

Contents

1. INTRODUCTION & METHODOLOGY	2
2. PV IN PLACE OF OIL: ALREADY FEASIBLE	2
3. PV IN PLACE OF GAS: NOT YET	6
4. ISSUES AROUND PV INTEGRATION	6
5. APPENDIX	7

Sun sets on oil for Gulf power generation

The Gulf Region has some of the world's best solar resources. However, governments in the region have historically valued oil and gas at cost and have provided their populations with subsidised electricity, two factors which have impeded the development of renewable energy. This study shows that falling costs of photovoltaic (PV) technology mean that solar energy is already a viable option for power generation in the region where it can be used to replace the burning of oil for power generation, as long as that oil is valued at the international selling price.

- Bloomberg New Energy Finance has modelled the economics of a modern, low-cost 100MW PV plant, and concludes that there is a strong economic rationale for Gulf Cooperation Council (GCC) states to build solar capacity today.
- The central scenario for the PV project's capital cost is based around the 2010 global (outside China) lowest price of \$3.14/W. We expect the cheapest bankable systems in 2011 to be developed and built for \$2.73/W and prices to drop further thereafter according to the established experience curve for PV technology (see Market Outlook, *PV in 2011: sunny now but clouds forecast*, 16 November 2010).
- A PV project in the GCC would generate a real internal rate of return (IRR) of 9.4% if oil prices rise to \$163/bbl (in real 2010 terms) by 2030, as per Standard Chartered Bank's future oil price expectations.
- Even if the oil price stays flat in real terms at \$80/barrel, a PV project costing \$3.14/W still offers a yield of 4.6%. By comparison, the longest available Abu Dhabi government bonds have a yield of 6.75% to 2019.
- We have also forecast two alternative scenarios for when the capital costs are 50 cents above or below the central scenario. The scenario based on a PV capital expenditure of \$2.64/W provides an IRR of 11.6% whilst the scenario based on a price of \$3.64/W gives an IRR of 7.6%.
- There is further upside to these IRR figures based on any residual value of the project after the first 25 years of operation (current-generation technology is still expected to generate 80% power at this time), and based on the value of any potential carbon credits under the Kyoto CDM scheme or in the voluntary markets.
- Any assessment of the economics of PV in the GCC depends critically on whether the comparison is with the extraction cost of oil or – surely more correctly – its international market price. If extraction costs are used as the comparator, then PV is uneconomic and will remain so for the foreseeable future.
- Immediate investment in PV in order to displace natural gas is not economically feasible because of low gas prices. However, continually decreasing PV system costs and rising gas

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prices will likely make PV displacement of natural gas generation feasible in the medium to longer term.

- The energy sectors of most Gulf countries are state-managed, but PV investments to offset fossil fuels could be used as a way of introducing private-sector participation, particularly via a clean energy tenders. Tenders offer the advantage of price discovery while maintaining the energy ministry's directing authority (see Research Note, *The sun also rises in the Middle East and North Africa*, 1 September 2010).

Bloomberg New Energy Finance would like to thank Standard Chartered Bank's Renewable Energy and Environmental Finance team for input into the methodology and for the use of its future oil price forecasts.

1. INTRODUCTION & METHODOLOGY

The Middle East domestic power generation sector is unlike any other, due to local availability of low-cost hydrocarbons and low electricity prices for consumers, who are generally subsidised by governments using oil export revenue. As a result, Kuwait still generated 70% and Saudi Arabia 57% of electricity from oil in 2008.

This study examines the value of a standard 100MW PV project, based on the assumption that the value of the displaced oil should be the international market price, rather than the marginal extraction cost, which currently drives domestic electricity pricing decisions.

Since OPEC production quotas include domestic use, in principle displacing domestic consumption results in increased exportable oil and hence export revenues, though discussion of OPEC compliance is beyond the remit of this note. In addition, if the rate of extraction from oil-fields in the GCC is limited, as has been postulated by a number of eminent oil analysts, then a barrel of oil burned locally is a barrel not sold in the international marketplace.

As Middle East economies develop, they are moving to more rational decision-making and adopting longer-term investment horizons. Applying the correct opportunity cost to local consumption of fossil fuels will place increasing focus on whether and when solar power will become competitive. There is already evidence of political will in this direction, as the establishment of Masdar and the King Abdullah City for Atomic and Renewable Energy shows.

