KAPSARC Discussion Paper

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King Abdullah Petroleum Studies and Research Center

Efficient Industrial Energy Use: The First Step in Transitioning Saudi Arabia's Energy Mix

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About KAPSARC

The King Abdullah Petroleum Studies and Research Center (KAPSARC) is an independent, non-profit research institution dedicated to researching energy economics, policy, technology, and the environment across all types of energy. KAPSARC's mandate is to advance the understanding of energy challenges and opportunities facing the world today and tomorrow, through unbiased, independent, and high-caliber research for the benefit of society. KAPSARC is located in Riyadh, Saudi Arabia.

Legal notice

Executive Summary

External observers worry about whether Saudi domestic consumption of oil will crowd out exports. This is based on simple extrapolations which suggest that in a little more than 20 years Saudi Arabia may become a net importer of hydrocarbon fuels.

However, our research does not support this. Based on the "baseline scenario" macroeconomic assumptions in Oxford Economics' global economic and industry models, we project Saudi Arabia's energy balances until 2032 using the KAPSARC Energy Model (KEM). We analyze several cases:

– continuation of current pricing policies;

– immediate deregulation of fuel prices;

– phased deregulation of fuel prices; and

– a combination of incentives and small price increases that capture many of the benefits of deregulation.

Our projections suggest that implementing these alternative fuel-pricing and technology investment policies would likely encourage the adoption of more efficient power generation and water desalination technologies. The alternative policies alter the transfer prices of fuels between sectors, but maintain the prices at which energy is sold to households. Future analyses will examine the next logical step of adjusting household energy prices in transitioning Saudi Arabia's energy economy to match the efficiency of developed nations.

For the Saudi energy economy, we find these alternative policies achieve a total economic gain that ranges between \$430 billion and \$505 billion (in real USD 2014), compared with continuing the current policies. Policies that manage transition can therefore be implemented without materially reducing the economic benefits.

Figure 1 deals with Saudi domestic consumption of oil and gas. Our model produces results that are very different from a simple growth extrapolation. According to our results, the continuation of current pricing policies (in real terms) leads to the consumption of 7.8 million barrels of oil equivalent per day (MBOED) domestically in 2032, whereas the growth extrapolation gives a domestic consumption of 12 MBOED. When the continuation of current real pricing of fuels to industrial sectors is assumed, our research suggests utilities will mitigate the growth in oil and natural gas consumption through the conversion of inefficient, single-cycle gas turbines to combined-cycle plants and by installing new combined-cycle plants.

The alternative policies examined are seen to lead to a decrease in domestic consumption of oil and gas in 2032 by up to 2.07 MBOED, compared with continuing current policies. Made profitable by the alternative policies, renewables and nuclear power enter the generation mix. As a result, oil exports can be maintained in the future at current levels. Our analysis does not consider the implications of new higher residential and transportation efficiency standards on end-user demand. This means that future domestic consumption could even be significantly lower than projected by the model.

Our results could be used as a benchmark for an efficient energy transition in the Kingdom. They apply whether decisions to invest in new capacity follow a reform of transfer prices of fuels, or simply result from collective stakeholders' decisions.

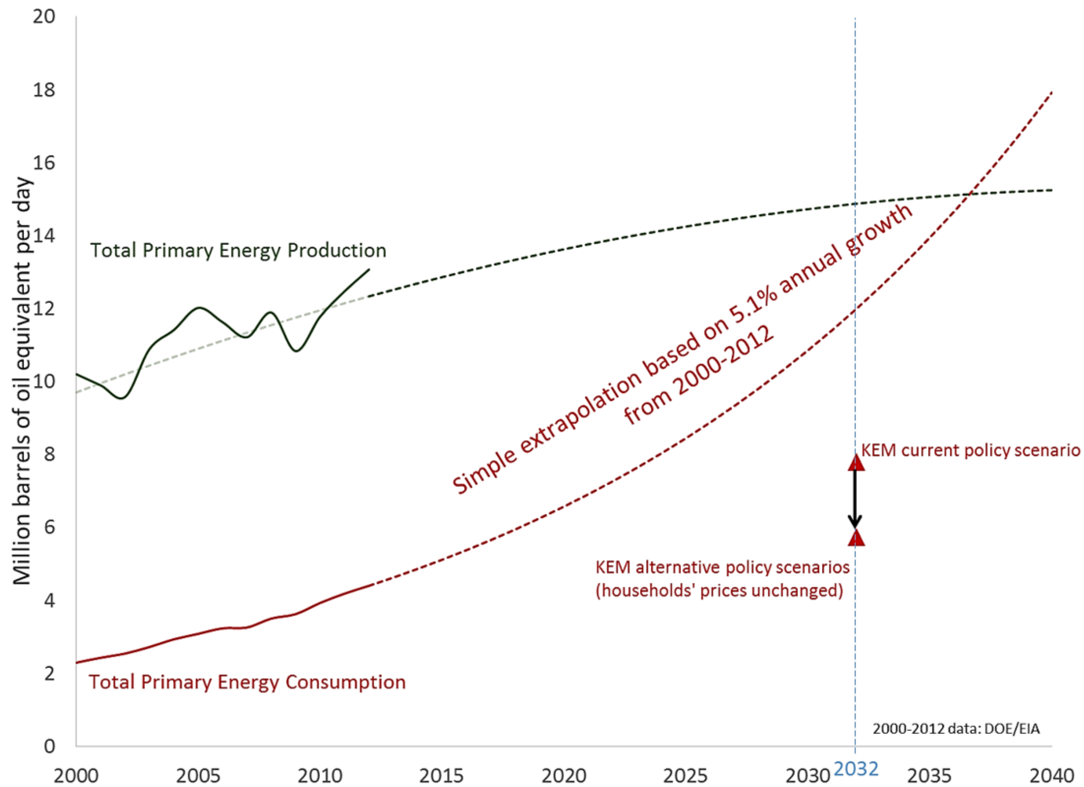

Figure 1 – Saudi Arabia's oil and gas consumption and production (Source: KAPSARC analysis, Energy Information Administration)
Note: The green broken line is a concave extrapolation of historical domestic oil and gas production, made only for illustrative purposes.

The Role of Industrial Fuel Prices

In Saudi Arabia, transfer prices of fuels between sectors are administered in order to balance sectoral budgets and meet development objectives (by promoting economic diversification). This, however, creates both a lack of economic coordination between sectors and economic inefficiencies within sectors.

The equipment mix and fuel consumption rates in the large energy-consuming sectors thus reflect the low administered prices charged for fuels. Table 1 contains the transfer prices charged to the power, water desalination, and petrochemicals sectors.

Currently, Saudi power generation capacity is almost entirely composed of conventional thermal plants

Methane and ethane	$0.75/MMBtu
Arab light	$4.24/bbl
Arab heavy	$2.67/bbl
Diesel	$0.65/MMBtu
HFO 360cst	$0.36/MMBtu

Table 1 – Transfer prices for fuels paid by the power, water, and petrochemicals sectors (Source: Council of Ministers Resolution No. 55 and Electricity & Co-generation Regulatory Authority (ECRA))

fueled by a mix of crude oil, refined oil products and natural gas. The Joint Oil Data Initiative (JODI) (2014) states that direct use of crude oil approached 0.9 MMbbl/d in July 2014, or about 9 percent of the country's total production, the vast majority of which was used for power generation.

Putting the potential fuel saving from changing industrial prices into perspective

A total of 860 Thousand barrels per day (Mbbl/d) of crude oil could have been saved in 2011 by deregulating transfer prices of fuels between sectors. To compare, the same long-term static version of KEM shows that 230,000 bbl/d of oil would have been saved in 2011 if total electricity demand had been 25 percent lower. If price elasticity is, say, -0.25, this implies doubling electricity prices.

Previous research, Matar et al. (2015), shows the potential economic gains that could have been realized in 2011 by deregulating the transfer prices of fuels among industrial sectors or by introducing government credits to encourage investment in more efficient power generation capacity. This previous analysis demonstrates that as much as 860 Mbbl/d of crude oil could have been saved in 2011 by focusing on more efficient electricity and water production and on improvements in intermediate industrial energy use, without changing prices in the transportation sector or for households.

We improve on these results by examining the transition issues raised by this analysis. Using a multi-period version of KEM, we analyze the effects of various policies on the evolution of the power generation mix and fuel consumption, mitigating the growth in consumption. The economic gains shown to result from the policies are compared with those from a continuation of current policies. The policies we analyze include deregulating transfer prices of fuels or introducing investment credits or feed-in-tariffs. Our results may help formulate the appropriate policies to facilitate the emergence of alternative technologies in the Saudi power system.

Overview of KEM

The KAPSARC Energy Model represents the major energy producing and consuming sectors of Saudi Arabia. The sectors covered and physical flows are shown in Figure 2.

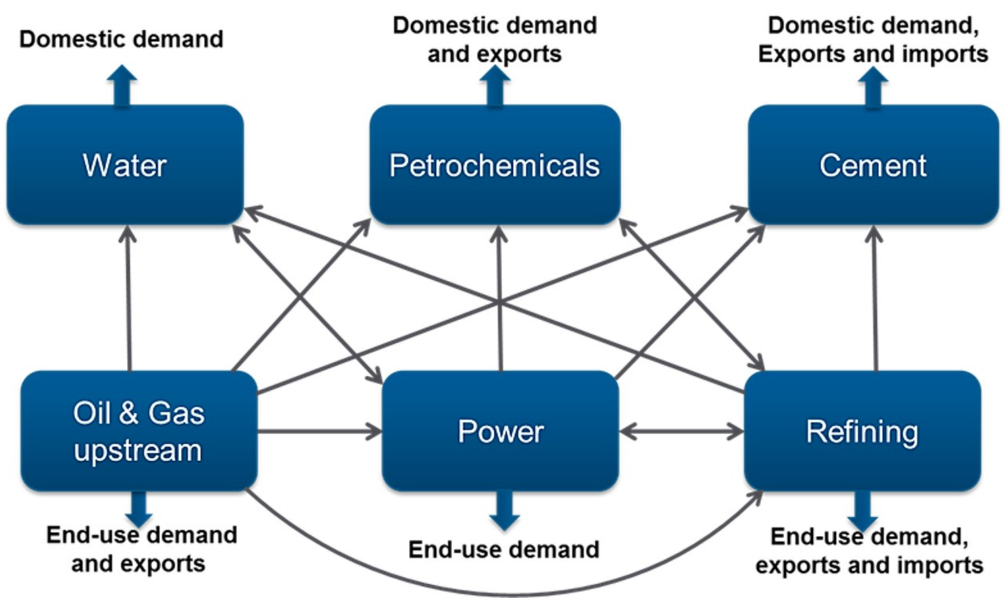

Figure 2 – The sectors represented in KEM and the major flows among the sectors (Source: KAPSARC)

The version of KEM used here is an extension of the model used by Matar et al. (2015). The central difference, however, is that this version is a multi-period model that allows us to examine the impact of alternative energy policies over time, while the previous version is a single-period static model that examines the long-run consequences of policies without the capacity to examine the transition to the longer run.

