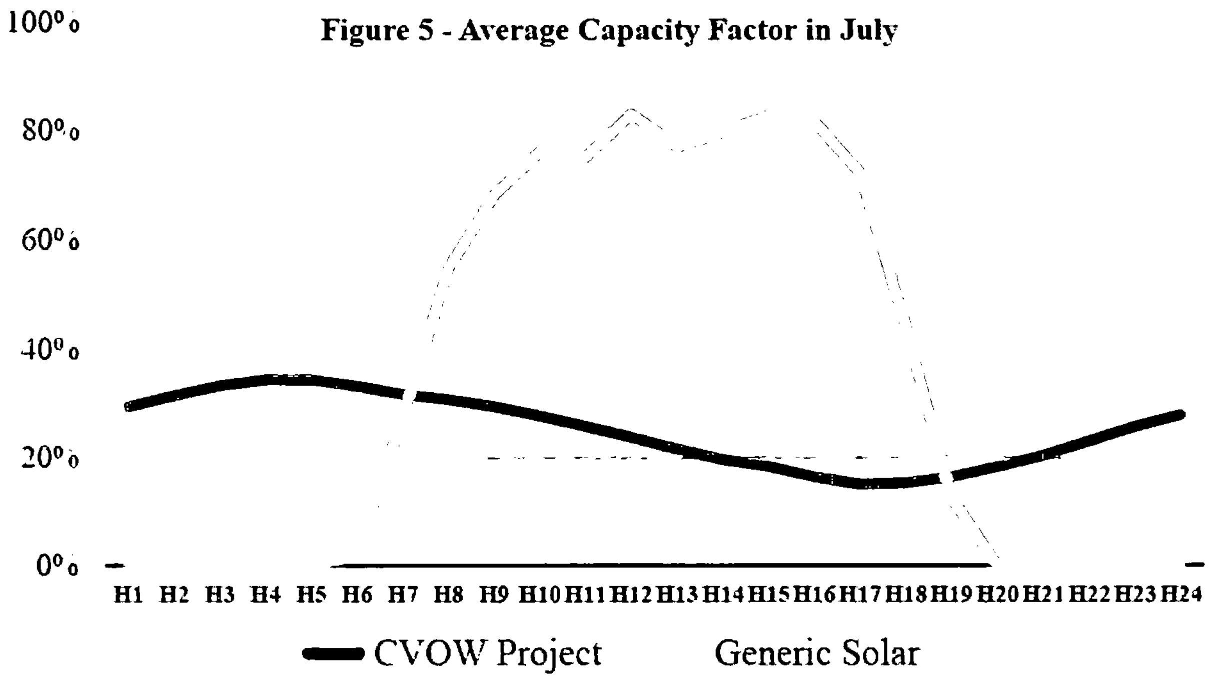


Figure 5 - Average Capacity Factor in July



Further, when it comes to capacity, both the table and the July chart above show that the CVOW Commercial Project's capacity factor is expected to be at its lowest during the PJM system peak in late afternoon summer hours, which may create the need for the Company to purchase expensive off-system energy during these peak hours.

The Commission may wish to consider directing the Company to provide a detailed analysis of the "duck curve" effect for the proposed additions of renewable resources, including but not limited to the future RPS filings and the potential second tranche of offshore wind. The Commission may also wish to consider directing the Company to provide a consolidated "duck curve" analysis for its existing and planned renewable resources' portfolio in its future RPS plans and IRP cases.

Market risks of the Project

Q. HAS STAFF IDENTIFIED MARKET RISKS PERTINENT TO SALES OR PURCHASES OF ENERGY?

A. Yes. The Company has provided an ICF forecast of monthly energy prices,[127] partially copied below. It demonstrates that energy prices are expected to be lower during shoulder months and higher in the winter and summer. Thus, the CVOW Commercial Project is expected to generate more energy during the months of lower energy prices and less energy during the months of higher energy prices in summer. The winter is the only season in which higher expected energy production of the CVOW Commercial Project coincides with higher energy prices.

Table. ICF forecast of monthly energy prices.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Jan		**$ 51**	$ 43	$ 40	$ 36	$ 36	$ 39	$ 37	$ 38	$ 41	$ 42	$ 42	$ 43	$ 43	$ 46	**$ 50**
Feb		**$ 49**	$ 39	$ 31	$ 27	$ 27	$ 29	$ 29	$ 29	$ 32	$ 33	$ 32	$ 33	$ 34	$ 37	$ 39
Mar		$ 35	$ 31	$ 30	$ 28	$ 29	$ 31	$ 30	$ 30	$ 32	$ 33	$ 33	$ 33	$ 34	$ 36	$ 39
Apr		$ 30	$ 26	$ 25	$ 24	$ 24	$ 24	$ 25	$ 26	$ 26	$ 27	$ 29	$ 30	$ 31	$ 31	$ 32
May		$ 29	$ 26	$ 24	$ 23	$ 23	$ 22	$ 24	$ 25	$ 25	$ 27	$ 28	$ 30	$ 31	$ 31	$ 32
Jun		$ 29	$ 29	$ 30	$ 30	$ 29	$ 28	$ 29	$ 29	$ 29	$ 30	$ 32	$ 33	$ 34	$ 34	$ 35
Jul	$ 37	$ 34	$ 33	$ 35	$ 35	$ 36	$ 36	$ 35	$ 37	$ 37	$ 37	$ 40	$ 41	$ 43	$ 43	$ 44
Aug	$ 36	$ 32	$ 33	$ 36	$ 36	$ 37	$ 32	$ 35	$ 37	$ 37	$ 36	$ 40	$ 42	$ 44	$ 44	$ 44
Sep	$ 34	$ 30	$ 29	$ 29	$ 30	$ 29	$ 28	$ 30	$ 30	$ 29	$ 30	$ 32	$ 34	$ 34	$ 34	$ 36
Oct	$ 32	$ 29	$ 25	$ 24	$ 23	$ 22	$ 22	$ 24	$ 25	$ 25	$ 25	$ 26	$ 28	$ 29	$ 29	$ 30
Nov	$ 34	$ 30	$ 27	$ 24	$ 24	$ 24	$ 25	$ 26	$ 27	$ 27	$ 29	$ 30	$ 32	$ 34	$ 35	$ 36
Dec	$ 39	$ 34	$ 35	$ 35	$ 36	$ 37	$ 38	$ 39	$ 39	$ 38	$ 38	$ 40	$ 42	$ 43	$ 43	$ 44

[127] *See* Attachment KK-30, which summarizes monthly energy prices forecast over the lifetime of the CVOW Commercial Project, prepared by ICF and provided by the Company in response to Staff Interrogatory No. 02-20 as Confidential Attachment Staff Set 02-20.

Risk management of offshore wind projects

Q. HOW DO OTHER U.S. STATES PROTECT RATEPAYERS AGAINST THE RISKS OF OFFSHORE WIND PROJECTS ON THE U.S. ATLANTIC SHORELINE?

A. Staff notes that construction of an offshore wind facility as an in-house asset developed by a regulated utility is unique to Virginia; every other state that has chosen to require offshore wind development does so through a power purchase agreement ("PPA") or offshore renewable energy certificate ("OREC") contracts,[128] which necessarily limit the risks to ratepayers by shifting construction, operational, and market risks from ratepayers to project owners. Under such scenarios, utility customers, therefore, will pay only for the actual produced energy and RECs, and will not have to bear the performance risks of the respective offshore wind facilities. If such facilities run during periods of negative locational marginal prices for energy, credits would apply.[129] Prices of energy set in many such offshore wind PPAs are known at the onset, as are the PPAs' contract term lengths.[130]

Q. HOW CAN THE COMMISSION PROTECT RATEPAYERS IN VIRGINIA AGAINST THE RISKS OF THE CVOW PROJECT?

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[128] The U.S. Department of Energy, Offshore Wind Market Report: 2021 Edition, table 3 at 16-17, attached hereto as Attachment KK-31. The report is available for download at https://www.energy.gov/sites/default/files/2021-08/Offshore%20Wind%20Market%20Report%202021%20Edition_Final.pdf

[129] For example, this is the case in the states of Massachusetts and Connecticut. As will be discussed later in my testimony, Staff incorporated a carve out for such periods of negative locational marginal pricing in its proposed performance guarantee design for CVOW.

[130] The U.S. Department of Energy, Offshore Wind Market Report: 2021 Edition, at 79, attached hereto as Attachment KK-32. The report is available for download at https://www.energy.gov/sites/default/files/2021-08/Offshore%20Wind%20Market%20Report%202021%20Edition_Final.pdf

A. The risks of cost overruns or lower than expected energy output may lead to higher than projected LCOE for the CVOW Project. Such risks are inherent to a project's ownership for any energy generating asset, but particularly to the offshore wind technology which is still nascent on the U.S. Atlantic shoreline. Further, if future energy prices are lower than forecasted, the Project's LTRR may also increase.

Staff reiterates the importance of the Commission's consideration of ratepayer protections suggested by Staff for the CVOW Project, including protections against cost overruns and a performance guarantee.

Protection Against Cost Overruns

Q. HOW HAS THE COMMISSION PREVIOUSLY PROTECTED RATEPAYERS AGAINST COST OVERRUNS?

A. In its Final Order in Case No. PUE-2007-00066, the Commission imposed certain requirements to protect customers from potential cost overruns. Specifically, the Commission determined:

> Pursuant to § 56-585.1 D of the Code and based on the record before us, we do not find that it is reasonable or prudent for the Company to incur *any* amount of costs above the cost estimates that comprise the projected level of $1.8 billion. We cannot approve in essence a blank check for Virginia Power to build the Coal Plant at *any* cost above the amount represented by the Company in this proceeding. While we recognize that construction cost overruns may occur for reasons that are both unforeseeable and outside the control of Virginia Power, any costs of constructing the Coal Plant that exceed the cost estimates comprising the $1.8 billion level must be proven by Virginia Power in a future proceeding to be reasonable or prudent under § 56-585.1 D of the Code before any recovery thereof from ratepayers shall be permitted.
>
> As discussed further below, we approve the Company's proposed Rider S for cost recovery for the Coal Plant. Rider S will be set to recover the Company's projected costs for the upcoming year and is subject to annual cost true-ups beginning in 2010; that is, there will be an annual proceeding in which the Commission will set the rate for Rider S. In order to recover any costs that *exceed* cost projections approved herein or hereinafter by the Commission (including new costs not included in the projections), Virginia Power shall be required to prove that such costs are reasonable or prudent as part of the annual Rider S proceeding *immediately following* the incurrence of any such cost overrun, unless good cause is shown for recovery in a later Rider S proceeding.[131]

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[131] *Application of Virginia Electric and Power Company, For a certificate of public convenience and necessity to construct and operate an electric generation facility in Wise County, Virginia, and for approval of a rate adjustment clause under §§ 56-585.1, 56-580 D, and 56-46.1 of the Code of Virginia*, Case No. PUE-2007-00066, 2008 S.C.C. Ann. Rept. 385, 391, Final Order (Mar. 31, 2008).

Q. DOES STAFF RECOMMEND SIMILAR PROTECTIONS FOR THE CVOW PROJECT?

A. Yes. Similar to the Commission's approval granted for the Company's Virginia City Hybrid Energy Center ("VCHEC") in the above case, the Commission could determine that in order to recover any costs that exceed the Company's cost projections of $9.8 billion for CVOW, Dominion must prove that such costs beyond the $9.8 billion are reasonable or prudent. This proof would be provided as part of the Company's annual Rider OSW proceeding that immediately follows the incurrence of any such cost overrun.

Staff notes that for VCHEC the Company did not have to provide notification of any cost overrun until *after* the cost overrun had already happened. In other words, even if the Company anticipated or projected that there would likely be cost overruns several years into the future, it did not have to provide such information to the Commission until the cost overrun actually occurred. Given this, Staff additionally recommends that the Company: (i) notify the Commission immediately if it anticipates or projects an increase in total capital expenditures of 5% or greater beyond the $9.8 billion currently projected for the Project; (ii) file an updated LCOE calculation with the most current assumptions, including the Company's LCOE model in executable Microsoft Excel format with formulae intact; and (iii) provide a written explanation as to the reason for the overruns and the reasonableness and prudence of the additional costs.

Performance guarantee

Q. HAS THE COMMISSION PREVIOUSLY ORDERED A PERFORMANCE GUARANTEE FOR ANY OF THE COMPANY'S RENEWABLE ENERGY FACILITIES?

A. Yes. The Commission ordered a performance guarantee for the US-3 Solar Projects in Case No. PUR-2018-00101. In that case, Dominion's customers will be held harmless for the US-3 Solar Projects' performance below a 25% annual capacity factor for a period of 20 years from the date that the first US-3 Solar Project enters commercial operations.[132] Below the 25% capacity factor, the US-3 Solar Projects' NPV was found to become negative for customers.[133] Further, by year 20, 78% of the total cost of the US-3 Solar Projects would be paid for by the Company's customers through the respective RAC.[134]

The Commission also ordered a performance guarantee for the US-4 Solar Project in Case No. PUR-2019-00105. In that case, Dominion's customers will be held harmless for the US-4 Solar Project's performance below 22% capacity factor for a period of 20 years from the date that the US-4 Solar Project enters commercial operations.[135]

[132] *Petition of Virginia Electric and Power Company, For approval and certification of the proposed US-3 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, and for approval of a rate adjustment clause, designated Rider US-3, under § 56-585.1 A 6 of the Code of Virginia,* Case No. PUR-2018-00101, 2019 S.C.C. Ann. Rept. 239, Order Granting Certificates (Jan. 24, 2019) at 246-247.

[133] *Id.* at 15.

[134] *Id.* at 18, footnote 54.

[135] *Petition of Virginia Electric and Power Company, For approval and certification of the proposed US-4 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, and for approval of a rate adjustment clause, designated Rider US-4, under § 56-585.1 A 6 of the Code of Virginia,* Case No. PUR-2019-00105, 2020 S.C.C. Ann. Rept. 290, Order Granting Certificate (Jan. 22, 2020) at 295.

Q. SHOULD THE COMMISSION ADOPT A PERFORMANCE GUARANTEE FOR THE CVOW COMMERCIAL PROJECT?

A. Staff believes the Commission may wish to consider imposing a performance guarantee in this proceeding. Staff offers the following justifications.

First, as described above, there is precedent for the Commission imposing a performance guarantee (tied to projects' capacity factors) for new renewable energy assets. As such, imposing a performance guarantee for the CVOW Project would not be novel.

Secondly, Staff emphasizes the inherent risks of offshore wind technology, as it is only just emerging on the U.S. Atlantic shoreline. This fact was acknowledged by the EIA by assigning the highest technological optimism factor (1.25) to offshore wind projects.[136] Further, as previously mentioned, the Company **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted] **[END EXTRAORDINARILY SENSITIVE]**

Q. PLEASE DESCRIBE STAFF'S PROPOSED PERFORMANCE GUARANTEE.

A. First, Staff emphasizes that the Company anticipates CVOW will operate for 30 years with a net capacity factor of 42%,[138] which the Company states is the long-term annual average

[136] https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf at 2. The technological optimism factor is applied by the EIA to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[137] *See* Filing Schedule 46.b.1.v, Statement 1, at 22 (Slide 21).

[138] *See* Attachment KK-33 for a copy of the Company's response to Staff Interrogatory No. 01-08.

over the life of the facility.[139] Next, Staff notes that the lowest capacity factor used by the Company for the purposes of the LCOE sensitivity analysis for the CVOW Commercial Project is 38%, before adjustments for availability factor.[140] Further, the Project's estimated availability factor is 97% in the Company's LCOE model.[141] Therefore, Staff suggests that the 38% capacity factor adjusted for the 97% availability factor be used for the proposed performance guarantee.[142]

Staff recommends that, if the Commission finds it appropriate to require a performance guarantee for the CVOW Commercial Project, energy that was not generated but could have been produced at the time of potential negative locational marginal pricing in the DOM Zone should not count towards these targets, so as to avoid an incentive for the Company to run the facility at such times, thus creating risks for the system's reliability. Further, curtailing energy production during times of negative energy pricing would potentially produce more value to customers than running the project at a loss in the energy market for the sole purpose of avoiding a violation of the performance guarantee.

Q. IF THE COMMISSION FINDS A PERFORMANCE GUARANTEE FOR THE CVOW COMMERCIAL PROJECT NECESSARY, HOW LONG SHOULD SUCH PERFORMANCE GUARANTEE STAY IN EFFECT?

[139] *See* Attachment KK-34 for a copy of the Company's response to Staff Interrogatory No. 14-128.

[140] *See* Attachment KK-22 for a copy of the Company's response to Consumer Counsel's Interrogatory No. 04-84.

[141] *See* Corrected Attachment III.A of the Generation Appendix, at 47, filed as a part of the Company's errata filing on March 2, 2022.