This analysis is also of relevance in examining the economics of exporting solar power from North Africa while burning abundant gas reserves to meet local power needs. Economic factors being equal, European nations are likely to be more comfortable importing gas than electricity, and the local electricity demand in North Africa will more accurately match daily PV production curves.

2. PV IN PLACE OF OIL: ALREADY FEASIBLE

Using estimated PV system costs and oil forecasts to 2030, Bloomberg New Energy Finance analysis shows that PV projects built to offset oil-fired generation will already in 2011 demonstrate positive returns.

2.1. PV assumptions

Bloomberg New Energy Finance modelled the use of a 100MW PV project built in 2011 to displace oil-fired power generation, freeing that oil to be sold at world market prices. As most PV panels, are warranted to produce at least 80% of their initial capacity for at least 25 years, we have assumed the project generates until 2036, however at that point we have assigned a residual value of zero. Operation and maintenance cost are assumed to equal 1% of capital costs per year and the panels are assumed to degrade at rate of 0.7% per year. The key drivers of returns are:

- The cost to develop and build PV plants

If 100MW of PV is built in 2011 for \$3.14/W, and oil prices follow Standard Chartered Bank's central scenario, the project would generate a real IRR of 9.4%

- The oil price development over the 25-year project life of a PV asset.

The model makes a number other simplifying assumptions. It assumes that every unit of PV power can replace a unit generated by oil in a fossil fuel plant with a heat rate of 10.85Btu/kWh. Figure 4 shows that electricity demand in Abu Dhabi, a representative economy with good data, peaks during sunlight hours, due to air-conditioning load, and is also very seasonal, with summer peaks more than double winter peaks. This makes it more likely that PV could be introduced into the grid without significant costs of extra backup generation. We have also assumed that the PV plant can generate at 20% capacity factor (ie, a sunny location, even for the Middle East).

Based on these assumptions, this model is applicable to all GCC states except for Qatar, which is wholly reliant on gas for its electricity generation (see Appendix, Table 2).

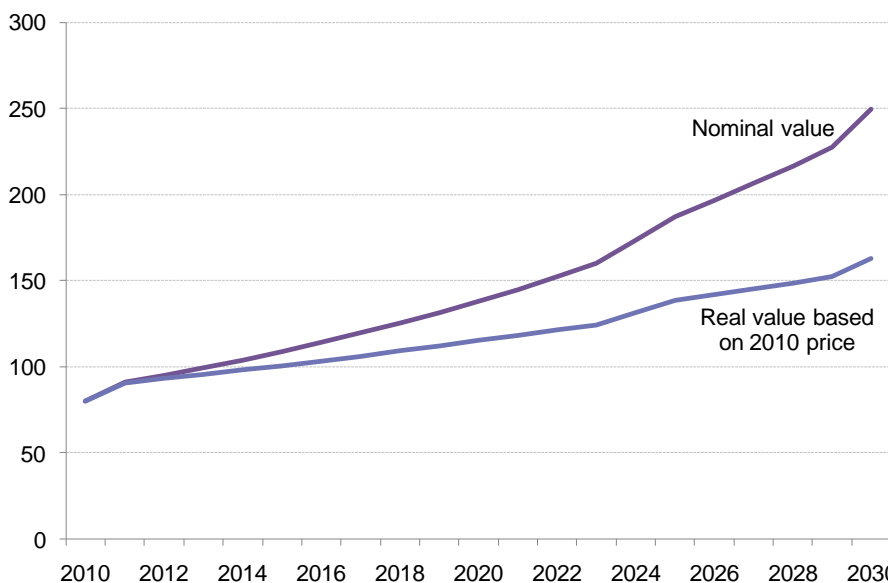
The conclusions of the exercise in the central scenario were that if 100MW is built in 2011, the project would generate an internal rate of return of 9.4%. If a carbon price is included (see Figure 2) it would generate a 10.8% IRR (see Appendix, Table 4).

The impact of tax has been ignored for the purposes of comparison.

2.2. Oil price assumptions

The key ongoing cash impact from building PV capacity in the GCC would come from the sale of the displaced oil, which makes the future oil price a key driver of returns. Standard Chartered Bank forecasts oil prices through 2030 (see Figure 1) at which point we have assumed for our central scenario that the price remains flat for the remaining six years of the PV project’s life.