To find the equilibrium for all years through the forecast horizon of 2032, we use a technique called recursive dynamics that is described in Appendix A. This method is a compromise between assuming full information, with capacity added optimally through the model's horizon – even though uncertainties alter the decisions, and the 'myopia' of the single-period model.

As detailed by Matar et al. (2015, 2014), the model is calibrated to data for the year 2011, but also includes partial data for what has already taken place until 2014. We treat 2012 through 2014 as forecast years because the data for these years is incomplete. In our model, the planning for power generation expansion begins in 2015. Any plants already under construction, which are listed in Appendix B, are included.

The Oxford Economics' Global Economic (GEM) and Global Industry (GIM) models are used to generate a set of consistent macroeconomic assumptions that we use in defining our scenarios. Appendix C gives an overview of the assumptions common to all policy scenarios. Appendix D details the assumptions made as to the costs of the technologies.

For specific details about how different sectors are represented in the model, see Matar et al. (2015, 2014). Additional developments introduced in the multi-period version of the model used in this paper are described in Appendix E. All figures given in the paper are expressed in real dollars, with 2014 as the reference year.

Policy Scenarios Analyzed

Our policy choices focus on fuel-pricing policies and levels of investment credits. In all scenarios we maintain current industrial electricity prices; this applies to the electricity transferred between the power and desalination firms. Residential electricity prices, which are between 1.3 cents/kWh and 6.9 cents/kWh, and gasoline prices at 12 cents/liter, are unchanged in all scenarios. We acknowledge that higher residential and transportation efficiency standards have been enforced since 2013, or will be implemented in the coming years. These standards will have long-term effects on the diurnal shape of the load curves and the magnitude of the peak loads and will also affect future demand for transportation fuels. This analysis does not consider the implications of those efficiency policies on end-user demand.

In all scenarios:

– The long-term contractual agreements in the petrochemicals sector that set the prices of methane and ethane for existing plants are maintained, with the methane and ethane supplied to the petrochemicals sector in 2014 valued at $0.75 per MMBtu for the entire horizon.

– In every sector of the model, we cap future purchases of heavy fuel oil (HFO) and diesel at administered prices at the levels observed in 2011. The use of HFO in steam turbines with desulfurization units is exempt from this restriction.

– We keep the current administered prices unchanged in real terms for end-consumers.

The following scenarios are examined:

Current Policy Baseline

In this scenario we keep the current administered transfer prices of fuels constant in real terms until 2032. Since natural gas supply is below potential demand at current prices, we extrapolate quotas for gas supplied to gas-consuming sectors through the forecast horizon by maintaining the same sectoral allocation percentages observed in 2011. We chose something as simple and obvious as this because this scenario is untenable economically and our goal is to provide a baseline for showing the benefits of pursuing other policies. Thus we take the projected domestic gas supply in each year and allocate it to the various consuming sectors based on their shares of consumption in 2011. This simplification may lead to excess supply in some consuming sectors over time, since the demands for the sectors' outputs do not grow at exactly the same rate and the technology stock changes over time. We assume that any natural gas that is not consumed is re-allocated to the electricity sector.

Immediate Deregulation

This scenario provides the maximum economic gain and serves as a benchmark for economic efficiency. We can compare the economic gain of other scenarios with this one to estimate the trade-off between economic gain and policies that fall between immediate deregulation and current policy and which meet the social goals of the country. In this scenario we use world prices for crude oil and oil products and domestic market-clearing prices for natural gas starting in 2015.

Gradual Deregulation

In this scenario, beginning in 2015, transfer prices of fuels are raised gradually to world prices for oil and market-clearing prices for natural gas over an eight year period.

Implicit Fuel Contracts

In the Implicit Fuel Contracts Scenario, sectors continue to receive allocations of natural gas and petroleum products at low prices, even if there are no formal long-term contracts as in the petrochemical industry. This scenario honors the implicit agreements by continuing to supply low-cost fuels with a gradual phasing out of the quantities sold at the low prices. The model sets government allocations of fuels in each sector and region at the current consumption levels at the current administered price. Then the allocations are gradually reduced to zero over eight years. Incremental fuel purchases beyond the allocated amounts in current agreements are at market-clearing prices. Because incremental supply is at market prices, no allocation mechanism is necessary for the incremental fuels. The formulation of this scenario in KEM is detailed in Appendix F.

Investment Credits

When a company receives an investment credit for investing in new power capacity, the credit represents that portion of the investment that is paid by the government. The goal of the Investment Credit Scenario is to achieve higher economic efficiency without a drastic increase in the administered prices for fuels. Investment credits will reduce the capacity costs of selected technologies, bringing the relative costs of fuel and capacity in this scenario closer to their relative costs under deregulation. This leads to efficiencies that are closer to those in the deregulation case than those achieved under current policies. Matar et al. (2015) found that a range of investment credits would produce economic gains close to those observed under deregulation. Without going into the technicalities of how the credits are calculated, adding the time dimension explodes the computational difficulty of using the solution method adopted in the single-period model beyond reasonable computing capability. For this reason the scenario has been redesigned.

Starting in 2015, we raise the administered prices of crude oil and natural gas to $30/bbl and $1.50/MMBtu, respectively, and keep them constant in real dollars. These prices, already used to define an investment credit scenario by Matar et al. (2015), could be viewed as a possible compromise between the government and industrial stakeholders. Although the sectors buy natural gas at the administered price, the fuel is allowed to flow to where it is the most valuable, without enforcing sectoral quotas. We apply a simple formula for the price of refined products, where the administered prices of diesel and HFO are equal to the administered crude oil price multiplied by the ratio of their world market prices to the world price of oil. Complementing the price increase, for all years we introduce an investment credit of 50 percent that is applied to the non-carbon power generation technologies which are economic in the Immediate Deregulation Scenario. The monetary value of the investment credit applied to capacity additions in a given year is that which is observed in the year the decision to build is made, and not when the capacity comes online. This is important for the new technologies with capital costs that decrease over time.

Feed-in Tariffs

As an alternative to investment credits, the government can, instead, provide feed-in tariffs that would achieve the same renewable and nuclear capacity additions observed in the Investment Credit Scenario. A feed-in tariff consists of guaranteeing a price for a given quantity of electricity produced using selected new technologies. The idea behind it is that it guarantees a minimum level of revenue early in the life of the new technology so that suppliers of the technology can lower costs by working down the experience curve, eventually competing with current technologies. This scenario incorporates the features of the Investment Credits Scenario, with the exception that feed-in tariffs are used instead of credits on investment. Rather than run the model separately for this scenario, we calculate the feed-in tariff for the capacity of the new technology that is added in the Investment Credits Scenario, based on the incoming cash flows that result in a net present value of zero over the lifetimes of the plants.

The difference between investment credits and feed-in tariffs is that an investment credit lowers the equipment cost to make the technology economic and is one payment. A feed-in tariff is a guarantee of an ongoing income stream, which implies an ongoing subsidy.

Results and Discussion

We use the sum of annual net economic gains, discounted at the real rate of 5 percent, to evaluate the effectiveness of the scenarios. The net economic gain for the Saudi energy economy (aggregating the government and the model's sectors) is defined as the difference between incremental export revenues and incremental costs incurred annually compared with the Current Policy Scenario; the costs component uses the annualized investment costs. The economic gains between 2015 and 2032 for the analyzed scenarios are shown in Table 2. The Immediate Deregulation Scenario produces the highest gain and serves as a benchmark for economic efficiency. The

Scenario	Total net economic gain (billions of 2014 USD)
Current Policy	-
Investment Credits/Feed-in Tariffs	430
Implicit Fuel Contracts	462
Gradual Deregulation	476
Immediate Deregulation	505

Table 2 – Discounted sum of annual economic gains between 2015 and 2032 (relative to the Current Policy Scenario)

high economic gains seen in the alternative scenarios arise in part from displacing the use of oil in power generation with the introduction of non-fossil fuel generation technologies.

Figure 3 presents the projected net cash flows for the Saudi energy economy compared with those observed in the Current Policy Scenario. The net cash flows are calculated in the same way as economic gain, except that the full investment and financial costs are used instead and are distributed over the construction period of the plants. Essentially, the large investment in renewable and nuclear technologies in the alternative scenarios allows for higher oil exports. The sum of the annual oil revenues greatly exceeds the outgoing flows required for investment in the early years.