[142] This would result in a 36.86% net capacity factor.

A. Staff recommends that the performance guarantee for the CVOW Commercial Project, if approved by the Commission, stay in effect for at least 20 years after the Project enters commercial operation. By the end of year 20, 76% of the total costs of the Project (not adjusted for capacity, energy, or REC benefits) would be recovered by the Company from customers.[143] Further, according to the Company's revenue requirement calculation for the Project, starting from year 21, the Project's benefits allocated to customers through Rider OSW would become higher than the Project's costs payable by customers through that Rider.

Q. IF THE COMMISSION FINDS A PERFORMANCE GUARANTEE FOR THE CVOW COMMERCIAL PROJECT NECESSARY, HOW WOULD THE PERFORMANCE GUARANTEE WORK?

A. It would work similar to the guarantees applied to the US-3 and US-4 projects previously approved by the Commission. Customers would be held harmless for any production that falls short of the capacity factor threshold established by the Commission. The Company would need to replace (1) the value of any shortfall in energy production at the average PJM energy price; and (2) the value of any shortfall in RECs based on either tier 1 REC prices in PJM or the deficiency payment. This could be accomplished through a true-up factor in a future Rider OSW proceeding.

[143] *See* Attachment KK-35 that includes Staff's calculation of the proportion of the Project's cost recovered from the Company's customers for each year from 2022 through 2056.

IV. NPV ANALYSIS

NPV analysis of the Project – the Base Case - Low Solar and High Battery Saturation

Q. WHAT IS NPV?

A. NPV stands for the Net Present Value of costs and benefits associated with the CVOW Commercial Project, calculated by discounting to their present dollar value both future cash flows (costs and revenues in nominal dollars over the lifetime of the Project) and benefits, which include deemed savings (or avoided costs) and the SCOC benefit. The year of the application, 2021, is considered as the "present" for the purposes of the NPV calculation.

Q. HOW DID THE COMPANY CALCULATE THE NPV OF THE CVOW COMMERCIAL PROJECT?

A. Company witness Glenn A. Kelly describes the Company's approach to calculating the NPV of costs and benefits of the CVOW Commercial Project on pages 12 through 16 of his direct testimony. The modeling assumptions are generally consistent with those used in the Company's 2021 IRP Update.[144] The Company ran PLEXOS to evaluate the Project on a *system* basis. First, the Company ran PLEXOS for a base case to model costs and benefits of the Company's whole system without the CVOW Commercial Project; this base case is also referred to as the "base case without CVOW." The base case without CVOW includes nuclear license extensions, CE-1 and CE-2 solar projects, and the full build-out of energy storage facilities envisioned by the VCEA; it does not include the second tranche

[144] Kelly Direct at 15. The only difference in assumptions in the instant case is that the Company has updated the effective load carrying capability ("ELCC") values for the purposes of capacity value modeling; the updated ELCC values were taken from the PJM July 2021 ELCC Report.

of offshore wind or solar facilities envisioned by the VCEA but not yet approved by the Commission. Next, the CVOW Commercial Project was added to the base case without CVOW in PLEXOS, and the system's costs and benefits were modeled again. This case is referred to as the "base case with CVOW." The Company then calculated the NPVs for its whole fleet in the base case without CVOW and the base case with CVOW and subtracted the former from the latter. The resulting CVOW Commercial Project's NPV reflects the *change in the total NPV of the Company's whole system*. In other words, costs and benefits of the CVOW Commercial Project are merged with the Project's effects on the Company's system in PLEXOS.[145]

Staff does not oppose the system approach to NPV calculation of the CVOW Commercial Project. Staff notes for clarity though that the NPV calculation under a system approach results in a different NPV than if the Project had been evaluated as a stand-alone generation asset. The reason for the difference between a stand-alone and system NPV is that, once a project is added to the Company's system, it may eliminate the need to run other generating assets, which may lead to savings on fuel or emission costs, and impact volumes of energy sold into the PJM market or procured from it.[146] Considering the large size of the CVOW Commercial Project, its effects on the Company's system are significant; they will be discussed in detail later in this section.

NPVs of the SCOC benefit and avoided costs of RECs were calculated separately from the PLEXOS model and added to the NPVs based on the PLEXOS modeling. Staff

[145] Such effects are called synergies, they may be positive or negative, and their NPVs are usually factored in when an acquisition of an asset is considered.

[146] The Company also asserts that adding the CVOW Commercial Project to its system will result in avoided capacity cost in the PJM market, notwithstanding the Company's election to be a Fixed Resource Requirement utility within PJM.

will discuss its position with regard to the Company's calculation of the SCOC benefit later in this testimony. The Company uses the $45 deficiency payments set forth in Code § 56-585.5 as the value of RECs for the purpose of calculating avoided costs associated with energy generation by the CVOW Commercial Project. Staff will also provide an estimate of avoided cost of RECs based on the ICF forecast, as the Commission found value in such analysis in its Final Order in Case No. PUR-2021-00146.

Q. WHAT IS THE NPV OF THE CVOW COMMERCIAL PROJECT?

A. According to Company witness Kelly, the NPV of the CVOW Commercial Project is $2.5 billion.[147] This amount includes a negative $5.6 billion change in system NPV as a result of the CVOW Project's addition ("PLEXOS NPV"), a $4.9 billion avoided cost of RECs based on statutory deficiency payments, and a $3.2 billion SCOC benefit.

Q. PLEASE DESCRIBE KEY COMPONENTS OF THE PROJECT'S PLEXOS NPV.

A. Key components of the Project's PLEXOS NPV[148] can be grouped as follows:

- NPV of fixed costs is approximately negative $9.4 billion. The Company's response to Staff Interrogatory No. 08-98 states,

> "Fixed Costs is an output calculated by the PLEXOS model which is the sum of total system fixed O&M and the total system levelized annual capital costs, including depreciation, reoccurring annual capital expenditures, applicable tax benefits[149] and costs, and financing costs."

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[147] Kelly Direct, Summary.

[148] As calculated by Staff based on Attachment Staff Set 01-16(1).

[149] As stated on page 13 of Kelly Direct, the Company estimated the NPV of the CVOW's ITCs at approximately $1.05 billion, assuming that approximately 83.27% of the Project's CAPEX qualifies for 30% ITC. However, as stated previously, **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted] **[END EXTRAORDINARILY SENSITIVE]**

- NPV of dispatch costs savings is approximately $1.2 billion. It is comprised of decreases in fuel costs of approximately $979 million, variable O&M costs of approximately $56 million, and emissions costs[150] of approximately $167 million due to displacement of generation from the Company's fossil-fueled units by the Project.
- NPV of potential PJM capacity revenue is approximately $0.4 billion. It represents both the market value of capacity and avoided cost of capacity due to the addition of the Project to the Company's system.[151]
- NPV of PJM energy revenues and avoided costs of energy due to addition of the Project to the Company's system is approximately $2.1 billion.

As is generally the case with forward-looking modeling, the assumptions underlying the Company's NPV analysis for the CVOW Commercial Project are subject to change in the future. However, the Company did not test the model's sensitivity to the impact of lower than forecasted energy or capacity prices in the PJM market.[152] Considering the 30-year operating life of the CVOW Commercial Project modeled by the Company, changes in future market prices may have significant effects on the Project's NPV.

Q. WILL THE CVOW COMMERCIAL PROJECT DISPLACE ENERGY GENERATED BY THE COMPANY'S EXISTING FLEET?

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[150] "Emissions cost" is a label in PLEXOS for what is called "direct carbon tax" in the 2021 IRP Update, and it is the sum of Federal and Regional Greenhouse Gas Initiative ("RGGI") prices per ton of CO2 emissions. The Company confirmed in response to Consumer Counsel's Interrogatory No. 4-83, attached hereto as Attachment KK-36, that it did not perform an analysis of costs and benefits that would estimate the impact of Virginia not participating in RGGI. The RGGI portion in total emission cost or direct carbon tax gradually decreases from 78% in 2026 to 71% in 2046, according to Staff's calculation based on the ICF forecast.

[151] *See* Attachment KK-37 for a copy of the Company's response to Consumer Counsel's Interrogatory No. 04-72, which describes PJM capacity revenue and explains why it is included in the CVOW Commercial Project's NPV.

[152] *See* Attachment KK-38 for a copy of the Company's response to Consumer Counsel's Interrogatory No. 04-85, which states that the Company has not performed an analysis that estimates the impact of lower than forecasted energy or capacity prices on the costs and benefits of the base case with CVOW and the base case without CVOW.

A. Yes. Staff's analysis of the PLEXOS model data reveals that the CVOW Commercial Project's generation will cannibalize energy generation of the Company's gas fueled and coal fueled units in the base case with CVOW; the combined cycle gas units are affected the most, as shown in the table below.[153] The potential costs and benefits associated with the displacement of the Company's own generation are incorporated in the PLEXOS NPV of the CVOW Commercial Project. **[BEGIN CONFIDENTIAL]**

[redacted]

[END CONFIDENTIAL]

However, the PLEXOS model runs that support the original filing in the instant case do not include solar facilities envisioned by the VCEA but not yet approved by the Commission. As a result, in Staff's view the CVOW Commercial Project's potential impact

[153] The table was created by Staff based on analysis of the information on each unit's generation provided by the Company in Corrected Attachment AG Set 02-24 (1) for the base case without CVOW and Corrected Attachment AG Set 02-24 (3) for the base case with CVOW.

on the Company's system was not modeled comprehensively, because the addition of the CVOW Commercial Project could also displace solar facilities built in the future.

Q. HOW MUCH ENERGY DOES THE CVOW COMMERCIAL PROJECT ADD TO THE COMPANY'S SYSTEM?

A. The Company's baseline assumption is that the CVOW Commercial Project will operate for 30 years with a net capacity factor of 42%, which the Company states is a long-term annual average over the lifetime of the Project.[154] Under this scenario, *gross* cumulative addition of energy by the CVOW Commercial Project is 286,035 GWh in 2027 – 2056.[155] Considering the displacement of 111,777 GWh of the Company's fossil-fueled unit's generation, net cumulative addition of energy by the CVOW is 174,257 GWh. Such *net* cumulative energy addition of 174,257 GWh to the Company's system due to CVOW would translate into a 25.6% average capacity factor for the CVOW Project *on a system basis*.

As mentioned previously, the CVOW Project's addition to the Company system also results in an 8,132 GWh increase in the new generic energy storage units' cumulative generation[156] and 12,462 GWh increase in Bath County Pumped Storage generation in 2027 - 2056.[157] Therefore, technically, the addition of the CVOW Project's energy to the

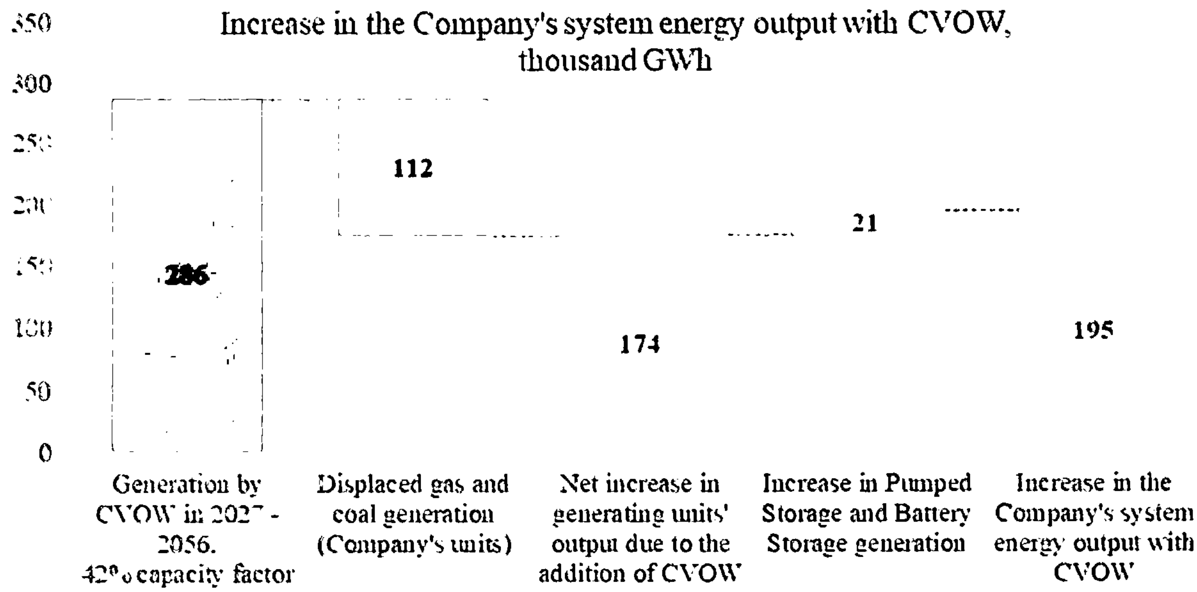
[154] *See* Attachment KK-35 for a copy of the Company's response to Staff Interrogatory No. 14-128.

[155] Staff's analysis is based on information regarding each unit's generation as provided by the Company in Corrected Attachment AG Set 02-24 (3) for the base case with CVOW.

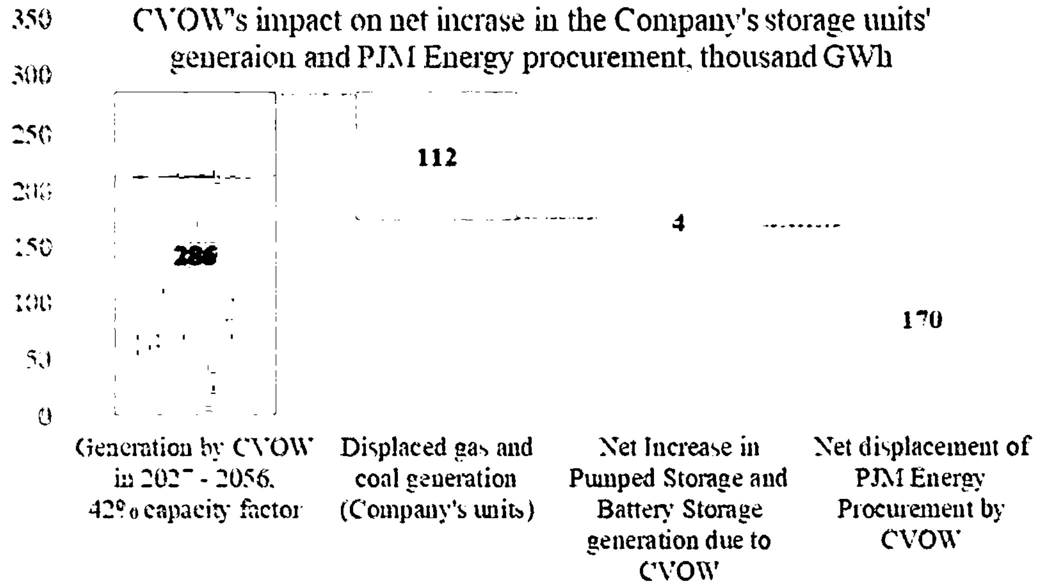
[156] Staff's analysis of the information on battery storage generation provided by the Company in Attachment Staff Set 09-103 (a).

[157] Staff's analysis of the information on pump storage generation provided by the Company in Attachment Staff Set 09-103 (c).

Company's system increases the system's energy output by 194,858 GWh in 2027 – 2056.



However, the Company's storage units can "charge" either from power purchases from the PJM market or from the Company's units. For the Commission's reference, Staff notes that the CVOW Project displaces only 169,904 GWh of energy purchases (rather than 194,858 GWh) in 2027 - 2056. As previously mentioned, the CVOW project displaces 111,777 GWh of the Company's owned fossil-fueled units. The sum of the displaced energy purchases and displaced generation of the Company's owned fossil-fueled units is 281,681 GWh, which is less than the total stated CVOW Production of 286,035 GWh. Therefore, it appears to Staff that CVOW's net effect on storage units' generation is 4,353 GWh over the same time period; in other words, storage units charge from CVOW, so that the Project would still add 174,257 GWh of energy over its lifetime to the Company's system.



Q. WHAT ARE THE IMPLICATIONS OF GRADUALLY ADDING THE SCOC AS AN INDIRECT COST TO DISPATCH PRICE OF THE COMPANY'S FOSSIL-FUELED UNITS?

