How Low-Carbon Heat Requirements for Direct Air Capture of CO$_2$ Can Enable the Expansion of Firm Low-Carbon Electricity Generation Resources

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A rapid build-out of direct air capture (DAC), deployed in order to mitigate climate change, will require significant amounts of both low-carbon thermal and electrical energy. Firm low-carbon power resources, including nuclear, geothermal, or natural gas with carbon capture, which also will become more highly valued as variable renewable energy penetration increases, would be able to provide both heat and electricity for DAC. In this study, we examined the techno-economic synergy between a hypothetical DAC plant in the year 2030 and a nuclear small modular reactor, and determined two avenues for which this relationship could benefit the nuclear plant. First, we demonstrated that, under certain assumptions, selling a portion of its energy to a DAC facility allows the nuclear plant to take in 21% less revenue from selling electricity to wholesale markets than its projected levelized cost, and still break even. Second, after estimating a potential revenue stream, we showed that an integration with DAC allows for the nuclear plant's capital costs to be up to 35% higher than what would be required if only selling electricity to wholesale markets. This could enable the nuclear plant to operate economically even in the face of variable and decreasing wholesale electricity prices, and also could offer developers more financial certainty when planning a new project. Ultimately, this study shows that the need for low-carbon energy for DAC plants might incentivize the development of advanced nuclear plants and firm low-carbon resources more broadly.

Keywords: climate change, direct air capture, firm low-carbon power, nuclear, small modular reactor

INTRODUCTION

Many changes to current energy systems are required to reach net-zero carbon emissions throughout the world, though the pathways will vary by sector. Electricity generation, for example, is one of the more straightforward sectors to decarbonize, yet with each increment of greenhouse-gas emissions abated, deeper decarbonization will become increasingly more expensive and difficult (Friedmann et al., 2020). Negative-emissions technologies (NETs) could reduce the cost of reaching net-zero emissions (Bistline and Blanford, 2021); the Intergovernmental Panel on Climate Change (IPCC) has stated that any chance to keep the global average temperature increase from pre-industrial levels under 1.5°C will require some utilization of NETs (IPCC, 2018).

Direct air capture (DAC) with permanent CO_2 storage is one NET that could make a significant impact. DAC is a process that captures CO_2 directly from the atmosphere *via* an engineered system. A typical DAC module pulls in ambient air and extracts the CO_2 through a chemical reaction (Sanz-Pérez et al., 2016). The CO_2 capture medium is regenerated to release a stream of nearly-pure CO_2 that then can be reused or permanently sequestered. The treated air then is returned to the atmosphere. Despite its potential, commercializing and deploying DAC systems at a large scale may prove challenging (National Academies of Sciences Engineering Medicine, 2019).

DAC systems have a substantial energy requirement of both heat and electricity. Electricity is required to run fans and other auxiliary equipment, and a significant amount of heat is needed to separate the CO_2 from the capture medium. The two primary DAC technologies being commercialized today are high-temperature liquid solvent (HTLS) and low-temperature solid sorbent (LTSS) systems, although there are a number of newer concepts using alternative regeneration inputs such as moisture and electricity. HTLS systems utilize water solutions that contain hydroxide sorbents that have a strong affinity for CO_2, while LTSS methods utilize amine materials that are bonded to a porous solid structure. The hydroxide solutions in HTLS DAC systems require high-temperature heat above 800°C to be regenerated, currently supplied by firing natural gas with oxygen (Keith et al., 2018). Amine adsorbents in LTSS DAC systems require heat at roughly 100°C, which allows for more flexibility in their energy source (Realmonte et al., 2019). The LTSS method may have a significant economic advantage over the HTLS method, as it can reduce its costs by taking advantage of low-grade heat from a co-located thermal power plant (McQueen et al., 2020). Although current costs for most of these systems are around 600 $/t$CO_2$, estimates in the literature for possible costs range from below 100 $/t$CO_2$ up to 1,000 $/t$CO_2$ (National Academies of Sciences Engineering Medicine, 2019). However, once technology developers are able to scale up their manufacturing and operations, it is likely that costs will fall closer to the 100 $/t$CO_2$ mark (Fasihi et al., 2019).

Due to its high energy requirements, any future scenario with large amounts of DAC systems may require a significant buildout of low-carbon thermal power generation resources. These resources, which can include nuclear, geothermal, and natural gas with carbon capture and sequestration (CCS), can be referred to as "firm" sources of power, since they are capable of running reliably and continuously over long durations. As decarbonization progresses, there likely will be increased demand for firm low-carbon power resources for three main reasons. First, increased electrification of end-use technologies in the transportation, residential, commercial, and industrial sectors will cause an increase in overall electricity demand (Mai et al., 2018). Second, as low-carbon energy becomes more highly valued, existing fossil-fuel generation will be replaced with clean energy resources. Third, as the power sector becomes further decarbonized, mostly through the increased penetration of variable renewable energy (VRE), firm sources of power likely will become more valuable for keeping system-wide costs of electricity lower (Sepulveda et al., 2018).