We constructed the same cash flow profile for the power sector, as shown by Figure 4. As expected, the combination of high fuel prices and investment in alternative technologies yields large negative flows in the early years that dissipate over time. The graph, however, highlights a major benefit of

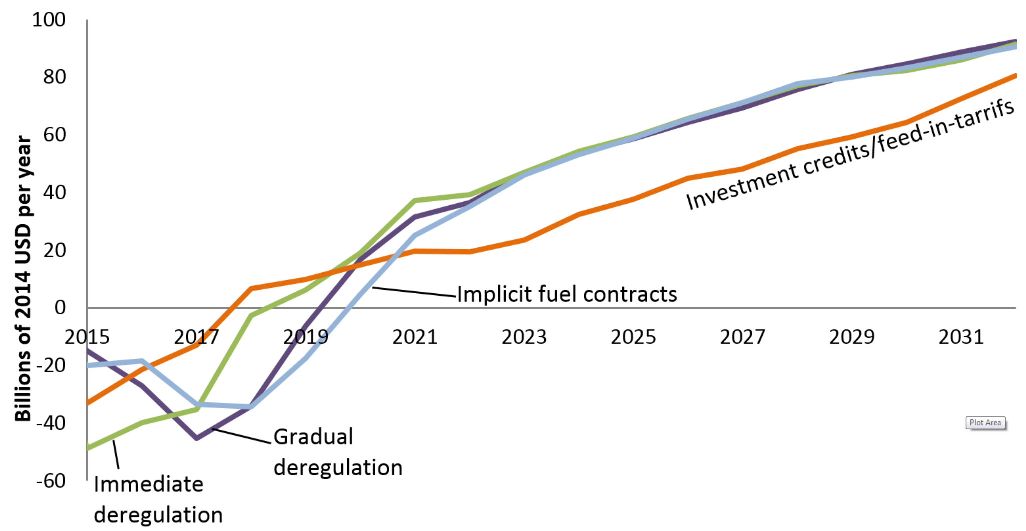

Figure 3 – Annual net cash flows for the Saudi energy economy compared with the Current Policy Scenario

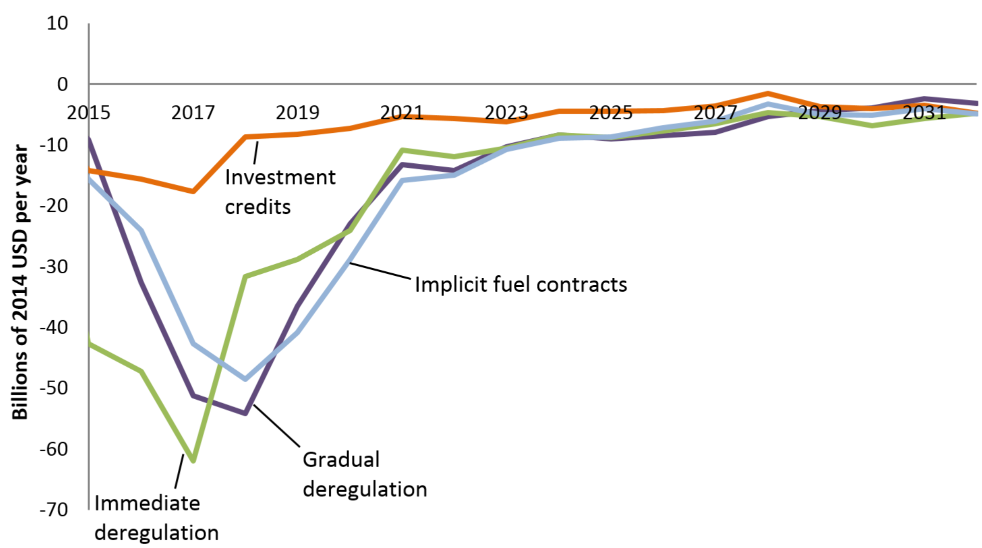

Figure 4 – Annual net cash flows for the power sector relative to Current-policy Scenario

investment credits in incentivizing the adoption of renewable and nuclear technologies. As the government would bear half of the investment cost, this would significantly lower the costs to be shouldered by the power sector.

The Implications of Fuel Pricing Policies on Future Energy Consumption

Figures 5 and 6 illustrate the historical profiles and model projections for total domestic primary oil and natural gas consumption in MBOED.

Saudi Arabia exports significant quantities of refined products. The above figures include all the oil used domestically, even the amounts used for exported products. As exports can vary significantly by scenario, we also correct for the energy content in the net exports of refined oil products. Figure 7 shows the projected energy consumption profile for oil and gas condensate minus the embodied energy in the net export of refined products.

All alternative scenarios yield significant reductions in energy use over the entire horizon compared with the Current Policy Scenario. In all scenarios the model shows that domestic oil use would not endanger Saudi Arabia's ability to export crude oil and petroleum products. Even when continuing current policies, the model shows that technical efficiency improves over time and compensates for demand growth. This is demonstrated by the power sector, where the addition of generation capacity consists of converting existing single-cycle gas turbines to combined-cycle plants, or building new combined-cycle plants. Thus, as Figure 8 shows, the average efficiency of electricity generation in the power sector increases over time, plateauing at around 49 percent by 2032. This is a significant increase from just over 34 percent in 2013.

The Technology Mix for Electricity Generation

A continuation of current fuel pricing and allocation policies would not, however, encourage investment in renewable or nuclear technologies. Figure 9 shows the shares of electricity generation by technology between 2015 and 2032 for the scenarios analyzed. The equipment mix is similar across scenarios in 2015, as the penetration of alternative technologies is delayed by their respective construction lead-times.

A scenario without nuclear generation

In all alternative scenarios, nuclear technology would progressively dominate the generation mix by 2032. In the Immediate Deregulation Scenario, for example, an average of 3.3 GW of nuclear capacity is added every year between 2022 and 2032. We realize there may be challenges to overcome for nuclear to come online in Saudi Arabia. Therefore, we explored an Immediate Deregulation Scenario where building nuclear is prevented. We found that the void in base load capacity would be mostly filled by a combination of PV and CSP plants. The total net economic gain is then $500.1 billion.

Our analysis shows that the immediate deregulation of prices results in a sudden emergence of alternative technologies in significant quantities. The Gradual Deregulation and Implicit Fuel Contracts Scenarios produce a less sudden investment shock for the utilities. The Investment Credit and Feed-in Tariff Scenarios create the appropriate cost and income trade-offs for solar and nuclear plants to emerge. These two scenarios show steadier additions of alternative capacity over time. They also produce more than 85 percent of the economic gains realized in the Immediate Deregulation Scenario.

A substantial amount of investment in new power infrastructure is required to meet the projected demand by 2032. Some of these investments are necessary to replace decommissioned plants and the remaining increase in capacity meets future demand growth and the increased reserve requirement to cover equipment outages and spikes in demand. In the Current Policy Scenario, where more than 57 GW of conventional thermal plants are added, $103

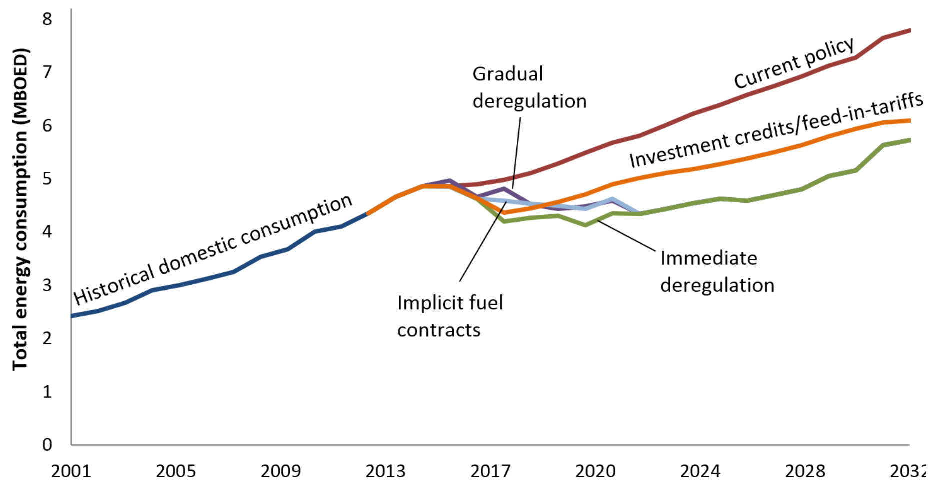

Figure 5 – Total domestic primary crude oil, natural gas, and gas condensate consumption (Source: KAPSARC analysis; historical data from BP (2014))

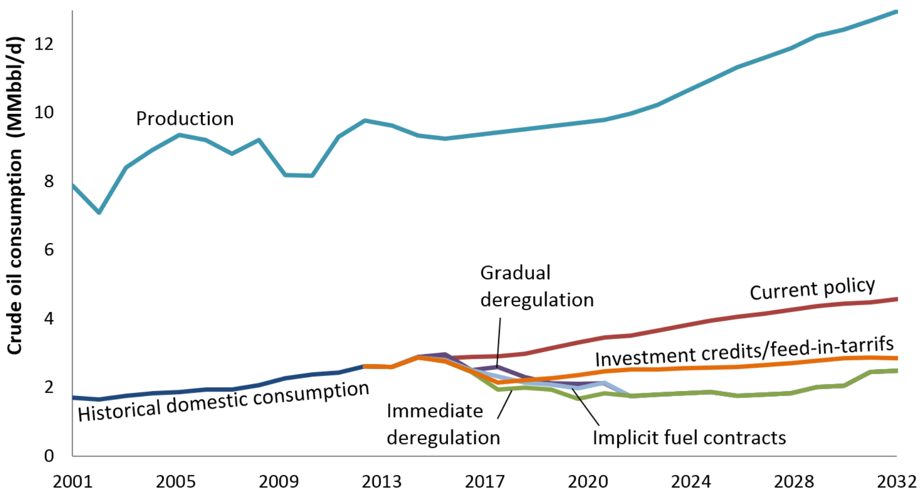

Figure 6 – Domestic crude oil consumption and production (Source: KAPSARC analysis; historical data from Saudi Aramco and Saudi Arabian Monetary Agency (SAMA) (2014); projected production based on Oxford Economics)