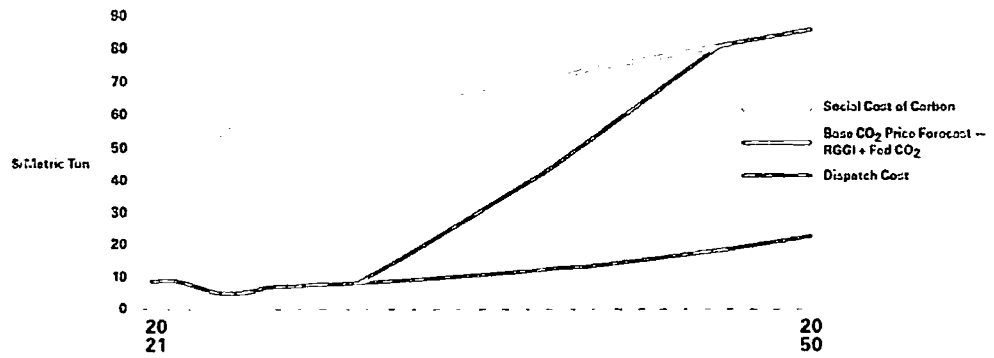
A. As stated on page 9 of the 2021 IRP Update,

> "As shown in Figure 1.2.1, for the first ten years of the Study Period,[158] the Company included a carbon dispatch adder equal to the forecasted price of a direct carbon tax.[159] Starting in 2031, the Company then blended the forecasted social cost of carbon with the direct carbon tax through 2046 (i.e., the end of the Study Period).

[158] In the 2021 IRP Update, the Study Period begins in 2021. Hence, its first ten years are 2021 – 2030.

[159] Direct carbon tax is modeled by the Company as a sum of Federal and RGGI prices per ton of CO2 emissions, as forecasted by ICF.

Figure 1.2.1: Carbon Dispatch Price



> Adding the social cost of carbon as indirect cost, or "shadow price," results in the Company's carbon-emitting generating units operating less often, thus lowering projected carbon emissions from the Company's system.... Because the social cost of carbon is an indirect cost, these costs were not included in the net present value ("NPV") of the Alternative Plans; only costs related to the direct carbon tax were included in the NPV results."

As explained informally to Staff by Company witness Kelly, for the purposes of the CVOW Commercial Project's NPV calculation, the Company employed the same approach described above to PLEXOS modeling of the dispatch of its fossil-fueled units and the resulting need in energy procurement from PJM. Staff concludes that the consequence is that the PLEXOS model presumes the Company's fossil-fueled units' dispatch cost to be more expensive than the direct or cash cost of dispatch, which makes energy procurement from PJM appear more economic, especially in later years. Therefore, the modeled capacity factors and energy generation of the Company's fossil-fueled units are lower than they would have been without adding the "shadow price" of the SCOC in the model, even though this "shadow price" does not impact direct or cash dispatch cost of these units.

Staff converted carbon prices from the chart above, in which they are expressed in dollars per metric ton, into prices in dollars per MWh. This allows a comparison of carbon dispatch price with average monthly PJM energy price forecasts, prepared by ICF, in the chart below.[160]

[BEGIN CONFIDENTIAL]

[redacted]

[redacted].

[END CONFIDENTIAL] The cost of energy procured from the PJM market will be real,

[160] CO_2 emission prices in dollars per short ton was provided by the Company in Attachment Staff Set 01-16 (3) and converted in dollars per MWh by Staff. Carbon dispatch price was calculated by Staff based on the blending methodology described in the 2021 IRP Update, as quoted above. For ICF energy price forecasts, Staff used numbers provided by the Company in Attachment Staff Set 02-20 (b).

however. As for potential environmental benefits of procuring energy from the PJM market, they would only materialize if marginal units called to generate energy within PJM emit less carbon than that of the Company's units available for dispatch.

To summarize, it is Staff's position that adding the "shadow price" to dispatch cost of the Company's fossil-fueled units in PLEXOS in this case results in higher avoided cost of energy and therefore higher NPV of the CVOW Commercial Project.[161] Even though the Company did not include SCOC in the PLEXOS NPVs, the Company adjusted the dispatch cost of its fossil-fueled units for SCOC "shadow price" as an indirect cost. Without the "shadow price" added, PLEXOS could have dispatched the Company's fossil-fueled units more frequently, based on real dispatch cost comparison with PJM energy prices, and the avoided cost of energy for the purposes of the CVOW's NPV calculation would have been lower. Instead, PLEXOS would plan to procure energy from PJM, which would be more expensive because the Company's own units would not appear competitive due to this indirect SCOC "shadow price" addition.[162]

Q. WHAT ARE THE IMPLICATIONS OF INCLUDING BATTERY STORAGE IN THE BASE CASE WITHOUT CVOW AND THE BASE CASE WITH CVOW MODELS?

[161] The Company has not performed an analysis to identify the sources and cost of replacement energy that is expected to be incurred due to the increasing levels of intermittent renewable energy resources in its system. *See* Attachment KK-39 for a copy of the Company's response to Consumer Counsel's Interrogatory No. 04-91.

[162] At the same time, the NPV of dispatch cost savings for the Company's fossil-fueled units would be higher. Nevertheless, because the PLEXOS model would only plan for dispatch of the Company's own units when it is cheaper than energy procurement from PJM, the conclusion holds.

A. The Company instructed PLEXOS to require the full build-out/procurement of battery storage capacity[163] in both the base case without CVOW and the base case with CVOW. Battery storage allows for more flexibility to balance generation output of the Company's system and energy purchases from PJM. It also allows for optimization of the timing of energy sales and energy procurement, thus increasing the value of energy generated by the Company's system and decreasing the cost of energy purchases. Therefore, the NPV of PJM energy revenues and avoided costs of energy is likely higher than it would have been without battery storage. However, it should be noted that the NPV of battery storage costs of approximately $3.8 billion[164] and the NPV of battery storage capacity revenues of approximately $1.2 billion[165] are not included in the PLEXOS NPV of the CVOW Commercial Project. As such, it is impossible to isolate the impact of battery storage availability on the CVOW's PLEXOS NPV based on the PLEXOS model runs that supported the original filing in the instant case.

Q. WHAT WOULD BE THE NPV OF AVOIDED COST OF RECS IF REC PROXY VALUES ARE TAKEN FROM THE ICF REC PRICE FORECAST?

A. The ICF forecast includes three REC price scenarios for 2021 – 2046, each stemming from one of the three commodity forecasts utilized for the 2021 IRP Update.[166] To calculate the NPVs of avoided cost of RECs for each of these REC price scenarios, Staff extrapolated

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[163] Consistent with the storage capacity directed by the VCEA to be proposed for Commission approval.

[164] As per Attachment Staff Set 01-16 (1).

[165] *Id.*

[166] The three commodity forecasts prepared by ICF are (1) RGGI + Federal CO2, (2) RGGI + Federal CO2 High Fuel Price, (3) RGGI + Federal CO2 Low Fuel Price. The two latter cases are based on high and low cases for natural gas price and their ripple effects on energy, capacity, and REC prices. The 2021 IRP Update provides more detail on pages 32 and 33.

REC prices into the future (2047 – 2056), assuming an annual percent in price increase to be constant and equivalent to the forecasted change in 2046. The resulting NPVs of avoided REC costs are:

- Approximately $875 million in the baseline RGGI + Federal CO2 scenario;
- Approximately $782 million in the RGGI + Federal CO2 High Fuel Price scenario;
- Approximately $939 million in the RGGI + Federal CO2 Low Fuel Price scenario.

The Company also used REC prices from ICF's baseline RGGI + Federal CO2 scenario forecast for PA Tier 1 RECs for the period from 2047 through 2056, for the purposes of REC adjustment in the long-term revenue requirement calculation.[167] Staff calculated the NPV of avoided REC cost based on these prices as well, and it is approximately $861 million.

Q. DID THE COMPANY ASSUME THAT ANY RECS WOULD BE AVAILABLE FOR PURCHASE OVER THE LIFETIME OF THE CVOW PROJECT?

A. In the initial filing, the Company assumed that the CVOW Commercial Project's generation would avoid only $45 deficiency payments as set forth in Code § 56-585.5, but not REC purchases from the market. However, as will be discussed in detail later, in the course of the discovery process, the Company performed additional PLEXOS model runs that optimized RPS deficiency payments by assuming that an amount of REC equivalent to 15% of the Company's annual RPS goal would be available for purchase in the market in

[167] This information was provided by the Company in Attachment Staff Set 02-20 (a). The source of the forecast was confirmed through Staff Interrogatory No. 08-96.

2027 - 2056.[168] Further, the Company acknowledged that it "may meet more or less than 15% of its RPS Program compliance requirement with purchased RECs based on the pricing and availability of eligible RECs."[169]

Q. HOW WOULD THE NPV OF THE CVOW COMMERCIAL PROJECT CHANGE IF THE AVOIDED COST OF RECS WAS BASED ON THE ICF FORECAST?

A. Substituting the NPV of avoided REC costs based on the ICF REC price forecast for the $4.9 billion NPV of avoided cost of REC deficiency payments embedded in the Company's NPV calculation for the CVOW Commercial Project would reduce the Project's NPV by approximately $4 billion. The resulting NPV of the CVOW Commercial Project is approximately negative $1.6 billion.

Beyond the scenario with the negative CVOW NPV, the table below shows that total *customer* benefits of the CVOW Commercial Project (shown in the column shaded in the darker color) are lower than the Project's costs, if the social cost of carbon benefit is considered a separate *societal* benefit. In the scenario with ICF REC price forecast, total customer benefits are approximately half of the Project's cost.

REC proxy value scenario	Fixed costs, $M	Dispatch cost savings, $M	Capacity revenue, $M	Energy revenue, $M	Avoided REC Cost, $M	Total customer benefits, $M	Social cost of carbon benefit	NPV, $M
Deficiency payment	$9,399	$1,202	$421	$2,140	$4,891	$8,654	$3,221	$2,476
ICF forecast	$9,399	$1,202	$421	$2,140	$861	$4,624	$3,221	[illegible]

[168] See Attachment KK-40 for a copy of the Company's response to Staff Interrogatory Nos. 08-100 (b).

[169] *Id.*

Q. DOES STAFF HAVE METHODOLOGICAL CONCERNS WITH THE COMPANY'S CALCULATION OF THE NPV OF THE SOCIAL COST OF CARBON BENEFIT?

A. Yes, partly for the same reasons outlined in Staff's testimony in Case No. PUR-2021-00146, in which the Company petitioned the Commission for approval of the CE-2 Projects ("2021 RPS Case"), and partly because the more granular analytical approach employed by Staff in the instant case raised new concerns and recommendations.

The Company's approach to the SCOC benefit's NPV calculation is described on pages 14 and 15 of Company witness Kelly's testimony; it is largely the same approach as the one employed in the 2021 RPS Case.[170] Again, the Company did not assume any change in PJM marginal emission rates over time despite their observed average 8% per year decrease between 2016 and 2020. Also, the Company did not incorporate potential carbon effects of woodlands loss due to construction of electric interconnection and transmission facilities (i.e., the Virginia Facilities) required for the CVOW Project.[171]

The Company assumed that the CVOW Commercial Project's generation would displace PJM purchased power.[172] Indeed, in the base case with CVOW, the CVOW Commercial Project displaces 169,904 GWh of energy purchases from PJM. However, as

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[170] The only methodological difference is that the Company used the average between marginal on-peak and off-peak CO2 emission rates within PJM in 2020 in the instant case. Staff's position is that the average between marginal on-peak and off-peak CO2 emission rates within PJM is appropriate, but "freezing" PJM marginal CO2 emissions rates at their 2020 values is reasonable only for the purposes of estimating CO2 emissions of *fossil-fueled* generation displaced by renewable assets.

[171] The Department of Forestry ("DOF") stated that the impacts on woodlands would differ across several transmission routes for the Virginia Facilities that the Company submitted for consideration. These impacts were not quantified in the DOF letter.

[172] Kelly Direct at 15.

previously mentioned, 111,777 GWh of energy generation by the Company's gas-fueled and coal-fueled units is also displaced.

Staff's recommendations regarding the SCOC calculation methodology for each source of displaced energy are outlined below.

- For displaced generation from the Company's gas and coal units (111,777 GWh), Staff does not oppose the Company's SCOC calculation methodology, because the displaced generation composition by fuel type is similar to the PJM's 2020 fleet composition by fuel type.
- For net displacement of energy to be purchased from PJM in 2027 – 2056 (169,904 GWh), Staff's methodological concerns raised in the 2021 RPS case remain. Specifically, as PJM's fleet changes over time, marginal CO2 emission rates will also change; this should be reflected in the Company's SCOC calculation.

Q. HOW DOES THE OPERATING LIFE OF THE CVOW COMMERCIAL PROJECT IMPACT THE NPVS OF AVOIDED COST OF RECS AND SCOC BENEFIT?

A. The Company assumed that the CVOW Commercial Project would remain operational for 30 years, until 2056.[173] Staff suggests that the 25-year useful life (until 2051) assumption be considered also; this assumption was used by Sargent & Lundy in EIA's Case 22 in the 2020 Annual Energy Outlook. It was also used by the Company for the CVOW Pilot Project.

[173] *See* Attachment KK-41 for a copy of the Company's response to Consumer Counsel's Interrogatory No. 03-38, which lists the Company's justification for this assumption. Staff notes that the EIA's "Levelized Costs of New Generation Resources," published in February 2021, states, in part, "EIA calculates all levelized costs and values based on a 30-year cost recovery period.... In reality, a plant's cost recovery period... can vary by technology and project type." Therefore, 30 years is a simplifying assumption for all resources, not the EIA's guidance specific to offshore wind. Also, Staff emphasizes that the paper titled "Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals" authored by Ryan Wiser and Mark Bolinger of Lawrence Berkeley National Laboratory indicates that project life cycles have increased over time for *land-based* wind power plants.

The 25-year operating life assumption would lower the NPV of the avoided cost of RECs by $383 million in the case of deficiency payment as a REC proxy value, and by $98 million in the case of ICF forecasted REC proxy values. Staff notes that the Company's need for RECs after 2051 becomes significantly higher due to the expiration of the Surry nuclear plant license extensions.[174] The NPV of the SCOC benefit will decrease by approximately $276 million.

The table below compares the NPVs of avoided cost of RECs and SCOC benefit under the 30-year and 25-year operating life assumptions. All values are shown in millions of 2021 dollars.

Operating life of the CVOW Commercial Project	NPV of avoided cost of RECs (where REC proxy value = deficiency payments), $ million	NPV of avoided cost of RECs (where REC proxy value = ICF REC price forecast), $ million	NPV of SCOC benefit, $ million
25 years	$4,508	762	2,945
30 years	4,891	861	3,221
NPV difference	383	98	276

Q. PLEASE SUMMARIZE STAFF'S CONCERNS WITH THE NPV ANALYSIS OF THE CVOW COMMERCIAL PROJECT.

A. Staff has several concerns with the Company's NPV calculation. First, total *customer* benefits[175] of the CVOW Commercial Project are lower than the Project's cost, if the SCOC benefit is considered a separate *societal* benefit. Further, if the ICF REC price forecast is

[174] Surry nuclear plant license extensions expire after 2051 for Unit 1 and 2052 for Unit 2; each unit is projected to generate 7,124 GWh per year while in operation, according to Corrected Attachment AG Set 02-24(1). Thus, their phase out leads to a sharp increase in REC procurement targets for the Company and, consequently, a risk of a higher proportion of deficiency payments in 2052 - 2056.

[175] Customer benefits included in the Company's analysis are ITCs, dispatch cost savings, PJM capacity revenues and avoided costs, PJM energy revenues and avoided costs, and avoided cost of RECs.

used as a source for REC proxy values, total customer benefits are approximately half of the Project's cost, and the Project's NPV becomes negative.

Second, adding the "shadow price" to the dispatch cost of the Company's fossil-fueled units in PLEXOS in this case results in higher avoided cost of energy and therefore higher NPV of the CVOW Commercial Project.

Third, the NPV of PJM energy revenues and avoided costs of energy is likely higher than it would have been without battery storage added by the Company in both the base case without CVOW and the base case with CVOW. However, the NPV of battery storage costs of approximately $3.8 billion and the NPV of battery storage capacity revenues of approximately $1.2 billion are not included in the PLEXOS NPV of the CVOW Commercial Project.

Fourth, the PLEXOS model runs that support the original filing in the instant case do not include solar facilities directed by the VCEA to be proposed for Commission approval. As a result, in Staff's view the CVOW Commercial Project's potential impact on the Company's system was not modeled comprehensively, because the addition of the CVOW Commercial Project could displace solar facilities built in the future.

Finally, the Company's methodology for calculating the SCOC benefit may be refined, such that displacement of the Company's own generation by the CVOW Commercial Project and *net* change in PJM power purchases are taken into account and analyzed separately.

NPV analysis of the Project – the Revised Base Case - High Solar and Low Battery Saturation

Q. DID STAFF REQUEST ADDITIONAL ("REVISED") PLEXOS MODEL RUNS?

A. Yes. Staff requested two additional model runs, with and without the CVOW Commercial Project, respectively. Staff asked the Company to remove all model instructions to include battery storage resources that have not yet been approved by the Commission or pending before the Commission, and allow the model to re-optimize the portfolio on a least-cost optimization basis. The Company accommodated this request, and titled the respective model runs "revised base case without CVOW" and "revised base case with CVOW."