This study examines the techno-economic integration between one type of firm low-carbon resource, a nuclear small modular reactor (SMR), and a hypothetical LTSS DAC plant, and is based on a scenario in the year 2030. In the United States, VRE deployment has increased to provide roughly 40% of the power generation in many areas, resulting in a decrease in average wholesale electricity prices, but an increase in price volatility (Seel et al., 2018). Firm low-carbon power systems, such as nuclear SMRs, have proven technologically viable but do not yet contribute a significant amount of energy to the grid. In order to mitigate climate change, policies have been enacted that incentivize the deployment of DAC systems, which have become cost-competitive (Friedmann et al., 2020). Demand for additional DAC systems is high, but each new plant requires a substantial amount of energy. In addition, as VRE penetration increases, the need for more storage or transmission will increase system-wide costs of electricity (Sepulveda et al., 2018). Concerns about electricity price volatility and rising system-wide costs have created a desire to deploy more firm, low-carbon resources, but many of these options are not yet cost-competitive. Through this scenario, we attempt to determine the economic benefits that a nuclear SMR might realize from providing low-grade heat and electricity to a co-located DAC plant in addition to selling electricity to conventional wholesale markets.

RESULTS

We modeled a cogeneration facility that includes a DAC system and a nuclear SMR, and examined how this combination could improve the economics of the nuclear plant. First, we looked at the cost required to build a LTSS DAC plant when it buys power from wholesale markets for its electrical operations and for a heat pump to supply its thermal energy. Next, we considered a DAC plant that instead pays a co-located SMR for its required heat and electricity. This benefits the SMR because it would receive an additional source of revenue through the utilization of its low-grade heat, and it benefits the DAC plant because it would have a designated, reliable source of low-carbon energy nearby and would not require new transmission connections, which are expensive and time-consuming to construct (Eto, 2016).

The cost parameters of our hypothetical DAC plant were taken from Fasihi et al. (2019), which presents a detailed techno-economic assessment of DAC plants based on a literature review of DAC technologies and their possible costs.[1] This plant, shown in **Table 1**, captures 360,000 tons of CO_2 per year, has a lifetime of 25 years, and operates at a 91% capacity factor. It was assumed that a manufacturing learning rate, due to increased DAC development over the previous decade, has allowed for reduced capital expenses, which has enabled lower overall costs (Fasihi et al., 2019).

$$LCOD = \frac{CAPEX_{DAC} \times crf + OPEX_{fix}}{Output_{CO2}} + OPEX_{var}$$
$$+ DAC_{el.input} \times LCOE + DAC_{th.input} \times LCOH \quad (1)$$

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[1]Fasihi et al. (2019) reports all costs in Euros. The exchange rate used is 1.33 USD/EUR.

The parameter used to evaluate the overall economics of the DAC systems is the levelized cost of DAC (LCOD). This can be calculated using Equation (1) above (Fasihi et al., 2019). The LCOD for the baseline DAC plant is 102 $/tCO$_2$. A spreadsheet containing this calculation and other results can be found in the **Supplementary Material**.

In this baseline scenario, illustrated in **Figure 1**, the DAC plant is assumed to purchase all of its energy in the form of electricity from the grid. Both the thermal and electrical requirements for the DAC system, shown in **Table 2**, were assumed to be the average of their range provided (National Academies of Sciences Engineering Medicine, 2019).

The assumed cost of purchasing electricity for the baseline DAC plant is 25 $/MWh$_e$, which was estimated by the average wholesale electricity prices across a range of scenarios for U.S. markets in 2030 with 40% VRE penetration as described in Seel et al. (2018). Its assumed cost of heat is 24.34 $/MWh$_t$, which was determined by the levelized cost of heat (LCOH) for a heat pump

that is run at full capacity with electricity prices of 25 $/MWh (Dominković, 2015).

Next, we considered the scenario where this DAC plant is integrated alongside a nuclear SMR power plant, shown in **Figure 2**. This power plant was assumed to be sized to provide all of its low-grade heat to the DAC plant. In other words, for every MWh of electricity that the SMR produces, it also produces one MWh of steam at 100°C for the DAC plant. However, this extraction of heat causes a reduction in the potential amount of electricity that can be produced. In a power-plant steam cycle that consists of a high-pressure turbine, intermediate-pressure turbine, and low-pressure turbines, steam can be accessed and diverted to heat exchangers between the intermediate and low-pressure turbines at temperatures up to 159°C (Qvist, 2020). Extracting all available steam at a temperature of 100°C will result in a 15% decrease in electric output (Qvist, 2020). In addition, with the electricity requirement assumptions stated previously, 21% of the generated electricity from the SMR must be used to power the electrical equipment in the DAC plant. This leaves 64% of the power plant's available energy to be sold as electricity to wholesale markets, or as described in **Table 3**, there will be a ratio of 0.64 MWh of electricity *sold* to wholesale markets per MWh of electricity *produced*.