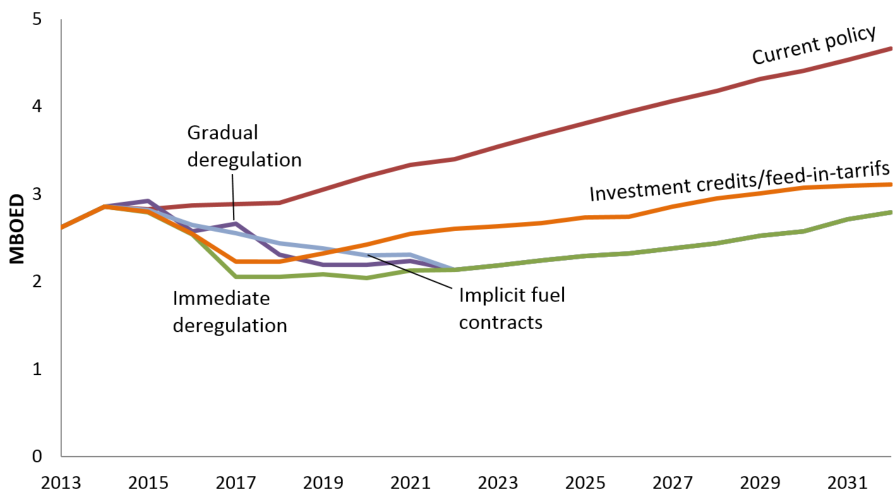

Figure 7 – Consumption of crude oil and gas condensate excluding the energy embodied in net exports of refined products

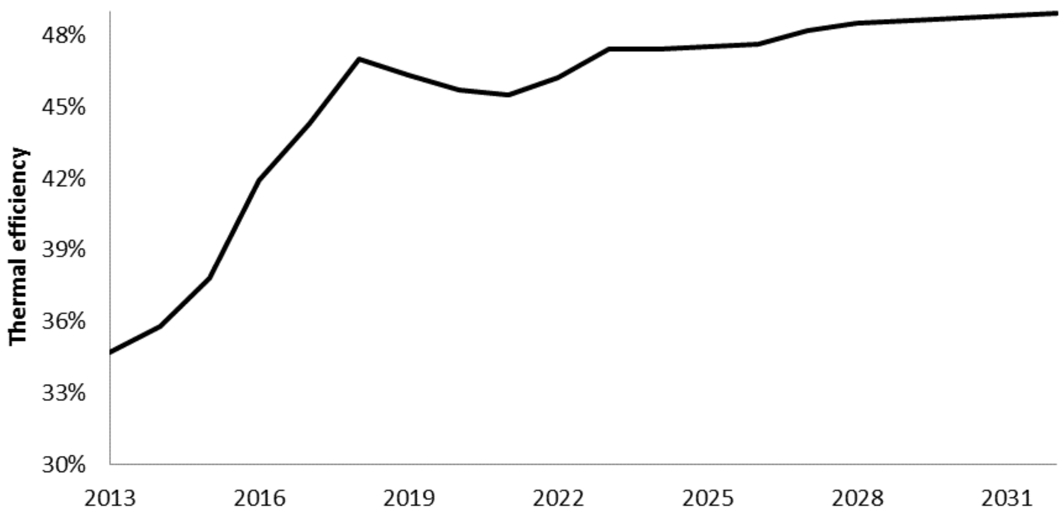

Figure 8 – Average thermal efficiency of generated electricity by the power sector in the Current Policy Scenario

billion would be spent to expand the generation capacity from its 2013 level. The Implicit Fuel Contracts Scenario leads to the construction of 131 GW of additional capacity, of which 110 GW are nuclear and renewables. Achieving the associated technology mix would require $392 billion in capital investment.

In the Investment Credits Scenario, 123 GW of new capacity is brought online. The associated capital investment is $384 billion. By 2032, the power sector sees 52 GW of photovoltaics (PV), 5 GW of concentrating solar power (CSP), 2 GW of wind, and 46 GW of nuclear power installed. The larger amounts of added capacity in the alternative scenarios reflect the lower capacity factors for intermittent renewable plants and the increased need for capacity to back up the renewable generators when they cannot generate power due to cloud cover or low wind conditions.

Table 3 shows the feed-in tariffs that would be paid in lieu of capital investment credits to achieve the national renewable and nuclear capacity observed in the Investment Credits Scenario. The values are shown as a range corresponding to the beginning and end of their online years; the decrease is attributed to lower capital and fixed operating costs over time.

The potential role of CSP in the Saudi power system

By examining the operating decisions made by the model, we investigated the added value of CSP with thermal storage to the power generation mix. For example, the Immediate-deregulation Scenario results in 11.5 GW of installed CSP capacity by the year 2032. The results show a complementary relationship with photovoltaic plants. When PV plants operate during the day, CSP plants opt to simultaneously operate below capacity and store solar heat for later use. The stored heat is then dispatched to satisfy the early evening electricity demand and some of the nighttime load when PV cannot operate. This way, solar energy can be exploited throughout most of the day.

We further studied the sensitivity of using CSP capacity to contribute to the planning reserve. Due to limitations in ramping plants with thermal storage as described in Appendix A, all of the scenarios presented here assume CSP capacity does not contribute to the reserve margin requirement. However, we wanted to test the potential added economic value to CSP if those restrictions were removed. We ran the Immediate-deregulation Scenario assuming that CSP with thermal storage can fully contribute to the planning reserve. This added value resulted in an installed capacity of 13.3 GW, or around two more GW versus when ramping limitations are enforced.

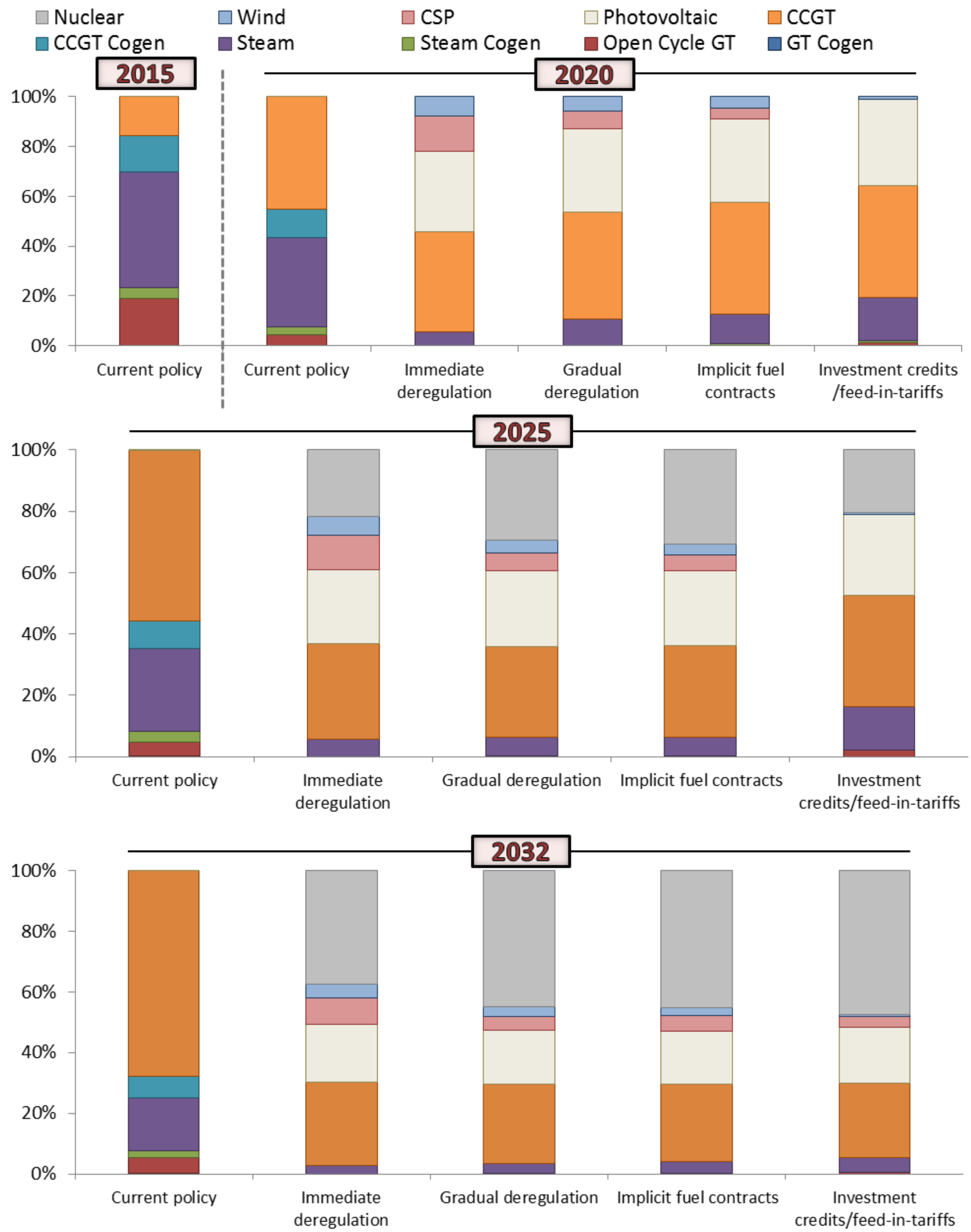

Figure 9 – The technology shares in total electricity generation (TWh) 2015-2032

Online years	Feed-in-tariff by technology (2014 US cents/kWh)			
	PV	CSP	Wind	Nuclear
2017-2022	6.5 to 6.0			
2018-2019			7.9	
2026-2032		8.1 to 7.6		
2022-2032				5.9

Table 3 – The range of feed-in tariffs applied to renewable and nuclear capacity to achieve the technology mix in the Investment Credits Scenario in 2014 money

A key practical difference is that investment credits are applied at the point of initial investment, whereas the feed-in tariffs are calculated at the time the capacity comes online.

Exploring the Investment Credit and Fuel-Price Trade-Offs

We have used one set of possible choices in the Investment Credits Scenario. We also investigated two contrasting cases: In one, we keep the current administered fuel prices but introduce the 50 percent credit for all alternative technologies. In the other, we raise the fuel prices as previously described for the Investment Credits Scenario and exclude investment credits. We found the former case performed exactly like the Current Policy Scenario, where even the 50 percent credit did not make alternative technologies economical, given the low fuel prices. No economic gain is realized by introducing credits while neglecting fuel prices. The latter generated a discounted sum of annual economic gains of $72 billion in 2014 money. Hence, compared with the cumulative net economic gain of the Investment Credits Scenario, an additional $360 billion can be saved by complementing the fuel price increase with capital credits. These results highlight the importance of a packaged policy that includes both measures to achieve the fuel-to-capital cost ratios that are necessary to encourage the adoption of alternative technologies.