Q. PLEASE DESCRIBE THE REVISED PLEXOS MODEL RUNS PERFORMED BY THE COMPANY.

A. The revised base case without CVOW modeled the Company's system on an economic basis. Beyond nuclear license extensions and the CE-1 and CE-2 solar projects, it includes significant additions of generic solar facilities, up to approximately 1,200 MW per year in 2025 – 2038, and somewhat smaller quantities almost each year thereafter. It does not include Company-built battery storage; however, energy storage PPAs are added in 2049 and thereafter, partially due to expiration of Surry nuclear plant license extensions in 2051 and 2052. The Company allowed PLEXOS to procure RECs in these model runs, and the model purchased 205,095 GWh of RECs in this scenario in 2027 – 2056.[176] The power purchase limit from the PJM market was set at 5,200 MWh per hour in 2021 - 2056.[177]

[176] Staff's analysis of Attachment Staff Set 05-63 (2).

[177] See Attachment KK-42 for a copy of the Company's response to Staff Interrogatory No. 08-102.

Next, the CVOW Commercial Project was added to the revised base case without CVOW in PLEXOS, and the system's costs and benefits were modeled again. The Company states that the CVOW Commercial Project displaced 2,760 MW of new generic solar facilities in this case. Staff notes that construction of 2,640 MW of new generic solar facilities was postponed in this case as well.[178] The amount of energy storage PPAs selected by the model after 2049 was lower by 570 MW in the revised base case with CVOW as compared to the revised base case without CVOW, according to the Company. The cumulative volume of RECs purchased by the model was 201,334 GWh of RECs in the revised base case with CVOW in 2027 – 2056, or 3,760 GWh lower that in the revised base case without CVOW.

Q. WHAT IS THE REVISED NPV OF THE CVOW COMMERCIAL PROJECT?

A. According to the Company, the revised NPV of CVOW is $1.1 billion,[179] which includes:

- A negative $3.3 billion change in system NPV as a result of the CVOW Commercial Project's addition ("revised PLEXOS NPV");[180]
- $1.2 billion NPV of avoided cost of 3,760 GWh of REC purchases and 97,060 GWh of avoided deficiency payments (i.e., for a total of 100,820 GWh, not 286,035 GWh of the total lifetime generation of the CVOW Project); and
- $3.2 billion NPV of the SCOC benefit, calculated based on 286,035 GWh of the total lifetime generation of the CVOW Project.

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[178] Based on Staff's analysis of Attachment Staff Set 09-107 (1) and Attachment Staff Set 09-107 (2), in the Revised Base Case without CVOW, the PLEXOS model selected a total of 6,000 MW of new solar facilities in 2026 through 2030 on the least-cost basis. In the Revised Base Case with CVOW, the PLEXOS model selected to add 1,380 MW of new solar facilities over the same period. Gradual addition of solar capacity in 2031 and thereafter may be more expensive due to inflation. The gap between the amount of solar capacity needed in these two cases widens to 5,400 MW in 2034 and does not begin to decrease until 2041.

[179] See Attachment KK-43 for the copy of Attachment Staff Set 05-63(1), which describes the revised PLEXOS model runs.

[180] Revised PLEXOS NPV is a difference in the Company's system NPV in the revised base case with CVOW and the revised base case without CVOW.

Q. PLEASE DESCRIBE KEY COMPONENTS OF THE PROJECT'S REVISED PLEXOS NPV.

A. The Project's revised PLEXOS NPV includes the following components:

- NPV of fixed costs is approximately negative $5.7 billion. Because the CVOW Commercial Project displaces 2,760 MW of new generic solar facilities and postpones construction of 2,640 MW of new generic solar facilities, the NPV of the Project's fixed costs is fused with fixed costs savings of displaced and postponed Company-built solar facilities in this composite fixed costs estimate.

- NPV of dispatch costs savings is approximately $1.8 billion. It is comprised of decreases in fuel costs of approximately $279 million and emissions costs of approximately $51 million due to displacement of fossil-fueled units by the Project, as well as decreases in variable O&M costs of approximately $1,470 million. Variable O&M costs incorporate solar PPA costs in the revised model runs, and the addition of the CVOW Project displaces and postpones solar PPAs.[181]

- NPV of potential PJM capacity revenue is approximately negative $186 million. It represents both the market value of capacity and avoided cost of capacity. The NPV is negative in the revised base case with CVOW because the addition of the CVOW Project to the Company's system displaces new solar and battery builds,[182] and they have higher ELCC values than those of offshore wind in 2027 – 2029.[183]

- NPV of PJM energy revenues is approximately negative $305 million, primarily due to a combined impact of lower system energy sales.[184] However,

[181] *See* Attachment KK-44 for a copy of the Company's response to Staff Interrogatory No. 09-111 (a).

[182] *See* Attachment KK-44 for a copy of the Company's response to Staff Interrogatory No. 09-111 (b).

[183] *See* page 9 of the July 2021 PJM ELCC Report https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-for-july-2021-results.ashx

[184] *See* Attachment KK-44 for a copy of the Company's response to Staff Interrogatory No. 09-111 (c).

the NPV of avoided costs of energy due to addition of the Project to the Company's system is approximately $1 billion.[185]

- NPV of battery costs and revenues is approximately $59 million, which is a combined effect of approximately $116 million of fixed O&M savings (which Staff believes are cost savings on displaced battery PPAs in the revised base case with CVOW) and approximately $57 million of forgone battery capacity revenues.[186]

Q. WHAT ENERGY GENERATION DOES THE CVOW COMMERCIAL PROJECT DISPLACE IN THE REVISED PLEXOS RUNS?

A. The lifetime projected generation of CVOW is still 286,035 GWh, unchanged from the model runs that supported the original filing.

The Project displaces 185,025 GWh of solar generation in 2027 – 2056 in the revised base case with CVOW,[187] partly due to eliminating the need for 2,760 MW of new generic solar facilities, which could have generated approximately 154,000 GWh over the lifetime of the CVOW Project, and partly due to postponed construction of 2,640 MW of new generic solar facilities, which could have generated approximately 31,000 GWh more over the lifetime of the CVOW Project if they had been built earlier.

[185] *Id.*

[186] *See* Attachment KK-45 for a copy of Staff's analysis of Attachment Staff Set 05-64 (1).

[187] Staff's analysis of information provided by the Company in Attachments Staff Set 05-63(2) and 05-64(2).

Further, the Project's addition decreases system storage needs by 1,799 GWh from Bath County Pumped Storage and 5,181 GWh from battery storage.[188]

Finally, the Project displaces approximately 40,000 GWh of generation by the Company's fossil-fueled units and approximately 62,000 GWh of net power purchases from the PJM market.

Q. PLEASE DESCRIBE METHODOLOGICAL CHANGES IN THE NPV CALCULATION OF AVOIDED COST OF RECS IN THE REVISED NPV ANALYSIS OF THE CVOW PROJECT.

A. The Company implemented two methodological changes in the NPV calculation of the avoided cost of RECs in the revised NPV analysis of the CVOW Project.

First, because the CVOW Project displaces solar and battery generation in the revised PLEXOS model runs, the Company calculated the avoided costs of 3,760 GWh of REC purchases and 97,060 GWh of deficiency payments, i.e. only for the portion of the CVOW Project's generation that does not displace renewable generation.[189]

Secondly, as previously mentioned, the Company assumed that RECs equivalent to 15% of the Company's annual RPS goal would be available for purchase in the market in 2027 - 2056.

[188] Including 4,975 GWh from new storage PPAs added after 2049, 173 GWh from CE-2 Storage units, and 35 GWh from storage pilots. Source: Staff's analysis of the information provided by the Company in Attachment Staff Set 05-63(2) and Attachment Staff Set 05-64(2).

[189] The PLEXOS model optimized REC purchases and deficiency payments for the whole Company's system in the revised base case without CVOW and the revised base case with CVOW, as explained in the Company's response to Staff Interrogatory No. 09-109, attached hereto as Attachment KK-46. The Company then calculated the NPV of the avoided costs of REC purchases and deficiency payments for the CVOW Commercial Project in Microsoft Excel based on the PLEXOS model outputs for the revised base case with and without CVOW; the calculation was provided to Staff as Attachment Staff Set 08-100.

The resulting NPV of avoided cost of RECs and deficiency payments optimized by PLEXOS is approximately $1.2 billion. The PLEXOS model has not been configured to bank RECs.

If RECs were available for purchase at prices forecasted by ICF and in amounts necessary for RPS compliance (i.e., assuming additional 97,060 GWh of REC purchases instead of deficiency payments), the NPV of avoided cost would have been approximately $0.3 billion, based on Staff's calculation.

Q. SHOULD THE DISPLACEMENT OF FUTURE GENERIC SOLAR FACILITIES' GENERATION IMPACT THE SCOC BENEFIT CALCULATION FOR THE CVOW COMMERCIAL PROJECT?

A. Yes, in Staff's view. Staff believes that the SCOC benefit in the revised base case with CVOW applies to the same proportion of the Project's generation that adds renewable generation to the Company's system and displaces 3,760 GWh of REC purchases and 97,060 GWh of deficiency payments in the Company's analysis. A SCOC benefit would not be created by the CVOW Commercial Project for the 185,025 GWh of displaced solar generation over its lifetime.

The revised NPV of the CVOW Project's SCOC benefit, calculated by Staff, is approximately $1.341 billion.

Q. HOW WOULD THE REVISED NPV OF THE CVOW PROJECT CHANGE IF THE COMPANY COULD PURCHASE ADDITIONAL 97,060 GWH OF RECS IN PLACE OF DEFICIENCY PAYMENTS AND THE CALCULATION OF THE NPV

OF THE SCOC BENEFIT EXCLUDED SOLAR GENERATION DISPLACED BY THE PROJECT?

A. If the SCOC benefit does not apply to solar generation displaced by CVOW, the revised NPV of the CVOW Commercial Project would be approximately negative $1.7 billion. This amount includes:

- A negative $3.3 billion change in system NPV as a result of the CVOW Commercial Project's addition ("revised PLEXOS NPV");
- Approximately $0.3 billion NPV of avoided cost of 100,820 GWh of REC purchases (i.e., for a sum of 3,760 GWh and 97,060 GWh); and
- Approximately $1.3 billion NPV of the SCOC benefit, calculated based on approximately 101,000 GWh, the total lifetime generation of the CVOW Project net of displaced solar generation.

Q. WHAT ARE THE CONCLUSIONS OF YOUR ANALYSIS OF THE REVISED NPV OF THE CVOW COMMERCIAL PROJECT?

A. In the original NPV analysis discussed in direct testimony of Company witness Kelly, the Company analyzed the CVOW Commercial Project as compared to the PJM market[190] rather than to other renewable resources. However, Staff believes a comparison of the CVOW Commercial Project to solar and battery resources may be more relevant. As demonstrated by the Project's revised PLEXOS NPV being negative $3.3 billion, solar resources are a more economic choice to solve for the Company's *energy and capacity* requirements. Even though the Company's system with high saturation of solar resources, but without CVOW, would deliver lower avoided cost of REC and deficiency payment benefits, adding $1.2 billion (the NPV of the CVOW Project's avoided cost of REC and

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[190] Kelly Direct at 12.

deficiency payment benefit in the revised base case with CVOW) would still keep *customer benefits* negative in this case. Further, if the SCOC benefit of the CVOW Project is calculated based on its net addition of carbon-free generation (i.e., net of displaced solar generation), the CVOW Project's NPV would be negative. Therefore, the CVOW Project does not appear economic compared to the alternative of solar resources.

Comparison of the Project's NPV under the Base Case and the Revised Base Case

Q. PLEASE COMPARE THE CVOW PROJECT'S NPV IN THE BASE CASE AND THE REVISED BASE CASE, AS CALCULATED BY THE COMPANY.

A. The table below provides a comparison of the CVOW Project's NPV components.

[BEGIN EXTRAORDINARILY SENSITIVE]

[redacted]

[END EXTRAORDINARILY SENSITIVE]

Q. PLEASE COMPARE THE CVOW PROJECT'S NPV IN THE BASE CASE AND THE REVISED BASE CASE, WITH SENSITIVTIES CALCULATED BY STAFF.

A. The table below provides a comparison of the CVOW Project's NPV components. It shows that if the avoided cost of RECs is based on the ICF REC price forecast and if the SCOC benefit does not apply to displaced solar generation, the CVOW Project's NPVs are similar in the "low solar, high battery saturation base case" and the "high solar, low battery saturation revised base case."

[BEGIN EXTRAORDINARILY SENSITIVE]

[redacted]

[END EXTRAORDINARILY SENSITIVE]

V. NEED

Q. PLEASE SUMMARIZE THE VCEA'S POLICY GOALS THAT CREATE THE NEED FOR THE CVOW COMMERCIAL PROJECT.

A. The CVOW Commercial Project fits the description of an offshore wind facility declared by the VCEA to be in the public interest. It would also replace generation from fossil-fueled units slated for retirement by the VCEA, and the RECs associated with its generation would be eligible for the Company's RPS compliance, as described below.

Code § 56-585.1:11. C. 1. of the VCEA states, in part,

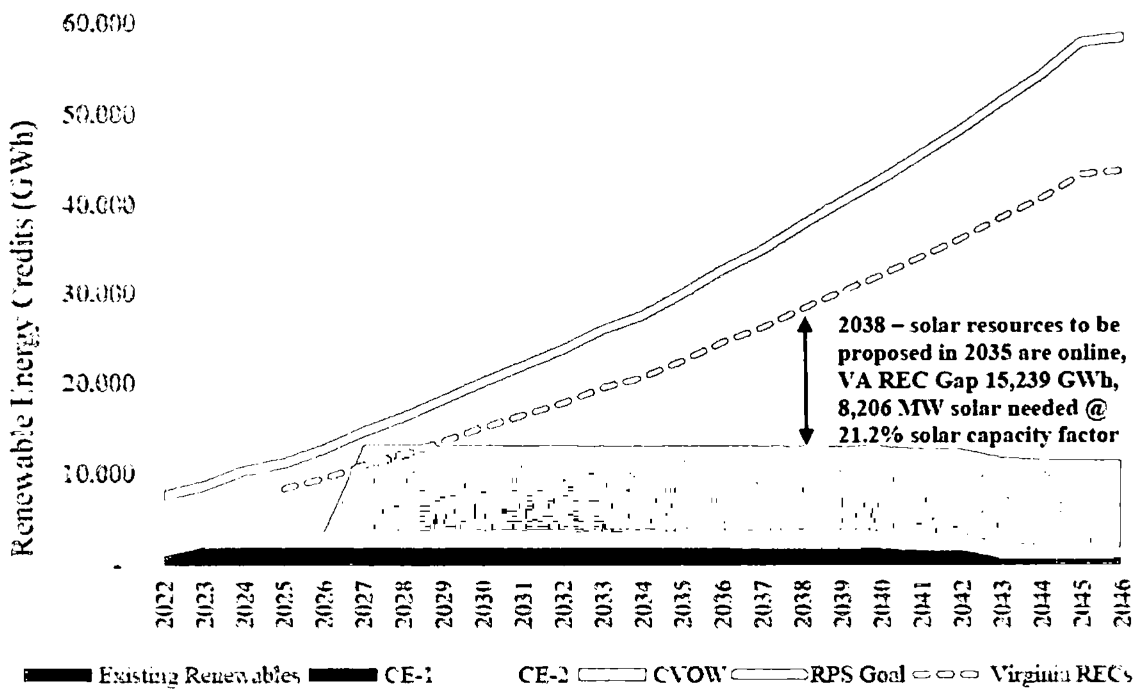
> [C]onstruction by a Phase II Utility of one or more new utility-owned and utility-operated generating facilities utilizing energy derived from offshore wind and located off the Commonwealth's Atlantic shoreline, with an aggregate rated capacity of not less than 2,500 megawatts and not more than 3,000 megawatts, along with electrical transmission or distribution facilities associated therewith for interconnection is in the public interest.

Code § 56-585.5 B establishes the timeline for fossil-fueled unit retirements in Virginia, such that certain coal-fired units and oil-fueled units shall retire by the end of 2024, certain biomass-fired units shall retire by the end of 2028, and all other carbon emitting generating units shall retire by the end of 2045. The Company may petition the Commission for relief from these requirements if the retirements would threaten the reliability or security of electric service.

Further, Code § 56-585.5 C establishes the mandatory annual renewable energy requirements based on the percentages of the Company's prior year total non-nuclear electric energy sold. These annual requirements can be satisfied through the use and retirement of RECs from renewable resource types that are eligible for RPS compliance. Code § 56-585.5 C also requires that, beginning in 2025, at least 75% of RECs used to comply with the RPS requirements be generated by RPS-eligible generation resources located within Virginia. Code § 56-585.5 C allows Dominion to "bank" RECs produced or acquired in excess of annual target requirements to be used for compliance in later periods.