In order to determine the revenue the SMR would receive in return for providing the DAC facility with 36% of its energy, we

TABLE 1 | Cost parameters for the baseline DAC plant (Fasihi et al., 2019).

Parameter	Value	Units
DAC capacity	360,000	tCO$_2$/year
CAPEX	450	$/(tCO$_2$/year)
Fixed OPEX (fraction of CAPEX)	4	%
Variable OPEX	12	$/tCO$_2$
Lifetime	25	Years
Weighted avg. cost of capital	0.07	-
Capital recovery factor	0.086	/year
Capacity factor	91	%
DAC electrical requirement	0.24	MWh$_e$/tCO$_2$
DAC thermal requirement	1.14	MWh$_t$/tCO$_2$
Average cost of electricity	25	$/MWh$_e$
Average cost of heat	24.34	$/MWh$_t$
Electricity cost	5.89	$/tCO$_2$
Heat cost	27.72	$/tCO$_2$
Levelized cost of DAC (LCOD)	102	$/tCO$_2$

TABLE 2 | Energy requirements for LTSS DAC systems (National Academies of Sciences Engineering Medicine, 2019).

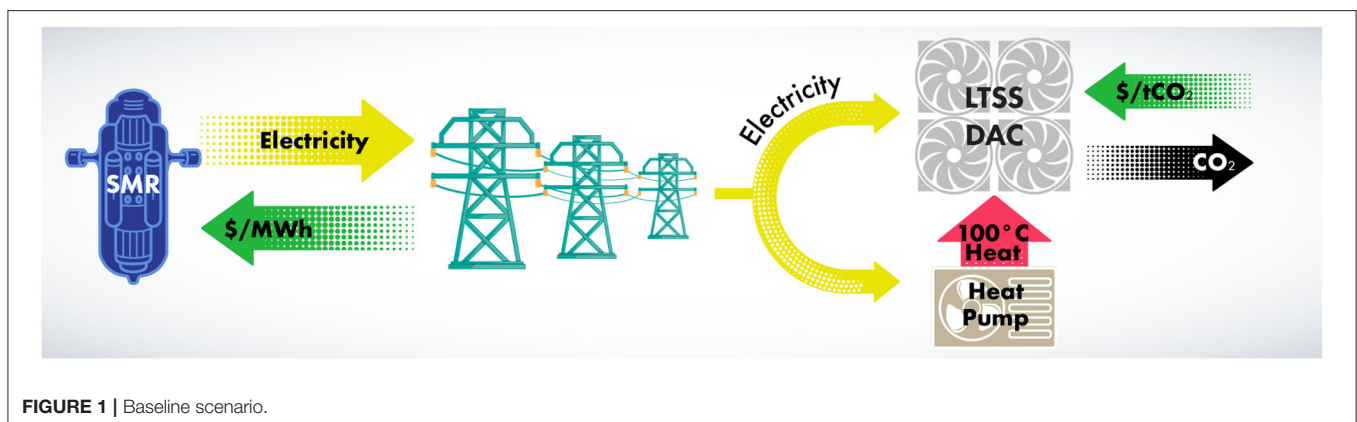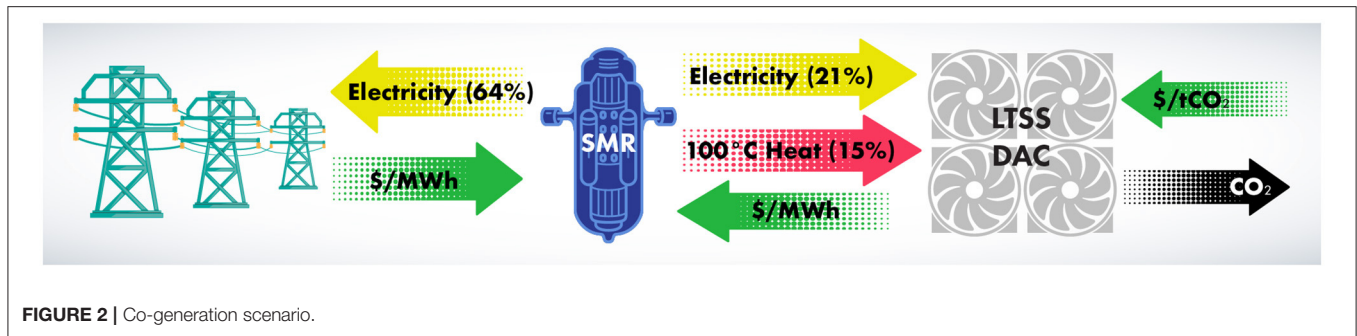| Unit operation LTSS DAC	Energy requirement	Energy required (MWh/tCO$_2$)		
		Low	High	Average
Desorption heat (100°C steam)	Thermal	0.944	1.333	1.139
Air contractor fans	Electrical	0.153	0.311	0.232
Desorption vacuum pump	Electrical	0.003	0.004	0.003
Total Thermal	Thermal	0.944	1.333	1.139
Total Electrical	Electrical	0.156	0.315	0.235

FIGURE 1 | Baseline scenario.