Fuel Consumption for Electricity Generation

In Saudi Arabia, electricity is mostly generated using crude oil and refined petroleum products and this would not change even under existing policies for fueling future generation capacity. Figure 10 presents the amounts of fuels we project as being used for electricity generation in the years 2015 and 2032; these values take into account fuels used for co-generation. The consumption of crude oil would decline significantly in the alternative scenarios or be discontinued altogether. Oil-fired generation would be replaced with natural gas and alternative technologies, except in the Investment Credits Scenario. Despite unchanged gas allocation, replacing turbines with combined-cycle plants frees up the gas needed to expand gas-fired generation. According to our model, all forms of oil would be removed from the power system by the year 2022 with immediate deregulation – crude oil would no longer be used as from the year 2018.

Valuing Natural Gas in the Saudi Economy

As natural gas is assumed to be neither exported nor imported, this raises the question of assessing its implied domestic market price. This price is determined by the model as the value, for the Saudi energy economy, of adding 1 MMBtu of natural gas supply. Figure 11 shows the projected marginal value of natural gas in the Immediate Deregulation Scenario and compares it to the exogenous oil price projection – i.e. the price of oil offered to the

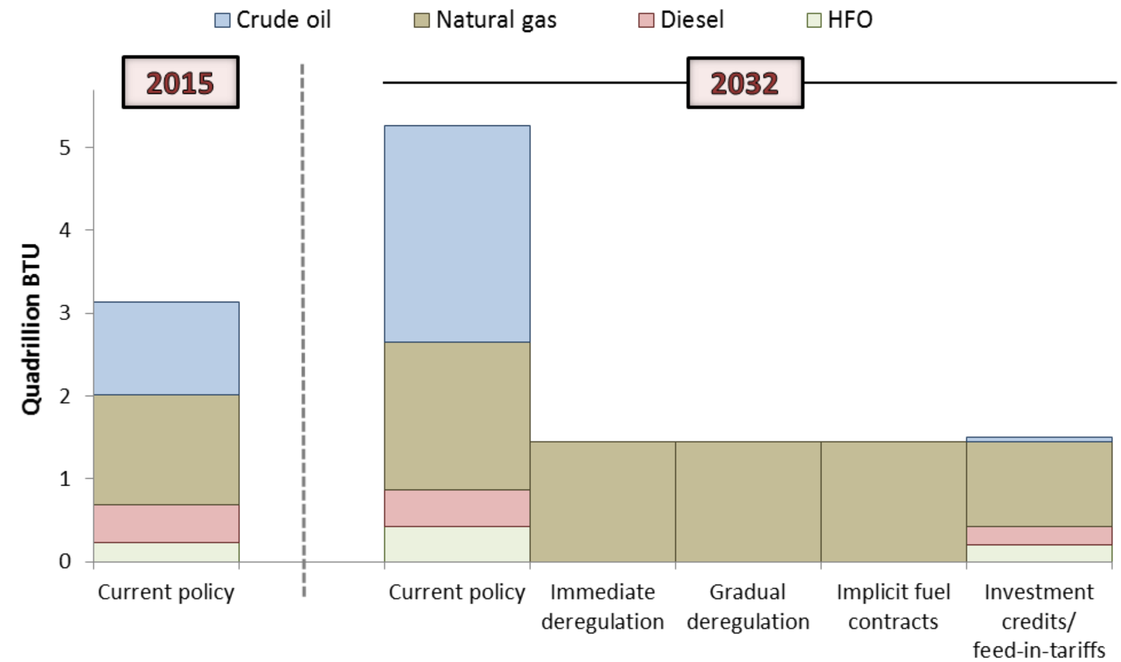

Figure 10 – Fuel consumption for electricity generation

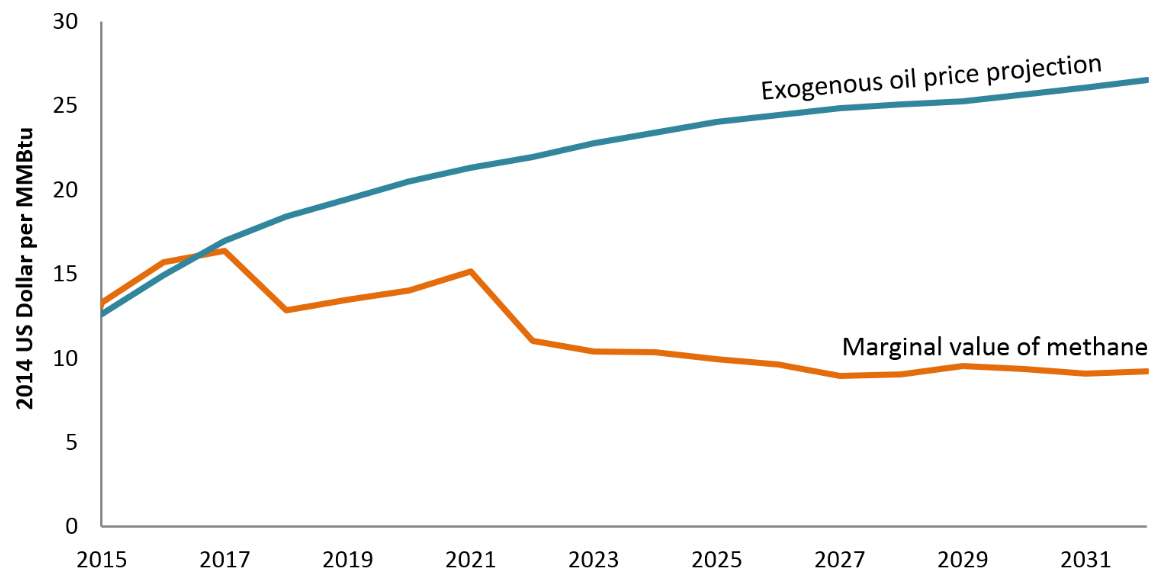

Figure 11 – The calculated marginal value of methane in the Immediate-deregulation Scenario

industrial sectors in this scenario–that we take in the analysis. The two prices are essentially correlated until crude oil is no longer used for power generation in 2018. The gas price declines because the capital stock adjusts to using gas more efficiently. It is projected that some HFO is used for power generation until 2022, due to the introduction of a steam plant with a desulfurization unit that is planned to come online in 2017. In our analysis, and based on the exogenous natural gas supply projections, the marginal value of gas stabilizes at around $9 per MMBtu in the long-run.

Conclusions

In all our scenarios Saudi Arabia continues as a major exporter of crude oil and petroleum products. In all alternative policy scenarios the country's capacity to export is greater at the end of the planning horizon than it is now. These scenarios show increases in Saudi Arabia's ability to export and raise its economic surplus. According to our analysis, fears of a decline in its ability to export through the years of our study are misplaced.

Renewable and nuclear power technologies have generated significant interest in Saudi Arabia. Our modeling shows that the continuation of current fuel pricing policies would not produce the economic signals that are necessary to encourage investment in alternative power generation technologies and an efficient mix of capacity types. Alternative fuel pricing and investment-credit policies would help to facilitate the integration of alternative technologies into the Saudi energy system and achieve efficiencies close to those resulting from deregulation. The potential economic gains that could be attained as a result of these policies are significant. A gradual deregulation of fuel prices is shown to yield a smooth transition path for technologies without much of a reduction in the economic gains observed with the Immediate Deregulation Scenario.

The scenarios that incentivize investment in alternative power generation technologies without the need for a drastic increase in fuel price show increases in fuel prices that are attainable. In our analysis, higher fuel prices lead to investment in more efficient plant. Similarly, lowering capital costs, while maintaining administered prices, is also shown to improve the equipment mix. By introducing investment credits that lower capital costs, we demonstrate how the system could achieve most of the economic gains of Immediate Deregulation while maintaining fuel prices at levels well below their marginal values.

Although a continuation (in real terms) of current pricing policies would not result in the introduction of nuclear and renewable plants, the efficiency of electricity generation would improve over time due to investment in combined-cycle plants. Structural changes of this type mean simple extrapolation techniques based on past growth rates probably grossly overestimate projected energy demand. The failure of the simple model highlights the need to use an economic model with a detailed technological representation, such as KEM, when projecting the energy system of countries.

Up to this point, our use of KEM has focused on the supply side of the production sector, taking the end-use demand for its products as exogenous, because end-user prices are fixed. Possible further research in the future includes the modeling of end-user demand for electricity and transportation fuels.

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Appendix A – The Dynamic Framework: A Recursive Approach

Multi-period, dynamic models have the ability to capture the effects of decisions both during the period in which the decisions are made and in subsequent periods. This can be important in models that represent investment decisions in situations where there are significant structural changes over the time periods of interest. The trade-off with static models is that dynamic models are much larger, resulting in the number of variables totaling roughly the number of variables and equations in a static, single-period model times the number of periods when the model is deterministic. Since computational costs increase more rapidly than the number of variables and equations, modeling trade-offs have to be made when building multi-period models. Included in these trade-offs is the detail in each period, such as the number of regions and technologies considered, and the number of periods in the model's horizon.

The standard approach in a multi-period model is to set a sufficiently long planning horizon, replicate much of the structure of the single-period model and optimize over the whole horizon. This approach has the virtue of matching the full-information assumption in most economic models. However, the model can be very large and full information does not represent the real uncertainties in the future. It is possible to step back from full information by generating a probability distribution of outcomes in each period, including scenarios in the model for each possible outcome. The problem with this approach is that over time the scenarios branch from one period to the next, leading to a tree of possibilities and a number of variables and constraints that grows exponentially with the number of time periods. Exacerbating the problem with this approach is that probability distributions are often unknown. For example, the fall in oil prices in 2014 and 2015 was not generally anticipated as a possible scenario when planning in 2012 or 2013.