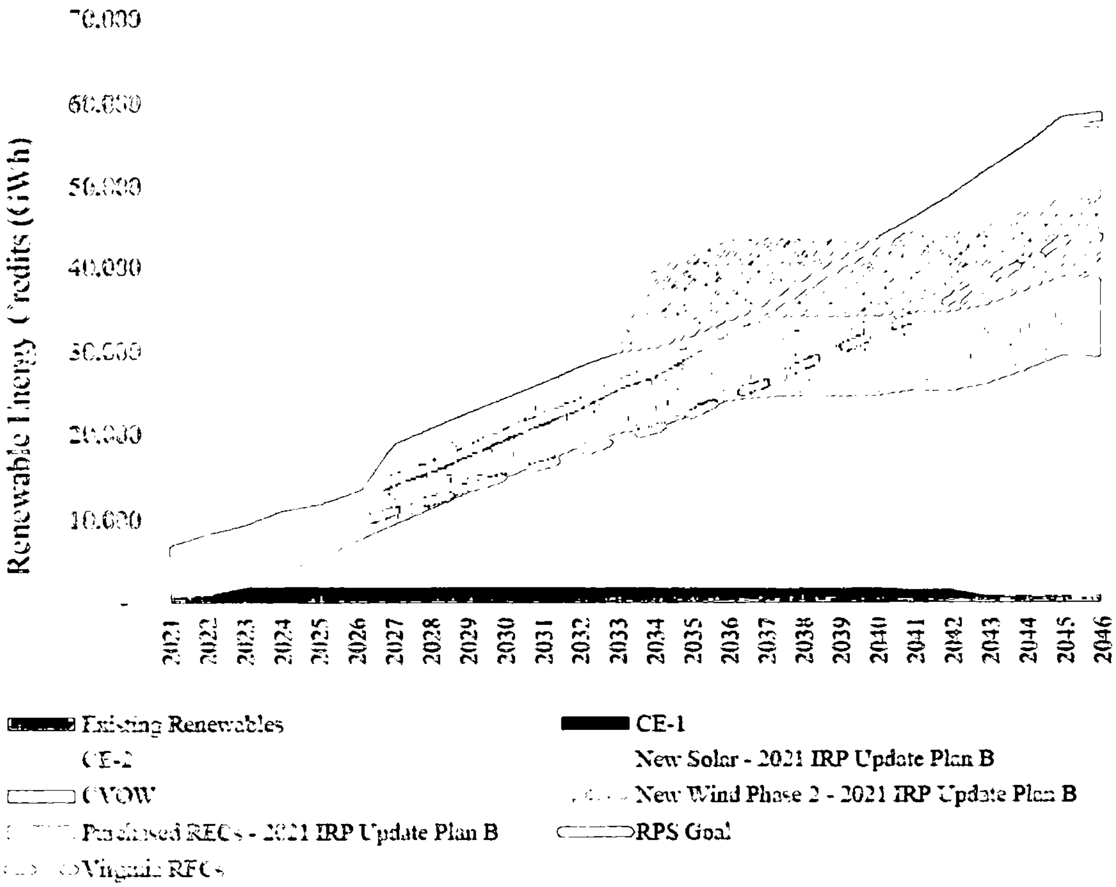
Q. PLEASE DEMONSTRATE HOW THE CVOW COMMERCIAL PROJECT CAN HELP THE COMPANY MEET ITS REC NEEDS.

A. The chart below demonstrates that RECs produced by the CVOW Commercial Project would partially fill the gap between the RPS REC requirements and the volume of RECs expected to be produced by the Company's existing and approved renewable generation resources, including CE-1 and CE-2 resources.[191]



[191] At Staff's request, the Company has extended the chart shown in Figure 1 of Company witness Kelly's testimony and added the dashed line that shows the need for RECs originating in Virginia. The Company provided this chart in Attachment Staff Set 01-13. Based on Staff's estimate, 8,206 MW of new solar capacity would be needed in 2038 (the first fully operational year for solar resources to be proposed by the Company in 2035 to comply with the VCEA) to fill the need for RECs originating in Virginia. Staff added the respective comment to the Company's chart.

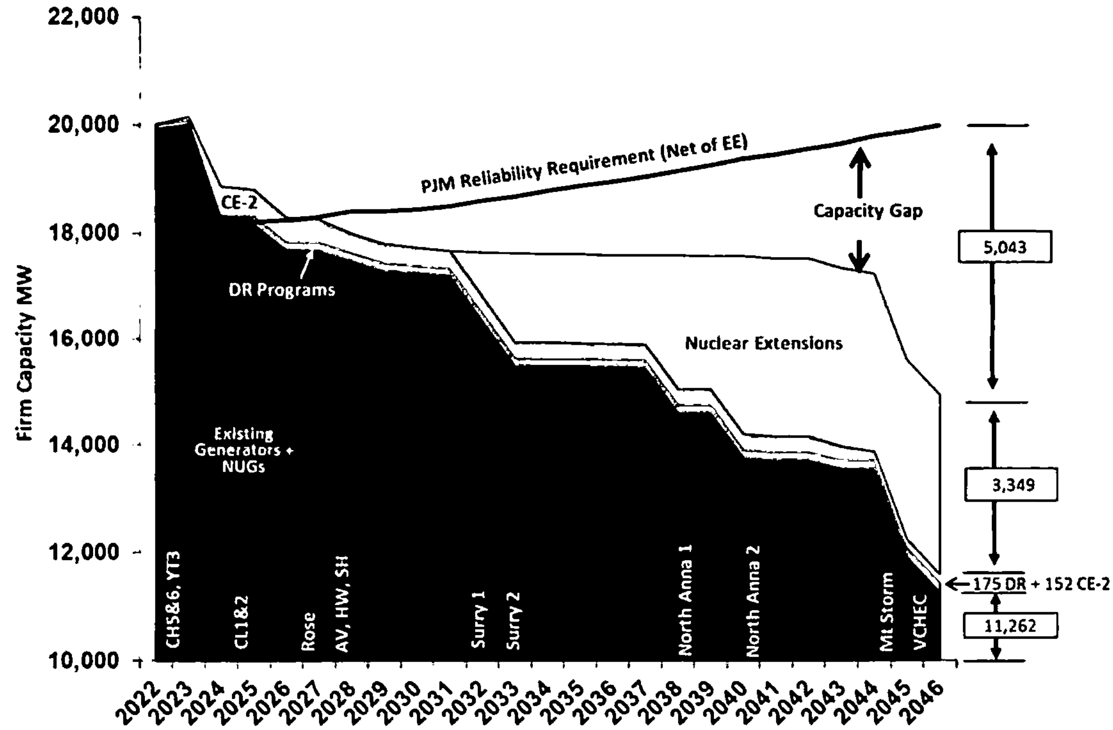
Further, at the request of the Office of Attorney General's Division of Consumer Counsel ("Consumer Counsel"), the Company provided a revised analysis of its RPS position for 2021 through 2035, including RECs provided from existing and planned new renewable resources, REC market purchases, and RECs from any other resources.[192] The chart shows that the Company may be able to comply with RPS requirements through building only solar resources until 2036.



[192] This analysis was provided by the Company in Attachment AG Set 02-08. Staff modified the chart by extending it through 2046 and adding the dashed line that shows the need for RECs originating in Virginia. Staff also rearranged the order in which the existing and planned resources meet the need for RECs, such that planned solar resources lie below the CVOW Project and the planned second tranche of offshore wind.

Q. WHAT IS THE COMPANY'S FORECASTED CAPACITY POSITION?

A. At Staff's request, the Company has extended the chart shown in Figure 2.1 of Company witness Kelly's testimony and added firm capacity resulting from potential nuclear license extensions.[193] Staff further added the CE-2 Projects and PPAs approved in Case No. PUR-2021-00146.[194] The chart demonstrates that the projected capacity gap results primarily from the VCEA-mandated retirements of the Company's coal-fired and oil-fired units.[195]



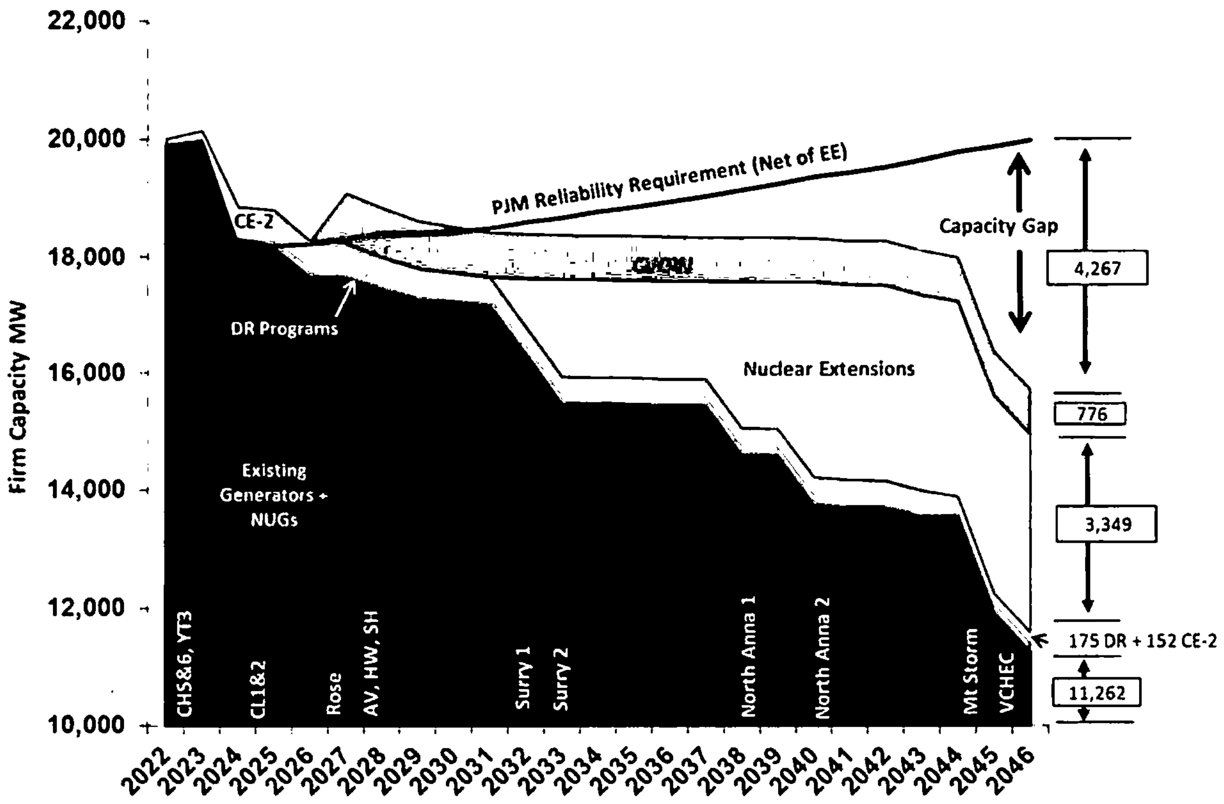
[193] On December 21, 2021, the Company made an errata filing to add the CE-1 Projects and PPAs to the blue portion of the Figure 2.1 of Company witness Kelly's testimony, which shows existing generators and NUGs. Attachment Staff Set 01-17 includes the same chart with nuclear license extensions added.

[194] *Petition of Virginia Electric and Power Company, For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia*, Case No. PUR-2021-00146, Doc. Con. Ctr. No 220320113, Final Order (March 15, 2022).

[195] The coal-fired units include Chesterfield Units 5 and 6 ("CH5&6") retiring in 2023 and Clover Units 1 and 2 ("CL1&2") retiring in 2025. The oil-fired units include Yorktown Unit 3 retiring in 2023 and Rose Unit retiring in 2027.

Q. HOW WOULD THE ADDITION OF THE CVOW COMMERCIAL PROJECT CHANGE THE COMPANY'S FORECASTED CAPACITY POSITION?

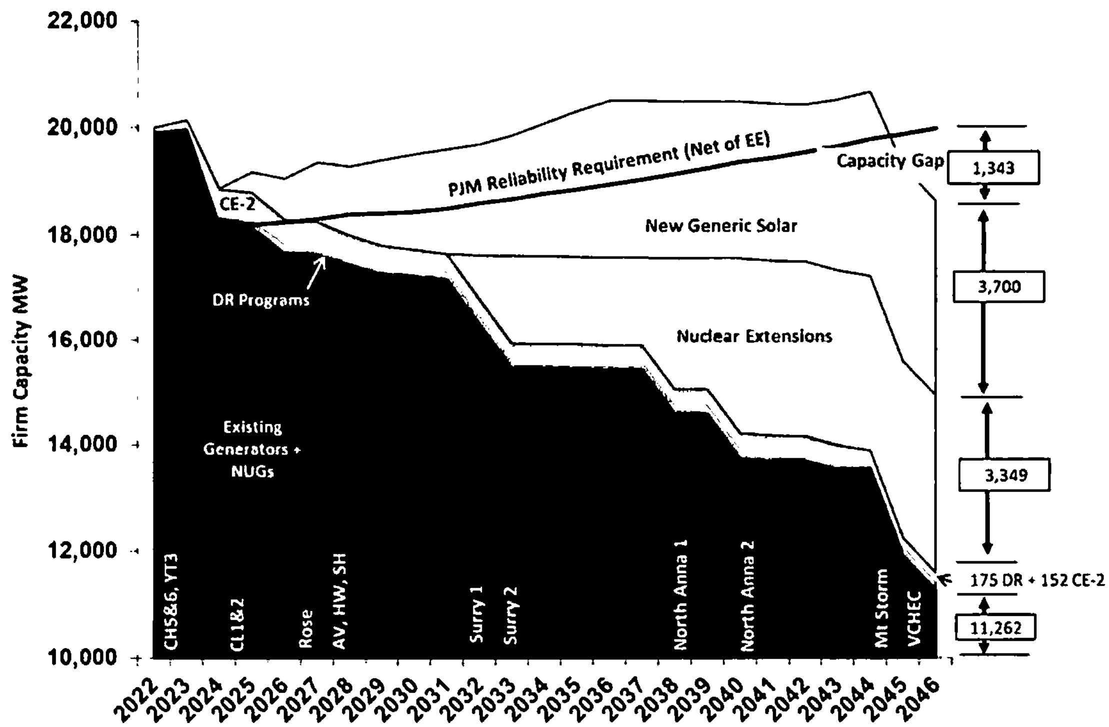
A. At Staff's request, the Company has extended the chart shown in Figure 2.2 of Company witness Kelly's testimony and added firm capacity resulting from potential nuclear license extensions.[196] Staff further added the CE-2 Projects and PPAs, approved in Case No. PUR-2021-00146. The chart demonstrates that the CVOW Commercial Project would partially alleviate the need for capacity. Staff notes that bilateral capacity purchases may also be used to close the gap.



[196] On December 21, 2021, the Company made an errata filing to add the CE-1 Projects and PPAs to the blue portion of the Figure 2.1 of Company witness Kelly's testimony, which shows existing generators and NUGs. Attachment Staff Set 01-17 includes the same chart with nuclear license extensions added.

Q. COULD SOLAR RESOURCES INCLUDED IN THE COMPANY'S PROPOSED RPS BUILD PLAN, RATHER THAN THE CVOW PROJECT, CLOSE THE CAPACITY GAP?