FIGURE 2 | Co-generation scenario.

TABLE 3 | Energy distribution metrics for nuclear power plant co-located with DAC.

Parameter	Ratio	Units
Thermal/electric energy ratio	4.8	MWh_t/MWh_e
Amount of electricity produced	1	$MWh_e(p)/MWh_e(p)$
Amount of 100°C heat per electricity produced	1	$MWh_t/MWh_e(p)$
Electricity reduction penalty	0.15	$MWh_e(s)/MWh_e(p)$
Portion of electricity that can be sold after penalty	0.85	$MWh_e(s)/MWh_e(p)$
Electricity required for DAC	0.21	$MWh_e(s)/MWh_e(p)$
Portion of electricity left to sell to wholesale markets	0.64	$MWh_e(s)/MWh_e(p)$

TABLE 4 | Cost analysis for nuclear SMR and DAC integration.

Parameter	Value	Units
Levelized cost of nuclear plant	60	$/MWh_e(p)$
Amount of captured CO_2 per $MWh_e(p)$	0.878	$tCO_2/MWh_e(p)$
LCOD difference for energy costs	34	$/tCO_2$
Revenue SMR receives from DAC	30	$/MWh_e(p)$
New average revenue requirement for selling electricity	47	$/MWh_e(s)$
Percent improvement from incorporating DAC	21	%

assumed that the SMR and the DAC facility formed a bilateral agreement. Within this agreement the LCOD is recalculated with the energy costs as zero, at 69 $/tCO_2$ (LCOD$_{Cogen}$). Then, instead of buying this electricity from wholesale markets, the DAC plant would pay the power plant a revenue that is equal to this difference in LCOD converted to be in terms of energy, as shown in Equation (2), which equals 30 $/MWh of energy produced.

$$Revenue\ SMR\ receives\ from\ DAC = (LCOD_{Base} - LCOD_{Cogen}) \times$$
$$\frac{Amount\ of\ 100°C\ heat\ per\ electricity\ produced}{DAC\ thermal\ requirement} \quad (2)$$

The average LCOE of an advanced nuclear power plant is projected to be 60 $/MWh_e$ (EIRP, 2017). This means that this power plant will need to receive an average of 60 $/MWh_e$ in revenue over its lifetime in order to break even financially; developers will only build this plant if at least this amount of revenue can be projected.[2] For a conventional power plant, this revenue largely would come from selling electricity to wholesale electricity markets, though some markets also offer capacity payments, which could range from 5 to 15 $/MWh_e$ (Ingersoll et al., 2020). With an average wholesale electricity price of 25

[2]While in reality, a detailed pro forma cost breakdown that calculates estimated net present value would be the appropriate financial input in determining whether or not a new power plant should be built, for our purposes the LCOE gives a close-enough approximation.

$/MWh_e$ and capacity payments of 15 $/MWh_e$, this nuclear plant would still be 20 $/MWh_e$ away from being financially viable. Some of this shortfall could be made up through zero-emissions credits (ZECs), which some states have enacted in order to help subsidize clean energy. New York and Illinois both offer (ZECs) that had initial prices of 17.50 $/MWh_e$ (Sciascia, 2017) and 16.50 $/MWh_e$ (IPA, 2017), respectively. Additionally, it is possible a ZEC program will be implemented federally in the U.S. by 2030 (Stokes et al., 2021). However, it is still uncertain if ZECs would provide enough revenue to make these plants financially viable.

A co-located DAC plant would provide an additional revenue stream that could make up for this difference. Though the power plant receives a revenue of $30 from the DAC plant for every MWh of electricity it produces, it only has 64% of this energy left to sell to wholesale electricity markets. Factoring this in, as shown in **Table 4**, instead of needing an average of 60 $/MWh_e$ in order to break even, the SMR now only needs an average of 47 $/MWh_e$. In other words, the SMR needs 21% less revenue from conventional energy and capacity markets in order to be economically viable.

Since nuclear plants are capital-intensive projects, evidenced by recent high-profile failures in Vogtle, Georgia (Holt, 2018), the capital cost is a key consideration if determining whether or not to build a new nuclear power plant. Even though many next-generation nuclear reactors are being designed for modular manufacturing in order to reduce capital expenses, this still remains a primary concern. The SMR considered above with an

TABLE 5 | Potential revenue streams for allowed CAPEX.