Figure 1: Standard Chartered Bank oil price forecasts, 2010–30 (\$/barrel)



Source: Standard Chartered Bank, Bloomberg New Energy Finance Note: See Table 1 for explanation of assumptions

Table 1: Standard Chartered Bank's oil price forecast methodology

Our model for oil demand trends to 2030 is based on a forecast of oil intensity – the number of barrels of oil required to produce \$1,000 of GDP. The global average is currently 0.54 (ranging from 0.31 in Japan and Europe to 0.96 in India). We use oil intensity as the basis for our model, rather than oil demand as a function of GDP growth, as intensity is less volatile yet incorporates key trends such as price-driven demand destruction (through inter-fuel substitution, greater thrift or increased efficiency) and policy-driven de-carbonisation of energy sources.

We assume a pace of decline in oil intensity based on recent history, local oil market characteristics, technological changes and future policy expectations. Specifically, we expect that the pace of change will accelerate after 2020 due to higher prices and the increasing commercialisation of alternative energy sources. The net result of our model is that global oil intensity is forecast to drop to 0.3bbl/\$1,000 of real GDP by 2030. This suggests that demand will still rise to 112 million barrels per day (mbd) by 2030 from 87mbd today, and per capita oil use will rise to \$4.9bbl, from \$4.6 today.

We believe that supply is limited not by underground reserves, but by the pace of investment in capacity. Because the forecast declines in oil intensity are already relatively aggressive and are limited by technology, we expect productive capacity to increase (albeit with a lag) to ensure sufficient output. We conclude that crude oil prices will need to rise in order to ensure adequate supply to meet the future demand implied by our GDP forecasts, even accounting for greater efficiency and substitution for other fuels.

By 2024, spare capacity will fall below 5% of demand on our forecasts, at which point we expect a supply premium to be built into the oil price, lifting prices above marginal costs and raising supply further, but with a lag. By 2030, our model suggests that spare capacity will still drop below 3% of demand for the first time since 2007, and we expect a supply risk premium of \$20/bbl at this stage. We forecast that nominal prices will rise to \$138/bbl by 2020 and \$247/bbl by 2030. In real terms, this is a doubling in prices. Expenditure on oil as a proportion of GDP will need to remain at a higher level than was seen during the 1985-2000 period putting a burden on personal budgets or, where subsidies are prevalent, government finances.

Source: Standard Chartered Bank, 17 December 2010

We also calculated IRR for a range of scenarios in which the oil price rises linearly from the current \$80/barrel to a high price in 2030. The current oil price was based on a 200-day average for Brent Crude in late 2010. These IRRs are shown in Figure 3, along with the IRR under the Standard Chartered Bank forecast, our central scenario.

2.3. PV initial project costs

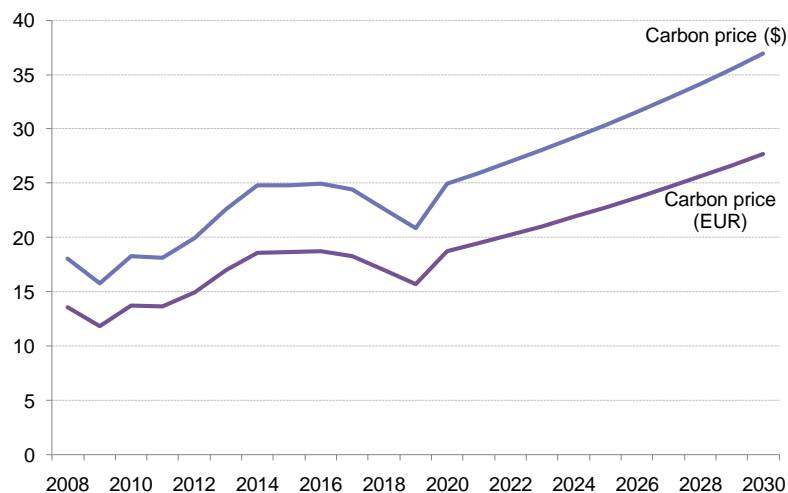
The key cost and therefore a key assumption for the model is the large-scale PV system cost. These have been based on our best in class system cost estimate for fixed axis crystalline silicon, which in 2010 is \$3.14/W. This 2010 price is only achievable by experienced, mostly German engineering firms operating in a low margin market, but there is no reason why these firms should not bid for an engineering tender in the GCC, and the figure includes an allowance of \$0.18/W towards development costs. We also ran scenarios for two alternative project cost figures of 50 cents lower and higher than our central scenario (see Appendix, Figure 5, Figure 6).