The standard behavior of the solution to a multi-period model is that after several periods the capacity additions stabilize into a clear pattern. In the case of capacity additions for electricity generation, after several periods all of the types of generation equipment that are economic are added. Once this happens, adding periods to the planning horizon no longer changes the solution in the years of interest. Having a solution with this property, or having a solution close to this property makes it possible to keep the planning horizon relatively short.

Given the issues associated with choosing a planning horizon, KEM incorporates a form of bounded rationality known as recursive dynamics: capacity is added with a planning horizon less than that of the forecast period and the model is solved recursively, stepping forward through all of the years in the planning horizon. The planning horizon covers five years. As the model steps through the forecast years, the planning horizon shrinks and in the last year of the forecast, T, the horizon is a single period. In this study T= 2032.

Stated more formally, the model performs a myopic optimization of capacity for the years t, $t + 1$, …, $t + H$ and optimizes operating decisions for year t. When in year t+1, the capacity decisions made in prior years for years $t + 1, t + 2, \ldots, t + H + 1$ are replaced with an optimization over those years.

In this myopic framework, the cost of adding capacity available in year $t + k$ ($k \in \{0, \dots H\}$) is the present value (in year $t + k$) of the economic depreciation/annualized cost occurring between years $t + k$ and $t + H$. Let

i = interest rate

L = useful life of the equipment

I = investment cost measured at the time the facility first operates, including interest paid during construction.

The annualized capital cost is

$$a = \frac{I}{\sum_{l=0}^{L-1} \frac{1}{(1+i)^l}}.$$

At time t in KEM the cost of plant and equipment in the k^{th} year beyond t in the recursion is the present value of the annualized capital cost over the remaining years in the planning horizon

$$c_{t,k} = a \sum_{j=0}^{H-k} \frac{1}{(1+i)^j}.$$

The agent optimization in each year t can therefore be viewed as a multi-period optimization done over H years. The only capacity that is retained in year t+1 in the solution is the capacity added in year t. All out-year capacities are discarded as their only role in the model is to make the capacity additions in t less myopic. The solution process then moves to finding the equilibrium for the year t+1 with the new sub-model covering years t+1 through t+ H+1. Again, only the results for year t +1 are retained when solving the sub-model subsequent years.

The model distinguishes three different kinds of capacity, existing capacity as of 2013, capacity added from plants currently under construction, the total new builds of capacity prior to year t beyond what is currently under construction. Projects already under construction or with firm commitments, as well as the scheduled decommissioning of existing capacity, are included in determining the amount of existing capacity in each forecast year. The capacity "built" in year t, when t is the solution year of interest, is added to the last category when moving forward to year t+1.

Consider a plant that requires $\boldsymbol{l}$ years to build. This plant can be added to the capacity mix available in year $t + k$ (k $\in$\{0, ... T\} if the lead time is sufficient to build the plant, that is, $t + k \geq 2015 + \boldsymbol{l}$. The notion is that the decision to build this plant could have been made in or after 2015. The sub-model also allows equipment with low capital costs, such as turbines, to be built with zero lead times. This ensures the feasibility of the sub-model.

Appendix B – Plants Already Under Construction

At the initial condition, power generation and water desalination capacities already installed by the end of 2012 are included as existing capacity. Plants that were scheduled to come online in 2013 and 2014 are assumed to have been completed. To be conservative, all planned power, refining, and water desalination projects are added as existing capacity at the end of their expected year of operation. Table B-1 presents the capacities of power plants already under construction or for which the investment has been made as of 2014. Until 2014, the model can only decide to build gas turbines.

Existing steam and gas turbine capacities that exceed their operating life are withdrawn from service according to the plan published by ECRA (2010).

Project Name	Capacity (GW)	Technology	Expected year of operation
SEC PP12	2.00	CC	2015
SEC PP10	2.20 GW of GT to be converted	Conversion to CC	2015
Rabigh 2 IPP	2.10	CC	2017
Shuqaiq Steam Power Plant	2.64	Steam with flue gas desulfurization	2017
Jeddah South Thermal Power Plant	2.65	Steam	2017
Qurayyah IPP	3.93	CC	2017

Table B-1 – Power plants already under construction across Saudi Arabia as of 2014 (source: KAPSARC analysis)

Appendix C – Assumptions Common to all Policy Scenarios

The projected growth rates of population are used to estimate the regional growth in municipal water demand. The projections published by ECRA (2010) are used to shift the 2011 regional load curves throughout time, with the peak electricity demand approaching 120 GW by 2032. The growth rates of end-use demand for petroleum products are shown in Figure C-1.

We rely on public estimates for the future supply of oil and gas. Using the database released in December 2014, Saudi crude oil production in 2032 is projected by Oxford Economics' Global Economic Model (GEM) to be just short of 13 million barrels per day. The production shares of Arabian crude grades are assumed to remain constant over time.

We calculate projected crude-oil prices in real USD (2014) per barrel by taking the nominal oil price projections of GEM and deflating the series using the Saudi imports deflator. As Saudi Arabia is a major oil exporter with spare capacity, it may value a barrel of oil saved from domestic consumption at a price that is lower than the international market price. As shown by Matar et al. (2015), the value attributed to the oil saved significantly influences the magnitude of the economic gain realized by alternative policies. In this paper, we value crude oil saved at its international price; a sensitivity analysis would provide additional insight. In addition, we estimate the export prices for refined oil products and petrochemicals by assuming that the margin between their prices and that of crude oil remains constant over time, based on the prices observed in 2011.

Estimated domestic demand and export growth relative to 2011 are shown in Figure C-1. Applying the projections of the Central Department of Statistics and Information (CDSI) for the total population of Saudi

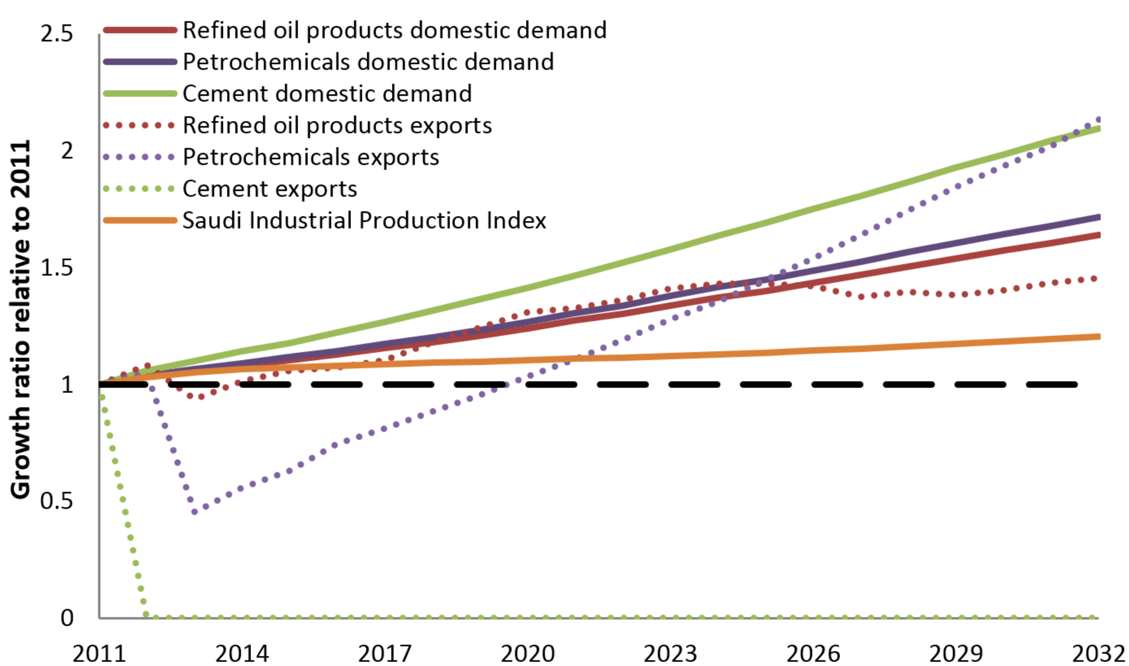

Figure C-1 – Estimated national demand growth for sectors' outputs and exports growth relative to 2011 (sources: KAPSARC analysis, Oxford Economics' Global Economic Model, GIM)

Arabia, we use Oxford Economics' Global Industry Model (GIM) to estimate projected gross outputs for the petrochemicals, refining, and cement sectors; we use the database released in November 2014. Additionally, we use projected real GDP and estimates for income elasticities to compute the portion of the gross outputs aimed at meeting domestic demand; an elasticity of unity is applied for cement demand, a value of 0.65 is used for petrochemicals demand, and the value of 0.58, reported by Al-Yousef (2013), is applied for the demand of refined oil products. The difference between projected gross output and domestic demand is used to cap annual exports in the model. In the case of petrochemical exports, we use actual export data published by the CDSI for 2012, and apply the projections of GIM thereafter. As an extension of current policy, the 2012 ban on cement exports is extended through the planning horizon. The consumption of oil and gas by industrial sectors not captured in the model is increased by the projected growth of Oxford Economics' Saudi Industrial Production Index.

Saudi natural gas production is projected by EIA (2013) to increase by an average 1.73 percent per year between 2011 and 2032. The split between ethane and methane in natural gas production is assumed to remain constant. We also assume that natural gas produced within Saudi Arabia will continue to be used only for domestic consumption. Table C-1 below displays the supply estimates for natural gas and the projected world price of Arabian Light crude.