Parameter	Units	Only selling to the grid	Selling to the grid + DAC
Expected average electricity revenue	$/MWh$_e$(p)	25	16.08
Capacity payments	$/MWh$_e$(p)	10	6.43
ZECs	$/MWh$_e$(p)	17	10.94
DAC payments	$/MWh$_e$(p)	0	30
Total expected revenue	$/MWh$_e$(p)	52	63
Max allowable CAPEX	$/kW	3,006	4,069

LCOE of 60 $/MWh$_e$, is consistent with a capital cost of 3,782 $/kW. However, there is a large uncertainty to capital costs for advanced nuclear plants, which could range from roughly 2,000 to 6,000 $/kW (EIRP, 2017).

The decision whether or not to build electricity generators depends on whether their capital costs allow the plant to be economically competitive based on current and anticipated market conditions. **Table 5** shows a possible list of expected revenue sources, and the capital expenses that would be required, assuming the plant would receive these revenues on average over the course of its lifetime. Notably, most of the values in this table are reported in terms of $/MWh$_e$ *produced* by the SMR; the values in the second column are lower because the SMR can only sell 64% of its produced electricity to wholesale markets when also providing some energy to the DAC system. The SMR in our future baseline scenario that is built to only sell electricity can expect to receive an average revenue of 52 $/MWh$_e$, and the plant would need to have a CAPEX[3] of 3006 $/kW or lower to be economically viable. In comparison, the SMR that is built to sell electricity to a co-located DAC plant as well as to wholesale electricity markets can expect an average revenue of 65.45 $/MWh$_e$, which would allow for a CAPEX up to 4,069 $/kW, or 35% greater, thus significantly increasing the chances it would be built.

$$CAPEX = \frac{8760 \times Capacity\ Factor}{1000 \times crf} \times$$
$$(Total\ expected\ revenue - Total\ OPEX) \quad (3)$$

Sensitivity Analysis

One of the primary variables in determining our results is the average wholesale electricity price. This variable affects the LCOD of the DAC plant in the Baseline scenario, which then affects the difference in LCOD between the two scenarios, ultimately impacting the revenue that the SMR would receive from the DAC plant. The value used here, 25 $/MWh, is taken from Seel et al. (2018) and although there are many capacity expansion and production cost modeling reports to explore

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[3]The CAPEX is calculated based on average values taken from EIRP (2017). The OPEX is assumed to be 21 $/MWh and the capacity factor 95%. The capital recovery factor (crf) is calculated with an interest rate of 7% over 25 years.