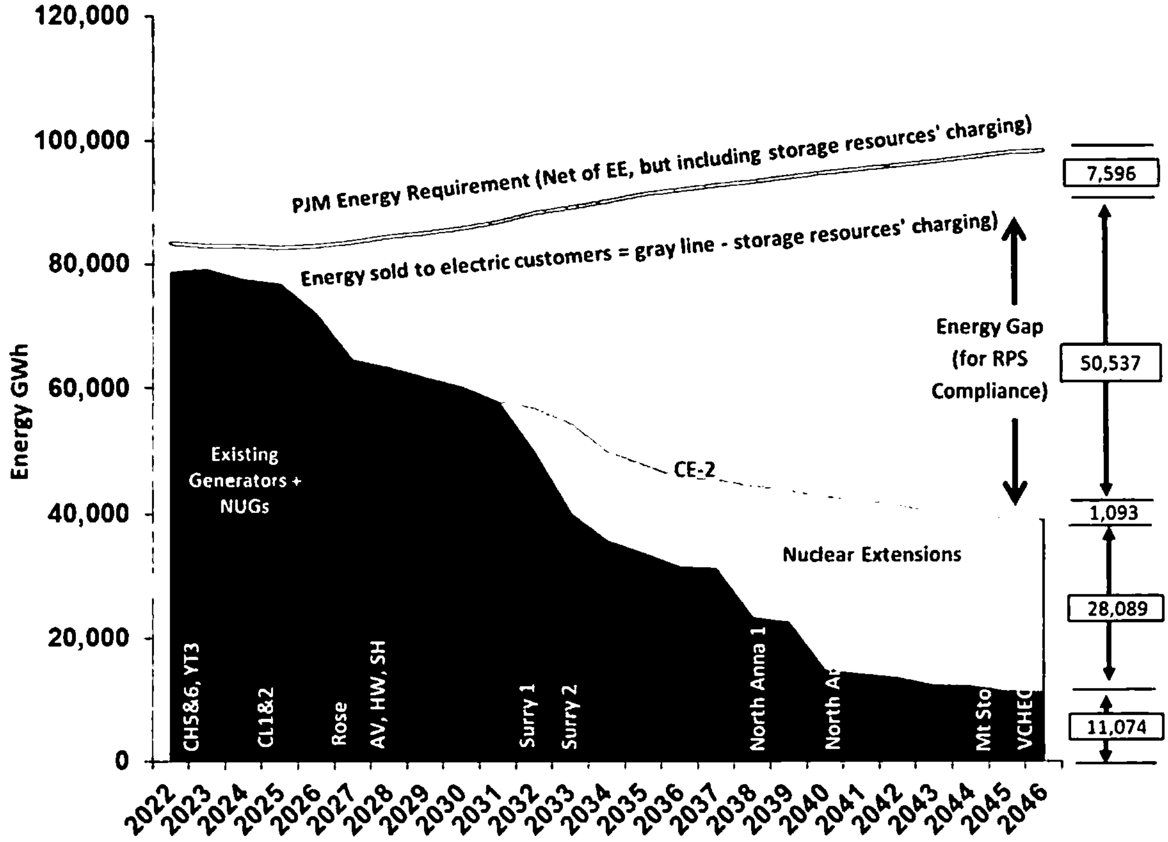
A. Yes. Staff substituted planned new builds of generic solar resources for the CVOW Commercial Project in the chart below.[197] The chart demonstrates that, if the new solar resources contained in the Company's proposed RPS Development Plan are approved by the Commission, they would cover the forecasted capacity gap until the retirement of Mt. Storm and VCHEC generating facilities in 2045. The chart does not include introduction of new generic energy storage resources, which would add more firm capacity if approved.



[197] Staff used the new planned solar resources from the Company's capacity table in Attachment Staff Set 01-17. In its response to Staff Interrogatory No. 14-135, The Company confirmed that the information in the table matches the Alternative Plan B of the Company's 2021 RPS Development Plan.

Q. WHAT IS THE COMPANY'S FORECASTED ENERGY POSITION?

A. At Staff's request, the Company has extended the chart shown in Figure 3.1 of Company witness Kelly's testimony and added energy generation resulting from potential nuclear license extensions.[198] Staff further added the CE-2 Projects and PPAs, approved in Case No. PUR-2021-00146, as well the orange line that represents energy sold to retail customers, which is the basis for calculating the Company's RPS compliance needs.[199]

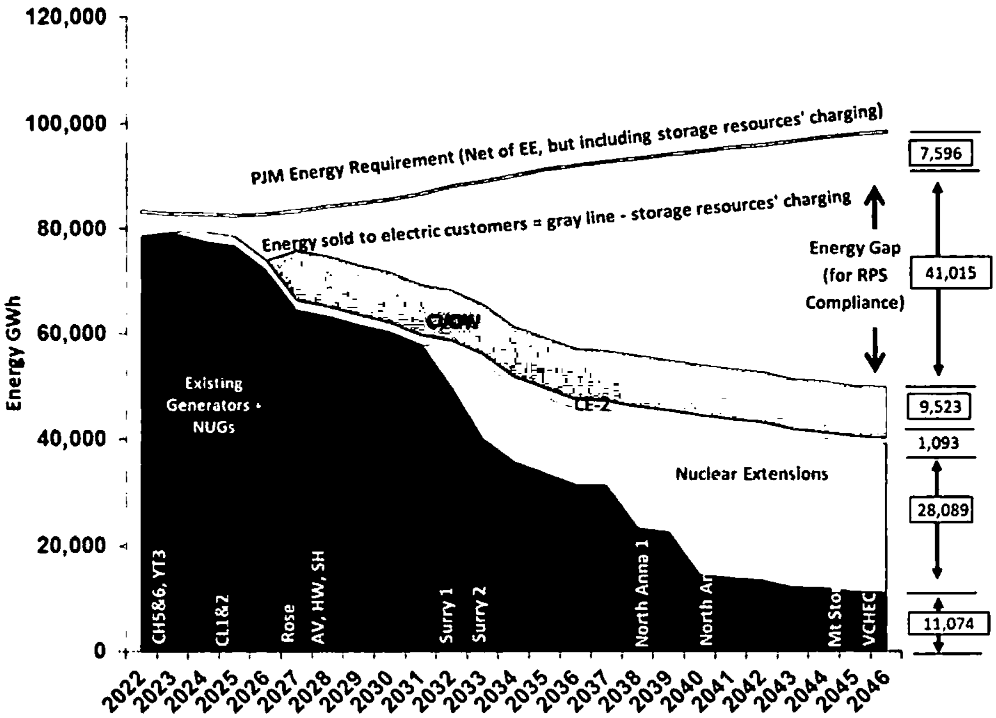


[198] On December 21, 2021, the Company made an errata filing to add the CE-1 Projects and PPAs to the blue portion of the Figure 3.1 of Company witness Kelly's testimony, which shows existing generators and NUGs. Attachment Staff Set 01-17 includes the same chart with nuclear license extensions added.

[199] The difference between the gray and orange lines is "Pump Load," which includes the addition of the energy necessary to charge the Company's energy storage resources for discharge at a later time. See Attachment KK-47 for a copy of the Company's response to Staff Interrogatory No. 11-217 in Case No. PUR-2021-00146.

Q. HOW WOULD THE ADDITION OF THE CVOW COMMERCIAL PROJECT CHANGE THE COMPANY'S FORECASTED ENERGY POSITION?

A. At Staff's request, the Company has extended the chart shown in Figure 3.2 of Company witness Kelly's testimony and added energy generation resulting from potential nuclear license extensions.[200] Staff further added the CE-2 Projects and PPAs, approved in Case No. PUR-2021-00146. The chart demonstrates that the CVOW Commercial Project would partially alleviate the need in energy. Power purchases from the PJM market may also be used to close the gap.[201]

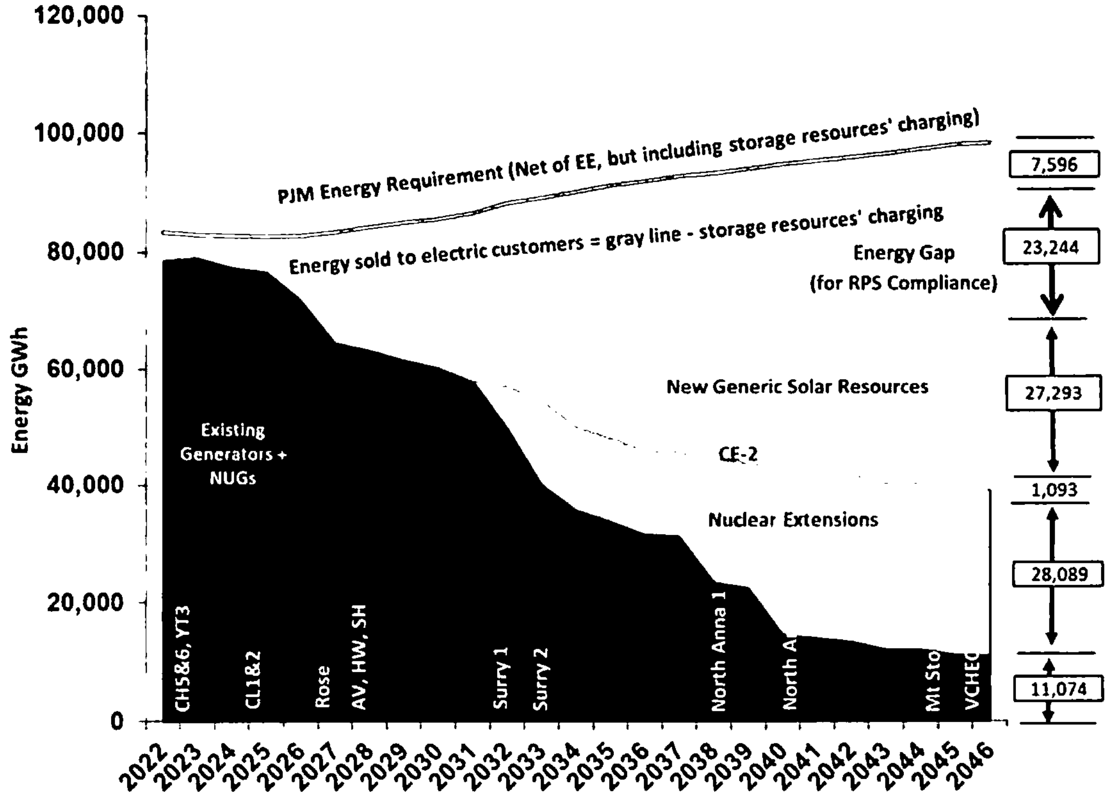


[200] On December 21, 2021, the Company made an errata filing to add the CE-1 Projects and PPAs to the blue portion of the Figure 3.2 of Company witness Kelly's testimony, which shows existing generators and NUGs. Attachment Staff Set 01-17 includes the same chart with nuclear license extensions added.

[201] The Company set the limit of external energy procurement from the PJM market to 5,200 MW per hour in 2021 – 2052 for modeling purposes, according to the Company's response to Staff Interrogatory No. 08-101, attached hereto as Attachment KK-48. This allows the Company to procure up to 45,552 GWh per year (5200 MW multiplied by 8760 hours in a year), although in the real world, the need for energy procurement would materialize mostly in summer and winter, and hourly need may exceed 5,200 MWh.

Q. COULD SOLAR RESOURCES INCLUDED IN THE COMPANY'S BUILD PLAN CLOSE THE ENERGY GAP?

A. Staff substituted planned new builds of generic solar resources for the CVOW Commercial Project in the chart below.[202] The chart demonstrates that, if the new solar resources are approved by the Commission, they would partially alleviate the need for energy. With the addition of the new generic solar resources, however, the need for external energy procurement from the PJM market decreases. Staff notes that the Company's need for energy would necessarily vary by month and time of day.



[202] Staff used the new planned solar resources from the Company's energy table in Attachment Staff Set 01-17.

Q. HOW DOES THE EIA COMPARE ECONOMIC COMPETITIVENESS BETWEEN GENERATION TECHNOLOGIES?

A. The EIA not only considers the LCOE for a potential generating asset but also compares it with the levelized avoided cost of electricity ("LACE") that would be displaced by that asset, as described below.

According to the EIA's 2021 Annual Energy Outlook, (emphasis added)

> "*EIA compares economic competitiveness between generation technologies by considering the value of the plant in serving the electric grid. This value provides a proxy measure for potential revenues from sale of electricity generated from a candidate project displacing (or the cost of avoiding) another marginal asset*. EIA sums this value over a project's financial life and converts that sum into an annualized value (that is, divided by the average annual output of the project) to develop the levelized avoided cost of electricity [("LACE")]. ...
>
> Estimating LACE is more complex than estimating LCOE ... because it requires information about how the grid would operate without the new power plant or storage facility entering service. EIA calculates LACE based on the marginal value of energy and capacity that would result from adding a unit of a given technology to the grid as it exists or is projected to exist at a specific future date. LACE accounts for both the variation in daily and seasonal electricity demand and the characteristics of the existing generation fleet to which new capacity will be added. Therefore, *LACE compares the prospective new generation resource against the mix of new and existing generation and capacity that it would displace. For example, a wind resource that would primarily displace generation from a relatively expensive natural gas-fired peaking unit will usually have a different value than one that would displace generation from a more efficient natural gas-fired combined-cycle unit or coal-fired unit with low fuel costs.*"[203]

Although Staff did not attempt to calculate the LACE for the CVOW Commercial Project, Staff analyzed the generation and energy procurement mix that would be displaced.

[203] The EIA's 2021 Annual Energy Outlook at 3-4. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

Q. WHAT ARE THE VOLUMES AND SOURCES OF ENERGY THAT ARE EXPECTED TO BE DISPLACED BY THE CVOW PROJECT?

A. The displacement analysis performed by Staff was discussed in detail in the NPV Analysis section of this testimony. However, Staff compares energy displacement (in thousands of GWh, cumulative in 2027 through 2056) between the "low solar, high battery saturation case" presented in the direct testimony of Company's witness Kelly and the "high solar, low battery saturation revised base case" prepared by the Company in the course of the discovery process.

In the "low solar, high battery saturation case," the CVOW Project displaces:

- Approximately 112,000 GWh of Company-owned fossil-fueled units' generation; and
- Approximately 170,000 GWh of power purchases from the PJM market.[204]

In the "high solar, low battery saturation revised base case," the CVOW Project displaces:

- Approximately 40,000 GWh of Company-owned fossil-fueled units' generation;
- Approximately 62,000 GWh of power purchases from the PJM market;
- Approximately 31,000 GWh of future solar units' generation over the lifetime of the CVOW Commercial Project, due to postponed addition of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of future Company-owned units and PPAs;[205] and
- Approximately 154,000 GWh of future solar units' generation, which will be permanently displaced by the CVOW Project (i.e., 2,760 MW of solar

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[204] As calculated by Staff based on information provided by the Company in Attachment Staff Set 11-117.

[205] **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

capacity will not otherwise be built by the Company or procured through PPAs.)

To facilitate the determination of need and economic competitiveness of future renewable resources, the Commission may wish to consider directing the Company to provide a detailed energy and asset displacement analysis and a calculation of levelized avoided cost of energy for the proposed additions of renewable resources, including but not limited to the future RPS filings and the potential second tranche of offshore wind.

Q. WHAT ARE THE ADVANTAGES AND DISADVANTAGES OF THE CVOW PROJECT'S ENERGY GENERATION PROFILE?

A. The generation profile of the CVOW Commercial Project is displayed in Figures 4, 5, and 6 of Company witness Kelly's testimony and discussed further in the Costs and Risks Analysis and Proposed Ratepayers' Protection section of my testimony.

On a high level, the key advantage of the Project's generation profile is that it is generally complementary to solar facilities because the CVOW Project is expected to produce energy from dusk to dawn, the period when solar energy is not available. Also, the CVOW's projected capacity factor in winter months—December, January, and February—is roughly three times higher than the projected capacity factor of generic solar facilities in the same months.

Key disadvantages of the Project's generation profile include its projected low capacity factors during late afternoon hours in summer—15% to 16% in July and 23% to 25% in August—when the PJM system peak may occur. Also, CVOW is projected to have the highest capacity factors in March, April, and November, which may lead to generation of energy in excess of customer demand and CVOW's generation being in conflict with solar generation in these shoulder months. The resulting market risks are described in the Costs and Risks Analysis and Proposed Ratepayer's Protections section of my testimony.

Q. WHAT IS THE OPPORTUNITY COST OF BUILDING THE CVOW COMMERCIAL PROJECT?

A. Based on the Company's analysis of the high solar, low battery saturation revised base case, in which the Company allowed the PLEXOS model to select resources on an economic least-cost basis with no resource forced into the model, "CVOW displaces 2,760 MW of new solar, 570 MW of batteries and avoids 3,760 GWh of total REC purchases and 97,060 GWh of RPS deficiency payments."[206]

The displaced solar nameplate capacity is similar to the nameplate capacity of the CVOW Commercial Project, which is 2,587 MW. Based on 2021 cost estimates of $1,969 per kilowatt ("kW") for the Company's CE-2 solar facilities, each kW of solar capacity cost the Company approximately half as much to construct as the estimated construction CAPEX of $3,788 per kW for the CVOW Project.[207] The three-year historic average capacity factor of the Company's solar facilities in Virginia was 21.2%, approximately half the projected capacity factor of the CVOW Commercial Project at 42%. However, an expected operating life of solar facilities is 35 years; the Company's original assumption for an operating life of the CVOW Project was 25 years, which was later revised to 30

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[206] *See* Attachment KK-43 for Attachment Staff Set 05-63(1), slide 3.

[207] Direct Testimony of Company witness Emil Avram in Case No. PUR-2021-00146, at 18 for the CE-2 Solar facilities. The estimated construction CAPEX for the CVOW Project was calculated by Staff by dividing the Project's construction CAPEX by its capacity.

years. Also, solar facilities are substantially cheaper to operate than offshore wind facilities.[208]

Staff notes that the previously mentioned 570 MW of batteries refers to PPA-sourced batteries, which the PLEXOS model selected after 2049, partially in response to the expiration of Surry nuclear plant license extensions in 2051 and 2052. The model did not select—hence, the CVOW Project did not displace—any Company-built battery resources.