	2015	2020	2025	2030	2032
Arabian Light crude price (2014 USD/barrel)	68.81	111.67	130.85	139.87	144.38
Methane and ethane supply (QBTU)	3.39	3.56	4.01	4.50	4.67

Table C-1 – Projected Saudi Arabian natural gas supply and the price of crude oil to 2032 (sources: KAPSARC analysis, GEM, EIA (2013))

Appendix D – Cost Assumptions

The estimated costs for power generation technologies in 2014 and their construction lead times are summarized in Table D-1. All costs are given in USD (2014), with the adjustments made using the Saudi import price index for capital costs and the Saudi consumer price index for operating costs. Because the model uses inflation-adjusted real USD, the costs of conventional thermal technologies, nuclear technology, and all variable operation and maintenance (O&M) costs are kept constant between 2011 and 2032. The capital and fixed O&M costs of PV and onshore wind turbines decrease over time and are estimated from the cost curves used by IEA (2013). We also consider the degradation of PV capacity over time due to thermal stresses. Jordan and Kurtz (2012) reported a degradation rate of 1 percent per year for crystalline silicon in desert climates. For CSP, the expected percent reduction in the cost reported by IEA (2013) is applied to the 2011 value cited by IRENA (2012). The evolution of capital and fixed O&M costs for the renewable technologies is shown in Figure D-1. The decrease in the costs of renewable technologies is attributed to learning effects and higher adoption rates over the time horizon.

The costs incurred from installing an SO_2 scrubber are added to the costs of a steam plant without flue-gas desulfurization; capital and operation costs of a scrubber are reported by the United States Environmental Protection Agency (EPA) (2013). Additionally, EPA (2013) estimates a 1.33 percent heat rate increase due to the higher in-plant consumption of electricity to operate a scrubbing unit.

Technologies represented in the desalination, petrochemicals, refining, and cement sub-models are well-established, and therefore, we use constant real investment costs over the projection horizon.

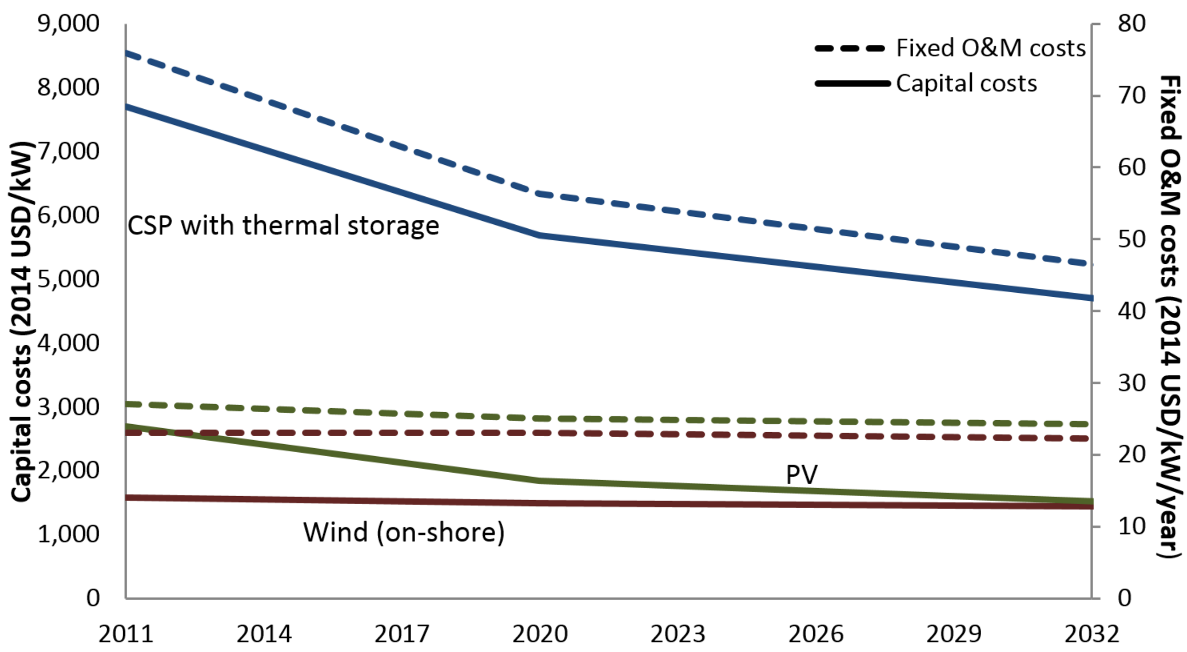

Figure D-1 – Profiles of capital and fixed O&M costs over time for renewable technologies (source: KAPSARC analysis)

Power Technology	Capital cost (thousand USD/kW)	Fixed O&M cost (USD/kW/year)	Non-fuel variable O&M cost (USD/MWh)	Lead time (years)
Gas turbine	1.61	12.31	4.40	-*
Combined cycle	1.89	13.63	3.63	3
Conversion of single-cycle gas turbine to combined cycle	0.26	-	-	1
Steam	2.30	12.31	1.80	2
Steam with SO_2 Scrubber	2.79	18.35	4.87	2
Nuclear	4.88	109.88	2.35	7
PV	2.42	30.27	0	2
CSP (with thermal storage)	7.03	70.29	3.09	3
Wind (on-shore)	1.56	24.57	0	3

Table D-1 – Real costs for power generation technologies in 2014 and their lead times (sources: KAPSARC analysis, ECRA (2010), IRENA (2012), and IEA (2013))
*Note: we allow for gas turbines to come online immediately

Appendix E – Model Development

Additional power generation technologies now represented in KEM are CSP with thermal storage, wind turbines, and steam plants with flue gas desulfurization. We have to distinguish among the hours throughout the day to incorporate the use of thermal storage in a CSP plant. A load curve is used to represent the levels of demand at different times of the day, with weekdays distinguished from weekends. We also represent three seasons: winter and summer, with the fall and spring seasons combined into a single season, which means we have six load curves per region. Figures E-1 to E-3 show the average hourly weekday loads corresponding to each season and region for 2011. As illustrated by Figure E-1 for the southern region, the load curves are discretized into eight load segments, with the discretization selectively performed to provide finer resolution around the afternoon and early evening periods. The chronological representation of demand also allows us to specify administered electricity tariffs for industrial sectors that vary seasonally and by time-of-day.

The representation of CSP in the current version of KEM is limited to parabolic trough technology with molten salt thermal energy storage. The storage mechanism is allowed to store enough heat to operate the plant at full capacity for up to eight hours. Figure E-4 illustrates the approach taken to model the operating decisions of a CSP plant. Heat transferred out of the solar field may either be used to provide instantaneous heat to the steam generator or be stored for use when it is needed. Using the direct normal irradiation (DNI) measurements made by the National Renewable Energy Laboratory (NREL) and King Abdulaziz City for Science and Technology (KACST) (NREL and KACST (2013)), the amount of solar irradiation directly incident on the aperture plane of the collectors is first calculated to determine the rate of energy transfer from the solar field. Single-axis tracking is done by arranging the collectors along the north-south axis and varying their tilt angle from east to west throughout the day.

Because of irreversiblilities such as friction effects, we consider a 35 percent loss in heat between the point of reception and either the storage device or the steam generator (Rovira et al. (2013)). An energy balance is performed on the storage mechanism that, once heat is stored, considers cycling losses and hourly heat

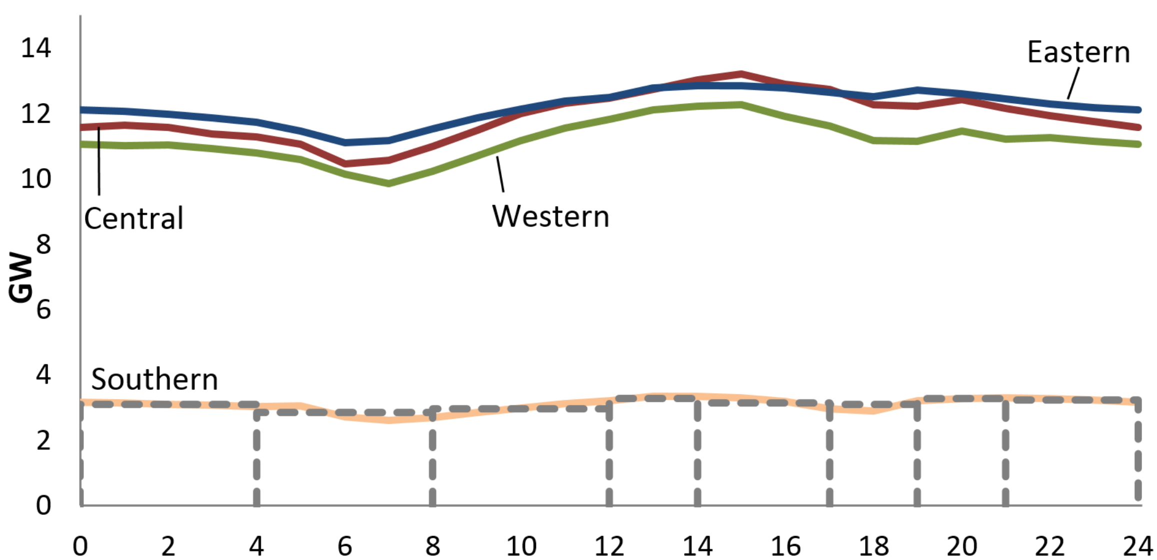

Figure E-1 – Weekday hourly loads in the summer dissipation. Madaeni et al. (2012) estimate a cycling loss of 1.5 percent, and Sioshansi and Denholm (2010) document a 0.031 percent hourly loss of stored heat for a molten salt system. We incorporate a Rankine cycle thermal efficiency for a typical CSP plant to calculate the amount of electricity generated from the heat input. Like Sioshansi and Denholm (2010), we assume that CSP plants do not contribute to the planning reserve margin due to limitations in ramping and start-up. The major performance characteristics of CSP in the model are summarized in Table E-1.(2010).

Another power generation technology added to KEM is onshore wind turbines. The rate of energy transfer with wind is proportional to turbine speed cubed. Wind turbines are designed to operate only if the wind speeds are between some cut-in and cut-off speeds, and their power output plateaus once their rated wind speed is observed. For a typical turbine, we consider a cut-in speed of 3 meters per second, a cut-off speed of 25 meters per second, and a rated speed of 13 meters per second (Al-Abbadi (2005)).