future electricity market scenarios, there are few instances in which the locational marginal price (LMP) of electricity is reported. Given the uncertainty around future electricity market conditions, we conducted a sensitivity analysis to examine how our results would change based on different average wholesale electricity prices.
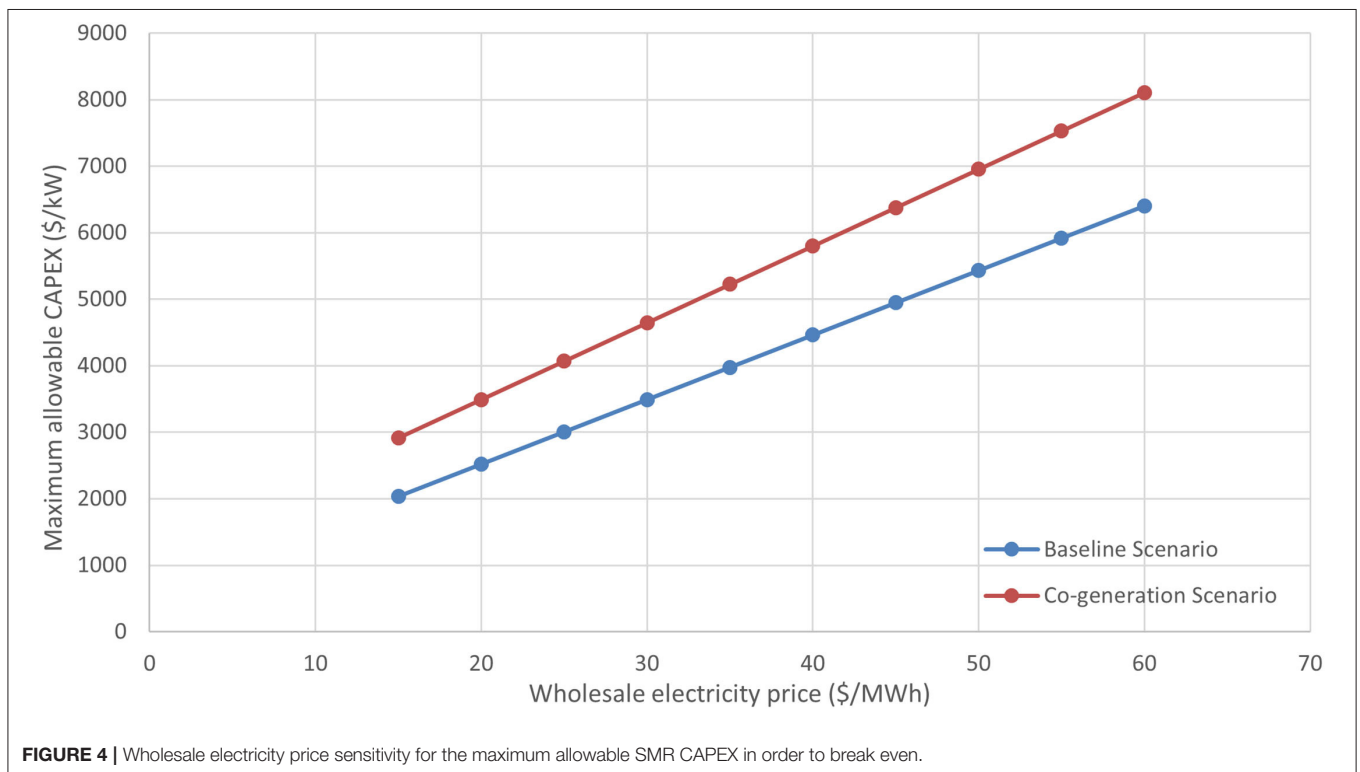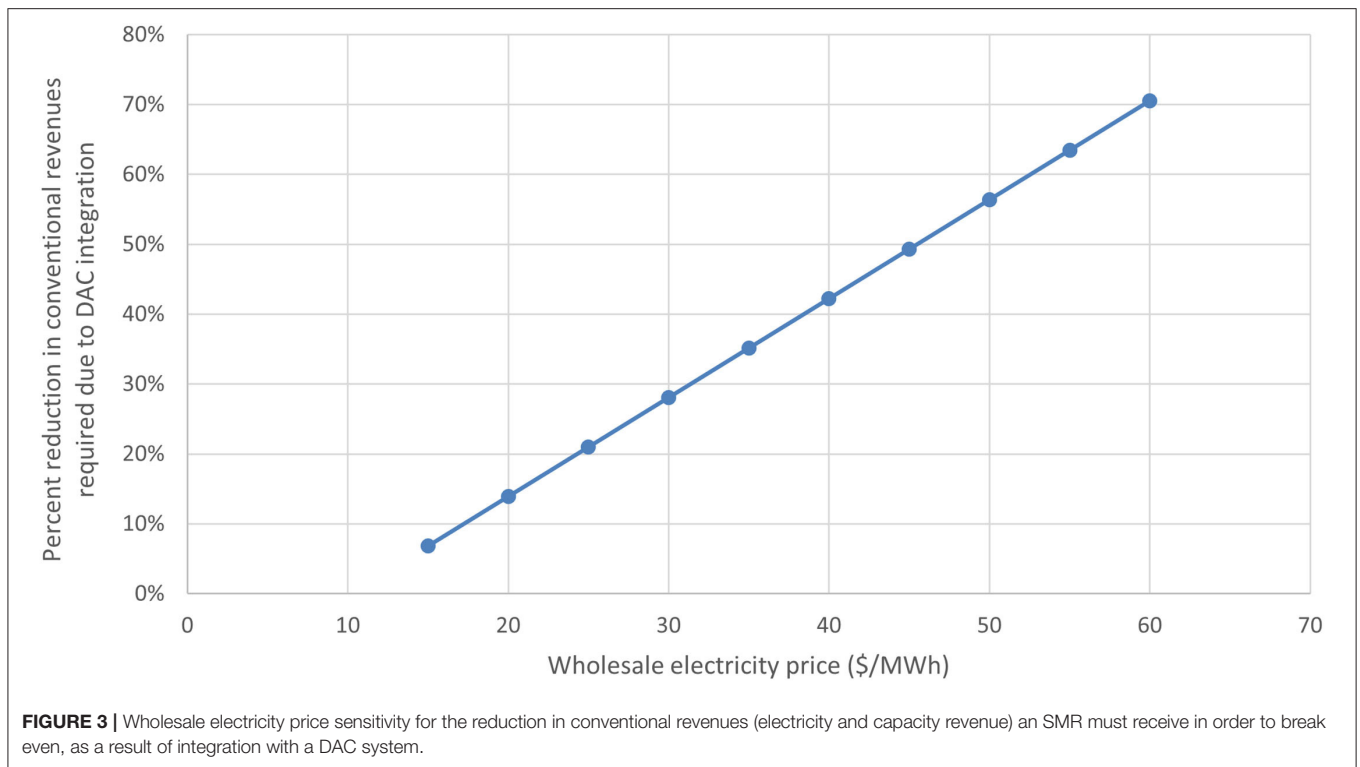
For this sensitivity analysis, we chose a range of 15–60 $/MWh. Notably, varying this price also changes the LCOH for the heat pump, which provides heat to the Baseline scenario DAC plant. The new LCOH values were estimated by plotting a distribution of three heat pump scenarios given in Dominković (2015) and recalculating LCOH values based on its trendline. We then calculated new results for every 5 $/MWh change within this range and plotted the results, shown in **Figures 3**, **4** below.