The Company's estimate of displaced deficiency payments is based on an assumption that 15% of RECs needed for RPS Compliance would be available each year. The Company acknowledged, however, that it "may meet more or less than 15% of its RPS Program compliance requirement with purchased RECs based on the pricing and availability of eligible RECs."[209] The Company also did not "bank" excess RECs generated by the Company's renewable resources for the purposes of minimizing its future RPS deficiency payments. With these assumptions, the NPV of the avoided cost of RECs and RPS deficiency payments is approximately $1.2 billion.[210]

If the Company is able to procure RECs needed for RPS Compliance at prices forecasted by ICF (i.e., if the Company meets its RPS Compliance targets through REC

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[208] A study performed for EIA estimates Fixed O&M to be $110 per kW-year for a generic 400 MW offshore wind facility and $15.25 per kw/year for a generic 150 MWAC solar photovoltaic facility with single-axis tracking. Source: 2020 Annual Energy Outlook in the EIA report *Capital Cost and Performance Characteristic Estimates for Utility-Scale Electric Power Generating Technologies* prepared by Sargent & Lundy, released on February 5, 2020 and available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf Also, investment firm LAZARD estimates Fixed O&M to be $65.75 - $79.50 per kW-year for a generic offshore wind facility and $13.00 per kw/year for a generic solar photovoltaic facility with single-axis tracking. https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf, slides 16-17.

[209] *See* Attachment KK-40 for Attachment Staff Set 08-100 (b).

[210] *See* Attachment KK-43 for Attachment Staff Set 05-63(1), slide 7.

procurement only), the NPV of the avoided cost of RECs and RPS deficiency payments would be approximately $0.3 billion.

Q. DOES STAFF AGREE THAT THE CVOW PROJECT WOULD RESULT IN ENVIRONMENTAL BENEFITS?

A. Staff agrees that the CVOW Project would not emit carbon once in operation. It is projected to displace carbon-emitting generation of the Company's fossil-fueled generating units and PJM purchased power, which would result in a net carbon benefit. It is also expected to displace or delay construction of solar facilities by the Company, according to the Company's revised PLEXOS model runs, and such displacement is carbon neutral. Further, as the CVOW Project is a marine facility, its effects on land use would be much less substantial than those of solar farms of comparable nameplate capacity.[211]

However, some environmental impacts of the CVOW Project would be negative. For example, the Environmental Routing Study prepared by the ERM Group has identified multiple birds of conservation concern; high priority species within the project vicinity;[212] and federal and commonwealth listed species, some of which are critically imperiled.[213] Also, the turbine blades of offshore wind facilities are not recyclable.[214]

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[211] *See* pages 201 and 204 of the ERM Study in Volume 8 of the Application. Harpers to Fentress Route 1, proposed as preferential by the Company, would have a 295.5-acre footprint, of which 134 acres would overlap with the existing Dominion's right of way and 161.5 acres would be new or expanded right of way. In contrast, the average footprint of a solar facility is 10 acres per MW; therefore, solar facilities with a combined capacity of 2,587 MW would require approximately 25,870 acres of land.

[212] Volume 9 of the Application, Appendix G of the Environmental Routing Study, Table G-1

[213] *Id.*, Table G-2.

[214] https://www.bloomberg.com/news/features/2020-02-05/wind-turbine-blades-can-t-be-recycled-so-they-re-piling-up-in-landfills

A. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MOODY'S
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Power generation projects – US

Strategic owners and robust contractual protections offset US offshore wind power's increased risks

We expect the US offshore wind (OSW) market will expand to about 21,000 megawatts (MWs) by 2035 from around 30 MWs today. Experienced strategic sponsors and strong contractual protections will be vital to mitigate construction and operating risks for OSW projects. These OSW projects have higher levels of execution risk compared with the typical onshore projects that have dominated wind power development in the US. Project sponsors can carry over their extensive experience from Europe, but they will also need to overcome additional and unique obstacles in the US market.

» **Globally, offshore wind has greater construction and operating risk compared with onshore peers.** These challenges include heightened sensitivity to weather conditions, less proven technology, need for substantially more balance-of-system equipment and greater subsurface geophysical risk.

» **US offshore wind projects face additional difficulties compared to their European counterparts.** The lack of a developed supply chain represents the most significant hurdle as the US offshore industry grows from infancy compared to the extensive and well developed supply chain in Europe. Multiple regulatory bodies spanning local, state and federal levels in the US, off-take contracts that compensate only for renewable attributes and likely incorporation of tax equity financing adds further complications for US projects.

» **Well designed offshore wind projects with strong contractual protections result in strong credit characteristics.** A fully wrapped construction contract with a creditworthy and experienced contractor can help mitigate construction risk. During operations, a full service operations and maintenance (O&M) contractual arrangement with a creditworthy and experienced operator and conservative plant design can minimize risk.

» **Project sponsorship by an experienced and strategic company will be a key factor for the success of early US projects.** Large strategic companies — such as Ørsted A/S (Baa1 stable) and Iberdrola SA (Baa1 stable), through Avangrid Inc (Baa1 stable) — bring extensive experience developing, building and operating offshore wind projects that can be carried over to the US and also have deep industry ties necessary to build out the US supply chain. Large European oil and gas companies such as Royal Dutch Shell Plc (Aa2 stable) and Equinor ASA (Aa2 stable) have also moved into the US market.

Globally, offshore wind has greater construction and operating risk compared with onshore peers

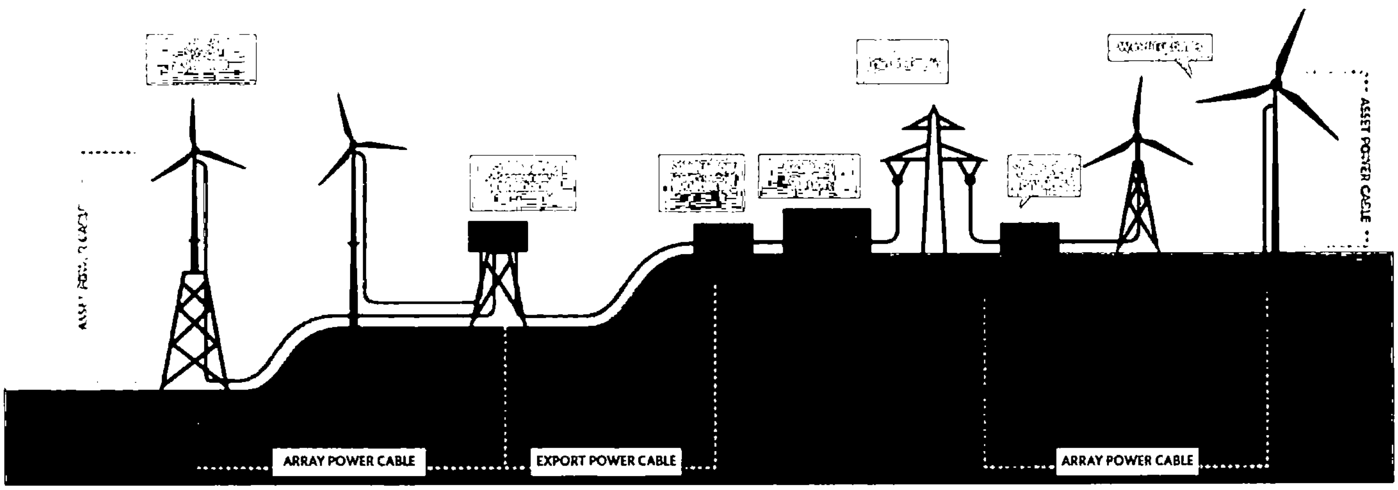
Offshore wind projects face more construction and operating complexity and risk compared with onshore wind projects that are built on land. These complexities include heightened sensitivity to weather conditions, use of less proven technology, need for substantially more balance of system equipment and uncertain geophysical conditions.

Construction risks

Offshore wind construction is especially sensitive to weather, which can restrict access to a project's site. To minimize weather risk, installation work is typically restricted to the late spring, summer and early fall to avoid adverse and unsafe weather conditions, especially the rough seas typical during the winter. In Europe, projects have recently sought to push construction into the winter, but this exposes them to significant downtime during periods of adverse weather.

Furthermore, offshore wind requires additional equipment such as seabed foundations, offshore substations and subsea export cables — together known as balance of system equipment — that are not necessary for onshore wind (see Exhibit 1). For example, the wind turbine towers for onshore wind typically sit on concrete pads while offshore wind turbines sit on foundations, which are typically fixed to the seafloor and rise above the water. Not only is such additional equipment necessary, but that equipment must be built specifically for the harsher offshore environment, including protection against corrosion, and its installation requires the use of specialized vessels.

Exhibit 1
Offshore wind has greater complexity than onshore wind



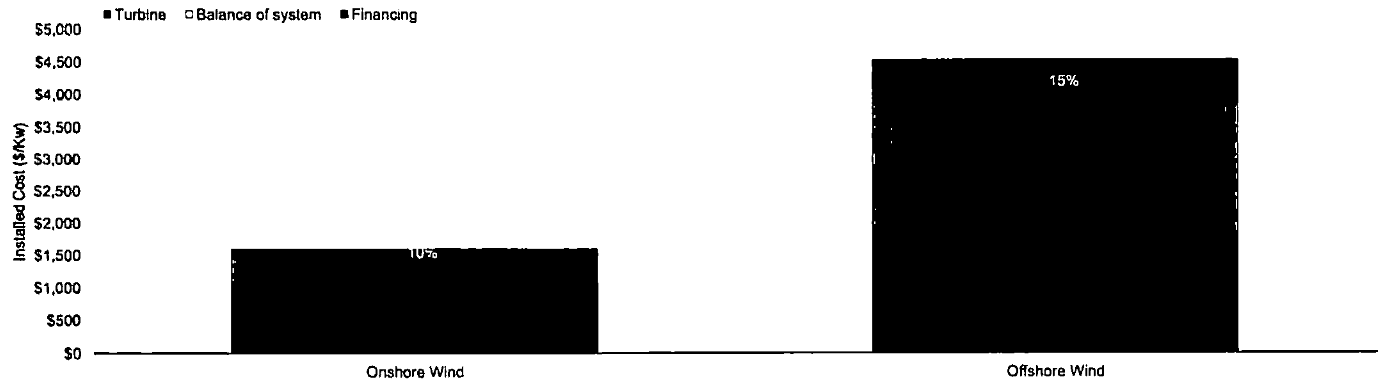
Source: DNV GL

Foundation technology is still evolving, resulting in additional technology risk. About 73% of offshore wind projects globally used proven, monopile foundations as of 2018, according to the US National Renewable Energy Laboratory (NREL). Historically, most offshore wind projects have been built in more shallow waters in depths up to 40 meters that allows for the use of monopiles.

However, use of alternate, less proven foundation technology will grow as offshore projects are located in deeper waters. Between 40 to 60 meters, jacket-type foundations can be used and NREL estimates 25% of new installations will use the jacket foundations compared to only 7% installed plants at the end of 2018. Past depths of 60 meters, floating foundation technology is necessary although they are not commercially proven on a large scale. Currently, several small scale projects using floating foundations at water depths greater than 60 meters such as the 30 MW Hywind Scotland project in the UK are in operation or under construction.

The foundations and other balance of system equipment highlight the greater overall complexity of offshore wind and contributes substantially to added costs. The balance of system costs are over six times greater for offshore wind on a $/kW basis versus onshore contributing to about three times larger total installed costs, according to NREL (see Exhibit 2).

Exhibit 2
Offshore wind's balance of system costs far exceed onshore peers



Source: NREL's 2017 Cost of Wind report

Greater subsurface geophysical uncertainty adds further risk to OSW construction especially for undeveloped markets like the US. During installation, unexpected challenges can arise, including differing seabed soil conditions, existence of boulders and unexploded military ordnances that can delay construction and add costs. These obstacles can force the project to change turbine locations, use alternate installation methods or spend resources on specialized disposal. Other risks that could delay construction or add costs include environmental permitting restrictions such as limiting construction during wildlife migration periods or external stakeholder considerations like commercial fishing.

Operational risks

During the operational phase, offshore wind turbine performance is riskier because of offshore wind turbines' rapid technology development. Since 2014, turbine capacity has grown 16% on an average annual basis, according to Wind Europe, driven by the desire for greater cost efficiency and higher capacity factors. While the advances are typically incremental improvements to earlier technology, the newer turbine technology does not have extensive operational history and have led to industrywide challenges such as early leading edge erosion of the blades, which occurred at WindMW GmbH (Baa3 stable). The leading edge erosion issue may be caused by solid particle impact on the blades or a manufacturing defect. Water absorbed into the blades can cause the damage during the winter months when it starts to freeze and expand. If not rectified, it could lead to decreased power production and possibly blade failure over time.

For the balance of plant equipment, the array and export cables can also be a source of operating problems especially at joints typically used for long cables. For example, Gwynt y Mor OFTO PLC's (A3 stable) export line in the UK suffered electrical faults in 2015 that reduced availability. Hypothetically, if an export cable failure occurs, the revenue loss can be much greater than the underlying cost to repair (see Exhibit 3). The illustrative example demonstrates how a 130-day failure of an export cable for an 800 MW offshore wind project could lead to $125 million of revenue losses using our assumptions compared to an assumed cost of repair of $25 million leading to a total financial loss of $150 million. The long assumed outage period incorporates the challenges of buried cable repair such as the need to source custom replacement cables, the potential wait time until a specialized cable repair vessel is available and the need to address any geotechnical conditions that could have contributed to the damage. Furthermore, the risk for US projects are greater than those in Europe. For example, in Germany, the grid operator is responsible for transmission cables and has to compensate offshore wind projects in the event of prolonged downtime.

Exhibit 3

Illustrative example: Revenue lost could far exceed the cost of repairing a failed export cable in an outage

	Single Export Cable
PPA ($/MWh)	$100
Capacity (MW)	800
Assumed Capacity Factor	50%
Outage length (days)	130
Hours in a Day	24
Export Capacity During Outage (%)	0%
Lost MWh	1,248,000
Revenue Lost	$124,800,000
Cost of repair	$25,000,000

Source: Moody's Investors Service assumptions

Similar to the construction period, weather and the limited availability of specialized vessels represent risks that can delay site access or prevent the implementation of necessary repairs or replacements that can lead to longer outages.

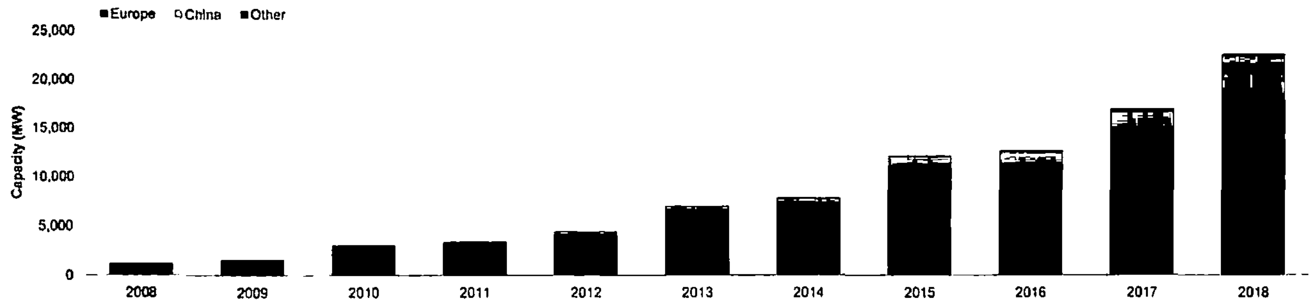
While offshore wind has inherently greater complexity, it also has benefits over onshore wind including less complex topography because there are no hills or valleys, typically higher wind speeds, and less permitting constraints such noise or height restrictions. For example, attractive offshore sites off the US northeast coast have wind speeds around 9 to 10 m/s that are similar to the windy US midwest. Also, in the US, OSW further benefits from closer proximity to the densely populated coastal communities, including the US northeast, which should reduce the possibility of curtailment as the power will be delivered closer to demand.

Offshore wind is a rapidly growing renewable energy asset class

The offshore wind power sector has grown rapidly over the last decade with installed capacity rising to around 23 GW at the end of 2018 compared with 1 GW in 2008 (see Exhibit 4). Europe has led the way with almost 80% of the global capacity at the end of 2018 with China as the second largest market with almost 20%. The rapid growth of offshore wind in both Europe and China have been supported by both strong regulatory and political backing as policymakers shift the power sector to zero carbon emitting power sources given the power sector's elevated environmental exposures (see Heat map: 11 sectors with $2.2 trillion debt have elevated environmental risk exposure). Given their distance from shore, OSW projects can also avoid societal issues that can apply to onshore wind such as excessive noise.