2.4. Potential upside from carbon revenue

There is also a possibility of revenue from offsetting CO₂ emissions under the Kyoto Clean Development Mechanism (CDM). We therefore modelled a possible IRR upside from carbon prices based on Bloomberg New Energy Finance's central CER price forecasts (see Figure 2). The two existing large solar projects in the GCC are both in Abu Dhabi and both are currently

registered under the CDM. Due to the uncertainty surrounding global carbon pricing schemes, this revenue stream is not included in the central scenario, but could still play a role since the CDM retains global support: the Cancun agreements extended the CDM after the expiration date of the Kyoto Protocol's commitment period on 31 December 2012.

Figure 2: Assumed certified emission reduction (CER) price (\$ and EUR/tonne)

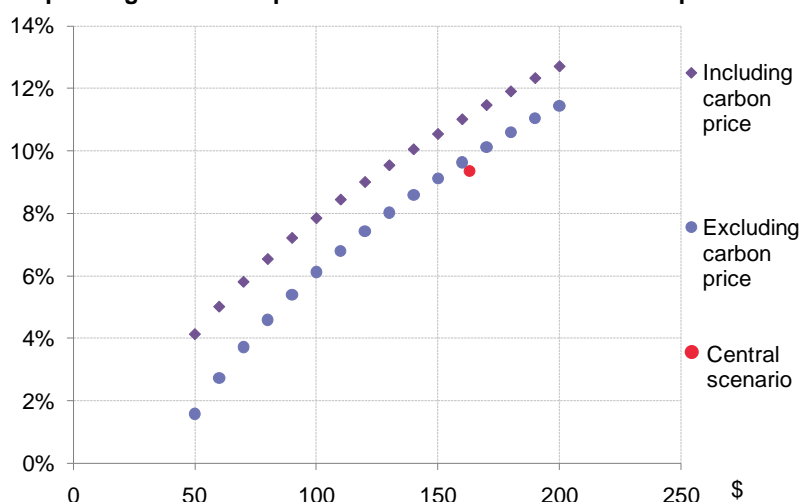


Source: Bloomberg New Energy Finance Note: Central scenario based on detailed analysis of global carbon supply, demand, and likely legislation.

2.5. Outcome

As Figure 3 shows, if the real price of oil increases over the next 20 years from its current \$80/barrel, a 100MW PV project built in 2011 would have made an inflation-adjusted IRR of at least 4.5%. The yield on Abu Dhabi government bonds due in 2019 is 6.75%, suggesting that as long as the government has a 25-year investment horizon and expects the price of oil to rise above \$120/barrel, such PV plants would be a good state investment.

It is also possible for the government to try to secure prices below \$3.14/W, either through an aggressive tender process with a ceiling price, or by waiting for module and inverter prices to fall further. Experience with tenders in India and China suggests that construction companies are willing to bid very low engineering, procurement and construction prices to get PV deals in potential new markets, although these companies often have little experience and will not be considered bankable.

Figure 3: IRR depending on the real price of oil in 2030 with initial PV capital cost of \$3.14/W

Source: Standard Chartered Bank, Bloomberg New Energy Finance Note: The red point is the central scenario based on Standard Chartered Bank's forecast for 2030, without carbon price.

3. PV IN PLACE OF GAS: NOT YET

Immediate investment in PV in order to displace gas is not attractive because of the low price of gas, and the higher efficiency of gas-fired power plants compared with oil-fired power plants. If the real gas price doubles over the next 20 years from a European price of \$9/MMBtu to \$18/MMBtu in 2030, a 100MW PV project built in 2011 at \$3.14/W would have made an inflation-adjusted IRR of 2.2% excluding the carbon price, and 4.2% including it.

However, it will become more viable as the price of PV decreases. If we continue to assume that the gas price doubles over the period, but use a PV capex of \$2/W (our experience curve projections suggest this will be feasible by 2015), a 100MW PV project built in 2011 would provide an IRR of 9.1% including carbon and 6.7% excluding the carbon price. This suggests that using PV to displace gas is not a completely unrealistic prospect in the next 20 years.