In the first case of our results, we showed that, if co-locating a DAC plant, the SMR could take in 21% less revenue from conventional energy and capacity markets and still break even. **Figure 3** shows how that percentage will change based on different wholesale electricity prices. As the wholesale electricity price increases, the LCOD for the baseline DAC plant will increase; thus receiving energy from an alternative source becomes increasingly valuable. This is reflected in the results by an increasing revenue that the SMR would receive from DAC for its energy as part of their bilateral agreement, as wholesale electricity prices increase. When able to rely on a higher revenue from the DAC plant, the SMR would then require an even lower price from selling the rest of its electricity to wholesale markets in order to breakeven. The graph shows this percent improvement from its LCOE of 60 $/MWh to the new price it would be required to sell electricity at to remain economically viable, which ranges from 56 to 18 $/MWh.

In the second case in our results, we showed that if the SMR can incorporate this revenue from the DAC plant, it would be acceptable for its CAPEX to be 35% higher than if it were only developed for selling electricity to wholesale markets, or 4,069 $/kW as opposed to 3,006 $/kW. In the baseline scenario, as the expected average electricity revenue increases, the maximum allowable CAPEX also increases, ranging from 2,037 to 6,401 $/kW for 15–60 $/MWh. This range of CAPEX estimates is consistent with the CAPEX range for advanced nuclear plants in EIRP (2017), as noted above. Incorporating both the changing expected average electricity revenue and DAC payments, in the co-generation scenario, the allowable CAPEX ranges from 2,915 to 8,107 $/kW. **Figure 4** shows that as wholesale electricity prices increase, the relative difference between allowable CAPEX in our two scenarios also increases.

DISCUSSION

The analysis in this study estimated the potential benefits of integrating a nuclear SMR with a co-located DAC plant. It is more economically attractive for the nuclear plant to utilize and sell some low-grade heat along with some electricity than to only sell electricity. These results are notable because scaling of DAC will require a significant amount of low-carbon energy. Even

FIGURE 3 | Wholesale electricity price sensitivity for the reduction in conventional revenues (electricity and capacity revenue) an SMR must receive in order to break even, as a result of integration with a DAC system.

FIGURE 4 | Wholesale electricity price sensitivity for the maximum allowable SMR CAPEX in order to break even.

though wholesale electricity prices are expected to decrease due to build-outs of VRE, it is expensive to convert electricity back into the heat needed for DAC. Advanced nuclear reactors and other firm low-carbon resources will be needed to help meet increases in electricity demand, replace fossil fuel generation, and help lower total costs of decarbonization. Importantly, these resources also will have the ability to meet the demand from DAC for low-carbon heat. The analysis in this study shows

that if firm low-carbon resources can sell low-grade heat to DAC, in addition to selling electricity, this will increase their financial viability and create more opportunities for building new plants.

Our sensitivity analysis showed that if the future average price of wholesale electricity is higher than 25 $/MWh, DAC and SMR integration provides even more value to the SMR facility because the DAC facility would be willing to pay more to the nuclear plant in their bilateral agreement rather than buy more expensive electricity from the market. Conversely, if average electricity prices fall below 25 $/MWh, the benefits to the SMR facility are reduced, though still positive if the average electricity remains above ∼10 $/MWh.

Throughout the results section we did not specify a size for the SMR. Instead, we assumed that for every MWh of electricity that the SMR produces, it also produces one MWh of steam at 100°C for the DAC plant. This was done in order to keep the size of the SMR dependent on the size and energy requirements of the DAC plant, and to not give preference to a specific advanced nuclear technology. In reality, this dependency likely would be reversed, as LTSS DAC plants currently being developed are much more modular at smaller scales than what would be possible for advanced nuclear plants. However, a literature review on DAC uncovered only one paper that provided a detailed enough techno-economic breakdown of a LTSS DAC plant that could be replicated (Fasihi et al., 2019). Thus, for the purposes of our analysis, the size and capital cost of the DAC plant was the main constraint.

Even though it was not mentioned in our results, this assumption allows for a determination of the size SMR required for our specific DAC plant. Based on its output and energy requirements, our DAC plant requires 51.25 MW_t of thermal energy. Thus, the SMR must produce 51.25 MW_t of 100°C steam. Considering that utilizing this amount of steam equates to a 15% reduction in electricity generated, the nameplate capacity of our SMR would be 60 MW_e.

It is instructive to estimate the potential market for firm low-carbon power resources that a DAC industry might create. However, first, we must determine how much DAC could be feasibly built by the year 2030. Hanna et al. (2021) models the potential net removal from DAC if an international wartime-like deployment of DAC is enacted in response to climate change. With this type of concerted deployment effort, by 2030, DAC could reach removal rates of 0.03–0.07 $GtCO_2$ (Hanna et al., 2021, p. 6). Assuming the average energy requirements shown in **Table 2**, this would create a demand for about 2–5 GW of new energy. This could represent a considerable market opportunity for SMRs, or other firm low-carbon power developers looking to deploy their products.