We could not obtain hourly wind speed data for Saudi Arabia. To bypass this issue, we used the monthly Weibull distribution curves of hourly data presented by Rehman et al. (1994) to estimate profiles of the hourly wind speeds using the season- and region-specific Weibull shape and scale parameters. The shapes of the daily profiles are then calibrated to the distributions' mean values and the average diurnal speed variations graphically presented by Al-Abbadi (2005) and Rehman and Ahmad (2004).

For each region, the power output of the turbine in every load segment is normalized by the maximum annual output, and the decisions to operate any existing capacity or install additional units are made based on the impact the output would have on the load curve. Due to the intermittent nature of wind speeds, the additional costs of operating spinning reserves are also captured when operating wind turbine capacity.

Steam plants with flue gas desulfurization exhibit slightly different operating characteristics when compared with those without. While we generally restrict the upper bound of HFO use in power generation to the values observed in 2011, this restriction is lifted for plants with desulfurization units. In addition, the increased self-consumption of electricity due to the operation of a desulfurization unit results in lower thermal efficiency for the plant.

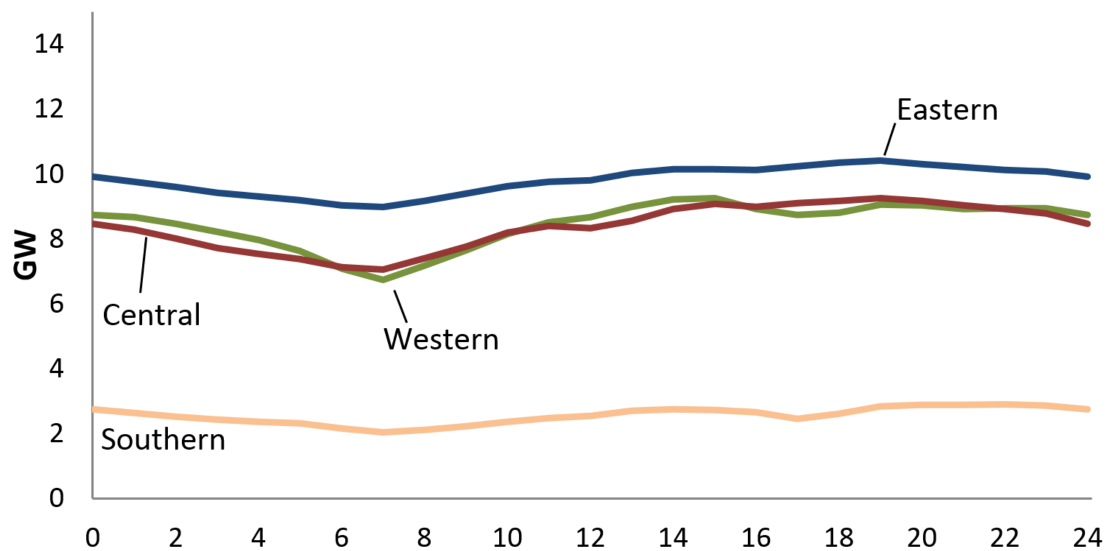

Figure E-2 – Weekday hourly loads in the spring and fall (Source: ECRA)

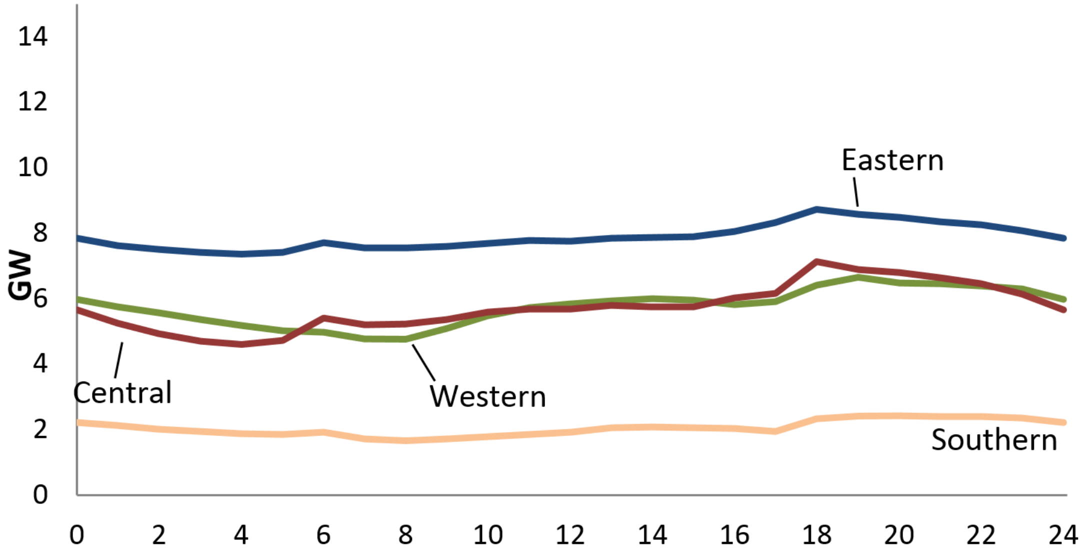

Figure E-3 – Weekday hourly loads in the winter (Source: ECRA)

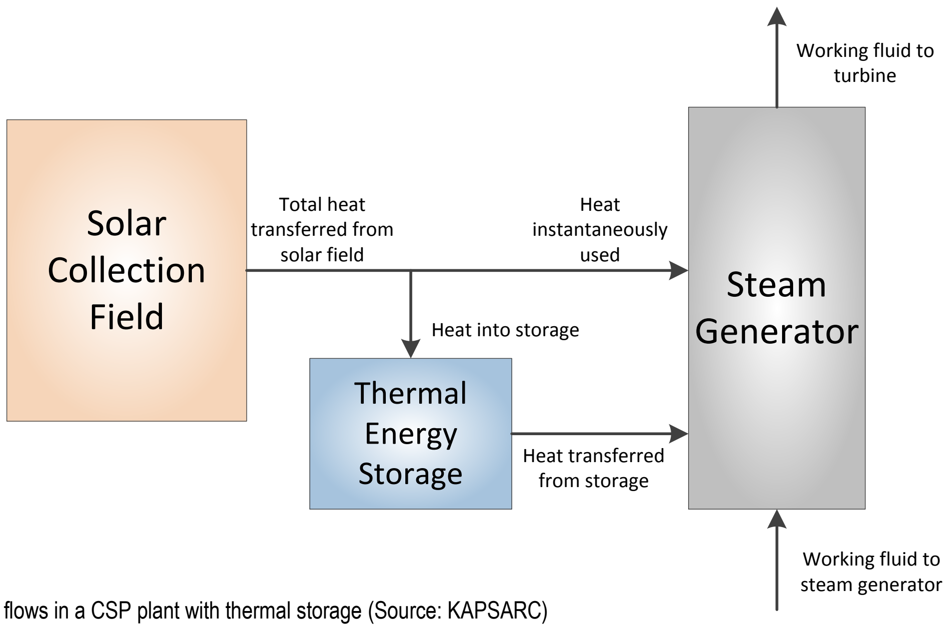

Figure E-4 – Heat flows in a CSP plant with thermal storage (Source: KAPSARC)

Net thermal efficiency of Rankine cycle	38%
Aperture area per unit of generation capacity*	10 km^2/GW_e
Heat transfer loss from solar field	35%
Hourly heat dissipation in storage device	0.031%
Heat loss due to cycling	1.5%
Thermal storage limit	Energy equivalent to 8 hours of full operation

Table E-1 – Major performance characteristics of CSP in KEM (*Source: Kearney (2010))

Appendix F – *The Implicit Fuel Contracts Scenario*

This section details the mathematical implementation of the Implicit Fuel Contracts Scenario. Let

r index the regions

f index the fuels

s index the sectors

i index the operating activities that consume fuels

QA_{sfr} = the quantity of fuels allocated at the lower price

DS_{sfr} = the discount from marginal cost of fuel for the lower-priced step

OP_{sifr} = the operate activities that consume fuel f

x_{sfr} = the amount of fuel consumed at the lower price

α_{sifr} = the fuel consumption per unit of operation of

P^{m}_{sfr} = the marginal cost of gas, the dual on the fuel material balance (1)

μ_{sfr} = the dual on the allocation constraint (2)

ν_{sfr} = the dual on the fuel consumption limit (3)

P^{adm}_{sfr} = the administered price on the first supply step

Note that we leave off the time index to simplify the notation. The amount of fuel f consumed in sector s in region r is

$$\sum_i \alpha_{sifr}\, OP_{sifr} \qquad (P^{m}_{sfr}) \tag{1}$$

We add two constraints. The first limits the amount of lower-cost fuel to the allocation and the second limits the amount of lower-cost fuel to the amount of fuel consumed. We have

$$x_{sfr} \le QA_{sfr} \qquad (\mu_{sfr}) \tag{2}$$

and

$$x_{sfr} \le \sum_i \alpha_{sifr}\, OP_{sifr}\,. \qquad (\nu_{sfr}) \tag{3}$$

The standard LP dual is

$$-P^{m}_{sfr} + \mu_{sfr} + \nu_{sfr} \ge 0.$$

When $x_{sfr} \geq 0$,

$$-P_{sfr}^{m} + \mu_{sfr} + \nu_{sfr} = 0.$$

With the price cap on supply, we want the price of fuel f to be P_{sfr}^{adm} In the MCP we can write the following inequality instead of the LP dual equation,

$$P_{sfr}^{m} \leq P_{sfr}^{adm} + \mu_{sfr} + \nu_{sfr}.$$

Here the duals on (2) and (3) add to the value of the rent on the allocated fuel. The complementarity condition becomes.

$$P_{sfr}^{m} \leq P_{sfr}^{adm} + \mu_{sfr} + \nu_{sfr} \perp x_{sfr}.$$

If , $P_{sfr}^{m} < P_{sfr}^{adm}$ then supply is available below the administered price, which we do not allow. We can allow this, in which case unallocated gas is taken first. If this happens, this is a meaningful result.

Note, once the model has a demand response, the rents on the allocated fuels have to be passed on to consumers through average-cost pricing.

Notes

Notes

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