Exhibit 4

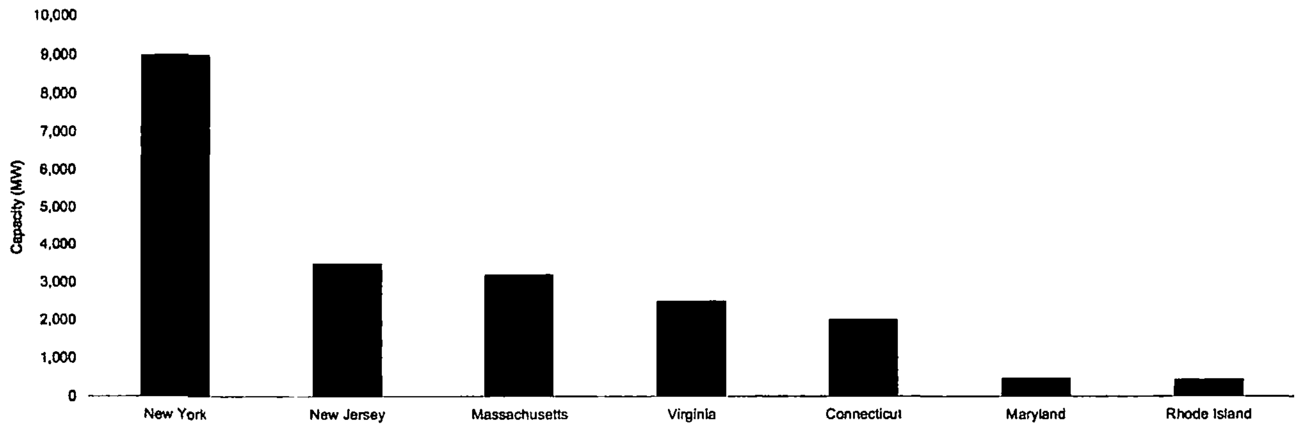
Global offshore wind power capacity has risen rapidly since 2008



'Other' category comprises the US and Asia (excluding China)
Source: US Department of Energy's 2018 Offshore Wind Technologies Market Report

Over the next five years, the total global capacity is expected to nearly triple to 67 GW by 2024 with nearly all of the capacity in either Europe or China. Over the longer term, the US is likely to become a new major market with potentially around 21 GW of new capacity by 2035, which represents the aggregate of state procurement objectives from only 30 MW installed at the end of 2018. We expect most of the development will be in the eastern US driven by state-level objectives to grow offshore wind, such as New York State's goal to have nine GW of offshore wind by 2035 (see Exhibit 5).

Exhibit 5
US offshore wind market could grow by around 21 GW by 2035
State procurement objectives



Virginia and Connecticut are proposed targets while the remaining states' objectives are supported by legislation.
Sources: State regulatory agencies, University of Delaware 'Supply Chain Contracting Forecast for US Offshore Wind Power' report

US offshore wind projects face additional challenges compared with their European counterparts

Given offshore wind's current low market penetration in the US, offshore wind development faces growth challenges such as a limited supply chain and regulations at the local, state and federal level (see Exhibit 6).

Exhibit 6
US faces key challenges to the growth of offshore wind

Consideration	US	Europe
Supply Chain	Limited supply chain that will require extensive development from the 'ground up'. The US Jones Act requirement for US ship and crew adds further constraints during both construction and operations phases.	Well-developed supply chain of equipment suppliers, port infrastructure, and vendors.
Permitting and Regulations	Combination of federal, state, and local permits and regulations	Typically, a single national regulator
Offtake contracts	Current solicitations take the form of PPAs (both physical and environmental attributes) or an offtake of just environmental attributes. The latter can introduce price risk for the physical power and capacity.	Historically, price risk is mitigated through a fixed price feed-in-tariff, contract for differences or some other mechanism that provides price stability.
Financing	A combination of debt, equity, and tax equity financing. The importance of tax equity will diminish given the expiration of the PTC and ITC at the end of 2019.	Typically, a combination of debt and equity financing

Source: Moody's Investors Service

Supply chain
The lack of a developed supply chain represents one of the most significant challenges for US development since the US market is in its infancy; the offshore wind supply chain includes equipment suppliers, specialized installation vessels and infrastructure to handle the transportation and installation of equipment. Further complicating the development of the US supply chain is the US Jones Act that requires goods or people transported between US ports including between a port and the project site to be on ships built, owned and operated by US citizens or permanent residents. The Jones Act could limit the ability to use specialized installation vessels in use in other parts of the world and necessitate separate vessels to transport equipment to the offshore site versus installing the equipment.

We expect experienced developers and suppliers to develop solutions to the supply chain challenges given the scale of the expected US development; the University of Delaware estimates that it will take $68 billion in equipment and installation costs alone to build 19 GW of offshore wind by 2030. Near term US development of the US supply chain will likely be a combination of importing equipment from Europe, creating new supply chains in the US and modifying existing US infrastructure. The infrastructure development will be aided by the experience and knowledge brought from Europe by experienced sponsors such as Ørsted. Key northeastern states have also started to take action. For example, New York started a solicitation process for a public-private partnership for port infrastructure to support offshore wind power development.

Permitting and regulations
Joint federal, state and local permitting and regulation adds further complications for US offshore wind development because the developer will have to appease multiple regulatory stakeholders unlike in Europe, where there is typically a single national regulator.

For example, the proposed 470 MW Cape Wind project faced strong local opposition and numerous lawsuits that ultimately led to the termination of its development. Given the large number of proposed offshore projects, federal regulatory approval has also encountered delays with Vineyard's final environmental impact statement likely in 2020 instead of late 2019 which will delay its originally expected start of construction into 2020.

Offtake contracts
Offtake arrangements in the US will also take on mixture of both physical energy and environmental attributes such as in Massachusetts or just the environmental attributes (e.g. offshore renewable energy credits) such as in Maryland. The former results in price certainty similar to arrangements in Europe that have a fixed feed-in-tariff, contract for differences or some other scheme. An arrangement that compensates the offshore wind project only for its environmental attributes (i.e. power generated from offshore wind) and disaggregates physical power and environmental attributes introduces price risk. Under such an arrangement, the portion of the revenue derived from normal physical power sales are subject to market risk while the revenue derived from the delivery of environmental attributes are paid a fixed price.

Financing
Financing for US projects could incorporate tax equity. which is usual for US renewable projects; although it adds further complexity relative to more traditional, project financings in Europe. For example, a US project financing with tax equity typically has the debt structurally subordinated at a holding company and the debt is only backed by the non-tax equity holders' interest in the project. Such a structure will typically result in a weaker collateral package and will be subject to any cash flow 'flips' that occurs between the tax and non-tax equity partners. The production tax credit (PTC) and investment tax credit (ITC) are currently set to sunset at the end of 2019, which will minimize the use of tax equity to less than 20% of total sources for upcoming US offshore wind projects since they are all expected to start construction after 2019. However, if the US government extends the PTC and ITC tax subsidies for offshore wind under current levels, the tax equity portion would increase up to 50% of the total capital funding.

Offshore wind projects with strong contractual protections and sponsorship best positioned to mitigate credit risk

Given the overall public, political and regulatory support for offshore wind, these projects generally benefit from price stability via a power purchase agreement (PPA), feed-in-tariff or some other form of long-term market price protection that typically serves as an important credit foundation for an investment-grade rated project.

In the US, seven eastern states have awarded contracts for about 5 GW of capacity across several eastern states (see Exhibit 7). Continued broader political and regulatory support also remains key as these projects (except Block Island which is operational) move to the construction phase and avoid challenges faced by Cape Wind so the sector can grow to meet state procurement objectives totaling 21 GW by 2035.

Exhibit 7
US offshore wind projects in operations or awarded off-take contracts

State	Project Name	Status	Actual/Expected COD	Capacity (MW)	Offtake (MW)	Sponsor(s)
RI	Block Island Wind Farm	In Operations	2016	30	30	Ørsted
ME	New England Aqua Ventus I	PPA Awarded	2022	12	12	Aqua Ventus
MA	Vineyard Wind I	PPA Awarded	2023	800	800	Avangrid/Copenhagen Infrastructure Partners
MA	Mayflower Wind Energy	PPA Awarded	2025	804	804	Shell/EDP Renewables
RI	South Fork	PPA Awarded	2022	130	130	Ørsted/Eversource
RI	Revolution	PPA Awarded	2023	704	704	Ørsted/Eversource
DE	Skipjack	PPA Awarded	2023	120	120	Ørsted
MD	US Wind	PPA Awarded	2023	248	248	US Wind, Inc
VA	Coastal Virginia Offshore Wind	Utility baseload	2020	12	12	Dominion Energy
NY	Empire Wind	PPA Awarded	2024	816	816	Equinor
NY	Sunrise Wind	PPA Awarded	2024	880	880	Ørsted/Eversource
OH	Icebreaker	PPA Awarded (Partial)	2022	21	21	LEEDCo/Fred Olsen Renewables
NJ	Ocean Wind	Preferred Bidder	2024	1100	TBD	Ørsted

Coastal Virginia Offshore Wind is expected to be in Dominion Energy's regulated utility rate base
Source: US Department of Energy's 2018 Offshore Wind Technologies Market Report, state agencies websites, issuer

Mitigating construction risks

For new offshore wind projects in the US, construction risk mitigation is vital because lenders are subject to both the typical risks inherent to offshore wind and the lack of a fully developed supply chain. Fully wrapped engineering, procurement and construction contracts with a creditworthy and experienced contractor are important means of mitigating construction risk.

Key protective provisions in well structured construction contracts are:

» fixed prices

» guaranteed completion dates

» minimum performance thresholds, such as capacity or power curve

» extended equipment warranties

» contractual enhancements for serial defects

» liquidated damage provisions for nonperformance or delays

A project that relies on a collection of subcontracts represents a weaker arrangement because it typically would provide contractual protection only at the equipment level such as a turbine's power curve but not the overall plant's performance nor overall construction delays. Moreover, a collection of subcontracts might also expose the project to potential disputes among multiple contractors as to the responsible party if an issue arose. Other credit enhancement measures, such as a robust contingency or completion guarantee from a creditworthy entity, could reduce or eliminate the risks associated with a weaker construction contract arrangement.

Mitigating operational risks

During the operating period, a strong O&M contractual arrangement with a creditworthy and experienced operator can minimize risk. For the first wave of US offshore wind farms, operation risks will be heightened by the need to train operating staff and develop efficient policies around restrictions like the US Jones Act. Features like yield guarantees, robust equipment warranties and fixed prices under a full-service O&M arrangement are best-in-class risk mitigants that protect investors.

Additionally, more resilient offshore projects have more conservative designs elements like multiple export cables that are interlinked to provide partial redundancy. Such a redundancy would minimize a cable failure's cash flow effect because the revenue lost from a cable failure can well exceed the cost of repair. Exhibit 8 illustrates how a dual export cable design can halve the revenue lost from a single export cable failure previously shown in exhibit 3.

Exhibit 8

Illustrative example: Dual export cable minimize lost cash flow in a cable outage

	Single Export Cable	Dual Export Cable
PPA ($/MWh)	$100	$100
Capacity (MW)	800	800
Assumed Capacity Factor	50%	50%
Outage length (days)	130	130
Hours in a Day	24	24
Export Capacity During Outage (%)	0%	50%
Lost MWh	1,248,000	624,000
Revenue Lost	$124,800,000	$62,400,000
Cost of repair	$25,000,000	$25,000,000

Source: Moody's Investors Service

ICF ENERGY PRICE FORECAST

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Jan		[redacted]	$ 43	$ 40	$ 36	$ 36	$ 39	$ 37	$ 38	$ 41	$ 42	$ 42	$ 43	$ 43	$ 46	[redacted]	$ 49	$ 49
Feb		[redacted]	$ 39	$ 31	$ 27	$ 27	$ 29	$ 29	$ 29	$ 32	$ 33	$ 32	$ 33	$ 34	$ 37	$ 39	$ 39	$ 39
Mar		$ 35	$ 31	$ 30	$ 28	$ 29	$ 31	$ 30	$ 30	$ 32	$ 33	$ 33	$ 33	$ 34	$ 36	$ 39	$ 39	$ 39
Apr		$ 30	$ 26	$ 25	$ 24	$ 24	$ 24	$ 25	$ 26	$ 26	$ 27	$ 29	$ 30	$ 31	$ 31	$ 32	$ 34	$ 36
May		$ 29	$ 26	$ 24	$ 23	$ 23	$ 22	$ 24	$ 25	$ 25	$ 27	$ 28	$ 30	$ 31	$ 31	$ 32	$ 34	$ 36
Jun		$ 29	$ 29	$ 30	$ 30	$ 29	$ 28	$ 29	$ 29	$ 29	$ 30	$ 32	$ 33	$ 34	$ 34	$ 35	$ 37	$ 39
Jul	$ 37	$ 34	$ 33	$ 35	$ 35	$ 36	$ 36	$ 35	$ 37	$ 37	$ 37	$ 40	$ 41	$ 43	$ 43	$ 44	$ 47	$ 49
Aug	$ 36	$ 32	$ 33	$ 36	$ 36	$ 37	$ 32	$ 35	$ 37	$ 37	$ 36	$ 40	$ 42	$ 44	$ 44	$ 44	$ 46	$ 48
Sep	$ 34	$ 30	$ 29	$ 29	$ 30	$ 29	$ 28	$ 30	$ 30	$ 29	$ 30	$ 32	$ 34	$ 34	$ 34	$ 36	$ 38	$ 40
Oct	$ 32	$ 29	$ 25	$ 24	$ 23	$ 22	$ 22	$ 24	$ 25	$ 25	$ 25	$ 26	$ 28	$ 29	$ 29	$ 30	$ 32	$ 33
Nov	$ 34	$ 30	$ 27	$ 24	$ 24	$ 24	$ 25	$ 26	$ 27	$ 27	$ 29	$ 30	$ 32	$ 34	$ 35	$ 36	$ 38	$ 40
Dec	$ 39	$ 34	$ 35	$ 35	$ 36	$ 37	$ 38	$ 39	$ 39	$ 38	$ 38	$ 40	$ 42	$ 43	$ 43	$ 44	$ 47	[redacted]

	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056
Jan	$ 52	$ 55	$ 57	$ 58	$ 57	$ 58	$ 59	$ 63	$ 65	$ 67	$ 68	$ 70	$ 72	$ 74	$ 75	[redacted]	[redacted]	[redacted]
Feb	$ 42	$ 44	$ 46	$ 46	$ 46	$ 47	$ 48	$ 51	$ 52	$ 54	$ 55	$ 57	$ 58	$ 60	$ 61	$ 63	$ 65	$ 67
Mar	$ 42	$ 45	$ 46	$ 46	$ 46	$ 46	$ 47	$ 48	$ 49	$ 50	$ 50	$ 51	$ 52	$ 54	$ 55	$ 57	$ 58	$ 59
Apr	$ 36	$ 37	$ 38	$ 39	$ 40	$ 41	$ 42	$ 42	$ 43	$ 44	$ 45	$ 46	$ 47	$ 48	$ 50	$ 51	$ 52	$ 54
May	$ 36	$ 37	$ 38	$ 39	$ 41	$ 42	$ 42	$ 43	$ 44	$ 45	$ 46	$ 47	$ 48	$ 49	$ 51	$ 52	$ 54	$ 55
Jun	$ 39	$ 40	$ 41	$ 41	$ 43	$ 44	$ 45	$ 45	$ 46	$ 47	$ 48	$ 49	$ 50	$ 51	$ 52	$ 54	$ 55	$ 56
Jul	$ 49	$ 50	$ 51	$ 53	$ 54	$ 54	$ 55	$ 57	$ 59	$ 60	$ 62	$ 63	$ 65	$ 67	$ 68	$ 70	$ 72	$ 74
Aug	$ 47	$ 46	$ 49	$ 50	$ 49	$ 51	$ 52	$ 54	$ 55	$ 57	$ 58	$ 59	$ 61	$ 62	$ 64	$ 66	$ 67	$ 69
Sep	$ 41	$ 42	$ 42	$ 44	$ 45	$ 46	$ 47	$ 47	$ 48	$ 49	$ 50	$ 51	$ 52	$ 54	$ 55	$ 57	$ 58	$ 59
Oct	$ 33	$ 34	$ 35	$ 36	$ 38	$ 39	$ 40	$ 40	$ 41	$ 42	$ 43	$ 44	$ 45	$ 46	$ 48	$ 49	$ 50	$ 52
Nov	$ 40	$ 41	$ 42	$ 43	$ 45	$ 46	$ 49	$ 48	$ 49	$ 50	$ 52	$ 53	$ 54	$ 56	$ 58	$ 60	$ 62	$ 64
Dec	$ 50	$ 50	$ 49	$ 51	$ 52	$ 54	$ 56	$ 56	$ 57	$ 58	$ 59	$ 61	$ 62	$ 64	$ 66	$ 68	$ 69	$ 71