Since our analysis was focused on the economics of advanced nuclear, it also may be useful to compare this to alternatives. As mentioned earlier, the average LCOE for advanced nuclear is projected to be 60 $/MWh, with a range of 36–90 $/MWh. Their capital costs likely will range from 2,000 to 6,000 $/kW, with an average of 3,782 $/kW (EIRP, 2017). Two other generation sources that can offer firm low-carbon power are natural gas with CCS and geothermal. Even with CCS integrated, natural gas plants are simpler to develop than nuclear plants, but are much more reliant on fuel costs. The capital expenses for a natural gas plant with CCS are estimated to be much lower on average than nuclear, at 1,984 $/kW, but the LCOE estimation is higher, at 74 $/MWh (James et al., 2019). There is much more uncertainty around the costs of geothermal systems, as they will heavily depend on technology, location, and well-characteristics. Thus, estimates for geothermal capital expenses range from 3,000 $/kW at an absolute minimum to tens of thousands (NREL ATB, 2020), while LCOE for geothermal range from 69 to 112 $/MWh (Lazard, 2019).

Lastly, in our analysis we assume that DAC plants will be economically viable by 2030, and that they at least will earn more revenue for the captured CO_2 than their levelized cost. However, concerted government policies or drastic market developments are needed in order for this to become a reality. Policies or programs that provide payment for the captured CO_2 may come in the form of carbon pricing, such as a carbon tax or cap-and-trade system, which could allow DAC to receive a direct payment at the set carbon price; tax credits, whether performance-based that provide revenue per captured ton of CO_2, or investment-based that lower the capital costs required to build; or low-carbon fuel standards, which would allow DAC to receive offset credits. In addition, revenue for DAC could come from selling captured CO_2 to various markets that would utilize the CO_2 for other purposes, such as enhanced oil recovery (EOR), polymers, synthetic fuels, chemicals such as ammonia, urea, or methanol, and concrete production (Hepburn et al., 2019).

This study sought to highlight the potential synergies between a DAC plant and firm low-carbon power plants. However, a number of assumptions and simplifications had to be incorporated in our analysis, which leaves room for future research endeavors. This might include a similar techno-economic comparison between a DAC system and other types of firm low-carbon resources, a focus on a specific SMR design and its optimal economic integration along with varying sizes of DAC systems, or an analysis utilizing detailed capacity-expansion modeling that would provide a more detailed look at potential future energy costs and revenues, which could then facilitate an analysis of the economic feasibility of the firm low-carbon power resource.

CONCLUSION

Two key technologies that can help to mitigate climate change are firm low-carbon power and DAC. Firm low-carbon resources can help decarbonize the power sector by replacing fossil fuel resources, working to meet increasing electricity demand, and reducing potential costs associated with the integration of VREs. DAC also will be needed to help offset emissions from sectors that may be too difficult or expensive to decarbonize, and to help reduce the vast sums of carbon that have already been emitted into the atmosphere. DAC systems will require a large amount of energy, most of it heat, but this creates another opportunity for firm low-carbon power.

This study aimed to delve deeper into this opportunity and demonstrate how it might incentivize building more firm low-carbon power. We examined the economics of a hypothetical DAC plant in the year 2030 and determined a potential revenue

amount its owners would pay for energy from a co-located nuclear SMR. We then suggested two examples of how this additional revenue could benefit the SMR. It could allow the SMR to take in revenue from selling electricity to wholesale markets that is about 21% less than its projected levelized cost, and still break even financially. This would enable the SMR to operate economically even in the face of variable and decreasing wholesale electricity prices. In addition, after estimating a potential external revenue stream, we show that additional revenue from DAC could allow for capital costs of the same SMR up to 35% higher than what would be required if only selling electricity to wholesale markets. For an energy resource that has been expensive to build, revenue from DAC could offer developers more financial certainty when planning a new project.

We illustrated the potential for synergy between advanced nuclear plants and DAC systems, while also noting that this benefit could extend to other firm low-carbon resources. The findings from this study can be used to inform policy-makers, technology developers, or investors as they plan how to provide low-carbon electricity and heat to new DAC facilities.

DATA AVAILABILITY STATEMENT

The original contributions presented in the study are included in the article/**Supplementary Material**, further inquiries can be directed to the corresponding author/s.

AUTHOR CONTRIBUTIONS

DS formulated the main idea for the paper and performed the bulk of the analysis and writing. SL helped shape the direction of the paper, advised heavily on the analysis, and performed much of the editing. All authors contributed to the article and approved the submitted version.

SUPPLEMENTARY MATERIAL

The Supplementary Material for this article can be found online at: https://www.frontiersin.org/articles/10.3389/fclim. 2021.728719/full#supplementary-material

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