4. ISSUES AROUND PV INTEGRATION

These economic calculations would suggest a boom in the building of PV projects in the GCC region in the coming years. Before this happens, consideration needs to be given to whether the resulting PV can be integrated usefully into the grid.

Although electricity demand in the region is highest between 12pm and 4pm, which complements PV generation, much of the region also experiences an early evening electricity demand peak (see Appendix, Figure 4) which PV without energy storage would be unable to satisfy. Investment in PV may thus be unable to entirely offset the capital cost of new build fossil fuel plants (or of grid-scale electricity storage, once this becomes significantly cheaper than today).

Another potential inhibitor is the cost of installing new transmission lines to connect the PV to the grid. The current infrastructure is sufficient to incorporate the new PV build without significant changes. Each MW of PV uses roughly 4 hectares of land, and conservatively 10-20MW capacity could be built adjacent to each existing grid substation. As the volume of PV grows to be significant, however, new grid capacity might be required.

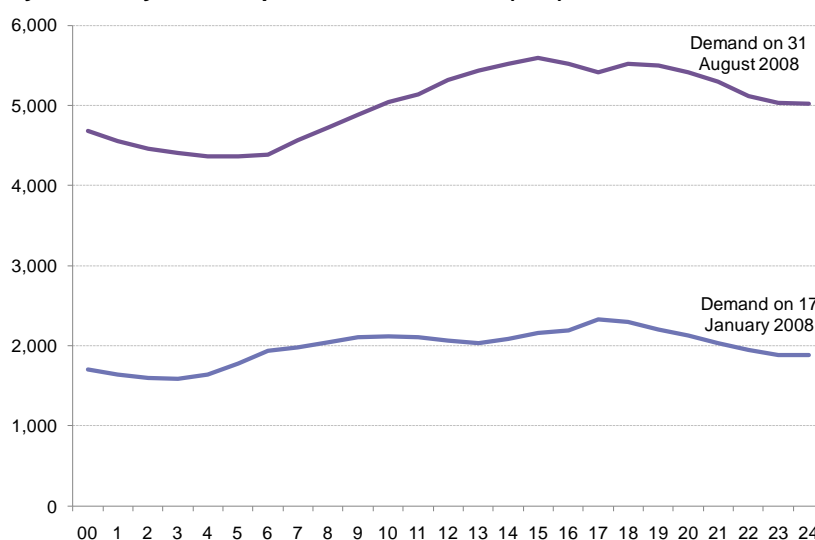
Another important consideration is the effect of large scale PV installations on the stability of each country's grid. The amount of PV which is likely to be installed in each country is unlikely to be sufficient to destabilise the grid in the near or medium term. Conservative estimates indicate that up to 10% of total capacity (see Table 3) could be met by PV without any significant effects on power quality, allowing at least 5GW of PV to be built in Kuwait and Saudi Arabia (the countries with the most oil-dependent electricity sectors) alone. The ongoing GCC grid integration will also

allow supply and demand to be aggregated over a wider area and may well increase the potential for PV to be usefully added to the grid.

Finally, it should be noted that any large-scale uptake of electric vehicles further tilts the economics towards the deployment of PV over fossil fuels, though most likely distributed generation rather than large-scale projects like the one analysed here.

5. APPENDIX

Figure 4: Daily electricity demand profile for Abu Dhabi (MW)



Source: Abu Dhabi Water and Electricity Authority Note: Peak load data is expected to be fairly similar across the region so Abu Dhabi has been used as a case study.

Table 2: Electricity generation by fuel type ranked in order of proportion % oil use

	Oil (GWh)	Gas (GWh)	Total (GWh)	Oil (%)	Gas (%)
Kuwait	36,000	15,700	51,700	70	30
Saudi Arabia	116,200	88,000	204,200	57	43
Oman	2,900	12,900	15,700	18	82
UAE	1,500	84,800	86,200	2	98
Bahrain	5	11,900	12,000	0.04	99.9
Qatar	0	21,600	21,600	0	100

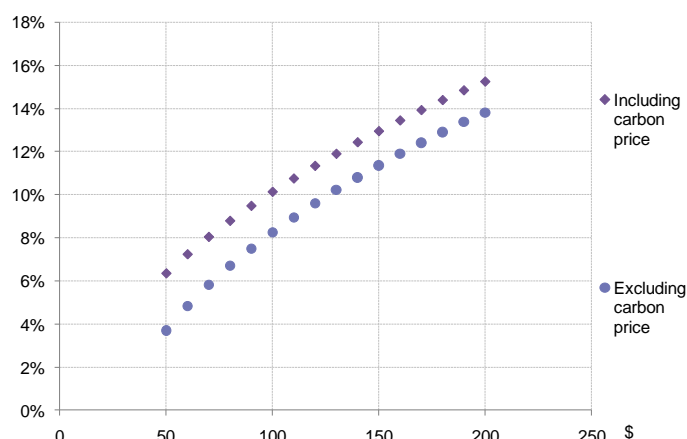
Source: IEA, Bloomberg New Energy Finance Note: Based on 2008 data.

Table 3: GCC electricity capacity and demand (GW)

	Total electricity capacity	Peak electricity demand
Saudi Arabia	44,500	41,200
UAE	21,500	17,100
Kuwait	10,800	10,500
Qatar	5,300	4,500
Oman	4,000	3,700
Bahrain	2,700	2,400

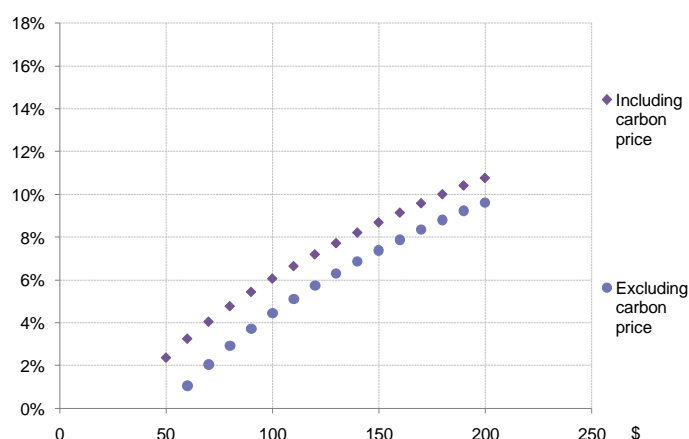
Source: MEED, Bloomberg New Energy Finance

Figure 5: IRR depending on the price of oil in 2030 with PV capital cost of \$2.64/W



Source: Standard Chartered Bank, Bloomberg New Energy Finance

Figure 6: IRR depending on the price of oil in 2030 with PV capital cost of \$3.64/W



Source: Standard Chartered Bank, Bloomberg New Energy Finance

Table 4: Project IRR for different oil price and capital cost scenarios (%)

Oil price in 2030 (real 2010 \$/bbl)	\$2.64/W including carbon	\$2.64/W excluding carbon	\$3.14/W including carbon	\$3.14/W excluding carbon	\$3.64/W including carbon	\$3.64/W excluding carbon
\$200	15.2	13.8	12.7	11.4	10.8	9.6
\$190	14.8	13.4	12.3	11.0	10.4	9.2
\$180	14.4	12.9	11.9	10.6	10.0	8.8
\$170	13.9	12.4	11.5	10.1	9.6	8.3
\$163 (non-linear Standard Chartered Bank forecast)	13.2	11.6	10.8	9.4	8.9	7.6
\$150	12.9	11.4	10.5	9.1	8.7	7.4
\$140	12.4	10.8	10.1	8.6	8.2	6.9
\$130	11.9	10.2	9.5	8.0	7.7	6.3
\$120	11.3	9.6	9.0	7.4	7.2	5.7
\$110	10.7	8.9	8.4	6.8	6.7	5.1
\$100	10.1	8.3	7.8	6.1	6.1	4.4
\$90	9.5	7.5	7.2	5.4	5.5	3.7
\$80	8.8	6.7	6.5	4.6	4.8	2.9
\$70	8.0	5.8	5.8	3.7	4.1	2.1
\$60	7.2	4.8	5.0	2.7	3.3	1.1
\$50	6.4	3.7	4.1	1.6	2.4	-0.1

Source: Standard Chartered Bank, Bloomberg New Energy Finance

ABOUT US

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